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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-21-01
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-21-01
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	DIRECT TESTIMONY
NATURAL GAS SERVICE TO ELECTRIC	)	OF
AND NATURAL GAS CUSTOMERS IN THE	)	JASON R. THACKSTON
STATE OF IDAHO	)	
	)	

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

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 and Environmental Compliance Officer 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. The Energy Resources group also includes environmental affairs, including compliance with, and management of, the licenses issued by the Federal Energy Regulatory Commission authorizing the Company to operate its hydroelectric facilities.

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

A. My testimony provides an overview of the Company's 100% Clean Electricity goal by 2045, carbon neutral electricity supply by the end of 2027, and why it is important to our Company. I will also provide an overview of Avista's resource planning and power supply operations. This overview includes summaries of the Company's current and future resource plans, as well as an overview of the Company's Energy Resources Risk Policy. I will address the generation-related capital projects included in the Company's Two-Year Rate Plan filed in this case, including capital additions associated with the Company's investment in Colstrip Unit Nos. 3 and 4 for the periods 2020 through August 2023. My testimony will conclude with a discussion of the Rattlesnake Flat Wind Power Purchase Agreement.

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit No. 7, Schedules 1 – 9. Exhibit No. 7, Schedule 1 is Avista's 2020 Electric Integrated Resource Plan and Appendices. Exhibit No. 7, Schedule 2C is Avista's Energy Resources Risk Policy. Exhibit No. 7, Schedule 3 contains Avista Utilities Generation Infrastructure Plan. Exhibit No. 7, Schedule 4 includes the capital business cases for the generation capital projects discussed later in my testimony. Exhibit No. 7, Schedule 5 provides additional documentation about the capital projects at Colstrip. Exhibit No. 7, Schedule 6C contains the 2018 Renewable RFP Report and Documentation. Exhibit No. 7, Schedule 7C includes the Rattlesnake Wind Power Purchase Agreement and Exhibit

No. 7, Schedule 8C includes the Board documentation concerning the Rattlesnake Flat Wind Power Purchase Agreement, and Exhibit No. 7, Schedule 9 includes the 2017 IRP.

II. CLEAN ELECTRICITY AND NATURAL GAS GOALS

Q. Would you provide an update to the Company's 100% clean electricity goal by 2045, and carbon neutral electricity supply by the end of 2027?

A. Yes, the announcement made by Avista in April 2019 bolsters our 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 five 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, discussed later in my testimony, 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. Why did Avista declare an electric carbon neutral?

A. We have seen a growing focus on clean electricity generation at the national, regional, and local levels. Our customers, communities and governments of all levels increasingly express 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 for all of our customers in Idaho, not just those we serve in Washington. Reaching this goal, of course, will require further improvements in technology and a reduction in their associated cost of clean electric generation and energy storage, as well as regulatory support. Going forward, we will track progress through our Integrated Resource Plan.

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 already served from clean, non-carbon emitting resources.

Q. What is the impact of this clean energy goal on Colstrip?

A. Colstrip has been an important source of generation in the region and for Avista's customers for over 35 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 the rivers to generate enough electricity to meet our customers' energy needs. Colstrip will no longer be used to serve Washington customers after 2025 to comply with CETA. As described below in the IRP section of my testimony, modeling for the 2020 IRP indicated that Colstrip will also no longer be economically beneficial to serve Idaho customers after 2025 as well. However, it is important to note that the Company will continue to have a contractual obligation to pay for past, ongoing, and future costs associated with the generation of this output based on the joint ownership agreement. We continue to work with our five co-owners related to the future operation of Colstrip Units 3 and 4.

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 them 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.

Even though natural gas creates less environmental impact than other fuels, the Company recognizes the opportunity to implement strategies that will further improve its environmental impact by reducing the carbon emissions associated with the direct use of natural gas. Examples of carbon emissions reduction strategies include the following:

- Diversify or transition from fossil fuel-based natural gas to renewable natural gas;
- Reduce natural gas consumption via conservation, energy efficiency and new technologies; and
- Purchase carbon offsets as necessary.

Achieving carbon emission reductions for the natural gas system will involve various pathways. The initial primary pathways include renewable natural gas (RNG), energy efficiency, customer voluntary RNG and carbon offset programs.

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

A. Energy efficiency has been an important piece of our energy resource puzzle for over 40 years, and we will continue to partner with our customers to use electricity and natural gas more efficiently through our own customer education, outreach and economic incentive programs, as well as regionally through participation in the Northwest Energy Efficiency Alliance. Energy efficiency continues to be an effective option to lower customers' energy use, reduce our need to build additional generation, and further reduce the carbon intensity of our local economy.

III. RESOURCE PLANNING AND POWER OPERATIONS

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 2020 IRP shows forecasted annual energy and capacity deficits beginning in 2026. The deficits are a result of the expiration of the Lancaster power purchase agreement and the expected elimination of Colstrip from the Company's resource portfolio. The capacity and energy load/resource positions are shown on pages 7-4 and 7-5 of Exhibit No. 7, Schedule 1. The 2021 Electric IRP is currently being developed, the draft IRP was released on January 4, 2021 for public comment and is scheduled to be filed with the Commission on April 1, 2021.

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

A. The Preferred Resource Strategy (PRS) in the 2020 Electric IRP guides the Company's resource acquisitions, subject to any additional legislative or regulatory requirements. The IRP provides details about future resource needs, specific resource costs, resource-operating characteristics, and scenarios used for evaluating the mix and timing of resources included in the PRS. 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 and market opportunities. Avista's 2020 IRP included as Exhibit No. 7, Schedule 1, was filed with the Commission on February

28, 2020 in Case No. AVU-E-19-01 and acknowledged in Order No. 34814.

Avista's 2020 PRS includes 1,133 MW of net supply-side resources which includes the addition of 1,667 MWs of new wind, pumped hydro, battery storage, solar and plant upgrades as well as the loss of 534 MWs of coal and natural gas-fired resources from the Company's resource portfolio. The PRS also includes 112 MW of demand response and 187 aMW of new energy efficiency through 2045. The timing and type of these resources included in the PRS for the 2020 IRP are provided in Table No. 1 below.

Table No. 1: 2020 Electric IRP Preferred Resource Strategy

Resource Type	Year	Capability (MW)
Montana wind	2022	100
NW wind	2022-2023	200
Kettle Falls upgrade	2026	12
Colstrip 3 & 4 exits portfolio	2026	-222
Rathdrum CT 1 & 2 upgrades	2026	24
Long-duration pumped hydro	2026	175
Lancaster PPA expires	2026	-257
Post Falls upgrade	2027	8
Montana wind	2027	200
Mid-Columbia hydro	2031	75
Northeast CTs retires	2035	-55
Long Lake 2nd powerhouse	2035	68
Liquid-air storage (16 hours)	2036-2041	100
Wind (including PPA renewals)	2041-2043	300
Lithium-ion storage (4 hour)	2042-2045	300
Solar w/ storage (4 hours)	2044	55
4-hr Storage for Solar	2044	50
Supply-side resource net total (MW)		1,133
Supply-side additions through 2045 (MW)		1,667
Demand Response through 2045 (MW)		112
Energy Efficiency through 2045 (aMW)		187

Q. What are some of the major changes in the draft 2021 IRP from the 2020 IRP?

A. The major changes in the draft 2021 IRP include changes in the following areas: capacity and energy position, energy efficiency and demand response, supply-side resource options, market analysis and the portfolio optimization analysis. Capacity and energy position changes include an increase in the summer planning margin from 14 percent to 16 percent, an increase in market availability from 250 MW to 330 MW for the 5 percent Loss of Load Probability analysis, and assumed retirements of the Northeast Combustion Turbine in 2035 and Boulder Park in 2040. The energy efficiency and demand response changes include the Utility Cost Test for Idaho program selection, a social cost of carbon for Washington customers only, and the inclusion of estimated energy savings from demand response programs in the portfolio analysis. The supply-side resource option changes include several new resource types being modeled such as several different energy storage options and hydrogen fuel cells and turbines, the use of levelized rather than annual energy and capacity costs, as well as several changes to the modeling of the social cost of carbon. The major market analysis changes include the use of the Aurora supplied database for most non-Avista inputs; the use of the Aurora capacity expansion logic for meeting clean energy policies; and a new natural gas price forecast using blended forwards, price forecasts from two consulting firms and the Energy Information Administration. Finally, the portfolio optimization analysis changes include a 24-year resource portfolio from 2022 to 2045 and portfolio optimization that allows selection of resources for either state or for the system. All of the major changes are described in greater detail in the 2021 draft IRP.

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 Exhibit No. 7, 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 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 IRP's Preferred Resource Strategy, while taking advantage of competitive opportunities to satisfy electric resource supply needs in the long-term. 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. Yes, as previously discussed with the Commission, Avista has chosen to participate in the CAISO Western Energy Imbalance Market (EIM) beginning in March 2022. Company witness Mr. Kinney provides details about Avista's participation in the EIM and the expenses required for joining and participating in the EIM.

IV. OVERVIEW OF 2020 – AUGUST 2023 NON-COLSTRIP GENERATION CAPITAL PROJECTS

Q. Please discuss the capital investments you sponsor included in the Company's Two-Year Rate Plan.

A. As discussed by Company witnesses Ms. Schultz and Ms. Andrews, Avista's capital witnesses, including myself, describe the capital projects included in the Company's proposed Two-Year Rate Plan, reflecting pro forma capital additions for the period between January 1, 2020 and August 31, 2023. For the generation projects, my testimony and Exhibit No. 7, Schedules 3 and 4 provide an overview of the need for the investments made and detail how those projects benefit our customers.

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 Company's long-range forecasting uses the Maximo enterprise asset management software 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 twice every year to review the long-range forecast, confirm that it is up-to-date and to 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 ensure 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 the progress of projects and any proposed changes to the execution plan. Adjustments and consensus take place at these meetings.

Q. Company witness Mr. Thies identifies and briefly explains 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 required for connecting new distribution customers or large transmission-direct customers. This driver is generally not applicable to Generation.

2. **Mandatory and Compliance** – These investment drivers are compelled by regulation or contract and are generally beyond the Company's control as they are a direct result of compliance with laws, regulations and agreements, including projects related to dam safety upgrades, public safety, air and water quality, and equipment essential to legally operating within the interconnected grid among others.

3. **Failed Plant and Operations** – This investment driver includes the replacement of equipment that is damaged or fails due to an accident, or normal wearing out requiring periodic replacement. The large, massive rotating equipment and associated support machinery used for electric generation can experience sudden mechanical failures or electrical insulation breakdowns even with the benefit of ongoing maintenance and preventive maintenance programs.

4. **Asset Condition** – Replace infrastructure assets or portions of assets at the end of their functional service life based on asset condition due to age, obsolescence and parts availability, and degradation of the asset. This category includes replacement of critical parts requiring replacement prior to failure, as

well as replacing or overhauling older equipment to bring it up to meet current codes and standards.

5. **<u>Customer Service Quality and Reliability</u>** – Meet our customers' expectations for quality and reliability of service, as well as increasing the reliability of operating assets.

6. **<u>Performance and Capacity</u>** – Programs and projects to address system performance and capacity issues so Company assets can continue to satisfy business needs and meet performance standards to support the interconnected grid and to ensure the ability to participate in the regional wholesale energy market.

The primary investment drivers for generation projects include Mandatory and Compliance, Failed Plant and Operation, Asset Condition, Customer Service Quality and Reliability, and Performance and Capacity. Exhibit No. 7, Schedule 3 – Avista Utilities Generation Infrastructure Plan contains additional details, more thorough discussions and specific examples concerning each of the six investment drivers, as well as overviews of the planned capital and maintenance investments from 2020 through 2024. The main drivers for each of the major generation-related capital investments in my testimony are discussed below.

Q. For the capital additions in the 2020 through 2023 timeframe, for which you are responsible, is the Company seeking to include all of those investments in general rates in this case?

A. Yes. The Company is providing more detailed information in testimony and exhibits related to the projects completed over the proposed Two-Year rate Plan beginning January 1, 2020 through August 31, 2023. Details about the generation-related capital projects over the period included in this case are discussed below. Table No. 2 below provides the system cost of each generation capital project included in this case for the 2020 through

August 2023 period. Additional details about specific generation capital projects associated with Colstrip Units 3 and 4 are covered in a later section of my testimony.

Table No. 2: 2020 through 2023 Non-Colstrip Major Generation Capital Projects

Generation Capital Projects (System) In $(000's)

Business Case Name	2020	2021	2022	2023(1)
Mandatory and Compliance				
Cabinet Gorge Dam Fishway	$ 122	-	$ 63,203	-
Clark Fork Settlement Agreement	1,041	6,471	6,073	2,978
Spokane River License Implementation	935	1,660	587	373
Hydro Safety Minor Blanket	-	50	50	33
Long Lake Stability Enhancement	-	3,249	-	-
KF_Ash Landfill Expansion	-	-	499	-
Failed Plant and Operations				
Base Load Thermal Program	2,178	2,764	2,899	1,610
CS2 Single Phase Transformer	2,849	18,801	-	-
Nine Mile Rehabilitation	(24)	63	-	-
Peaking Generation Business Case	299	450	450	113
Asset Condition				
Base Load Hydro	652	1,025	1,195	683
Cabinet Gorge 15 kV Bus Replacement	964	-	-	-
Cabinet Gorge Automation	4,062	3	-	-
Cabinet Gorge Gantry Crane Replacement(2)	(1,003)	-	-	-
Colstrip 3&4 Capital Projects	7,089	8,106	3,410	3,745
Generation DC Supplied System Update	209	250	233	150
Little Falls Plant Upgrade	474	1,451	-	-
Long Lake Plant Upgrade	87	1,331	-	-
Regulating Hydro	1,373	2,390	2,160	666
Cabinet Gorge Unit 3 Protection & Control Upgrade	-	2,818	-	-
Cabinet Gorge Unit 4 Protection & Control Upgrade	-	2,832	-	-
Post Falls Landing and Crane Pad Development	-	3,308	-	-
HMI Control Software	-	2,200	1,500	1,000
Generation Masonry Building Rehabilitation	-	-	700	700
KF_Fuel Yard Equipment Replacement	-	-	23,240	-
Customer Service Quality and Reliability				
Automation Replacement	405	419	300	-
Misc. accrual reversals, corrections or additional TTP	(92)	-	-	-
Total Planned Generation Capital Projects	**$ 21,619**	**$ 59,640**	**$ 106,500**	**$ 12,051**

(1) Includes system pro forma capital for the period of January 1, 2023 through August 31, 2023.
(2) Accounting correction made in September 2020. See Company witness Ms. Schultz direct testimony.

Q. Would you please explain the generation capital projects included in this case for 2020 through 2023?

A. Yes. The capital projects include generation capital investments grouped as Mandatory and Compliance, Failed Plant and Operations, Asset Condition, and the Customer Service Quality and Reliability investment categories. Brief descriptions of each project, the reasons for the projects, and the timing of the decisions follow. Additional details can be found in Exhibit No. 7, Schedule 4 – Generation and Environmental Capital Project Business Cases.

<u>Mandatory and Compliance Generation Capital Projects</u>

Cabinet Gorge Dam Fishway ($122,000 in 2020, $63,203,000 in 2022)

The Clark Fork Settlement Agreement (CFSA) and FERC License require Avista to implement the Native Salmonid Restoration Plan (NSRP), which includes a step-wise approach to investigating, designing and implementing fish passage at the Clark Fork Project. Fish passage is intended to restore connectivity of native salmonid species in the lower Clark Fork watersheds. During relicensing the U.S. Fish & Wildlife Service (USFWS) reserved its authority to require fish passage at both Noxon Rapids and Cabinet Gorge dams, in order to pursue the NSRP collaboratively. Those efforts, including involvement of Native American tribes and state agencies, as well as other stakeholders, continued over 15 years for the current project.

Clark Fork Settlement Agreement ($1,041,000 in 2020, $6,471,000 in 2021, $6,073,000 in 2022, $2,978,000 in 2023)

The ongoing operation of the Clark Fork Project is guided by the Clark Fork Settlement Agreement (CFSA) and FERC License No. 2058, which established the terms of the 45-year license issued to Avista. Imbedded in the License is the requirement to continue to consult agencies, tribes and other stakeholders. In addition, the CFSA and License provide decision-making participation for the settlement signatories, resulting in ongoing negotiations on implementing license terms. The CFSA and License also include a number of funding commitments to help achieve long-term resource goals in the Clark Fork and related watersheds.

Avista is required to develop an annual implementation plan and report, addressing all Protection, Mitigation and Enhancement (PM&E) measures of the License. Implementation of these measures addresses ongoing compliance requirements with Montana and Idaho Clean Water Act requirements, the Endangered Species Act, and state, federal and tribal water quality standards and regulations. License articles also describe operational requirements for items such as minimum flows, reservoir levels, dam and public safety requirements, land use, habitat, fisheries, recreation, land management, wildlife and other natural resources, and related matters. The investment drivers for this project are predominantly Mandatory and Compliance in nature.

Spokane River License Implementation ($935,000 in 2020, $1,660,000 in 2021, $587,000 in 2022, $373,000 in 2023)

This capital spending category covers the ongoing implementation of PM&E programs related to the FERC License No. 2545 and several other settlement agreements for the Spokane River Project including the Post Falls, Upper Falls, Monroe Street, Nine Mile and Long Lake dams. These capital projects include items enforceable by FERC, mandatory conditioning agencies, and through settlement agreements. The FERC License defines how Avista operates the Spokane River Project and includes several hundred requirements that must be met to retain this License. The License is issued pursuant to the Federal Power Act and it embodies requirements for a wide range of other laws such as 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 relating to fish, terrestrial resources, water quality, recreation, education, cultural, and aesthetic resources at the Spokane River Project. The License incorporates specific funding requirements to a 50-year settlement agreement between local and state agencies, as well as the Coeur d'Alene and Spokane Tribes. The License references our requirements for land management, dam safety, public safety and monitoring requirements, which apply for the term of the License and ensures Avista's ability to operate the Spokane River Project on behalf of our electric customers within our service territory over the 50-year license term.

Hydro Safety Minor Blanket ($50,000 in 2021, $50,000 in 2022, $33,000 in 2023)

The Hydro Generation Minor Blanket funds periodic capital purchases and projects to ensure public safety at hydro facilities both on and off water, for FERC regulatory and license requirements. The types of projects include barriers and other safety items like lights, signs and sirens. 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.

Long Lake Stability Enhancement ($3,249,000 in 2021)

During a recent FERC annual inspection, the inspector noticed a seeping joint in an airshaft and requested that Avista evaluate the internal plane stability of the intake and spillway dams. The analysis included an evaluation of all loading conditions the dam may experience including full-pool (normal) operations, probable maximum flood (PMF), and seismic conditions. The analysis revealed that Long Lake dam does not meet the internal plane stability minimum safety factor during a PMF event. Avista submitted a preliminary study to the FERC and is waiting for final design before sending the FERC the full scope of the project and timeline to address mitigation for this issue.

Avista is also currently revising the Spokane River PMF assessment, as well as performing a site-specific seismic hazard assessment, to fully understand what the loading on the facility is and how best to address any mitigation. Both of these studies are in their final stages and/or under the FERC review. Additional investigation of three-dimensional effects of the geometry of the facility is also actively being performed. Avista is developing a mitigation plan to address the stability issues. The current solution is anticipated to provide additional anchoring at the facility as well as potentially adding concrete mass to the dam structures.

Kettle Falls Ash Landfill Expansion ($499,000 in 2022)
The current landfill area for the Kettle Falls Plant is approximately 15 acres nested inside of a 42-acre fenced parcel designated for landfill operations and development. The ash generated from the plant has been stored at the landfill since 1986. The landfill consists of three engineered cells (Phase 1-3). Phases 1 and 2 were closed and covered in 2003 in accordance with WAC regulations. In February 2020, a permit modification request was submitted with the Department of Ecology to increase the slope of the Phase 3 cell from a 4-to-1 to a 3-to-1 slope. This request would increase the capacity of the current Phase 3 cell by 110,000 cubic yards. On May 5th, 2020, the Department of Ecology approved the request to increase the Phase 3 slope. Calculations with the newly approved slope and existing air space revealed Phase 3 reaching full capacity in 2025.

Environmental Information Logistics EIL and Schwyn Environmental Services were hired to assist in the planning and budgeting efforts to create a Landfill Master Plan for current operations, closure of Phase 3, and engineering and design of Phase 4. The creation of the new Phase 4 landfill area creates space for ash disposal at the current rate of nearly 40-50 years of as disposal. The Phase 4 landfill is the lowest cost impact to the customers for disposal of the ash when comparing the costs of disposal into the nearest acceptable landfill.

<u>Failed Plant and Operations Generation Capital Projects</u>

Base Load Thermal Program ($2,178,000 in 2020, $2,764,000 in 2021, $2,899,000 in 2022, $1,610,000 in 2023)
Avista's Base Load Thermal plants include Coyote Springs 2 and the Kettle Falls Generating Station. These two base load plants provide different operational flexibility to serve Avista's customer's energy demands. Coyote Springs 2 is a natural gas-fired combined cycle unit which generates 300 MW's. It is equipped with automation to adjustment unit output to match changing system loads and other types of services necessary to provide a stable electric grid. Kettle Falls is a base load renewable woody biomass resource with the ability to store energy in its fuel supply for long periods of time to optimize energy markets to best serve Avista's capacity, energy and renewable resource needs.

Projects for Coyote Springs 2 are identified and prioritized during the Annual Budgeting process, with emergent projects discussed during the Monthly Owners committee meetings between Avista and Coyote Springs management. Some of the projects that fall within this business case are joint projects between Portland General Electric (the plant operator) and Avista. These projects are also reviewed in an owner committee setting during monthly meetings at the plant. Kettle Falls Generation Station projects are identified and prioritized through the plant's Budget Committee. Both plants utilize the GPSS ranking matrix system to evaluate projects.

Individual projects which are identified are then reviewed and approved or denied by the Manager of Thermal Operations and Maintenance, specific plant managers and/or GPSS management before they are scheduled and implemented. Some projects completed under this program may require additional financial analysis if they are sufficiently large or if there are several options to meet the objective. These larger projects are reviewed with finance personnel to ensure they are in the best financial interests of our customers.

Coyote Springs 2 Single Phase Transformer ($2,849,000 in 2020, $18,801,000 in 2021)
The purpose of this project is to replace the currently in-service transformer, "T4", which exhibited unacceptably high gassing levels after only being in service a few months following the failure of its twin after approximately nine years of service. Following a detailed financial analysis, the recommended solution is to replace the existing three-phase dual-wound transformer, T4, with three single phase dual-wound transformers. The financial analysis included a calculation of Customer Internal Rate of Return (CIRR) compared to all possible alternative options. The CIRR of the proposed solution was the highest. This project is expected to increase reliability and reduce power supply expense at Coyote Springs 2. Additional details concerning the history and analysis of this project are provided later in my testimony.

Nine Mile Rehabilitation (-$24,000 in 2020, $63,000 in 2021)
The Nine Mile Redevelopment is a continuing capital project to rehabilitate and modernize the Nine Mile Hydroelectric Dam. Previous components of this project submitted for approval in prior general rate proceedings include the complete upgrades of Nine Mile Units 1 and 2 in 2016 and replacement of the Intake Deck and Debris System in 2017. The Sediment Bypass Enhancement, which included improvements to an existing passage for increased sediment diversion, and the Cooling Water System to prevent forced outages caused by excessive debris during runoff were completed in 2018. The 2021 capital projects for the Nine Mile Redevelopment include the closeout of this project work.

Peaking Generation Business Case ($299,000 in 2020, $450,000 in 2021, $450,000 in 2022, $113,000 in 2023)
The Peaking Generation program focuses on the ongoing capital maintenance expenditures required to keep Boulder Park, the Rathdrum Combustion Turbines, and the Northeast Combustion Turbines operating at or above their current performance levels. This program plans to keep the operating expenses of these plants as low as possible while ensuring starting and operating reliability by providing funding for specific efforts to allow the plants to accomplish those objectives. Work includes replacement of items identified through asset management decisions and programs necessary to maintain reliable and low operating costs of these plants. The program includes initiatives to meet FERC, NERC and EPA mandated compliance requirements.

Asset Condition Generation Capital Projects

Base Load Hydro ($652,000 in 2020, $1,025,000 in 2021, $1,195,000 in 2022, $683,000 in 2023)

The Base Load Hydro program covers the ongoing capital maintenance expenditures required to keep the Upper Spokane River Plants (Post Falls, Upper Falls, Monroe Street, and Nine Mile) operating at their current performance levels while meeting FERC and NERC mandated compliance requirements. This program focuses on ways to maintain compliance and reduce overall O&M expenses while maintaining a reasonable level of unit availability. Projects completed under this program include replacement of failed equipment and small capital upgrades to plant facilities. Most of these projects are short in duration, and many are completed in reaction to plant operations issues.

Cabinet Gorge 15 kV Bus Replacement ($964,000 in 2020)

In coordination with the Cabinet Gorge Station Service Project, a replacement bus was required to ensure that the bus was adequate given the generators and generation step up transformers being used. This required an upgrade of the existing 15 kV bus with a new 4,000 Amp segregated bus at Cabinet Gorge. The new configuration will have an increased load rating and the horizontal sections will have an increased load rating and the horizontal sections will be raised five feet to allow for acceptable access to the bus room equipment. The original 15 kV bus is underrated by approximately 10 percent based on the load requirements between the generators and the Generation Step-up transformers. In addition, the current configuration prevents access for the installation of new station service equipment in the bus rooms. This access requires the horizontal portion of the bus to be raised five feet. The design allows Avista to build as much of the new station service system as possible while the existing station service equipment remains in service. This construction approach greatly reduces generation unit outages from several months to just a few weeks. In addition, this project removes oil-filled equipment from the outdoor powerhouse deck. This requirement is based on the extensive amount of water that the powerhouse deck receives during spill season with the modified spillways now in service for total dissolved gas abatement and it will reduce risk of potential oil spills.

The B section of the bus was placed into service in November 2020. The A Section of the bus is expected to be completed by November 1, 2021. Design was completed in June 2020 and the ordering and receipt of material was completed in August of 2020. The bus outage for the B section began in October of 2020. The bus outage for the A section is expected to take place in September and October of 2021 timeframe.

Cabinet Gorge Automation ($4,062,000 in 2020, $3,000 in 2021)

The Cabinet Gorge Project was designed for base load operation. Today, it is often called on to provide load and to quickly change output in response to the variability of wind and solar generation, to adjust to changing customer loads, and other regulating services needed to balance system load requirements and assure transmission reliability. The controls necessary to respond to these new demands include speed controllers (governors), voltage controls (automatic voltage regulator a.k.a. AVR), primary unit control system (i.e. PLC), and the protective relay system. In addition to reducing unplanned outages, these systems will allow Avista to maximize these services for its own assets on behalf of its customers rather than having to procure them from other providers.

There are several NERC Reliability standards where existing equipment performs at a sub-standard level. A few of these standards involve frequency response and voltage control issues, which can lead to unplanned outages. There have been several unit outages associated with the existing control and protection equipment that this project will address. This equipment is at the end of its intended life and is subject to an increased likelihood of forced outages and subsequent loss of revenue and reliability.

The Cabinet Gorge Automation Project will also provide additional value when Avista joins the EIM in 2022 by helping the unit follow market dispatch signals. The investment drivers for this project includes Asset Condition, and Performance and Capacity. Design was completed in September 2019, followed by construction beginning in September of 2019 and ending in March 2020.

Cabinet Gorge Gantry Crane Replacement (-$1,003,000 in 2022)
This is an accounting correction made in September 2020 that is discussed in Company witness Ms. Schultz's testimony as referenced in Table 2.

Colstrip 3 & 4 Capital Projects ($7,089,000 in 2020, $8,106,000 in 2021, $3,410,000 in 2022, $3,745,000 in 2023)
Avista does not operate the Colstrip facility nor does it prepare the annual capital budget plan. The current operator develops and provides the annual business plan and capital budgets to the owner group every September. They also provide individual project summaries which characterize the work using categories similar in concept to the Avista business case drivers. Avista reviews these individual projects. Some of them are reclassified to O&M if the work does not conform to our own capital policy. Avista does not have a "line item veto" capability for individual projects under the Ownership and Operation Agreement although individual projects can be cancelled or postponed if a sufficient majority of the owners agree.

Generally, by the subsequent November meeting, the business plan is approved in accordance with the Ownership and Operation Agreement for Units 3 and 4 that six companies are party to. No budget agreement was made during 2020. The amount provided is an estimate taken from the prior year's forecast. As a result, the final Colstrip capital budget may not exactly match the amount provided above. We will update the Colstrip capital budget numbers when approved. Additional details regarding Colstrip Units 3 and 4 are discussed in the Colstrip Generation Capital section later in this testimony.

Generation DC Supplied System Update ($209,000 in 2020, $250,000 in 2021, $233,000 in 2022, $150,000 in 2023)
The Generation DC Supplied System program covers all the generation and control facilities. It is the backbone for supplying power to the protective relays, breakers, controls and communication systems. With NERC requirements being followed and design enhancements

being implemented, the DC system is being monitored, tested and continues to remain reliable. Experience shows that we must continually monitor, review and maintain our DC system. The equipment manufacturers provided an estimated life span for the batteries and auxiliary equipment. Some of these estimates have been wrong and some equipment has required early change out due to failing tests or other issues with the equipment. Proven manufacturers are used to improve the reliability and lifespan of this equipment.

Little Falls Plant Upgrade ($474,000 in 2020, $1,451,000 in 2021)
The Little Falls Plant Upgrade Program began in 2012 and is in the final phases of implementation in 2020 and 2021. Only the Plant Sump, Drain Field, and Panel Room Roof/Enclosure for the new controls equipment project components still need to be completed. Septic work was completed in November 2020, sump work is scheduled for completion in June 2021, and the Panel Room/Roof Enclosure in March 2021. The remaining work has very little risk exposure and minimal impact on the plant’s current operations.

Long Lake Plant Upgrade ($87,000 in 2020, $1,331,000 in 2021)
The Long Lake equipment ranged from 20 to more than 100 years old when this project began. We had experienced an increase in forced outages at Long Lake from almost zero occurrences in 2011 and increasing in number every year since then. The increasing number of outages was caused by equipment failures on a number of different pieces of equipment. Long Lake serves Avista’s allocated north electric district providing power to our transmission grid and local distribution power sources. The primary drivers for the Long Lake Plant Upgrade included Performance & Capacity, Asset Condition, and Failed Plant & Operations. The planned course of action was to replace the existing units in kind.

Currently, the turbines are thrusting too much (a sign of significant wear), including a failure in 2015. The 1990 vintage control system is failing, and only secondary markets can support this equipment. Inspections of other components of the generator show the stator core is "wavy" where the core lamination steel should be straight. The "wave" pattern is a strong indication of higher than expected losses occurring in the generator.

With the increase in generator output, the output of the generator step up transformer (GSU) has also increased to its rating. The existing GSU's are over 30 years old and operating at the high end of their design temperature, these are now approaching their end of useful life and need to be replaced proactively rather than waiting for a failure to occur. The other major drivers for the program is Station Service disconnect switching safety.

Regulating Hydro ($1,373,000 in 2020, $2,390,000 in 2021, $2,160,000 in 2022, $666,000 in 2023)
Avista’s regulating hydro plants have reservoir storage. This storage provides these plants with operational flexibility to support energy supply, provide peaking power, provide continuous and automatic adjustment of output to match the changing system loads, and to supply other types of services necessary for grid stability and to maximize value to Avista and its customers. The regulating plants include the four largest hydro plants on Avista’s system representing more than 950 MW of capacity. These plants include Noxon Rapids and Cabinet

Gorge on the Clark Fork River in Montana and Idaho, and Long Lake and Little Falls on the Spokane River.

This program funds smaller capital expenditures and upgrades required to maintain safe and reliable plant operation to provide customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System. Projects completed under this program include replacement of failed equipment and small capital upgrades to plant facilities. The business drivers for the projects in this program is a combination of Asset Condition, Failed (or Failing) Plant, and addressing operational deficiencies. Most of these projects are short in duration, typically well within the budget year, and many address plant operational support issues. Without this funding source, it would be difficult to resolve relatively small projects concerning failed equipment and asset condition in a timely manner. This could jeopardize plant availability and impact the plant's value to customers and the stability of the grid.

Cabinet Gorge Unit 3 Protection and Control Upgrade ($2,818,000 in 2021)
The Cabinet Gorge Project has retained most of its original equipment from the 1950s which is now at the end of life. This plant was designed for base load operation, but is now called on to not only serve load but to quickly change output in response to the variability of wind and solar generation, to changing customer loads, and other regulating services needed to balance the system load requirement and assure transmission system reliability.

Meeting these increasing demands for flexibility requires upgrades to protection and control equipment. This equipment includes speed controllers (governors), voltage controls (automatic voltage regulation a.k.a. AVR), primary unit control systems (Programmable Logic Controllers) and the protective relay system all of which serve to increase communications and reaction time for Cabinet Gorge Unit 3.

Cabinet Gorge Unit 4 Protection and Control Upgrade ($2,832,000 in 2021)
The Cabinet Gorge Project has retained most of its original equipment from the 1950s which is now at end of life. This plant was designed for base load operation but is now called on to not only serve load but to quickly change output in response to the variability of wind and solar generation, to changing customer loads, and other regulating services needed to balance the system load requirement and assure transmission system reliability.

Meeting these increasing demands for flexibility requires upgrades to protection and control equipment. This equipment includes speed controllers (governors), voltage controls (automatic voltage regulation a.k.a. AVR), primary unit control systems (Programmable Logic Controllers) and the protective relay system all of which serve to increase communications and reaction time for Cabinet Gorge Unit 4.

Post Falls Landing and Crane Pad Development ($3,308,000 in 2021)
The property located adjacent to the North Channel of the Post Falls Hydroelectric Development (HED) is being developed by the City of Post Falls for use as a public recreational area. In conjunction with the purchase of the property, the City of Post Falls and

Avista agreed to develop the area so it could be utilized by Avista for staging a crane, barges and equipment for maintenance and construction in support of the Post Falls HED. The area will be joint use and when not needed by Avista, the area would be utilized by the City of Post Falls and the public for recreational purposes.

HMI Control Software ($2,200,000 in 2021, $1,500,000 in 2022, $1,000,000 in 2023)
New Human-Machine Interface (HMI) control software is needed to prevent limitations going forward that will introduce security risks. The existing HMI software runs on Windows 7 and Microsoft will no longer support Windows 7 after 2020. Cyber security risks increase if we do not stay current with supported operating systems. Replacing unsupported HMI software allows the Company to upgrade control computers to supported operating systems such as Windows 10 which helps to control cyber security vulnerabilities and other issues associated with unsupported software.

In addition, developing new control screens on a new software platform will modernize control screens and allow operators to carry out their responsibilities more effectively. Control Screens will need to be developed for each generating facility; therefore, a planned approach will allow engineers and technicians to develop screens to coordinate with control upgrades.

This project addresses concerns with unsupported software, such as cyber security vulnerabilities and general operating issues. Engineering will assist with developing a new server-based architecture and developing and commissioning HMI control screens.

Generation Masonry Building Rehabilitation ($700,000 in 2022, $700,000 in 2023)
Several buildings for Avista's Power Plants are constructed of masonry and are approaching one hundred years in age. These buildings include The Little Falls Power House and Gate Building, The Long Lake Power House, the Nine Mile Power House, The Post Street Building, and The Post Falls Power House and Substation Building. The grout and brick in many cases has begun to fail which is creating a serious personnel and public hazard as bricks become loose in the walls and parapets and can fall to the ground. This safety issue has become critical, especially during the freeze and thaw cycles in the spring. The project funds a comprehensive inspection of each building to create a refurbishment plan which will remedy the issue long term ay each facility.

Kettle Falls Fuel Yard Equipment Replacement ($23,240,000 in 2022)
The Kettle Falls Generating Station was constructed in 1983 to generate power using wood waste from area sawmills that is trucked to the plant with contracted hauling companies. Trucking companies use semi-trucks and 53-foot trailers to transport the material from sawmills to the Kettle Falls plant.

Washington State increased the legal hauling capacity on the State highways allowing trucking companies to increase the trailer lengths from 48 to 53 feet in 1985. This increase in allowed trailer length and haul weight created efficiencies in transportation of materials but created a deficiency in the Kettle Falls fuel handling system. The current scale is too short for the entire truck and a 53-foot trailer to fit on, thus requiring drivers to lift the tag axle in order to weigh their load. The truck dumpers are not rated to lift the larger payload and physically cannot fit a truck and a fully loaded 53-foot-long trailer.

An operational work around was developed for the drivers to detach the truck from the longer trailers prior to offloading the wood waste. A contract driver died in 1983 while helping another driver during the disconnecting process. Another contract driver was seriously injured while attempting to manually offload an overloaded truck prior to unloading on the truck dumpers in 2015.

The Kettle Falls plant has operated for over 35 years and much of the equipment has reached its end of useful life. Many of the fuel yard components are failing and replacement parts are no longer available. The new fuel yard system will provide additional margin needed to assure compliance with visibility and particulate (PM) emission standards. Other equipment deficiencies include a short truck scale, steep conveyor angles that result in equipment downtime during cold weather events, inadequate wood screening, and a failing hammer hog. Key drivers for this project are Safety, Environmental and Failed Plant Assets.

The new fuel yard equipment will include inbound and outbound scales, two larger capacity truck dumpers, conveyance, disc screen and hammer hog, and an operating building. The new system will be greenfield construction allowing the plant to continue accepting material while construction and commissioning of the new equipment occurs. The new system will eliminate deficiencies with the scaling process, create safer dumping of the trucks with larger capacity dumpers, control fugitive emissions with covered equipment, increase truck turn time, and lower fuel transportation cost.

<u>Customer Service Quality and Reliability Generation Capital Projects</u>

Automation Replacement ($405,000 in 2020, $419,000 in 2021, $300,000 in 2022)
The Automation Replacement project systematically replaces the unit and station service control equipment at our generating facilities with a system compatible with Avista's current control standards for reliability. Upgrading control systems within our generating facilities allows us to continue providing reliable energy. The Distributed Controls Systems (DCS) and Programmable Logic Controllers (PLC) are used to control and monitor Avista's individual generating units as well as each total generating facility. The DCS and PLC work in this capital program is needed to reduce the higher risk of failure due to the age of the currently installed equipment. The DCSs are no longer supported and spare modules are limited. The modules in service have a high risk of failure as they are over 20 years old. The computer drivers that are needed to communicate to the DCSs are not compatible with the new computers using Windows 10 operating systems. This creates a cyber-security issue. The software needed to view and modify the logic programs only runs on Windows 95 and Avista has a very limited supply of Windows 95 laptops that are also failing as they age. Replacing the aging DCSs and PLCs before they fail will reduce unexpected plant outages that require emergency repair with like equipment. A planned replacement approach allows engineers and

technicians to update logic programs more effectively and replace hardware with equipment that meets current standards.

Avista's hydro facilities were designed for base load operation but are now increasingly called on to quickly change output in response to the variability of wind and solar generation, to adjust to changing customer loads, and other regulating services needed to balance system load requirements and assure transmission reliability. The controls necessary to respond to these new demands include speed controllers (governors), voltage controls (automatic voltage regulator a.k.a. AVR), primary unit control system (i.e. PLC), and the protective relay system. In addition to reducing unplanned outages, these new systems allow Avista to maximize ancillary services for its own assets on behalf of customers rather than procuring them from other providers.

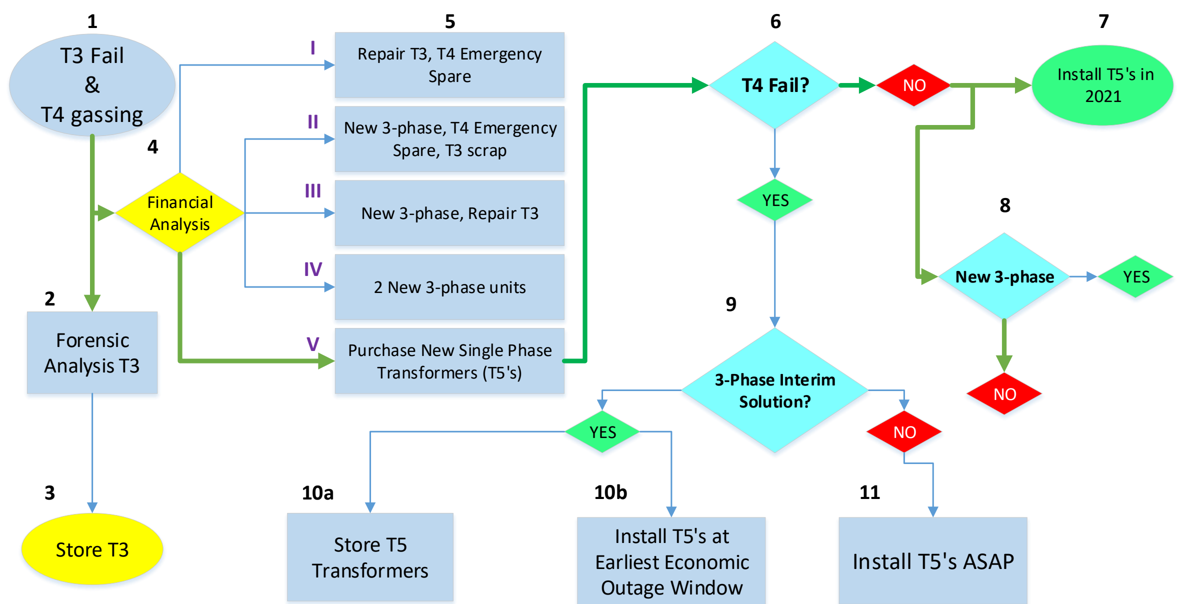
Q. Are there any of the above non-Colstrip generation capital projects that you want to provide more background concerning the history and need for the project?

A. Yes, I want to provide additional details about the history of and need for the Coyote Springs 2 Transformer Project. Avista has experienced multiple failures of its generator step-up (GSU) transformers at Coyote Springs 2 over its 17 years of operation. Four GSU's have been placed into service since 2003: two Alstom/Areva units (T1 and T2), which were manufactured in Turkey; and two Siemens units (T3 and T4), which were manufactured in Brazil. All four units were dual low voltage wound (13.8/18 kV) to 500 kV transformers. Most recently, in 2018, after nine years of service, T3 failed in service. The spare transformer, T4, was placed into service later the same year, but after several months of operation it also began exhibiting signs of internal deterioration that would eventually lead to failure. The Coyote Springs 2 generator facility is currently operating without a spare transformer and the in-service transformer, although able to function at near full capacity, is gassing internally and could fail in the same manner as T3. To reduce risk of failure the maximum plant generation output was reduced to keep heating in the windings down per recommendations from a consultant, until such time as the transformer can be replaced.

When Avista purchased T3 and T4, we specifically excluded Areva Turkey (the original manufacturer of T1 and T2) as a potential supplier to get a different transformer design and to have the unit manufactured in a different factory to avoid a factory-related systemic deficiency. This was successful in one aspect as the initial forensic analysis of the T3 failure shows a failure in an entirely different location from the failures that were observed in T1 and T2. Nevertheless, given that we have encountered multiple failures of this three-phase configuration over the operating lifetime, Avista chose to conduct a detailed financial analysis of multiple options that included an alternate single-phase configuration and also considered a risk element for options that would just continue using the three-phase dual wound configuration.

The decision tree below in Illustration No. 1 provides a high-level summary of where we are now regarding the transformer decision at Coyote Springs 2. Element 4 represents a financial analysis we performed to determine the best path forward. Options evaluated included various T3/T4 repair combinations, purchasing of two new dual wound three-phase units, and purchasing new single-phase dual wound units. The financial analysis determined the purchase of single phase dual wound transformers to be the most cost-effective solution for customers. Because of the extraordinarily long lead time associated with acquiring transformers of this size, Avista has had to keep other options open. In the decision tree below, the bolded green lines represent the chosen path to date. You may note that Element 6 presented a choice that could have taken us down a path of repairing T3 or T4 and placing it back into service even though new transformers of a completely different design had been ordered. The reason for maintaining this optionality is the long lead time required for these types of transformers to be built and shipped, and the potential for extremely long outages that expose the Company to market volatility and higher power supply expense. We are now at a point in time where construction of the new single-phase units is far enough along that we would be able to install them faster than any potential repair and reinstallation of T3/T4.

<u>Illustration No. 1: Coyote Springs 2 Transformer Decision Tree</u>



This project has two sub-projects. The portion of the overall project that transferred to plant in 2020 included the civil and structural modifications that needed to be made to accommodate the installation of the new transformers, oil containment, and firewall systems. This portion of the work was completed in 2020 to allow the transformers to be installed during the spring of 2021 before summer peak load conditions. The installation of the new transformers is scheduled to be completed by June 30, 2021. Included in Exhibit No. 7, Schedule 4 is the Business Case as well as other documents explaining the need for this project. The investment drivers for this project includes Failed Plant and Operation, Asset Condition, Customer Service Quality and Reliability, and Performance and Capacity.

Q. Did Avista consider alternatives to the Coyote Springs 2 Transformer

Project?

A. Yes, Avista considered multiple alternatives to this project as indicated in the decision tree in Illustration No. 1 above and detailed in the documentation included in Exhibit No. 7, Schedule 4. The Company selected what is considered by our expert consultants to be the premier transformer factory in the world, Siemens' facility in Austria, to manufacture four (4) single-phase dual wound transformers. These transformers are of a dramatically different design than the previous transformers at Coyote Springs 2. Each single-phase transformer is much lighter (thus much less costly to transport and handle) than the previous three phase transformers because the duty is divided between three units, yet the combined MVA capacity of these single-phase transformers is significantly higher than T1-T4, which provides significant additional operating margin and reliability. Had we chosen to replace T4 with a similar upgraded capacity three-phase unit, it likely would not have fit on the existing transformer pad.

Avista believes that the new configuration using individual single-phase transformers will provide long term dependable reliability and reduce the Power Supply expense associated with replacement power for the outages that we have observed over the life of the plant because of the first four transformer failures. Additionally, the new transformers have increased capacity to afford a larger operational margin and will accommodate increased output from the facility if any future plant upgrades are made.

V. <u>COLSTRIP GENERATION CAPITAL PROJECTS</u>

<u>A. Introduction and Summary of Capital Additions</u>

Q. Before discussing the operation of and capital additions for Colstrip Units

3 and 4, please discuss the purpose of this section of your testimony.

A. The following testimony provides additional details concerning the capital spending projects associated with the Company's ownership interests in Colstrip Units 3 and 4, as well as providing details about the capital spending decision process for Colstrip. Table No. 3 shows that planned annual capital expenditures for Colstrip from 2020 through the end of August 2023.

<u>Table No. 3: 2020 – 2023 Colstrip Capital Additions</u>

Colstrip Capital Projects (System) In $(000's)				
Business Case Name	**2020**	**2021**	**2022**	**2023(1)**
Asset Condition				
Colstrip 3&4 Capital Projects	7,089	8,106	3,410	3,745
Total Planned Colstrip Capital Projects	**$ 7,089**	**$ 8,106**	**$ 3,410**	**$ 3,745**

(1) Includes system pro forma capital for the period of January 1, 2023 through August 31, 2023.

Q. Can you provide some background about how Avista makes and manages Colstrip capital decisions?

A. Yes. Talen, the plant operator, makes ongoing assessments regarding the conditions of the equipment at the plant during operations, outages and overhauls. Talen uses the information obtained in these assessments to determine when particular components need to be repaired or replaced. This assessment process also includes the solicitation of advice from original equipment manufacturers, equipment vendors, internal and external plant engineers, as well as the plant Owners. Talen produces a budget after consideration of different options and timing for capital projects and presents them to the Project Committee for discussion, additional analysis if necessary, and for voting as directed by the ownership agreement. The approval of capital budgets requires at least 55 percent of the ownership and three members of the Project Committee including the Plant Operator.

Avista actively participates in the capital decision-making process at Colstrip and fully exercises its ownership interest in Units 3 and 4. 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 based on the operational, environmental and safety requirements of the project. 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 unilaterally stopping capital projects on its own, the Company nevertheless actively exercises its ownership rights while projects are being discussed. The compensation structure for the plant operator is cost-based and does not include any rate of return based on the capital spending at the plant. There is no economic incentive or justification for the plant operator to spend foolishly or "gold plate" the facility while maintaining and operating the plant. In fact, quite the opposite is true. The plant operator is an independent power producer whose business model requires low plant costs to ensure the plant is competitive in the market, so there is no financial incentive for them to spend needless capital on any projects. The plant operator's financial interests to minimize costs while meeting all regulations, are the same as all of the Colstrip owners and in turn their customers.

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

the plant is not expected to continue to serve Idaho customers beyond 2025 as determined in the 2020 IRP?

A. Continued capital projects at Colstrip are necessary to maintain present operational plant output expectations required by the plant owners to meet their anticipated load demands. The Colstrip Generating Station consists of Units 1 and 2 – 333 (MW) that operated from 1975 until their retirement in January 2020, and Units 3 and 4 – 805 MW each operating since 1983 and 1986, currently assumed to operate until 2025 to serve Idaho and Washington customers. An actual retirement date for Units 3 and 4 has not been determined by the collective owners at this time. Despite the ongoing discussion about retirement, Colstrip will continue to meet past, current and future regulatory obligations and environmental compliance requirements while maintaining a reliable and operational facility. This requires a strategic approach to planning and completing certain capital projects in order to meet current and future regulatory goals. Specifically, the entire facility will manage water and waste well beyond the operating life of the units according to the following requirements:

- 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, Montana Department of Environmental Quality (MDEQ) (July 2012), Settlement agreement entered (2016).

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 they exercise careful diligence in gathering information at the point in time when strategic decisions must be made.

Q. Will projects still need to be completed regardless of when the Plant is shut down?

A. Yes. The AOC required an extensive evaluation process that included site characterization, clean-up criteria, risk assessment that resulted in the MDEQ selection of a remedy and remedial action work plans. The draft and finalized documents can be found on the MDEQ website specific to the Plant groundwater clean-up.[1] 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. Below, I briefly discuss the Colstrip capital projects for the 2020 through August 2023 timeframe.

Q. Will the Washington Clean Energy Transformation Act requirement requiring the elimination of energy from Colstrip 3 and 4 serving Washington customers by the end of 2025 impact any of the capital projects in this case and will that law impact the cost of Colstrip for Idaho customers?

A. No. As discussed elsewhere in my testimony, the Company is required to meet

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

several regulatory obligations and environmental compliance requirements, in addition to maintaining Colstrip as a reliable, operational facility while it is still being used and relied upon to serve customers. This requires a strategic approach to planning and completing certain capital projects in order to meet required deadlines. As such, the owners 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 Owners have undertaken are necessary, irrespective of existing laws or additional legislation. Even though Colstrip will not be able to be used to serve Avista's Washington customers and it cannot be included in their rates for generation after 2025, the law specifically requires Washington customers to still pay for their portion of the eventual shutdown and remediation costs associated with Avista's ownership interests in Colstrip Units 3 and 4.

Q. Can you provide additional details concerning the main "environmental liabilities" associated with Colstrip that are being managed through these capital projects?

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 GPSS 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. <u>Coal supply</u>: 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: The combination of SmartBurn and regional plant closures place Colstrip Units 3 and 4 within the glide path and selective catalytic reduction is not expected to be required, but could still be made a requirement under the Regional Haze Program if the plant were to run longer than currently anticipated based on the economic analysis in the IRP.

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. Describe Avista/Talen's project management process that was used to manage the Colstrip capital projects.

A. Avista does not manage the projects at Colstrip directly. Talen as contract 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. Budget to Actual reports are issued to Avista by Talen on a monthly basis.

Q. Please continue with a description of the Colstrip projects impacting the Two-Year Rate Plan in this case.

A. Below, I briefly discuss the Colstrip capital projects for the 2020 through August 2023 timeframe. Many of these projects span over multiple years as described below. The cost status of each individual project, as well as descriptions of the projects, are included in the summary reports contained in Exhibit No. 7, Schedule 5.

Q. Please describe the <u>Separate Overfire Air Bucket Replacements Project</u>.

A. The overfire air system is a critical component used to manage the coal combustion process by providing a means to control the combustion by lengthening the combustion resulting in less air being combusted to create the same heat for production purposes. By this process, lower NOx levels are achieved while the fuel is still fully consumed to manage other constituents of the combustion process. The ability to control the combustion in the boiler is essential to managing the NOx emissions from the unit. In addition, proper combustion management is required to also manage opacity, PM emissions, and other elements and properties that result when coal is burned. Collectively, there are several components needed to allow the coal to combust as clean as possible, achieve low NOx emissions, and still provide the energy needed to produce the power from the unit. The separated overfire air (SOFA) elements are one of these components.

SOFA buckets are essential to meeting environmental compliance by helping control the combustion process. To maintain equipment function and help provide for NOx emission and opacity control, the separated overfire buckets (and the top overfire buckets (TOFA)) need to be replaced every four years during a unit overhaul. Overfire buckets warp with heat exposure over an extended time in service, which causes buckets to bind up in the boiler and restrict movement during unit operation. Through inspection during overhaul, the buckets on Unit 4 were found to be at the end of their life. The SOFA buckets were replaced during the 2020 overhaul. Part of the work included in the 2020 overhaul was the erecting of scaffolding in the boiler. The process of replacing buckets is most economical with a scaffold in place as this allows for an effective and cohesive removal of buckets, easier access to make repairs to support material, testing of movement, and alignment of all emission control components associated with the boiler corners at the same time. Complete failure of the buckets was highly probable if they were not replaced during the Unit 4 2020 outage. SOFA buckets are a portion of the NOx control system and need to be in good working order for combustion optimization and PM, opacity, and NOx control. Not performing this work would have resulted in a high risk that environmental compliance (NOx, PM, Opacity) could not be met possibly resulting in fines from the MDEQ for violating emissions standards. In addition to consequences from the resulting non-compliance situation, the Unit would need to be run at reduced load or be placed offline until new buckets were purchased and installed.

The lead time to obtain SOFA buckets is three to four months. The new Overfire Buckets were purchased in early 2020 so they would be available for planners to incorporate into the 2020 Unit 4 Overhaul work. Due to concerns with COVID-19, the Unit 4 Overhaul effort was rescheduled to mid-September 2020 and included the installation of the Overfire Buckets. Work began in September 2020 and was placed in service after the 2020 scheduled Unit 4 maintenance outage. The investment drivers for this project include Asset Condition, Customer Service Quality and Reliability, and Performance and Capacity.

Q. Please describe the New Brake/Shear/Electric Shop/CaBr2 System Building Project.

A. With the shutdown of Colstrip Units 1 and 2 in January 2020, several items need to be addressed that affect the near term continued operation of Units 3 and 4. One of these items is the bulk storage and transfer system for the Calcium Bromide (CaBr2) used for mercury abatement in Units 3 and 4. The existing bulk storage and transfer system is housed alongside the Condensate system in Units 1 and 2. With the demolition and removal of Units 1 and 2, that location will no longer be a serviceable location. This project is required to support the mercury abatement system. The Calcium Bromide (CaBR2) solution is injected into the scrubber slurry which reacts with the mercury and oxidizes it in the flue gas which can then be captured by the plant's existing scrubber equipment. This system is required to meet EPA Mercury and Air Toxic Standards, commonly referred to as MATS.

A new building will be erected on the East side of Unit 4, just south of the existing Hydrazine building. It will share a common wall with Unit 4. The new building will house the CaBR2 Bulk tank and transfer pumps in one end of the building in an enclosed space with tank containment built into the foundation. The other end of the new building will house the electric shop work area and an area where the existing brake and shear will be placed. The electric shop and the brake and shear area will be serviced by an electric overhead crane. These work areas are also currently within the Unit 1 and 2 footprint and are required for near term continued operation of Units 3 and 4. The investment drivers for this project include Asset Condition, Regulatory and Mandatory, Customer Service Quality and Reliability, and Performance and Capacity.

Talen considered other alternatives including erecting different buildings to house the brake and shear equipment, a separate building to house the electric shop, and the CaBr2 building. Conceptually, each building would be smaller than the single building being proposed. The alternatives turned out to be an estimated three times more expensive to construct the individual buildings rather than the single larger building. In addition, no alternate space was found where the Brake and Shear Equipment or the Electric shop could be reasonably located. The CaBr2 system must be moved so that it can continue to function because of the environmental permit requirements for the mercury abatement. Finally, there was consideration of not erecting the building to include the Brake and Shear equipment and the Electric Shop. Without this space, the work performed there would need to be contracted out, likely to the Billings area, which could cause delays in maintenance and corrective actions for Units 3 and 4 as well as increase expenses. Additionally, work areas for the electrical work would still be required to be set up throughout the plant on an ad hoc basis that would reduce efficiencies provided by a central electrical work location as well as increase access hazards throughout the plant.

Q. Please describe the <u>Capture Well Treatment System Project</u>.

A. By way of background, the Water Management System and Coal Combustion Residual are essentially a building block set of projects that support the same strategic goal of meeting our regulatory obligations and environmental compliance requirements under the AOC with the MDEQ and EPA rules on Coal Combustion Residuals (CCR). These requirements result in several multi-year capital projects that will likely extend out through 2024 to address groundwater quality at the Colstrip site.

A simple process description begins with raw water being 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 plant for reuse. All water is either reused or lost through evaporation because Colstrip is a zero-discharge facility. Throughout the years, some 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, this project has and will continue to have Capital Projects in each year from 2020 through the close of the Plant. The overall handling of the closed loop water system at Colstrip is subject to these two <u>Environmental Must Do</u> requirements.

The Colstrip Wastewater AOC requires specific actions by the plant to remediate impacted groundwater at the Plant Site. MDEQ approved actions requires treatment of the capture well water as part of the cleanup of impacted groundwater at the Plant Site. This project provides funding for a two-year design/construction schedule to implement a groundwater capture treatment system in accordance with the requirements identified in the Colstrip Wastewater AOC Plant Site Remedy as approved by MDEQ. The construction schedule meets the requirements of the approved MDEQ remediation for the plant site groundwater capture wells.

The MDEQ approved remedy for remediation also includes fresh-water injection into the plant water system. To implement this remedy, fresh-water injection wells will be installed, and additional capture wells developed this year as required by this approved remedy. Once the remediation injection wells are operating at full capacity, we expect the total capture rate to be approximately 500 gpm. At this full capacity rate, we will fill the Groundwater Capture Storage Pond in about two years. The two-year design and construction schedule proposed with this project will meet the remediation requirements as approved by MDEQ.

This project also includes the design and construction of a new Brine Concentrator, steam supply, and a Crystallizer. The steam supply unit will provide capacity for this groundwater capture treatment system and the other groundwater capture treatment systems (currently in service) when all four units cease operation. In addition, this steam supply unit is capable of supplying steam heating to Units 3 and 4 if both Units are off during winter months. Project engineering started in late 2019, with design in January 2020 and construction installation completion in 2021. The investment drivers for this project includes Mandatory and Compliance, Asset Condition, and Performance and Capacity. This system is required for the overall water handling requirements for the Colstrip site as directed by MDEQ under the AOC. Costs have been adjudicated between the Unit 1 and 2 Owners and the Unit 3 and 4 Owners for this project.

Q. Please describe the Unit 3 Auxiliary Transformer Project.

A. The auxiliary transformer provides the necessary power to run the mills, induced draft (ID) and forced draft (FD) fans, and other critical loads necessary to support the generation of steam to power the turbines. These are very large loads – enough load to serve a small town in many cases. In addition, other miscellaneous loads needed to run the unit are provided by this source. An auxiliary transformer is used rather than using the grid as a source in that it can be tapped directly from the output of the generator, saving considerable system losses if the power is sourced through the transmission system. Using the grid for this load would expose the plant and these critical loads to possible failures due to line faults, storms, "driver hits pole" incidents, and other risks.

Unit 3's auxiliary transformer is original equipment and has been in service over 36 years and it has been subject to several through faults due to in-plant electrical failures. The load tap changers (LTCs) on Unit 3's Auxiliary transformer have experienced internal arcing failure, oil leakage and controls failures in the last five years. The furanic compound testing of the in-service transformer oil shows insulation aging concerns. Recently, the 13.8 kV load tap changer failed, and troubleshooting indicated failed components on a control board. The failure was repaired by removing a control board from the failed Unit 4 auxiliary transformer and installing it in the Unit 3 auxiliary transformer. The auxiliary transformer for Unit 4 had failed in service previously (a year earlier). As a stop gap measure, a configuration was made with the transmission lines, the unit starting transformers, and station service bus to back feed the auxiliary load (normally served by the auxiliary transformer) through this arrangement. The resulting configuration results in substantial system losses. In addition, it would require a significant de-rate on the operating unit in order to start the other unit if it had been shut down for any reason. This placed the entire plant at risk of losing this key startup transformer. The startup transformers were not designed for this heavy continual loading condition. There was discussion to serve Unit 3 continuously with this configuration. Also, attempts were made to locate a used or a rebuilt transformer, but the unique configuration of the 1,000 MVA rating at the 26kV/13.8kV/4160 winding with load tap changer on both lower voltage windings is very rare. No other suitable units were located.

The new transformer was ordered in 2019 and delivered so that it is on site if the old auxiliary transfer fails. Installation of the transformer will coincide with the four-year outage plan for Unit 3. This outage is currently planned for a window of 56 days starting in early May of 2021, with in-service date in June 2021. The investment drivers for this project includes Failed Plant and Operation, Asset Condition, Customer Service Quality and Reliability, and Performance and Capacity.

Q. Please describe the <u>Unit 3 Turbine Generator Base Overhaul Project</u>.

A. This project entails a series of refurbishments and replacements of parts of the turbine controls to assure they will function properly to provide the output control for a variety of items including indirectly managing emissions levels (by managing the output of the turbine, it provides means to make adjustments to the combustion process that can affect emissions), controlling the turbine output and response to system conditions, and as a safety system to prevent turbine over speed.

This project has planned work in two years. The first year (2020 commitment) is to rebuild the turbine control valves that are removed from Unit 4 in 2020. This work is associated with shipping the removed valves to have them completely refurbished and prepared so they can be installed as part of the overhaul for Unit 3 scheduled in 2021. This rebuild is to assure the control valves will perform as they are crucial for turbine control and over speed protection.

The 2021 work includes the mobilization of labor, the high velocity oil flush, bearing work as required, general open and close on the generator, throttle valve pinned seat installation, governor valves, turbine control valves, reheat stop valve routine rebuilds, contractor overhead (site support staff, project management, contract engineering support, office/clerical help, etc.), scaffolding, insulation, tool use, general steam chest maintenance, non-destructive evaluation (NDE) testing and maintenance of the bolts and studs on the valves and steam chest and other assigned duties. This maintenance is performed every overhaul to ensure proper operation and reliability of the turbine/generator. This work would coincide with the four-year outage plan for Unit 3. This is currently planned for a window of 56 days starting in early May 2021, with in-service date in June 2021. The investment drivers for this project includes Asset Condition, Customer Service Quality and Reliability, and Performance and Capacity.

Q. Please describe the <u>Unit 4 Intermediate Pressure Turbine Overhaul</u>

Project.

A. This project was originally approved as part of the 2018 budget as a three-year project with completion in 2020. There was consideration given to ordering replacement turbine blades and rings to replace the damaged ones on the first three stages. Because of the extent of the damage observed in the inspection, it was determined to proceed with the replacement of the complete turbine blades, rings, and inner cylinder. The basis for the original 2018 approval was to address reliability concerns associated with the condition of the IP turbine blades and rings. Illustration Nos. 2 and 3 below show the current condition causing the concerns with this equipment and the need for its replacement.

Illustration No. 2: Gouges in Unit 4 RS Generator Blower Stationary Blade Casting

Illustration No. 3: Unit 4 Governor UH Blade Ring 1 Row 1 Typical FOD to Blades

Governor UH Blade Ring 1 Row 1 Typical FOD to Blades

As briefly discussed above, some consideration was given to only replacing the damaged components or doing nothing. When the decision was made, it was determined that replacing the entire turbine blade, ring and rotor sections would best address plant reliability and it would be less expensive to replace rather than repair due to the extensive field work necessary to repair in contrast to the shop work to replace the components.

This project entails disassembling the Intermediate Pressure (IP) Turbine and replacing the turbine rotor, stationary blades (blade rings), and the inner cylinder with new equipment. The current outer cylinder will be re-used. Blade rows 1-3 and blade rings on both sides of the existing IP Turbine have moderate to severe trailing edge erosion and some blunt leading edges. The inlet flow guide is out of round due to thermal distortion and the inner cylinder bolting hardware is starting to bottom out. The initial rows of the turbine have had shroud repairs to mitigate shroud lifting. This work coincided with the four-year outage plan for Unit 4. This outage started in mid-September 2020 with the decision to shift the outage from spring to fall due to the COVID-19 issues and was completed in November 2020. The investment drivers for this project include Asset Condition, Customer Service Quality and Reliability, and Performance and Capacity.

Q. Please describe the <u>Unit 4 Low Pressure Turbine Overhaul Project</u>.

A. Previous Unit 4 inspections found modest damage to the low-pressure turbine. The damage was due to several influences including some debris strike damage, erosion on the blade due to normal operation, and some minor cracking due to age and wear. If this damage was not addressed in a routine way, it could cause a major failure and extended unplanned outage in the future. The scope of this capital project is to perform base maintenance on the Low Pressure (LP) Turbine associated with the overhaul on Colstrip Unit 4. The work included General NDE, cleaning, blade and seal inspections and repairs as needed. This work was done during an overhaul to ensure proper operation and reliability of the LP Turbine. Long established industry practices have demonstrated the prudence of performing this type of work during a planned maintenance event to avoid the risk of a major unplanned failure in the future. The LP Turbine Overhaul Project is planned work driven by manufacturer's recommendations, the results of ongoing inspections, and needed work discovered when the unit is opened up for its planned overhaul. This work coincides with the four-year outage plan for Unit 4. Due to concerns from COVID-19, the spring outage was delayed until fall 2020. This work began in mid-September 2020 and was completed in November 2020. During the maintenance inspection, cracking was found on a low-pressure blade that will require replacement. The investment drivers for this project includes Asset

Condition, and Performance and Capacity.

Q. Please describe the <u>Unit 4 Turbine Generator Base Overhaul Project</u>.

A. This project includes a series of refurbishments and replacement of parts of the turbine controls to assure they will function properly to provide the output control for a variety of items including indirectly managing emissions levels (by managing the output of the turbine, it provides a means to make adjustments to the combustion process that can affect emissions), controlling the turbine output and response to system conditions, and as a safety system to prevent turbine over speed. The Unit 4 Generator Base Overhaul Project includes the mobilization of labor; high velocity oil flush; bearing work as required; general open and close on the generator; throttle valve pinned seat installation; governor valves, turbine valves, and reheat stop valve routine rebuilds; contractor overhead (site support staff, project management, contract engineering support, office/clerical help, etc.); scaffolding; insulation; tool use; general steam chest maintenance; NDE testing and maintenance of the bolts and studs on the valves and steam chest; and other assigned duties. This maintenance project is performed every overhaul to ensure proper operation and reliability of the turbine/generator.

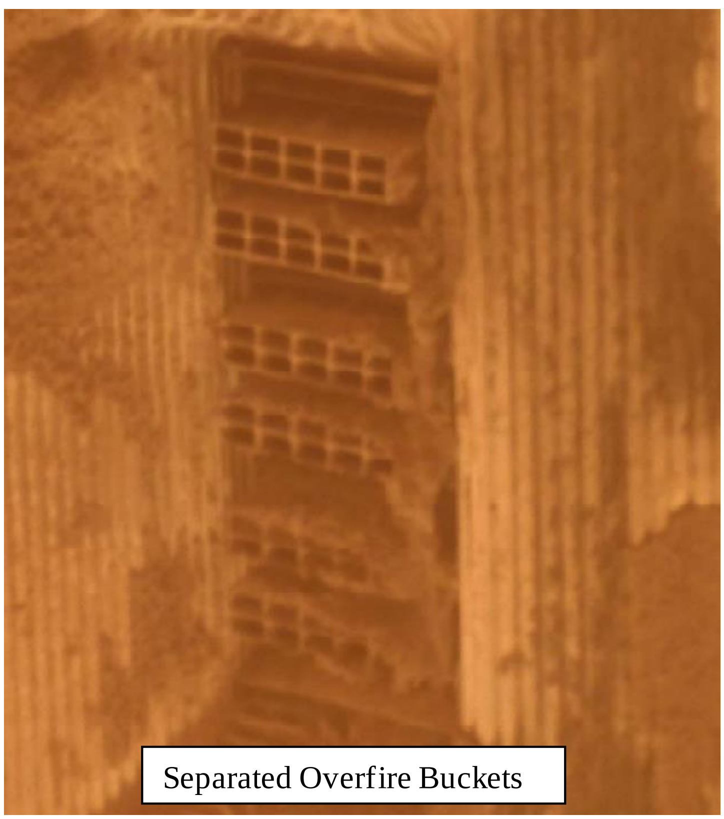
This work will installs a rebuilt turbine valve system that was removed from Unit 3 when it was overhauled in 2017. This project work coincides with the four-year outage plan for Unit 4. With the decision to shift the outage from spring to fall due to the COVID-19 issues, this work began in mid-September 2020 and was completed in November 2020. The investment drivers for this project includes Asset Condition, and Performance and Capacity.

Q. Please describe the <u>Unit 4 Boiler Bucket Burner and Auxiliary Air Replacement Project</u>.

A. A critical component of the NOx control system are the Burner Buckets and

Auxiliary Air Tips. In order to meet environmental emission targets, these elements must perform at a certain level. To maintain equipment function and to provide for NOx emission and opacity control, buckets (separated overfire air (SOFA), top overfire air (TOFA), and Burner) need to be replaced every four years during the unit overhaul. Buckets warp with heat exposure over an extended time, which causes the buckets to bind up in the boiler and restrict movement during unit operation (see Illustration No. 4). Through inspection during overhaul, the buckets are generally found to be at the end of their useful life within three to four years. The elements being replaced here are part of the combustion system. An optimal performing system compliments other emission controls to minimize all emissions from the plant. This project allows the plant to continue to operate within its permitted levels of emissions.

<u>Illustration No. 4: Separated Overfire Buckets</u>



Burner buckets/Aux Air tips are scheduled to be replaced on a four-year plan during an overhaul. Scheduling replacement of these components during an overhaul allows physical access to all buckets (SOFA, TOFA, and Burner) while a scaffold is installed in the boiler. The preventative maintenance process of replacing buckets is most economical with the use of a scaffold as this allows for an effective and cohesive removal of buckets, repairs to support material, testing of movement, and alignment of all emission components associated with the boiler corners at the same time. Burner buckets/Aux Air Tips are a portion of the SmartBurn NOx control system and need to be in good repair for combustion optimization, and particulate matter and NOx control. The work for this project was completed during the Unit 4 major planned outage that began in mid-September 2020 and ended in November 2020. The schedule had shifted from spring to fall due to the decision to delay the outage due to COVID-19 concerns. The investment drivers for this project includes Mandatory and Compliance, Failed Plant and Operation, Asset Condition, Reliability, and Performance and Capacity.

Q. Please describe the <u>Unit 4 Auxiliary Transformer Project</u>.

A. In 2018, the Unit 4 Auxiliary transformer developed high levels of gassing in routine oil sampling indicating internal problems. Specifically, high levels of acetylene. When the transformer was opened for inspection, damage to the tap changer and into the transformer winding was discovered. The damage was unrepairable, so it was determined that the most cost-effective solution was to place an order for a new transformer and replace the out of service unit. The failed auxiliary transformer was original plant equipment and had 36 years of service. As a stop gap measure, a configuration was made with the transmission lines, the unit starting transformers, and station service bus to back feed the auxiliary load (normally served by the auxiliary transformer) through this arrangement. The resulting configuration results in significant system losses. In addition, it would require a significant de-rate on the operating unit in order to start the other unit if it had been shut down for any reason. This configuration placed the entire plant at some risk of losing these key start up transformers as well. The startup transformers were not designed for this heavy continual loading condition. There was discussion to serve Unit 3 with this configuration.

The auxiliary transformer provides the necessary power to run the mills, ID and FD fans, and other critical loads necessary to support the generation of steam to power the turbines. These are very large loads, large enough load to serve a small town in many cases. In addition, other miscellaneous loads needed to run the unit are also provided by this source. An auxiliary transformer is used rather than using the grid as a source in that it can be tapped directly from the output of the generator, saving considerable system losses if the power is sourced through the transmission system. If the grid was used as a source of power for this load, it would expose the plant and these critical loads to a variety of possible failures due to line faults, storms, "driver hits pole" scenario, and other risks. The alternatives for this project were described above. A new auxiliary transformer was the best solution because it reduced exposure to possible grid faults or problems, prevented the use of equipment (i.e. startup transformers) in a manner for which they were not designed, reduced in system losses, increases unit reliability, and reduces wear on the LTC's.

Attempts were made to locate a used or rebuilt transformer, but the unique configuration of the 1,000 MVA rating at the 26kV/13.8kV/4160 winding with load tap changer on both lower voltage windings is very rare. No other units were located. Inquiries were also made to assess if repair of the failed transformer was an option, but vendor quotes indicated it was far more expensive to attempt to repair the unit than to just replace it. The chosen alternative was determined to mitigate risk as a reliability must do project. The order was placed for the transformer in 2019 and the Unit 4 Auxiliary transformer arrived on site in April 2020. Because of concerns with the COVID-19 Pandemic, a small outage of three weeks was taken in May 2020 to inspect Unit 4 in advance of the major overhaul outage rescheduled to September 2020. During this three-week outage, the Unit 4 Auxiliary transformer was installed and was placed into service. The investment drivers for this project includes Failed Plant and Operation, Asset Condition, and Performance and Capacity.

Q. Please describe the <u>Unit 4 Air Preheater Basket Replacement Project</u>.

A. The air pre-heater system is a key to overall boiler efficiency. This system extracts heat from the flue gas and transfers it to the boiler make up air before the fire. It takes less heat using hot air to reach operating temperatures within the boiler than colder air. This process improves the cost effectiveness of the overall system. The condition of the baskets is poor, they are falling apart and clogging the APH causing high differential pressure through the APH which causes more workload on the ID fans. The current design has shown to cause erosion and damage to additional baskets. The recommended replacement is with redesigned baskets.

The Unit 4 Air Preheater Basket Replacement project is to replace major sections of the air heat transfer baskets on the B Air Preheater (APH). Because of the arrangement of the baskets, they wear on the inner rows and some have caused damaged to the intermediate baskets. The wear on the baskets has caused the hot end baskets to fall apart and drop onto the top of the hot intermediate baskets. This has resulted in plugging with the APH that cannot be mitigated with a high-pressure wash. The only way to restore full function of the APH is to replace the damaged APH baskets. Illustrations No. 5 and No. 6 show the damaged condition of the baskets.

Illustration No. 5: Unit 4 Air Preheater Basket Condition

Illustration No. 6: Unit 4 Air Preheater Basket Condition

As this is a replacement of elements of an existing system required for the efficient and reliable operation of the unit, there are few options. Choosing to continue to run in their current condition would result in a continual failure of the system and the degradation of the ability to preheat air for the combustion process, resulting in a significant decrease in unit performance. Removing the Air Preheater is not a viable option as this is a critical element in the heat cycle process and unit performance would significantly change, thereby increasing the operating expense of the plant and subsequently increasing cost to customers.

The replacement option was chosen as it restores normal operating condition to the unit without penalty or significant risk of failure after the overhaul work is completed. Removal and installation of baskets and seals is most effective while done during an overhaul. An overhaul of an air preheater is a systematic process which involves repair of numerous sections of the air preheater as a whole, removal and replacement of baskets, repair of supports as well as removal of ash and other debris. If forced to replace baskets after the overhaul, cost would include about 24 days of lost generation, additional material required to move new and old baskets, cleaning prior to installation and removal, additional staffing, and equipment rental.

This is a reliability must do project. These baskets need to be replaced in order to maintain equipment operation, reliability and efficiency. This work was performed during the 2020 Unit 4 overhaul outage that began in mid-September 2020 and completed in November 2020. The original schedule had shifted from spring to fall due to the decision to delay the outage due to COVID-19 concerns. The investment drivers for this project includes Failed Plant and Operation, Asset Condition, Customer Service Quality and Reliability, and Performance and Capacity.

Q. Please describe the <u>Unit 4 Cooling Tower Fill Project</u>.

A. The Cooling Tower Fill has been in place for over ten years and is over its recommended life span. Cooling Tower Fill ("Fill") is typically replaced every 10 years, per the manufacturer's recommendations. The Fill is becoming brittle, as expected with increasing age; and additionally, the Fill has been subjected to additional breakage due to structural failures in the Cooling Tower structure. As these structural members fail due to normal age and wear, it causes those parts of the Fill material that those members supported to also fail and the brittle remnants of the failed cooling tower cause the circulating water system to plug up. This causes plugging at the screens and throughout the system, resulting in very high condenser back pressure which can lead to unit outages.

This project replaces 90 percent of the Fill and 50 percent of the piping and nozzles, in conjunction with the structural maintenance to replace those failed members during the 2020 overhaul. New Fill material will be installed over these new members that will help restore the Cooling Tower function. This is a partial retrofit intended to allow reasonable operation until a similar project will be done at the next overhaul outage in four years. Additionally, the Fill will need to be removed to replace the structural beams which will cause further degradation and breakage, resulting in reliability issues. The Unit 4 Cooling Tower Fill was replaced during in the 2020 scheduled overhaul outage in November 2020. The investment drivers for this project includes Asset Condition, Customer Service Quality and Reliability, and Performance and Capacity.

Q. Please describe the <u>Install New Capture Wells at Effluent Holding Pond Project</u>.

A. This project provides for additional capture wells to be installed at the Unit 3 and 4 Effluent Holding Pond (EHP) to capture water that seeps from the ponds into the ground. These wells collect this water to keep it from moving off the site. As required by the Colstrip Wastewater AOC, this project provides for additional capture wells to be installed at the Units 3 and 4 EHP to meet the remedy evaluation activities identified in Alternative 4 of the Units 3 and 4 Remedy Evaluation Report. Remedial activities are required under the AOC to mitigate impacted groundwater related to the Units 3 and 4 EHP. The Remedy Evaluation Report was approved by MDEQ and the Remedial Design/Remedial Action Report for Units 3 and 4 is currently under review. Alternative 4 identified the installation of 23 new vertical wells and 2 new horizontal wells in 2020 to meet the cleanup criteria in the time frame identified by MDEQ under the AOC.

Q. Please describe the <u>Design and Install in situ Flushing System EHP Project</u>.

A. This project provides for installation of 46 freshwater injection wells to be installed at the Unit 3 and 4 EHP to promote capture of water that seeps from the ponds into the ground. These wells inject fresh water into the ground to promote flows into the capture wells at the edge of the property near the EHP. This project is another part of the groundwater capture system. As required by the Colstrip Wastewater AOC, which dictates how water on the site is to be remediated, this project provides for design and installation of in-situ flushing wells to be installed at the Unit 3 and 4 EHP to meet the remedy evaluation activities identified in Alternative 4 of the Units 3 and 4 Remedy Evaluation Report. Remedial activities are required under the AOC to mitigate impacted groundwater related to the Unit 3 and 4 EHP. The Remedy Evaluation Report has been approved by the MDEQ and the Remedial Design/Remedial Action Report for Units 3 and 4 is currently under review. Alternative 4 identified the installation of 46 vertical injection wells in 2020 to provide clean flushing water to meet the cleanup criteria in the time frame identified by MDEQ under the AOC. The work on the In-Situ Flushing Well System item consists of design efforts in 2020 and installation in 2021.

Q. Please describe the <u>Design/Build Dry Waste Disposal System Project</u>.

A. This project provides for installation of a "non-liquid" disposal system for Coal Combustion Residue (CCR) material created by the operation of Units 3 and 4. This capital project is required as part of the AOC which dictates how water on the site is to be remediated. The Colstrip Wastewater AOC requires pond closure and remediation activities to address impacted groundwater at the Units 3 and 4 Effluent Holding Pond (EHP) area. Litigation on the AOC resulted in a Settlement that requires a "non-liquid" disposal system for CCR material generated by Units 3 and 4 at the EHP no later than July 1, 2022. This project designs and builds that "non-liquid" disposal system stipulated by the AOC and AOC Settlement requirements. Design efforts began in 2020 and construction will start in 2021 with estimated completion in mid-2022. The investment driver for this project is Mandatory and Compliance.

VI. RATTLESNAKE FLAT WIND POWER PURCHASE AGREEMENT

Q. Please explain the Rattlesnake Flat Wind Power Purchase Agreement and what was the need for that resource?

A. The Rattlesnake Flat Wind Power Purchase Agreement (Rattlesnake Wind PPA) is a 20-year agreement to purchase all of the generation output and all environmental benefits associated with the 144 MW Rattlesnake Flat Wind project. Avista's acquisition of the Rattlesnake Flat Wind project began with the goal of acquiring renewable energy at a price less than Avista's 2017 IRP avoided cost as filed with the IPUC on August 31, 2017 and acknowledged in Case No AVU-E-17-08, Order No. 33971 on January 31, 2018. Any long-term resource acquisition below these avoided costs is in the best interest of customers for two reasons. First, the expected cost is less than the forecast price of power at the time of the acquisition. Second, the price is fixed (known) as compared to the electric market that could change over time due to many factors that are often out of the Company's control.

Avista issued a renewable RFP in June 2018 to attempt to secure low cost renewable generation based on expiring tax breaks and indicative developer pricing. A full summary of the RFP process and justifications for signing the Rattlesnake PPA is provided as Exhibit No. 7, Schedule 6C – 2018 Renewable RFP Report.

Q. Please briefly describe the Rattlesnake Flat Wind Project.

A. The Rattlesnake Flat Wind Project consists of 50 Siemens S-129 2.9 MW wind turbines that are located on 20,000 acres about 12 miles southeast of Lind, Washington with a total capacity 160.45 MWs nameplate capacity "clipped" to 144 MWs of maximum delivery based on the interconnection contract with Avista. The project is directly connected to the Avista electric system and began commercial operation in December 2020.

Q. Can you provide a simplified timeline of events leading up to the execution of the Rattlesnake Flat Wind PPA?

A. Yes. The following list is a timeline of the major events leading up to the execution of the Rattlesnake Flat Wind PPA:

- **2014 to 2017:** Company received unsolicited indicative bids for wind projects with increasingly attractive pricing.
- **First Quarter 2018:** Lower indicative bid pricing received from potential developers.
- **March 2018 –** Initiated renewable RFP process internally.

- **March 2018:** Retained Black & Veatch as an Independent Evaluator for the RFP.
- **May 2018:** Outreach with Idaho Commission staff and intervenors.
- **June 6, 2018:** Phase I - RFP released.
- **June 21, 2018:** RFP Phase I bid opening and conference call with Commission Staff, among others.
- **June 29, 2020:** Phase II – Shortlist identified, eight bidders.
- **July 9, 2018:** Conference Call – RFP short list update and presentation to Idaho Commission Staff.
- **July 23, 2018 to August 15, 2018:** Questions and clarifications with Phase II bidders.
- **August 16, 2018:** Phase 2 – Requested price refresh from Phase II bidders.
- **August 24, 2018:** Received price refresh.
- **September 12, 2018:** Selected Rattlesnake Flat Wind Project as the preferred project.
- **September 19, 2018:** Notified Commission Staff of the winning RFP selection.
- **September 2018 – February 2019:** Contract negotiations.
- **March 7, 2019:** Signed contract with Clearway Energy for the Rattlesnake Flat 144 MW wind project - ***See Exhibit No. 7, Schedule 7C***

Q. Can you provide some background regarding why the Company initiated an RFP for renewable resources in 2018.

A. Yes. Avista began the 2018 RFP process with the goal of acquiring renewable energy below the avoided cost identified in the 2017 IRP ($31.87 per MWh for wind and $29.90 per MWh for solar, page 11-19 of the 2017 IRP). Obtaining this new, long-term renewable resource would be in the best interests of customers because the cost would be below the forecast price of power at the time of the acquisition and it would be at a known price thereby eliminating the variations inherent in shorter term market purchases.

The spring of 2018 was seen as an opportune time for the Company to request and evaluate renewable market options. Indicators for the timing of this RFP included the expiration of the Production Tax Credit (PTC) in 2020, indicative pricing and developer activity, competition for preferred projects and locations, technology advancements and competition for least cost resources. The PTC was lowering prices as compared to price quotes after 2020. The $23/MWh PTC was scheduled to be reduced or expire in 2020, as well as the investment tax credit (ITC) in 2022[2]. The $23/MWh PTC value is significant as it represents approximately 44 percent of the cost of the selected project for the first 10 years. Pricing was expected to increase after tax credits expired. Developer activity along with industry market insights provided Avista opportunities to observe and analyze changes in renewable energy technology and pricing. Indicative and actual pricing for renewables in the west at that time suggested renewable resources were competitive in the wholesale market. In fact, pricing provided to Avista during 2017 and early 2018 showed falling renewable prices. With advances of machine technologies and the sun-setting of tax credits, pricing for renewables had never been lower. Indications were pricing could increase if tax credit opportunities were not fully captured. A more detailed discussion of the background for initiating the 2018 Renewables RFP is available in Exhibit No 7, Schedule 6C – 2018 Renewable RFP Report.

Q. At the time of the 2018 Renewables RFP, please explain how the Company determined that a new resource was necessary.

A. The 2018 RFP for renewables was issued in June 2018 to leverage beneficial pricing including tax breaks going away and developer pricing. Although this RFP was held prior to the Company's announcement of its clean energy goals discussed earlier in my testimony, the RFP provided an opportunity for the Company to evaluate a transition to a cleaner resource portfolio at a lower cost. The Preferred Resource Strategy identified in the

[2] The Investment Tax Credit (ITC) was modified by the IRS to include certain projects completed by 2024 on June 22, 2018, subsequent to the issuance of the RFP.

2017 Integrated Resource Planning process only included the Solar Select renewable resource. The other new resources identified in that IRP included natural gas peakers, upgrades to existing facilities, energy efficiency, demand response and some distribution efficiencies. As discussed in the 2017 IRP, Avista relies on market purchases to meet a small portion of its energy and capacity needs. If Avista could replace these market purchases with a known lower cost resource, then it is in the best interest of its customers to do so.

Q. How did the Company determine the amount and type of resource needed?

A. The Company's energy, capacity and REC needs were used as inputs to the development of the Preferred Resource Strategy (PRS). The PRS is developed using a proprietary linear programming model called PRiSM. The PRiSM model helps select the PRS and uses:

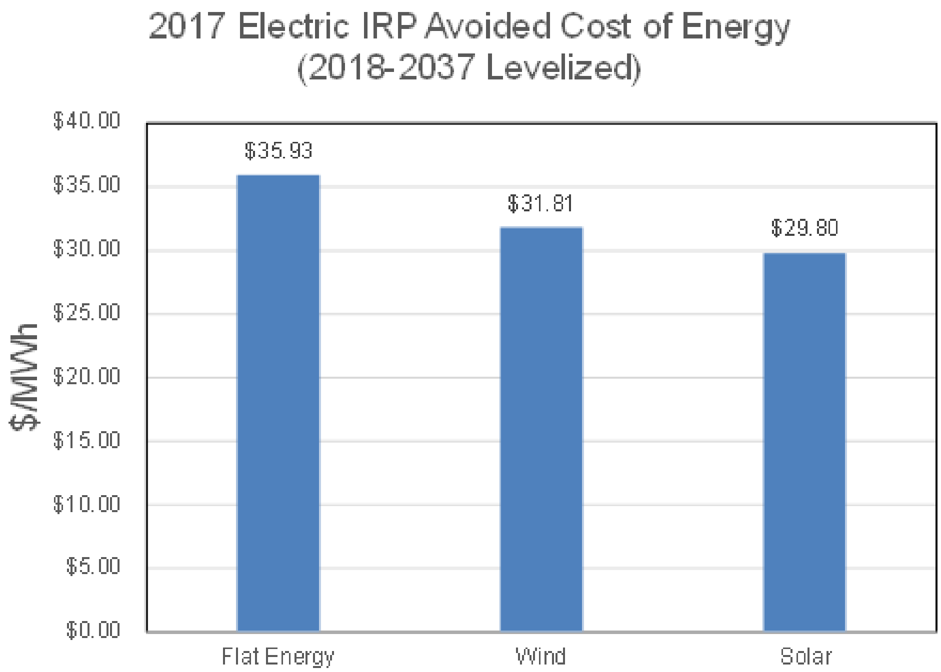
1. Load deficits (energy and capacity);
2. RPS requirements;
3. Avista's existing portfolio's costs (loads and resources) and operating margins (resources);
4. Fixed operating costs, return on capital, interest and taxes for each resource option;
5. Generation levels for existing resources and new resource options; and
6. Carbon emissions levels for existing resources and new resource options.

Additional details about the development of the PRS and the PRiSM model used to decide on the acquisition of Rattlesnake Flat Wind can be found in Chapter 11 of the 2017 IRP (Exhibit No. 7, Schedule 9).

Q. Is this resource consistent with the 2017 Preferred Resource Strategy in the Company's 2017 IRP?

A. Yes, the 2018 RFP for renewables was consistent with the 2017 Preferred Resource Strategy by considering acquiring additional resources if the resource has a lower long-term cost than electric energy market alternatives. Chart No. 1 below shows that the 2018-2037 levelized cost of energy in the 2017 IRP was projected to be less costly for wind and solar resources than for a flat energy project.

Chart No. 1: Levelized Electric IRP Avoided Cost of Energy*[3]



Q. How did Avista evaluate and consider alternatives to the Rattlesnake Flat Wind PPA?

A. The Company issued an RFP on June 6, 2018 for 50 aMW of Washington RPS-qualified renewable energy to be online by the end of 2020 and to secure the output through a Power Purchase Agreement (PPA) and/or an option to purchase the project from renewable generation resources, including electricity, capacity and associated environmental attributes.

[3] Source: Data from 2017 IRP, Table 11.6 on pages 11-19.

(See Exhibit No 7, Schedule 6C). Bidders could submit one or more proposals including wind, solar, geothermal, biomass, hydroelectric, and other renewable resources with or without storage with a minimum net annual output of 5 aMW AC up to 50 aMW. The RFP was open to parties who owned, proposed to develop, or held rights to new renewable resource generating facilities. Avista engaged an independent evaluator, Black & Veatch, for this RFP to review the selection criteria and provide an independent review of the received bids. The Company did not accept proposals for renewable energy certificates only and did not consider a self-build option in this RFP.

Avista produced an evaluation criteria and methodology for scoring bids in consultation with the independent evaluator. The RFP evaluation methodology was shared and discussed with the Staffs of the IPUC and WUTC on June 21, 2018. The methodology is provided in <u>Exhibit A of the 2018 Renewable RFP Report contained in</u> Exhibit No 7, Schedule 6C. The general qualifications for each proposal were evaluated on the five characteristics shown in Table No. 4 below. The weightings for each characteristic were determined based on their importance in helping the Company meet its resource development goals stated in the 2017 IRP. Within each characteristic, <u>points can be subtracted or added to the initial 100 points</u> based on responses to the RFP and Avista's interpretation of the data. Avista reserved the right to modify the scoring criteria in consultation with Black & Veatch and the Commission Staffs in Idaho and Washington if proposals were received that contained circumstances not considered in the original methodology. However, this was unnecessary, as the situation did not occur.

Table No. 4: 2018 Renewables RFP Evaluation Criteria and Weightings

Characteristic	Weighting (%)
Risk Management	25
Net Price	40
Price Risk	5
Electric Factors	20
Environmental	10
Total	100

Avista utilized a two-step bid process. Avista first evaluated and ranked projects based on preliminary information by allowing developers to submit a condensed initial bid utilizing a template provided in the RFP. The evaluation and ranking of the preliminary information focused on conformance of each bidder's submittal with the RFP requirements and the proposed net price, among other factors. Evaluation and ranking, performed in a fair and consistent manner, produced a short list of bids confirmed by Black & Veatch. Once the short list was compiled, short-listed bidders were asked to submit detailed proposals. Each short-listed bidder's detailed proposal was evaluated against the other proposals. In the end, 28 developers submitted over 40 responses to the RFP with projects in excess of 3,000 MW proposed. Potential projects were evaluated both quantitatively and qualitatively based on predetermined criteria shared with the staffs of the Idaho and Washington Commissions. Eight projects were selected for a short list and were asked to provide detailed responses to the proposal.

The first screening began on June 20, 2018. This screen focused on removing proposals that did not meet the minimum RFP requirements. Preliminary information was reviewed for all projects and an initial break point was established based on site control and other issues. Most projects had either executed a binding option to lease the project site or executed lease agreement(s) with landowner(s). Bids that had not discussed the project with the landowner or had not executed any agreements were removed from further consideration. Projects that did not provide a bid price were also removed. Sixteen project proposals were eliminated through this initial review process.

Further evaluation of Preliminary Information resulted in rankings with a clear break in the rankings after the top seven proposals. As we investigated one project further, it was confirmed this was a repowering of an existing wind farm at the same capacity so the project did not meet the RFP requirement for a new resource. Out of the top six ranked projects, five were wind projects. To provide some projects for comparison to the top ranked solar project, two additional solar projects were short-listed based on their next lowest solar PPA price and mitigation of interconnection concerns based on commercial operation date.

To help Avista differentiate between the short-listed bids from the first to the second rounds, eight short-listed bidders were asked to provide detailed proposals. The short-listed bidders were further evaluated and additional due diligence was performed on each of the more detailed offerings, which were then re-ranked according to the selection criteria.

Shortlisted bidders were allowed to refresh their prices in late August 2018 to help differentiate their projects from the competition. Based on the new price information, and the previous project descriptions, a new assessment and project ranking was performed. Exhibit No. 7, Schedule 6C provides additional details about each of the short-listed bidder projects and how they were ranked in the RFP. The price refresh established a clear winner based on

PPA price, permitting, and known integration and transmission costs. Ultimately, the cost for the Rattlesnake Flat project along with the results from the evaluation matrix confirmed the project as a top pick amongst the Avista RFP team and Black & Veatch.

Q. How was transmission considered in this decision?

A. The evaluation process included the transmission interconnection cost in the case of projects with proposed direct interconnection with the Avista transmission system or transmission and losses for projects proposed to interconnect to third party transmission systems and wheeling power to the Avista system. The Rattlesnake Flat Wind Project was designed to be directly interconnected to Avista's system, so no long-term third-party transmission is required for this project to serve our customers.

Q. Was Avista's Board of Directors involved with the acquisition of the Rattlesnake Wind PPA by Avista Utilities?

A. Yes. The Company's Board of Directors was apprised of the 2018 Renewables RFP and the evaluation process that was used to compare project bids from which the Rattlesnake Flat Wind PPA was selected. Documentation of Board involvement regarding the Rattlesnake Wind PPA is provided in Exhibit No. 7, Schedule 8C. This confidential exhibit includes presentations to the Board of Directors regarding the Rattlesnake Flat Wind PPA.

Q. What documentation for the analysis and decision-making process has the Company provided regarding the decision to enter into a contract for the Rattlesnake Flat Wind Project?

A. Exhibit No. 7, Schedule 6C includes the complete documentation concerning the RFP solicitation, and evaluation process that resulted in the selection and signing of the

Rattlesnake Flat Wind Power Purchase Agreement.

Q. Does the Company believe that the Rattlesnake Flat Wind PPA was a prudent contract acquisition?

A. Yes. My testimony and exhibits provide the documentation necessary to demonstrate the long-term economic benefit to Idaho customers for the Rattlesnake Flat Wind PPA and provide specific supporting details regarding the Company's analysis and decision. The executed PPA will support the Company's clean energy goals. The Rattlesnake PPA also fits within the analysis performed under the Company's IRPs. The Board of Directors agreed with the recommendation to issue the RFP for 50 aMW of RPS-qualified renewable energy in 2018 and was apprised of management's recommendation to negotiate a PPA with Rattlesnake Flat Wind, LLC under terms and conditions consistent with their bid proposal. The Company has provided and explained all of the analytical work that was completed related to this acquisition through a competitive RFP with the aid of an independent evaluator, as well as participation by both the Idaho and Washington Commission Staffs in the entire RPF process.

Q. Does this conclude your pre filed direct testimony?

A. Yes, it does.