Exh. JRT-1T

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-22____

DOCKET NO. UG-22____

DIRECT TESTIMONY OF

JASON R. THACKSTON

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Jason R. Thackston. I am employed as the Senior Vice President of Energy Resources 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 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 this case, including capital additions associated with the Company's investment in Colstrip Unit Nos. 3 and 4 for the periods 2021-2024. My testimony will conclude with a discussion of the Chelan PUD Power Purchase Agreement.

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits?

A. Yes. Exh. JRT-2 is Avista's 2021 Electric Integrated Resource Plan, Appendices and Update. Confidential Exh. JRT-3C is Avista's Energy Resources Risk Policy. Exh. JRT-4 includes the capital Business Cases for the 2021-2024 non-Colstrip generation projects, all of which are discussed later in my testimony. Confidential Exh. JRT-5C provides documentation about the reduction in scope of Colstrip's 2021 budget. Confidential Exh. JRT-6C provides the 2022 Colstrip Hurdle Sheets. Confidential Exh. JRT-7C provides the Colstrip Business Case and documentation tying to capital spend data. Confidential Exh. JRT-8C provides additional documentation about the capital projects at Colstrip, including transfer-to-plant data, in the 2021-2024 period. Confidential Exh. JRT-9C contains the 2020 Renewable RFP Report and Documentation. Finally, Confidential Exh. JRT-10C includes the Chelan PUD Power Purchase Agreement.

II. 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 Energy Resources Department (Energy Resources) is responsible for dispatch decisions related to those resources for which the Company has dispatch rights. Energy Resources 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 2021 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 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 Exh. JRT-2, Avista's 2021 Electric Integrated Resource Plan, which was filed with the Commission on April 1, 2021. An update to the 2021 IRP was filed on April 30, 2021 after signing the contract with Chelan PUD discussed in Section VI of my testimony.

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

A. The Preferred Resource Strategy (PRS) in the 2021 Electric IRP guides the

Company's resource acquisitions, subject to any additional legislative requirements, such as the clean energy requirements under Washington's Clean Energy Transformation Act (CETA). The IRP provides details about future resource needs, specific resource costs, resource-operating characteristics, and the scenarios used for evaluating the mix of resources for the PRS and under different future assumptions. The IRP represents the preferred plan at a point in time; however, Avista continuously evaluates alternative resource options to meet current and future load obligations, especially in light of new legislation and market opportunities.

Avista's 2021 PRS includes the addition of new wind, natural gas-fired peakers, battery storage, solar, liquid air storage and plant upgrades as well as the loss of coal, natural gas-fired solar and wind resources from the Company's resource portfolio. The PRS also includes 71 MW of demand response and new energy efficiency through 2045. The timing and type of these resources included in the PRS for the 2021 IRP are provided in Tables No. 1 through No. 3 below for the 2022-2031, 2032-2041 and 2042-2045 periods.

Table No. 1: 2021 Electric IRP Preferred Resource Strategy (2022 – 2031)[1]

Resource	Jurisdiction	Year	ISO Conditions (MW)	Equivalent Winter Peak Capacity (MW)	Energy Capability (aMW)
Colstrip 3 & 4[1]	System	TBD	-222	-222	-206
Montana wind	WA	2025	100	33	45
Post Falls modernization	System	2026	8	4	4
Lancaster PPA	System	2026	-257	-283	-209
Kettle Falls modernization	System	2027	12	12	10
Natural gas CT	WA	2027	84	93	76
Natural gas CT	ID	2027	84	96	76
Montana wind	WA	2028	100	33	45
Natural gas reciprocating ICE	ID	2031	55	54	50
Mid-Columbia Hydro Extension	WA	2031	75	44	33
Total New Resources			**518**	**369**	**339**
Net of Removed Resources			**39**	**-136**	**-76**

[1] The following three tables are the same as Tables 2-4 from Avista's April 30, 2021 "2021 Electric Integrated Resource Plan – Preferred Resource Strategy Update" which was provided after Avista executed the Chelan PUD PPA referenced later in my testimony. This "Update" has been included in Exh. JRT-2.

Table No. 2: 2021 Electric IRP Preferred Resource Strategy (2032 – 2041)

Resource	Jurisdiction	Year	ISO Conditions (MW)	Equivalent Winter Peak Capacity (MW)	Energy Capability (aMW)
Montana wind	WA	2034	100	28	45
Rathdrum upgrade	System	2034	5	5	4
Northeast CT[1]	System	2035	-62	-43	0
Natural gas CT	System	2036	84	93	76
Adams-Neilson Solar PPA	WA	2037	-19.2	0	-5
Solar w/ storage	System	2038	100	2	26
4-hour storage (lithium-ion)	System	2038	50	7	-2
Rattlesnake Flat PPA	System	2040	-145	-7	-55
Boulder Park	System	2041	-25	-25	-14
Montana wind	WA	2041	100	26	45
Natural gas reciprocating ICE	ID	2041	36	35	33
Total New Resources			**475**	**196**	**227**
Net of Removed Resources			**224**	**121**	**153**

Table No. 3: 2021 Electric IRP Preferred Resource Strategy (2042 – 2045)

Resource	Jurisdiction	Year	ISO Conditions (MW)	Equivalent Winter Peak Capacity (MW)	Energy Capability (aMW)
Palouse Wind PPA	System	2042	-105	-5	-36
Solar w/ storage	WA	2042	117	2	31
4-hour storage (lithium-ion)	WA	2042	58	9	-2
Solar w/ storage	WA	2043	122	2	31
4-hour storage (lithium-ion)	WA	2043	61	9	-2
Liquid Air Energy Storage	WA	2044	13	7	-1
Solar w/ storage	WA	2045	149	3	40
4-hour storage (lithium-ion)	WA	2045	75	11	-2
4-hour storage (lithium-ion)	ID	2045	16	2	-1
Total New Resources			**611**	**45**	**94**
Net of Removed Resources			**506**	**40**	**58**

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

A. Yes. Avista uses several techniques to manage the risks associated with serving customers and managing Company-owned and controlled resources. The Energy Resources

Risk Policy, which is attached as Confidential Exh. JRT-3C, provides general guidance to manage the Company's energy risk exposure relating to electric power and natural gas resources over the long-term (more than 41 months), the short-term (monthly and quarterly periods up to approximately 41 months), and the immediate term (present month).

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 period. Electric power and natural gas fuel transactions in the immediate term are driven by a combination of factors that incorporate both economics and operations, including near-term market conditions (price and liquidity), generation economics, project license requirements, load and generation variability and availability, reliability considerations, and other near-term operational factors.

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

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

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

A. Yes, as discussed in detail in the Company's last general rate case, Avista starts participating in the CAISO Western Energy Imbalance Market (EIM) beginning in March of 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.

III. OVERVIEW OF 2021 GENERATION CAPITAL PROJECTS

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.

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[2] enterprise asset management software as the central repository

[2] Avista utilizes IBM's Maximo asset management system - www.ibm.com/products/maximo/asset-management.

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. The following illustrates the process:

Illustration No. 1: Capital Planning Process

Q. Company witness Mr. Ehrbar 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 <u>for generation projects</u> include Mandatory and Compliance, Failed Plant and Operation, Asset Condition, Customer Service Quality and Reliability, and Performance and Capacity.

Q. Would you please provide a listing of the generation capital additions in 2021 that the Company is seeking to include in general rates in this case?

A. Yes. Table No. 4 below lists the projects and costs for the 2021 non-Colstrip generation capital projects included in this case. Details regarding each capital project, alternatives considered, how the project benefits customers, and any direct offsetting benefits are covered for each project are detailed below. Information and details regarding non-Colstrip generation capital projects for 2022, 2023 and 2024 will be covered in Section IV of my testimony. Exh. JRT-4 provides the Business Cases supporting each of these non-Colstrip generation capital projects. Note that the generation capital projects associated with Colstrip Units 3 and 4 are discussed in Section V.

Table No. 4: 2021 Non-Colstrip Generation Capital Projects

Project #	Business Case	2021 TTP (System)	Exh. JRT-4 Page #
Generation			
1	Automation Replacement	$ 632,112	3
2	Base Load Hydro	639,601	10
3	Base Load Thermal Program	2,501,333	18
4	Cabinet Gorge 15 kV Bus Replacement	394,671	26
5	Cabinet Gorge Dam Fishway	126,550	30
6	Cabinet Gorge Unit 3 Protection & Control Upgrade	3,073,449	39
7	Cabinet Gorge Unit 4 Protection & Control Upgrade	2,714,355	45
8	Clark Fork Settlement Agreement	5,477,022	51
9	Coyote Springs LTSA	15,898,972	57
10	CS2 Single Phase Transformer	17,052,971	64
11	Generation DC Supplied System Update	6,864	74
12	HMI Control Software	3,055,633	81
13	Hydro Safety Minor Blanket	49,317	90
14	Little Falls Plant Upgrade	1,680,999	95
15	Long Lake Plant Upgrade	2,264,782	102
16	Peaking Generation Business Case	598,839	113
17	Post Falls Landing and Crane Pad Development	3,508,167	121
18	Regulating Hydro	3,367,438	127
19	Spokane River License Implementation	904,651	135
20	Strategic Initiatives	3,373,971	142
21	Use Permits	27,142	151
22	WSDOT Franchises	20,525	157
Total Generation		**$ 67,369,363**	
Exh. JRT-1T Total 2021 Capital Additions		**$ 67,369,363**	

Q. Has the Company calculated and included a description of any offsetting factors to the capital projects in this case?

A. Yes. For those capital projects that have direct benefit offsets, I have included a description of the offsets in the project description. Company witness Ms. Andrews provides an explanation regarding how the direct offsets are factored into the revenue requirement of this case, an explanation of the Company's efficiency adjustment included in this case, and a description of indirect offsets associated with the capital projects in this case. The efficiency adjustment of 2% was used where there were no <u>direct</u> offsetting benefits, and where the projects were not otherwise required for mandatory and compliance purposes, as discussed by Ms. Andrews.

Q. Would you please describe the Company's investments in Project #1, <u>Automation Replacement</u> project?

A. Yes. The Automation Replacement project systematically replaces the unit and station service control equipment at our generating facilities with a system that is 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 is needed to reduce the higher risk of failure due to the age of the currently installed equipment. The DCSs are no longer supported in the industry, and spare modules are limited in availability. The modules in service have a high risk of failure as they are over 20 years old. The computer drivers 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 today are increasingly called on to quickly change output in response to the variability of wind and solar generation, to adjust to changing customer loads, and provide 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. Please see Exh. JRT-4, pp. 3-9 for additional information about this project.

Q. Did Avista consider alternatives to this approach?

A. Yes, the Company considered three alternatives for this project. The first alternative involved doing nothing and fixing the problem with old spare parts or refurbished third party parts. This option would allow for the continued use of existing infrastructure and logic programs for a period of time, but would not resolve the long-term problem of parts availability, and continuing to use computers with unsupported operating systems and subsequent cyber security risks. The second alternative considered a software upgrade from Windows 9 and Windows XP to Windows 10. This option would solve the software and security issues, but would require outages, would not align with our standard PLC platforms, and would introduce new software applications, making the systems less efficient to troubleshoot and resolve issues.

Q. How does this project benefit Avista's customers?

A. Proactively replacing these devices benefits customers by reducing unexpected plant outages that require emergency repair with like equipment. A planned approach allows engineers and technicians to update logic programs more effectively and replace hardware with current standards.

Q. Does this project have a target completion date?

A. This is an ongoing project with work currently scheduled through 2022. The balance of plant work at Post Falls, Noxon Rapids Units 1 through 5 and Coyote Springs 2 will be completed in 2023-2024.

Q. What capital investments for this project have been completed for 2021?

A. The total capital investment is $632,112 in 2021. Projects for 2021 for this program include Upper Falls Unit 1, Control Works and Boulder Park Design.

Q. Are there any direct offsets associated with this project?

A. No, there are not. However, the Company has included a 2% efficiency adjustment for this project in 2022, 2023 and 2024. That adjustment for this project is included in Ms. Andrews' adjustments 4.03 and 5.09.

Q. Would you please describe the Company's investments in Project #2, <u>Base Load Hydro</u> project?

A. Avista's Base Load Hydro plants are all located on the upper Spokane River and are "run of river" plants which means they have little to no storage capacity, and their operation is subjected to the flow in the Spokane River and the lake level requirements of Lake Coeur d'Alene. The facilities in this program include Post Falls, Upper Falls, Monroe Street and Nine Mile Hydroelectric Developments. This program also includes capital projects at the Generation Control Center and on the Generation Control Network, as well as some projects at the Post Street 115kV Substation, where the two downtown hydro plants (Upper Falls and Monroe Street) are tied into the electric grid.

This program funds smaller capital expenditures and upgrades required to maintain safe and reliable operation. 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 are 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 are reactionary to plant operational support issues. Without this program it would be difficult to resolve relatively small projects concerning failed equipment and asset condition in a timely manner. This would jeopardize plant availability and greatly impact the value to our customers and the stability of the grid. Due to the age of the facilities, more and more critical assets, support systems and equipment are reaching the end of their useful life. This program is critical in continuing to support asset management program lifecycle replacement schedules. The annual cost of this program varies depending on discovery of unfavorable asset conditions and the unpredictability of equipment failures. Please see Exh. JRT-4, pp. 10-17 for additional information about this project.

Q. Did Avista consider alternatives to this approach?

A. Yes. The primary alternative would be to attempt to repair this equipment instead of replacing critical assets at the end of their lifecycle. This will be unacceptably expensive and older equipment would become more unreliable until it becomes obsolete. Operating in a "run-to-failure" mode is proven to be an unsuccessful approach and subjects Avista and its customers to unacceptable risk.

Q. How does this project benefit Avista's customers?

A. The operational availability for these generating units in these plants is paramount. The purpose of this program is to fund smaller capital expenditures and upgrades that are required to maintain safe and reliable operation. Maintaining these plants safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System.

Q. Does the project have a target completion date?

A. No, as explained in the overview of the project, this is an ongoing project, with transfers to plant occurring in 2022-2024.

Q. What capital additions for this program will be completed for 2021?

A. The total capital investment is $639,601 in 2021. Projects completed in 2021 for this program include the replacement of the Monroe Street holding tank, replacement of the Nine Mile strainer gearbox, the Post Falls GS2 removal and GSU 1 refill, Post Falls Mercoid switch replacements, plumbing work at the Post Falls Cottage #2, Post Falls replacement of switch #1, the governor servomotor replacement at Upper Falls, the Upper Falls HH conduit installation and the replacement of the Upper Falls headgate cam.

Q. Are there any direct offsets associated with this project?

A. No, there are not. However, the Company has included a 2% efficiency adjustment for this project in 2022, 2023 and 2024. That adjustment for this project is included in Ms. Andrews' adjustments 4.03 and 5.09.

Q. Would you please describe the Company's investments in Project #3, <u>Base Load Thermal Program</u>?

A. The purpose of the Base Load Thermal Program is for Kettle Falls Generating Station and Coyote Springs 2 to keep their operating expenses as low as possible by providing funding for many individual projects under this program. These projects are typically to replace things that are broken or are at their end of useful life. The investment drivers for this project includes Asset Condition, and Performance and Capacity. 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. Please see Exh. JRT-4, pp. 18-25 for additional information about this project.

Q. Did Avista consider alternatives to this program?

A. The individual projects within the Base Load Thermal Program are evaluated by committees that are respective to Kettle Falls and Coyote Springs 2. One of the purposes of this evaluation is to ensure appropriateness of the project and analysis of any alternatives, if applicable. 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.

Q. How does this program benefit Avista's customers?

A. This program is designed to ensure continued safe, low cost, reliable, and compliant electrical generation for the use and benefit of Avista's electrical customers at the Kettle Falls Generating Station and at the Coyote Springs 2 natural gas-fired plant.

Q. Does the program have a target completion date?

A. No. This is a recurring program required for ongoing operations so there is no anticipated completion date, but anticipated transfers to plant are included for 2022-2024. The project is reviewed and renewed on a five-year cycle.

Q. What capital additions for this project will be completed for 2021?

A. The total capital investment is $2,501,333 in 2021 for various projects at Kettle Falls and Coyote Springs 2.

Q. Are there any direct offsets associated with this project?

A. Yes, there are $9,500 in direct O&M cost offsets in 2023, and a 2% efficiency adjustment for this project in 2022, 2023 and 2024 as shown in Exh. EMA-5. That adjustment for this project is included in Ms. Andrews' adjustments 4.03 and 5.09.

Q. Would you please describe the Company's investment in Project #4, the <u>Cabinet Gorge 15 kV Bus Replacement</u> Project?

A. Yes. The scope of this project includes the replacement of the existing 15 kV bus with a new 4000 Amp segregated bus at Cabinet Gorge. The new configuration increased load rating and the horizontal sections was raised five feet to allow for acceptable access to the bus room equipment. The replaced 15kV bus was underrated by approximately 10 percent based on the load requirements between the generators and the Generation Step-up (GSU) transformers. In addition, the replaced configuration and location of the bus was preventing access for the installation of new station service equipment in the bus rooms. This access required the horizontal portion of the bus to be raised five feet. Please see Exh. JRT-4, pp. 26-29 for additional information about this project.

Q. Did Avista consider alternatives to this project or program?

A. Yes. The first alternative considered raising the existing bus section. This alternative was unfavorable because it would extend the plant outage to approximately eight weeks. New transition sections would still be required and there was a signification risk to damaging the old existing hardware, insulators and bus sections. This alternative also did not address the marginal rating of the existing equipment. This would be the highest cost alternative.

The second alternative considered, and selected, was the replacement of the existing 15kV bus with a new 4000 Amp segregated bus. This was the least cost alternative. This alternative upgraded the bus rating to be more in line with the generators and GSU transformers and required only a two-week outage per bus section. The new bus will be seismically-certified as a packaged system and would include all the appropriate vertical and horizontal bus sections, hangers and support systems required to raise and install the bus.

Q. How does this project benefit Avista's customers?

A. Avista's safe and reliable infrastructure strategic initiative seeks to leverage technology and innovative products and services offered to existing and new customers. The work proposed for Cabinet Gorge 15 kV Bus Replacement will include equipment and component replacement geared toward increasing reliability and plant capacity. Customers benefit in that it will allow Avista to economically optimize an existing asset to provide energy and other energy related products.

Q. What is the project completion date?

A. The B section of the bus was placed into service on June 4, 2021. The A Section of the bus was completed in October 2021. The bus outage for the A section took place in September and October of 2021 and with a transfer to plant of approximately $190,000 in

November of 2021.

Q. What are the capital additions for this project that will be completed for 2021?

A. The total capital investment is $394,671.

Q. Are there any direct offsetting benefits associated with this project?

A. There are no direct offsetting benefits for this project, a 2% efficiency adder was included as shown in Ms. Andrews Exh. EMA-5.

Q. Please describe the Company's investments in Project #5, the <u>Cabinet Gorge Dam Fishway</u> <u>Project</u>.

A. 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. Appendix C of the CFSA commits Avista to fund Fishway design and construction as well as annual operations. 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 under Section 18 of the Federal Power Act to require fish passage at both Noxon Rapids and Cabinet Gorge dams, in order to pursue the NSRP more collaboratively. Those efforts, including involvement of native American tribes and state agencies, as well as other stakeholders, continued over 15 years to the current project. Please see Exh. JRT-4, pp. 30-38 for additional information about this project.

Q. Did Avista consider alternatives to this investment?

A. The Clark Fork Settlement Agreement (CFSA) under FERC License No. 2058 issued for Cabinet Gorge HED in 2001, and Amendment No. 1 of the Clark Fork Settlement

Agreement both stipulate that Avista will construct a fish passage facility for Bull Trout at Cabinet Gorge Dam. As such, there is no alternative to constructing the facility. Not doing so could jeopardize the FERC license and thus the ability to generate power at Cabinet Gorge Dam.

Q. How does this project benefit Avista's customers?

A. This project will benefit our customers by maintaining compliance with the CFSA and FERC License and subsequent agreements, which provide operational flexibility at Avista's Noxon and Cabinet Gorge Facilities. The Agreement and License support all electric customers in Washington and Idaho by authorizing the continued operation of Noxon and Cabinet Gorge dams.

Q. Does the project have a target completion date?

A. Yes, final construction is expected to be completed by July 2023 and FERC project closeout in October 2023.

Q. What capital additions for this project will be completed for 2021?

A. The total capital investment is $126,550 in 2021. Additional costs of $63,475,101 are reflected in 2023, as shown in Table No. 4.

Q. Are there any direct offsets associated with this project?

A. This is a mandatory project required under license. There are no direct or indirect offsetting benefits related to this Business Case in 2021 or in 2022-2024.

Q. Please describe the Company's investments in Projects #6 and #7, <u>Cabinet Gorge Unit 3 (Project #6) and Unit 4 (Project #7) Protection & Control Upgrade Projects</u>?

A. 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 control 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 Units 3 and 4.

Projects #6 and #7 are overall protection and control upgrades that addresses all of the components of the generator and turbine to ensure that each auxiliary system connects and communicates as one. If individual failures were realized, they would be addressed with a patchwork of components that would not connect and communicate with one another requiring the eventual forced rework of the whole systems. These protection and control upgrades mirror thirteen previous upgrades at plants throughout Avista's generating facilities. It provides consistency on the auxiliary systems for maintenance and troubleshooting. Reduced reliance on manufacturer support decreases overall maintenance costs for auxiliary equipment. Interchangeability of the equipment and knowledge transfer amongst technicians also plays a key role in reliability. Please see Exh. JRT-4, pp. 39-44 and 45-50 for additional information about these projects.

Q. Did Avista consider alternatives to this approach?

A. Yes, in addition to replacing the unit controls, monitoring and protection systems, an alternative to also reinsulate the pole pieces and a stator re-wedge was considered for both units. The temperature of the field did not exceed the designed temperature in Unit 3, resulting in no driver to rebuild the Pole Pieces. Measurements of the ripple springs used to keep the coils tight in the stator slots did not indicate a need to replace or re-wedge the stator for Unit 3. For Unit 4, the temperature of the field also did not exceed the designed temperature so there was no need to rebuild the Pole Pieces. Measurements of the ripple springs still needs to be performed to determine the necessity of a re-wedge for Unit 4.

Q. How does this program benefit Avista's customers?

A. The risks for not completing these upgrades on Units 3 and 4 include an inability to quickly respond to market demands, thereby jeopardizing Avista's ability to serve its customers. The customer benefits through higher reliability of controls through a reduction in unexpected outages and available manufacturer support of the new upgraded equipment.

Q. Does the project have a target completion date?

A. Yes, the protection and control upgrades to Unit 3 were started and completed in 2021, and the upgrades to Unit 4 began in 2021 and are expected to be completed in the first quarter of 2022.

Q. What capital additions for this project will be completed for 2021?

A. The total capital investment for Projects #6 and #7 in 2021 is $3,073,449 and $2,714,355, respectively. The work to Unit 3 was completed in 2021. Work to Unit 4 began in 2021 and will be completed in 2022, and the cost is reflected in Table No. 4.

Q. Are there any direct offsets associated with this project?

A. No, there are not. However, the Company has included a 2% efficiency adjustment for this project in 2022, as shown in Ms. Andrews Exh. EMA-5. That adjustment for this project is included in Ms. Andrews' adjustments 4.03 and 5.09.

Q. Would you please describe the Company's investments for Project #8, the

<u>Clark Fork Settlement Agreement</u>?

A. Yes. This capital program helps ensure the ongoing operation of the Clark Fork Project (Noxon Rapids and Cabinet Gorge dams), which is subject to the Clark Fork Settlement Agreement (CFSA) and FERC License No. 2058. Under this FERC License, Avista must develop and carry out Protection, Mitigation and Enhancement (PM&E) measures each year. These License measures consist of the completion of numerous specific projects each year for habitat, fisheries, recreation, land management, wildlife and other natural resources related to our Clark Fork hydro operations. Implementation of these measures also addresses ongoing compliance with Montana and Idaho Clean Water Act Section 401 Certification requirements, the Endangered Species Act, National Historic Preservation Act, Clean Water Act, and additional state, federal and tribal laws and regulations. Some projects are multi-year while other projects are one-time, but the entire capital program continues to evolve over the 45-year License term.

If the PM&Es and license articles were not implemented and/or funded, Avista would be in breach of an agreement and in violation of our FERC License. There would be a high risk for penalties and fines, new license requirements, higher mitigation costs, and potential loss of operational flexibility of the Cabinet Gorge and Noxon Rapids Hydroelectric Facilities. Loss of operational flexibility, or of these generation assets, would create substantial new costs, which would be detrimental to our electric customers and to the Company. Funding of the Clark Fork License Implementation is essential to remain in compliance with the FERC license and CFSA, which provides Avista the operational flexibility to own and operate the hydroelectric facilities. The investment drivers for this project are predominantly Mandatory and Compliance in nature. Please see

Exh. JRT-4, pp. 51-56 for additional information about this project.

Q. Did Avista consider alternatives to this program?

A. Funding of the Clark Fork License Implementation is essential to remain in compliance with the FERC License and CFSA for permission to continue to own and operate the Clark Fork hydroelectric facilities. Avista evaluated alternatives to a negotiated license through the Licensing process in the late 1990s as reflected in the consultation record submitted with the license application. Forgoing a collaborative relicensing process (and ultimately, an agreement) was determined to create significant risk to the operational flexibility of the dams, as well as risks for increased costs related to the process as well as a litigated license. This commitment was finalized by the issuance of a new 45-year License by FERC in 2001 and is ongoing. The CFSA was the result of collaborative negotiations between numerous federal and state agencies, several Native American tribes, local governments, non-governmental organizations, and Avista on behalf of our customers. Subsequently, FERC incorporated the CFSA in a License Order, along with other conditions. FERC continues to oversee License implementation through annual review and frequent orders. Each year, Avista and CFSA signatories, through a Management Committee and technical subcommittees, evaluate project proposals and alternatives before approving an annual work plan that is submitted to FERC for final approval.

Q. How does this program benefit Avista's customers?

A. As stated above, this program represents Avista meeting its regulatory and legal requirements under the FERC Clark Fork License. If we didn't do so, we would risk legal action, penalties, reputational loss and potential loss of operational flexibility.

Loss of operational flexibility, or of these generation assets, would create substantial new costs, which would be detrimental of all our electric customers and the Company.

Q. Does the program have a target completion date?

A. This is an ongoing commitment running with the Clark Fork FERC License #2058 and will continue at least until the License expires in 2046.

Q. What capital additions for this project were completed for 2021?

A. The total capital investment for this project is $5,477,022 in 2021. Projects included the following:

- Fish Passage Native Salmonid Operations,
- Montana Tributary Habitat Fund,
- Recreational Vehicle Park,
- Cabinet Gorge Total Dissolved Gas Mitigation,
- Minimum Flow,
- Wildlife Habitat Acquisition,
- Recreation Management Facilities,
- Cabinet Gorge Total Dissolved Gas Monitoring and Mitigation,
- Fish Passage/Native Salmonid Restoration Plan,
- Montana Tributary and Recreational Fishery, and
- Idaho Tributary and Fishery Enhancement Program.

Q. Are there any direct offsetting benefits associated with this project?

A. No, these projects are required based on our FERC license, with the indirect benefits described above.

Q. Turning now to Project #9 from Table No. 4 above, would you please describe the Company's investments in the <u>Coyote Springs LTSA</u>.

A. Yes. The gas turbine at Coyote Springs 2 requires major overhauls every 32,000 operating hours to remain operable. Components are subject to extreme high temperatures and stress and must be serviced at the Original Equipment Manufacturer (OEM) specified intervals. A Long-Term Service Agreement (LTSA) with the OEM (General Electric) was determined to be the most cost-effective solution for customers. Originally effective in 2003, the LTSA was renegotiated in 2012 and again in 2015.

This multi-year program covers the capital accruals required to execute the LTSA with GE for Coyote Springs Unit 2. Annual LTSA costs fluctuate because Avista pays on the number of fired hours that changes from year-to-year. Please see Exh. JRT-4, pp. 57-63 for additional information about this project.

Q. Did Avista consider alternatives to this approach?

A. Yes. When the Coyote Springs 2 LTSA was first negotiated and placed into action in 2003, and renegotiated in 2012, GE had the appropriate technical ability to service the combustion turbine and associated equipment. As the industry grew, other market alternatives arose which allowed Avista to research alternatives. Knowledge of these alternatives allowed Avista to negotiate a substantial reduction over the initial contract price. GE was able to continue to provide the LTSA service, and upgrades, <u>at a reduced rate</u>.

In 2016, the Company performed an Advanced Gas Path upgrade on the combustion turbine that included further efficiency and output improvements at Coyote Springs 2. Changes to the machine extended the time between major overhauls and because of this we were able to negotiate additional cash discounts on the fired hour based LTSA payments. We also negotiated an extension of the LTSA to approximately 2040. By renegotiating the LTSA in 2015, the actual fired hours charge was reduced by 12.4%. Those benefits were previously reflected in rates.

Q. How does this program benefit Avista's customers?

A. The LTSA with GE was determined to be the most cost-effective solution for customers. The total requested amount was approved in 2015 following the LTSA renegotiation as the best alternative for Avista's customers. The reduction in cost per operating hour, coupled with improved efficiency of the combustion turbine, allowed a better alternative from what was previously agreed upon in the 2012 LTSA.

Q. Does the project have any target completion date?

A. The current Coyote Springs 2 LTSA is expected to continue through approximately 2040 depending on annual hours of operation and the life expectancy of the plant.

Q. What capital additions for this program will be completed for 2021?

A. The total capital investment is $15,898,972 in 2021 for projects completed by GE under the LTSA. Capital investment for 2022-2024 is captured in Table No. 4.

Q. Are there any direct offsets associated with this project?

A. This is a mandatory project required under license. There are no direct or indirect offsetting benefits related to this Business Case in 2021 or in 2022-2024.

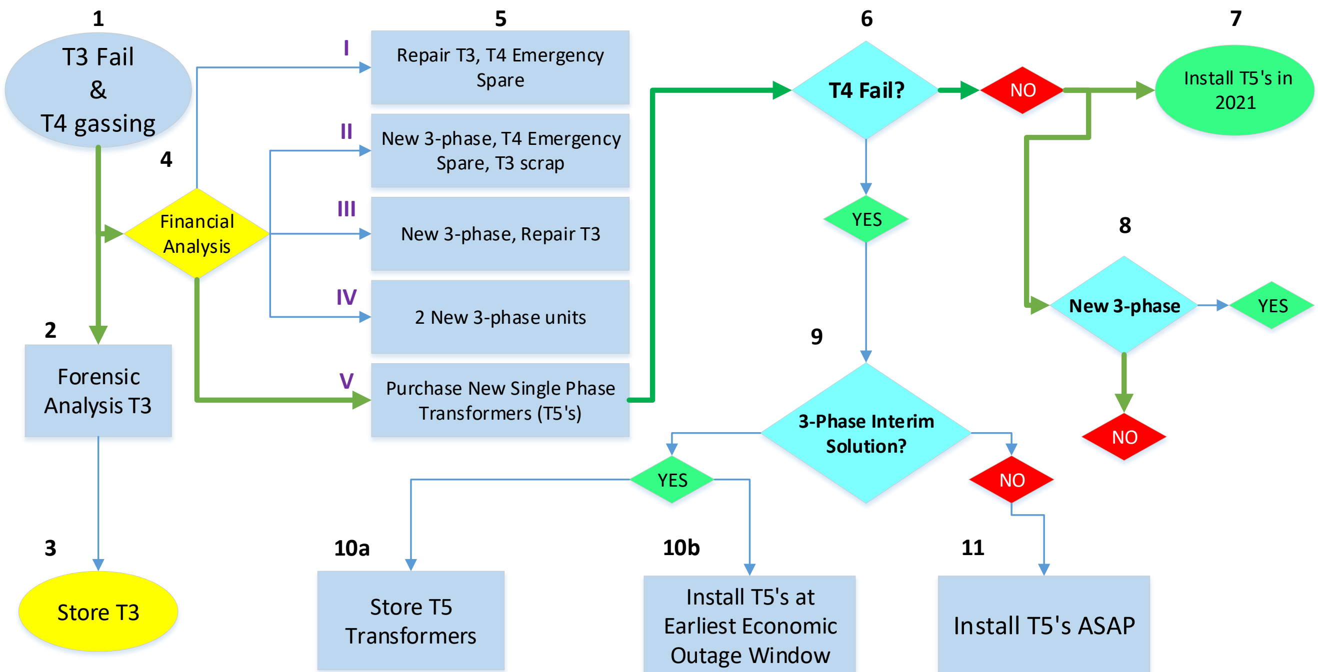
Q. Would you please describe the Company's investment in Project #10, <u>CS2 Single Phase Transformer</u> project?

A. Yes. 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 & T2), which were manufactured in Turkey; and two Siemens units (T3 & 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 weeks of operation it also began exhibiting signs of the same type of internal high energy faulting that led to the failure of T3. To reduce risk of catastrophic failure, the maximum plant generation output was reduced to keep heating in the windings down per recommendations from internal engineering and a consultant, until the transformer could be replaced.

When Avista purchased T3 and T4, we specifically excluded Areva Turkey (original manufacturer of T1 and T2) as a potential supplier so as to get a different 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 provided below in Illustration No. 2 below, provides a high-level summary of the decision process regarding the transformer design 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 kept other options open. In the decision tree below, the bolded green lines represent the chosen path. 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. Fortunately, this is not an alternative the Company had to act on as the units have since been installed successfully.

Illustration No. 2: Coyote Springs 2 Transformer Decision Tree



This project had 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 in order to allow the transformer installation to be completed in the Spring of 2021 before typical summer peak load conditions. Final installation was completed in June of 2021, on time and under the budget assumed in the final project financial analysis. With both portions of the work now complete, the full scope of the effort has been included in this case. Please see Exh. JRT-4, pp. 64-73 for additional information about this project.

Q. Did Avista consider alternatives to this project?

A. Avista considered multiple alternatives to this project as indicated in the decision tree in Illustration No. 2 above. 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 for 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.

Q. How does this project benefit Avista's customers?

A. This project replaces Transformer 3, which failed, and Transformer 4 that fortunately did not fail catastrophically in service but began exhibiting the same gassing evidence of high energy internal faulting as Transformer 3 after only a three-week in-service run. A reliable GSU and spare is required to keep Coyote Springs 2 in service and minimize exposure to market volatility. Coyote Springs 2 alone typically provides about 20 percent of Avista's annual energy needs. The financial analysis considered all options and selected the optimal cost option for customers.

Q. What capital additions for this program will be completed for 2021?

A. The total capital investment is $17,052,971 in 2021. The transformer installation was completed on June 30, 2021.

Q. Are there any direct offsetting benefits associated with this project?

A. There are no direct offsetting benefits, but Avista believes that the new configuration using individual single-phase transformers will provide long term dependable reliability over the life of the plant. Additionally, the new transformers have increased capacity to afford a larger operational margin and will accommodate increased output from the facility if future plant upgrades are made. Any of these benefits will flow through the power supply adjustment.

Q. Please describe the Company's investments in Project #11, the <u>Generation DC Supplied System Update</u> project?

A. The Generation DC Supplied System program covers all the generation and control facilities. This system 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 Avista must continually monitor, review and maintain its DC system.

Traditionally, the Direct Current (DC) system, (aka Battery System) at each generation plant is used for protection and monitoring of the plant. All the protection relays, breaker control circuits and monitoring circuits are fed from this source. The source is assumed to always be on-line and able to supply the critical load for a predetermined length of time. As technology evolved, other standalone DC systems were installed at different times. Typical plants now have standalone DC Systems for: general station, Uninterruptible Power Supplies (UPS), governors (electronic turbine speed controllers), communications and control systems. Each of these systems have a battery bank, battery charger, converters to supply different voltages, and distribution panels and circuits. As changes occurred on the generating units or in the balance of plant systems, the DC load requirement has significantly increased and the time duration for the systems to supply this critical load has increased. Our current practice is to replace the battery banks per manufacturers life cycle recommendations, but this practice is not addressing the additional load added to the systems.

Some of the other issues on the DC systems are failing battery cells due to inconsistent temperature and environmental control needed to maintain the present battery systems. The system life cycle is 20 years at its normal operating temperature of 77 degrees F. For temperatures 15 degrees F over the normal operating temperature the life cycle is decreased by 50 percent. Component failure, utilization from multiple extended outages and manufacturers quality are other problems experienced on these systems.

Finally, there are compliance requirements from the North American Electric Reliability Corporation (NERC) for inspections, maintenance and testing of the battery banks to ensure they are in good working order and will perform when called upon. In order to perform these inspections and maintenance, and testing needs, it requires either unit or plant outages to comply with the requirements for multiple DC systems that are now present in our stations. To address these multiple issues, a new Generation Plant DC Standard was developed by the engineering group. The new Generation Plant DC Standard System provides for layers of back up and redundancy to address current and future capacity needs as well as addressing maintenance and testing requirements. This Program will replace existing DC systems at Avista's owned and operated generation plants with a system that meets this new design standard. Please see Exh. JRT-4, pp. 74-80 for additional information about this project.

Q. Did Avista consider alternatives to this approach?

A. The risk of addressing the DC system after there is an issue is that it is then too late to avoid failure. We have already had one instance where the DC system failed and some equipment was damaged due to this not functioning correctly, so waiting until failure or near failure is not a practical solution in this situation.

Q. How does this program benefit Avista's customers?

A. The activity objectives are to order the plant replacements in a timeline that will allow for stages of a project to happen and use our engineering and construction staffing. This will allow a battery bank to provide load to the plant. If not approved and we have a failure of a battery then budgets, schedules and resources on other projects would be diverted to handle fixing the failure.

Q. Does the project have a target completion date?

A. This project is currently scheduled out through 2024, with transfers to plant reflected in Tables No. 4 and No. 5.

Q. What capital additions for this project will be completed for 2021?

A. The total capital investment is $6,864 in 2021, but will be closer to $500,000 annually for 2022 through 2024 as the project develops.

Q. Are there any direct offsets associated with this project?

A. This is a mandatory project. There are no direct or indirect offsetting benefits related to this Business Case in 2021 or in 2022-2024.

Q. Would you please describe the Company's investments in Project #12, the <u>HMI Control Software</u> project?

A. Yes. New Human-Machine Interface or 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 stopped supporting 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. Please see Exh. JRT-4, pp. 81-89 for additional information about this project.

Q. Did Avista consider alternatives to this approach?

A. The alternatives considered included inaction, upgrading existing Wonderware software, and complete product replacement. The selection of complete replacement was made based upon the risk/reward analysis performed at the onset of the project. Maintaining the Wonderware product still posed a near-term risk to operations by continuing a relationship with an antiquated and unsupported product. The decision to procure and design an entirely new solution better positions Avista for the future and mitigates more of the long-term risks associated with sunsetting technologies.

Q. How does this project benefit Avista's customers?

A. This project safely, responsibly and affordably improves the level of service we provide to our customers by minimizing direct impacts to services. This innovative approach allows us to pilot software updates and configurations before fully implementing on active sites which shortens our outage time and allows our operations team to reserve capacity for other critical needs.

Q. Does the project have a target completion date?

A. This project is currently scheduled to run through 2024.

Q. What capital additions for this project will be completed for 2021?

A. The total capital investment is $3,055,633 in 2021. Completed capital additions for this project in 2021 include the upgrade to the control software, the upgrade for ET, and the upgrade for the Generation Control Center PLC lab. Capital investment in 2022-2024 is shown in Table No. 5.

Q. Are there any direct offsets associated with this project?

A. This is a mandatory project. There are no direct or indirect offsetting benefits related to this Business Case in 2021 or in 2022-2024.

Q. Please describe the Company's investments in Project #13, <u>Hydro Safety Minor Blanket</u> project.

A. 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. Please see Exh. JRT-4, pp. 90-94 for additional information about this project.

Q. Did Avista consider alternatives to this approach?

A. Alternatives and possible mitigation strategies are considered on a case-by-case basis, for each proposed measure on the small projects covered in this program.

Q. How does this program benefit Avista's customers?

A. This work benefits customers by maintaining and enhancing safety, ensuring compliance, and reducing risk. Without this project, operating costs would increase as Avista would still need to maintain safety-related equipment to remain in compliance. In the absence of the funding provided in this project, Avista would undertake increased risk by delaying the purchase and installation of equipment.

Q. Does the program have a target completion date?

A. No, this is an ongoing project to maintain hydro assets.

Q. What capital additions for this project were completed for 2021?

A. The total capital investment is $49,317 in 2021. The Upper Falls Buttress Dam Fence project was completed in 2021 under the Hydro Safety Minor Blanket Project. Transfers to plant for 2022-2024 are shown in Table No. 5.

Q. Are there any direct offsets associated with this project?

A. This is a mandatory project. There are no direct or indirect offsetting benefits related to this Business Case in 2021 or in 2022-2024.

Q. Please describe the Company's investments in Project #14, the Little Falls Plant Upgrade project.

A. The Little Falls Plant Upgrade Program began in 2012 and is in the final phases of implementation. The final three project components (Plant Sump, Drain Field, and Panel Room Roof/Enclosure for the new controls equipment) will complete the project scope and the original risks will mitigated. The last projects had very little risk exposure and minimal impact on the plant's current operations. Driven initially by the age of the infrastructure at the plant, Alternative 3, a full replacement of all four generating units and all obsolete supporting equipment was selected, implemented and put in service. Please see Exh. JRT-4, pp. 95-101 for additional information about this project.

Q. Did Avista consider alternatives to this investment?

A. Yes, as detailed in prior general rate cases, multiple alternatives were considered including: leaving the plant as-is by replacing only the switchgear and exciter (Alternative 1), replacing the four generating units with larger, vertical units with more output and install new ancillary equipment and systems (Alternative 2); and the Selected Alternative 3 - replacing four generating units with the same generating capacity and installing new ancillary equipment and systems. Alternative 1, although the lowest cost, was not considered a viable solution based on the operating history of the generating units. The units had become unreliable and there was no guarantee they would be fully operational at any time of the year. Alternative 2 would have provided additional plant output, but the increase in generation for the extra cost was not as economical as just replacing all four generators in kind.

Q. Does this project have a target completion date?

A. Yes. The Little Falls Upgrade project was completed in 2021.

Q. What capital additions for this project will be completed for 2021?

A. The total capital investment is $1,680,999 in 2021 for the completion of this project.

Q. Are there any direct offsets associated with this project?

A. Benefits of this project upgrade over the last few years, would already be imbedded in the Company's test period.

Q. Please describe the Company's investments in Project #15, the <u>Long Lake Plant Upgrade</u>.

A. The Long Lake Plant experienced an increase in forced outages 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 several different pieces of equipment. Before the upgrade, the turbines were thrusting too much, showing significant wear, and experienced a failure in 2015. The 1990 vintage control system was failing, and only secondary markets could support the equipment. Inspections of other components of the generator showed the stator core was "wavy" where the core lamination steel should have been straight. The "wave" pattern was 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) had also increased to its rating. The existing GSU's are over 30 years old and operating at the high end of their design temperature, they were approaching the end of their useful life and needed to be replaced proactively rather than waiting for a failure to occur. The other major drivers for the program was Station Service disconnect switching safety. Please see Exh. JRT-4, pp. 102-112 for additional information about this project.

Q. Did Avista consider alternatives to this investment?

A. Yes. As discussed in prior rate cases, four alternatives were considered. The alternatives included installing four new 30 MW vertical units, constructing a new single unit powerhouse, constructing a new two-unit powerhouse, and replacing units in-kind. The last alternative was chosen for this project.

Q. How does this program benefit Avista's customers?

A. Upgrading the Long Lake Plant will enable it to continue to provide safe and reliable power to our customers as well as change the increasing trajectory of rising annual O&M costs. Due to the condition of the generators, it is likely that one of the generators or another piece of major equipment will fail and permanently disable equipment, increasing forced outage numbers.

Q. Does the project have a target completion date?

A. Yes, this project began in May 2017 and is expected to be completed by December 2026 with the completion of the Unit 4 upgrade.

Q. What capital additions for this project will be completed for 2021?

A. The total capital investment is $2,264,782 in 2021 for this multi-year upgrade. Further transfers to plant associated with this project in 2022-24 are shown in Table No. 5.

Q. Are there any direct offsets associated with this project?

A. No, there are not. However, the Company has included a 2% efficiency adjustment for this project in 2024. That adjustment for this project is included in Ms. Andrews' adjustments 4.03 and 5.09 and shown in Exh. EMA-5.

Q. Please describe the Company's investments in Project #16, the <u>Peaking Generation Business Case</u>.

A. 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.

The business drivers for projects in this program are a combination of Asset Condition, Failed Plant, and addressing operational deficiencies. Most of these projects are short in duration, typically well within the budget year, and many are reactionary to 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 would jeopardize plant availability and greatly impact the value to customers and the stability of the grid. Please see Exh. JRT-4, pp. 113-120 for additional information about this project.

Q. Did Avista consider alternatives to this approach?

A. Yes. The first alternative considered would be to create business cases using the business case template and process for each of these small projects. There are typically five to 10 projects a year funded by the program which would effectively overload the Capital Budget Process with small to medium projects whose governance can be effectively handled by the

Thermal Group. These projects are specific to these plants and the leadership in the Thermal Group understands the nature and context of these projects. These projects are, at times, unpredictable making it difficult to forecast unforeseen events such as equipment failures and identify critical asset condition that could effectively be put in the annual capital plan. A second alternative would be to attempt to repair this equipment instead of replacing critical assets at the end of their lifecycle. This would be unacceptably expensive and older equipment would become more unreliable until becoming obsolete. Operating in a run-to-failure mode is proven to be an unsuccessful approach and subjects Avista and its customers to unacceptable risk of project failure.

Q. How does this program benefit Avista's customers?

A. Maintaining these plants safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System.

Q. Does the program have a target completion date?

A. No, since this program is designed to keep Boulder Park, the Rathdrum Combustion Turbines, and the Northeast Combustion Turbines operating at or above their current performance levels, the program is expected to continue as long as these plants are still in service.

Q. What capital additions for this business case/program will be completed for 2021?

A. The total capital investment is $598,839 in 2021. Projects completed under the Peaking Generation Business Case Project in 2021 included the following:

- Boulder Park: replacement of failed Central Processing Unit, Selective Catalytic Reduction air receivers and Pre Combustion Chamber valves.

- Northeast Combustion Turbine: Engine A seal replacement, Engine B seal replacement and inlet filter replacement.
- Rathdrum Combustion Turbine: fuel pressure transmitter, turbine compartment heater and replacement of start air compressor.

Capital investment in 2022-24 is shown in Table No. 5.

Q. Are there any direct offsets associated with this project?

A. Yes, the Company has included a 2% efficiency adjustment for this project in 2022, 2023 and 2024. That adjustment for this project is included in Ms. Andrews' adjustments 4.03 and 5.09 and shown in Exh. EMA-5.

Q. Please describe the Company's investments in Project #17, <u>Post Falls Landing and Crane Pad Development</u>.

A. 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 jointly used, such that when it is not needed by Avista, the area would be utilized by the City of Post Falls and the public for recreational purposes. Staging heavy equipment for major work at the Post Falls HED is difficult due to the access and space constraints of the locations of spillways and the powerhouse on the Spokane River. Staging equipment at Post Falls Park, which is the area near the plant, will disrupt the public use of the park and present safety hazards to the public. In addition, access to this area is limited due to the size and capacity of the bridges across the river. The site of the landing greatly increases the access for cranes, barges and heavy equipment needed to support construction and maintenance of the plant. The work related to Post Falls cannot be delayed much longer. The North Channel

Spillway has reached the end of its useful life. The generating units are outdated and are at or near the end of their useful lives with Unit #6 already failed. The risk is that more of the units might fail and compromise the operation of the spillway causing serious repercussions with operating the plant and controlling the flow of the Spokane River and the elevation of Coeur d'Alene Lake. This could also result in violations of the Spokane River Licensing agreement which would present a serious risk to Avista and the public. Please see Exh. JRT-4, pp. 121-126 for additional information about this project.

Q. Did Avista consider alternatives to this investment?

A. Yes, the Company considered not moving forward with construction of the landing. This option would create logistical challenges for getting heavy equipment and materials to the Post Falls facilities and spillways due to limited access and the current constraint of bridge size and capacity. This option would have significantly affected the timeline and cost of large projects at the powerhouse and spillways. If Avista decided to not work with City to develop the property for joint use, the area would not be available for crane and barge access to the plant. In addition, the City may not have elected to develop the property without Avista's partnership and lose the opportunity to have a valuable public area that would benefit our customers in Post Falls.

Q. How does this project benefit Avista's customers?

A. This project provides an area for staging a crane, barges and equipment for maintenance and construction in support of the Post Falls HED to keep it operational.

Q. Does the project have a target completion date?

A. Yes, the project was complete and used and useful by December 31, 2021.

Q. What capital additions for this project will be completed for 2021?

A. The total capital investment is $3,508,167 in 2021.

Q. Are there any direct offsets associated with this project?

A. No, there are not.

Q. Would you please describe the Company's investment in Project #18, the Regulating Hydro program?

A. Yes. The purpose of this program is to fund smaller capital expenditures and upgrades that are required to maintain safe and reliable operation of Avista's regulating hydro plants. Maintaining these plants safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES).

Avista's regulating hydro plants are the four largest hydro plants on Avista's system representing more than 950 MW of power. The 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 in Washington. Avista's regulating hydro plants are unique in that they have storage available in their reservoirs. This enables these plants to have operational flexibility and as such are operated to support energy supply, peaking power, provide continuous and automatic adjustment of output to match the changing system loads, and other types of ancillary services necessary to provide a stable electric grid and to maximize value to Avista and its customers. Please see Exh. JRT-4, pp. 127-134 for additional information about this project.

Q. Did Avista consider alternatives to this program?

A. Yes. The primary alternative would be to attempt to repair this equipment instead of replacing critical assets at the end of their useful life. This alternative would be more expensive and older equipment will become increasingly unreliable until it becomes obsolete.

Operating in a run-to-failure mode is proven to be an unsuccessful approach and subjects Avista and its customers to an unacceptable level of risk.

Q. How does this program benefit Avista's customers?

A. The hydroelectric plants covered under this project are unique in that they have energy storage available in their reservoirs. This enables these plants to have operational flexibility and are operated to support energy supply, peaking power, provide continuous and automatic adjustment of output to match changing system loads, other types of ancillary services necessary to provide a stable electric grid and to maximize value to Avista and its customers.

Q. What is the program completion timeline?

A. This is an ongoing program with no set end date. It will continue as long as the hydroelectric plants it supports are still in service.

Q. What capital additions for this business case/program will be completed for 2021?

A. The total capital investment is $3,367,438 in 2021. Capital investments in 2022-2024 is included in Table No. 5.

Q. Are there any direct offsets associated with this project?

A. No, there are not. However, the Company has included a 2% efficiency adjustment for this project in 2022, 2023 and 2024. That adjustment for this project is included in Ms. Andrews' adjustments 4.03 and 5.09 and shown in Exh. EMA-5.

Q. Would you please describe the Company's investments in Project #19, the <u>Spokane River License Implementation</u> project?

A. Yes. The Spokane River License Implementation Project, or Spokane River

Implementation, is a capital program that helps ensure the ongoing operation of the Spokane River Project which includes the Post Falls, Upper Falls, Monroe Street, Nine Mile and Long Lake dams. The Spokane River Project is subject to FERC License No. 2545 and several other settlement agreements. This license, issued in 2009 following almost seven years of consultation, negotiations, and litigation, defines how Avista operates the Spokane River Project and includes several hundred requirements, expressed as license conditions.

The FERC license was issued pursuant to the Federal Power Act (FPA) and embodies the requirements of 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 expressed through specific license articles relating to fish, terrestrial issues, water quality, recreation, land use, education, cultural and aesthetic resources. Avista also entered into additional two-party agreements with local, state, and federal agencies, and the Coeur d'Alene and Spokane Tribes. Most of these agreements are embodied in the License. Avista's FERC License also includes mandatory conditions issued by the Idaho Department of Environmental Quality (401 Water Quality Certification, issued June 5, 2008), the Washington Department of Ecology (401 Water Quality Certification, issued May 8, 2009), the U.S. Forest Service (Federal Power Act 4(e), issued May 4, 2007), and the U.S. Department of Interior on behalf of the Coeur d'Alene Tribe (Federal Power Act 4(e), filed January 27, 2009). The FERC license 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. This capital program consists of numerous projects each year, and the total cost of implementing these projects varies each year, depending on specific license requirements and opportunities.

Complying with our FERC license is mandatory for continued permission to operate the

Spokane River Project and funding the implementation activities is essential to remain in compliance with the License. Ultimately, FERC has the authority to issue orders and penalties, or in the extreme, revoke our license, if we do not comply with the terms and conditions required by it. We would also be subject to additional legal sanctions from other agencies and settlement partners if we do not meet the conditions of the License and subsequent agreements. Loss of operational flexibility, or in the extreme, loss of our generation assets, would create substantial new costs to our customers and provide no benefits in return. In addition, Avista would suffer reputational costs for not meeting our commitments. Please see Exh. JRT-4, pp. 135-141 for additional information about this project.

Q. Did Avista consider alternatives to this program?

A. The capital projects included in the Company's Spokane River Implementation Project are mandatory obligations after agreements are reached with the various participants in the licensing process. If the license conditions and settlement agreements are not implemented and/or funded, we would be out of compliance and/or in violation of our License. This could lead to penalties and fines, new license requirements, court costs, higher mitigation costs, and loss of operational flexibility. Ultimately, FERC has the authority to revoke Avista's Spokane River License if it does not comply with the required terms and conditions. Loss of operational flexibility, or in the extreme, loss of our generation assets, would create substantial new costs to our customers, damage the company's reputation, make it more difficult to pursue other hydro projects, and ultimately provide no benefits to the Company or its customers.

Q. How does this program benefit Avista's customers?

A. As stated above, this program represents Avista meeting its regulatory and legal requirements under its Spokane River Project FERC License.

Q. Does the program have a target completion date?

A. No, the Spokane River Implementation Project is an ongoing commitment with the Spokane River FERC License No. 2545. This project will continue at least until the License expires in 2059. We would expect the same, modified or additional license conditions after that time depending on the results of future License requirements.

Q. What capital additions for this project will be completed for 2021?

A. The total capital investment is $904,651 in 2021, comprised of the following projects:

- Amy Lane Campsite Planting,
- Black Rock Slough Restoration,
- Falls Park Pedestrian Trail,
- Long Lake Spillway Revegetation,
- McKee Property Acquisition,
- Muley Canyon Campsite Planting,
- North Shore Boat-in Planting,
- Post Fall Landing Amenities,
- Ross Park Development,
- Southshore Day Use Planting,
- SRLI Chainsaw #1 Long Lake,
- SRLI Chainsaw #2 Long Lake,
- St. Joe Wetland Fencing, and
- Watering System.

Additional capital investment in 2022-2024 is shown in Table No. 5.

Q. Are there any direct offsets associated with this project?

A. No, there are not, given this work is undertaken to comply with federal and state requirements, and other agreements.

Q. Please describe the Company's investments in Project #20, the <u>Strategic Initiatives</u> project.

A. The Strategic Initiative Project is related to the Upriver Park Development, which includes vacating 1/3 mile of Upriver Drive between Mission Avenue and North Center Street and developing a 3-acre park to provide improved and new public access to the Spokane River while improving public safety in this reach of a newly realigned Centennial Trail. By developing the Park, Avista will address the increase in demand for non-motorized boating use in the Upper Falls Reservoir, meeting Spokane River FERC license requirements. In addition, the project will enhance public safety by eliminating shared use of the existing road by motor vehicles and pedestrians and cyclists. Creation of the park is expected to help reduce illegal camping along the shoreline by removing Jersey barriers, opening shoreline access to trail users, and by thinning and managing the vegetation between Upriver Drive and the Spokane River. The development is also expected to enhance ecological functions along the shoreline, as non-native and invasive species will be gradually replaced with native plants. The Development also addresses remnant stormwater discharges to the River and improves stormwater management to protect the River. Please see Exh. JRT-4, pp. 142-150 for additional information about this project.

Q. Did Avista consider alternatives to this investment?

A. Complying with our FERC license is mandatory to continued permission to operate the Spokane River Project.

Q. How does this project benefit Avista's customers?

A. The investment into Upriver Park adds public and ecological benefits. Customer interests in non-motorized boating, river access, increased safety for Centennial Trail use are represented in the goals of the park. It benefits from added safety of a compliant fire and sewer system. Removing discharges to the Spokane River fosters environmental stewardship.

Working closely with the City and other stakeholders on the park improves ties to our customers, employees, and the Spokane community, and meets requirements under our Spokane River FERC license.

Q. What is the target completion date for the Strategic Initiative Project – Upriver Park Development?

A. The Park will be completed in 2022.

Q. What capital additions for this project will be completed for 2021?

A. The total capital investment for the park is $3,373,971 in 2021. Remaining capital is shown in Table No. 5 for 2022.

Q. Are there any direct offsets associated with this project?

A. No, there are not, as this work is deemed mandatory as a part of the work the Company must undertake consistent with its Spokane River FERC license.

Q. Would you please describe the Company's investments in Project #21, Use Permits?

A. Yes. Avista owns and maintains electric transmission, distribution, and natural gas facilities which cross public lands managed by a variety of state, federal and local agencies, as well as entities who own extensive tracts, such as railroads. Traditionally, the Company has secured long-term rights-of-way permits for these facilities but has been required to renew them through an annual billing process. The cost of renewing these permits continues to increase, ranging from 3% to 10% annually depending on the agency, thereby increasing annual O&M expenses. Please see Exh. JRT-4, pp. 151-156 for additional information about this project.

Q. Did Avista consider alternatives to this approach?

A. The only other alternative is to continue processing annual permits and paying the annually-increasing fees as a charge to O&M.

Q. How does this program benefit Avista's customers?

A. This program secures long-term agreements with lump-sum payments in order to reduce overall expenses related to labor of tracking, research, and processing these annual permits. In some cases, the Company has also been able to negotiate a lower annualized cost over the term of the permit by paying a lump sum up front. Either case reduces costs to customers. Making long-term lump sum payments allows us to capitalize these costs, as the permit is a long-term asset. Without capital funding through this program, we will continue to incur increasing annual permitting fees and related internal costs as an O&M expense. These costs affect all customers, electric and gas, in the entire Avista service territory.

Q. Does the project have a target completion date?

A. No, this project is expected to be an ongoing project as long as there continue to be agency rights-of-way that need to be renewed.

Q. What capital additions for this project will be completed for 2021?

A. The total capital investment in 2021 is $27,142. Additional capital is shown in 2022-2024 in Table No. 5.

Q. Are there any direct offsets associated with this project?

A. This is a mandatory project. There are no direct or indirect offsetting benefits related to this Business Case in 2021 or in 2022-2024.

Q. Would you please describe the Company's investment in Project 22, <u>Washington State Department of Transportation (WSDOT) Franchises</u>?

A. Yes. The WSDOT Franchise Project renews expired franchises for Avista facilities located within Washington State highway rights-of-way. In accordance with WAC

468-34 and RCW 47.44, Avista enters into 25-year agreements with the Washington State Department of Transportation (WSDOT) to permit Avista to construct, operate and maintain electric and natural gas facilities within Washington highway rights-of-way. These agreements are referred to as franchises. WSDOT manages franchises by reaches of a state highway within a county. Avista has 35 such franchises, 29 of which are expired. Franchise applications cannot be submitted without a completed "Control Zone" analysis and mitigation plan for every above-ground object within the highway right of way. Please see Exh. JRT-4, pp. 157-162 for additional information about this project.

Q. Did Avista consider alternatives to this approach?

A. There are 29 of Avista's 35 franchises with WSDOT that are expired. These franchises are required for Avista to construct, maintain and upgrade facilities located within the WSDOT right of way. To renew or consolidate these franchises, approximately 950 poles or above ground objects must be moved or mitigated. This program addresses the survey, drafting and permitting work in support of the mitigation efforts to be carried out through electric operations plans in the future.

Q. How does this program benefit Avista's customers?

A. To continue delivering reliable, low cost power to our customers, we must be able to construct, maintain and upgrade our electric facilities in the WSDOT rights-of-way. Without approved franchises, Avista is unable to do anything but emergency related work.

Q. What capital additions for this project will be completed for 2021?

A. The total capital investment is $20,525 in 2021. Amounts are included for 2022-2024 in Table No. 5.

Q. Are there any direct offsets associated with this project?

A. This is a mandatory project. There are no direct or indirect offsetting benefits related to this Business Case in 2021 or in 2022-2024.

IV. OVERVIEW OF 2022-2024 GENERATION CAPITAL PROJECTS

Q. What generation capital projects are included in this case for 2022 - 2024?

A. Please refer to Table No. 5 below for the generation capital projects included for 2022, 2023 and 2024.

Table No. 5: 2022-2024 Non-Colstrip Generation Capital Projects

WA GRC Plant Group	Project #	Business Case	2022 TTP (System)	2023 TTP (System)	2024 TTP (System)	Exh. JRT-4 Page #
Large Distinct Projects	23	Boulder Park Generator Replacement	$ -	$ -	$ 999,998	163
	24	Cabinet Gorge HVAC Replacement	-	1,500,000	-	169
	25	Cabinet Gorge Station Service	7,761,859	5,152,936	-	178
	26	Cabinet Gorge Stop Log Replacement	-	1,200,000	-	184
	27	Cabinet Gorge Unit 4 Protection & Control Upgrade	750,000	-	-	45
	28	Cabinet Gorge Unwatering Pumps	395,000	395,016	-	192
	29	Generation DC Supplied System Update	550,001	550,001	400,000	74
	30	Generation Masonry Building Rehabilitation	493,993	493,995	493,990	198
	31	Generation Protection Upgrades	-	-	587,500	205
	32	KF_Fuel Yard Equipment Replacement	-	30,367,127	-	214
	33	Long Lake Plant Upgrade	-	-	19,541,000	102
	34	Monroe Street Abandoned Penstock Stabilization	-	899,992	-	226
	35	Nine Mile HED Battery Building	800,001	-	-	234
	36	Nine Mile Powerhouse Crane Rehab	1,699,988	-	-	243
	37	Nine Mile Units 3 & 4 Control Upgrade	-	2,000,000	1,999,999	251
	38	Noxon Rapids HVAC	-	-	1,250,002	259
	39	Peaking Generation Business Case	445,001	458,000	450,000	113
	40	Post Falls North Channel Spillway Rehabilitation	-	-	18,499,999	266
	41	Upper Falls Trash Rake Replacement	-	1,500,000	-	275
Total Large Distinct Projects			**$ 12,895,843**	**$ 44,517,067**	**$ 44,222,488**	
Mandatory & Compliance	42	Cabinet Gorge Dam Fishway	$ 63,475,101	$ 235,000	$ -	30
	43	Clark Fork Settlement Agreement	4,839,609	5,622,720	3,877,380	51
	44	Spokane River License Implementation	629,226	535,000	492,301	135
	45	Strategic Initiatives	225,225	-	-	142
	46	Use Permits	150,012	150,012	150,012	151
	47	WSDOT Franchises	99,996	99,996	99,996	157
Total Mandatory & Compliance			**$ 69,419,169**	**$ 6,642,728**	**$ 4,619,689**	
Programs	48	Automation Replacement	$ 349,999	$ 349,999	$ 600,000	3
	49	Base Load Hydro	958,925	963,504	963,504	10
	50	Base Load Thermal Program	2,484,254	2,693,105	2,623,988	18
	51	Regulating Hydro	2,947,845	2,961,000	2,961,000	127
Total Programs			**$ 6,741,023**	**$ 6,967,608**	**$ 7,148,492**	
Short-Lived Assets	52	HMI Control Software	$ 3,500,000	$ 2,550,000	$ 1,550,000	81
Total Short-Lived Assets			**$ 3,500,000**	**$ 2,550,000**	**$ 1,550,000**	
Exh. JRT-1T Total 2022-2024 Provisional Capital Additions			**$ 92,556,035**	**$ 60,677,403**	**$ 57,540,669**	

Q. It appears that project or program numbers 27, 29, 33, 39, 42 – 52 listed above in Table No. 5 are a continuation of projects and programs previously listed in Table No. 4, and which are fully described in the previous section of your testimony. Is that the case?

A. Yes, the above listed investments were either ongoing programs or projects that had substantial investments in 2021, and which will continue to occur in 2022 - 2024. The projects already included with descriptions earlier in my testimony include the following:

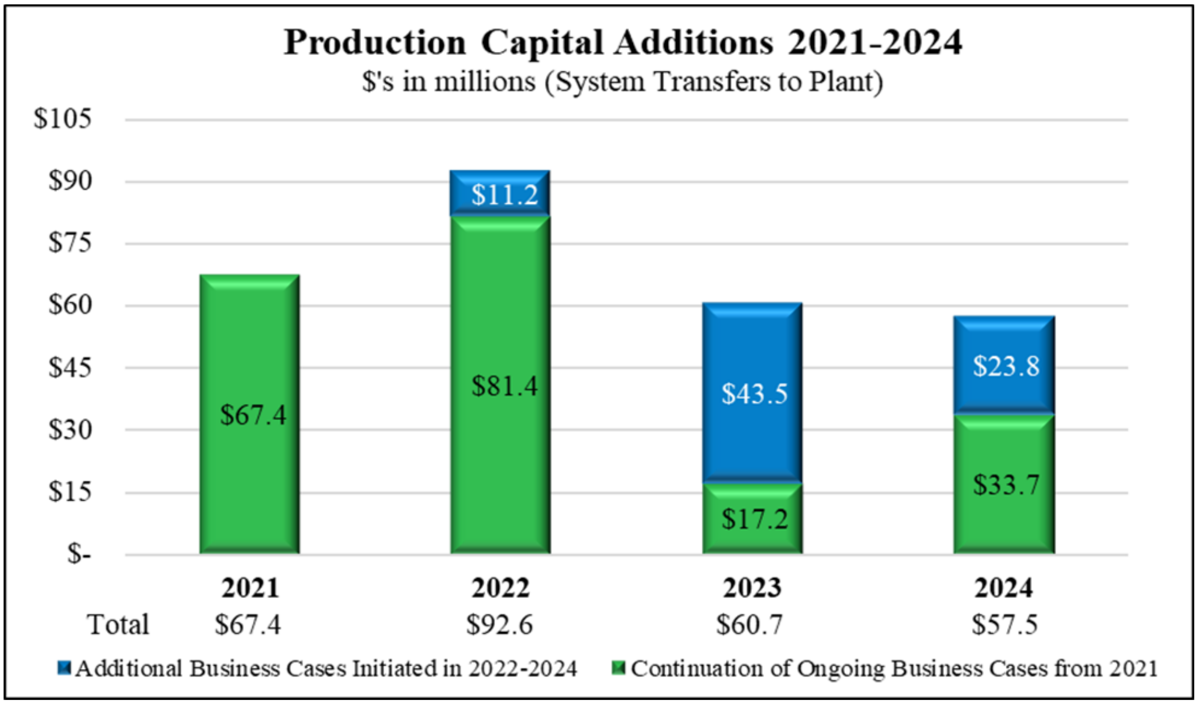
- 27 – Cabinet Gorge HVAC Replacement,
- 29 – Generation DC Supplied System Update,
- 33 – Long Lake Plant Upgrade,
- 39 – Peaking Generation Business Case,
- 42 – Cabinet Gorge Dam Fishway,
- 43 – Clark Fork Settlement Agreement,
- 44 – Spokane River Relicense Implementation,
- 45 – Strategic Initiatives,
- 46 – Use Permits,
- 47 – WSDOT Facilities,
- 48 – Automation Replacement,
- 49 – Base Load Hydro,
- 50 – Base Load Thermal Program,
- 51 – Regulating Hydro, and
- 52 – HMI Software Control.

Q. Is all of the support for these projects and programs in 2022 - 2024 the same as you described previously for 2021?

A. Yes, the support is the same, and therefore I will not repeat that same information for these programs in this section of testimony. The business cases referenced earlier in my testimony are applicable for the transfers-to-plant included for 2022-2024.

Illustration No. 3 below portrays the Production Capital Investments from 2021 through 2024 included in this case, distinguishing between what are ongoing projects from 2021, and new projects introduced in 2022-2024.

<u>Illustration No. 3: Production Capital Additions 2021-2024</u>



As you can see from Illustration No. 3, most of the capital investment relates to ongoing, multi-year efforts that continue over time, at various funding levels. The rationale and justification for these ongoing projects, however, does not change over time, only the funding levels. New incremental projects are discussed below. The largest of the new projects in 2023 is the Kettle Falls Fuel Yard Equipment Replacement of $30 M, which is discussed below. This and other "provisional" capital items in 2022 through 2024, as discussed by Ms. Andrews, will have a final review annually beginning in 2023, to assure that they are in service and used & useful and the final expenditures reviewed.

Q. These projects, taken as a whole, are all characterized as "provisional" in nature. What does that mean?

A. As explained by Ms. Andrews, projects for 2022 through 2024 have been characterized as "provisional". First, as provisional, the Company has segregated the capital investments into category designations discussed in the Commission's "Used and Useful Policy Statement," dated January 31, 2020 in Docket U-190531, including capital investments grouped as "Large and Distinct", "Programmatic", "Short-Lived" and "Mandatory and Compliance," for ease of review and audit. Second, "provisional" designates these capital additions as subject to final "review and refund" in a future period. "Provisional" does not mean to suggest that they are somehow uncertain. Ms. Andrews discusses the Company's proposal for Provisional Reporting for capital additions, by year, for 2022 through 2024.

Q. Before describing the 2022-2024 capital projects that you sponsor in your testimony, in general, has the Company applied offsets against the projects you discuss below?

A. Yes, as discussed further by Ms. Andrews, the availability of both direct and indirect offsets has been reviewed for each Business Case. As discussed in prior years, most projects do not have direct identifiable offsets that can be applied on an individual project basis; albeit they may have substantial indirect benefits by avoiding additional costs were the projects not completed. However, as discussed by Ms. Andrews, the Company has included a 2% efficiency adjustment, for non-mandatory projects, that have no direct offset in 2022, 2023 and 2024. Details of all direct O&M offsets, 2% efficiency adjustment and indirect offsets, by project, where appropriate, are included in Ms. Andrews' adjustments 4.03 and 5.09 and shown in Exh. EMA-5.

Q. Would you please describe the remaining 2022-2024 capital projects that you sponsor in your testimony?

A. Yes, as discussed below the remaining 2022-2024 capital projects include the following:

Project # 23 - Boulder Park Generator Replacement ($999,998 in 2024)

Boulder Park Generating Station (BPGS) is a 24.6 MW natural gas-fired power plant with six separate generators placed into service in March 2002 that provides 24.6 mw of electrical generation to Avista's service territory. In 2019, the Unit 5 generator failed and was replaced with the spare unit that was already on site. The recommended solution is to replace each generator over multiple years until the remaining five generators have been replaced, at the total cost of $5 million. The replacement of the BPGS generators will reduce the risk of unplanned failures that would cause a disruption in the electrical generation that supports the Bulk Electric System and increase safety around the units while in service. Although the damage to the generators is evident and there has already been one generator failure, the replacement of the BPGS generators has been scheduled to begin in 2024 (one generator) and be complete in 2026 to help balance capital spend, risk of failure, and customer rates. Failure to complete this project, over time, is highly risky as more generators will fail causing unplanned capital expenditure and loss of generation. Please see Exh. JRT-4, pp. 163-168 for additional information about this project, demonstrating that there are no reasonable alternatives and no offsetting direct benefits.

Project # 24 - Cabinet Gorge HVAC Replacement ($1,500,000 in 2023)

The current ventilation system in the powerhouse at the Cabinet Gorge Hydroelectric Development is still the original system and equipment installed in 1952. The original ventilation system controls are no longer functional and have been removed. There is no cooling capacity with the current ventilation system and the current air handling system can only be operated manually for ventilating and exhausting powerhouse air. There is no filter system for plant make up air which results in outside smoke from wildfires and dust in the outside air from entering the plant. The current summer temperatures in the powerhouse routinely rise to 90°F and additional transformers and electrical equipment planned to be installed within the powerhouse over the next three years will significantly increase internal plant heat loading. The Cabinet Gorge powerhouse needs to have a new HVAC System with cooling capacity. The estimated cost of the project is $1.5 million, and it is critical that this project is completed prior to the completion of the planned Cabinet Gorge Station Service upgrade which is expected to be completed in 2023. Without this system replacement, plant personnel will be subjected to unacceptably high internal powerhouse temperatures and critical electrical equipment will fail due to inadequate cooling. Please see Exh. JRT-4, pp. 169-177 for additional information about this project, demonstrating that there are no reasonable alternatives and no offsetting direct benefits.

Project # 25 - Cabinet Gorge Station Service ($7,761,859 in 2022 and $5,152,936 in 2023)

Cabinet Gorge Hydroelectric Development (HED), located on the Clark Fork River in Bonner County, Idaho. With four generators, it has a 270 MW output capacity. Built in 1952, the plant has retained most of its original equipment which is now aging and at end of life. In particular, the Station Service equipment is vital to the plant's continued operation. Station Service equipment includes Load Centers, Transformers, Switchgear, Power Centers and Neutral Grounding Resisters. This equipment is used to operate the generating plant. It includes energy consumed for plant lighting, power, and auxiliary facilities in support of the electricity generation system. It is recommended that this aging equipment be replaced to ensure the continued safe operation of the plant. Safe operation of the plant contributes to grid optimization, reliability and personnel safety. As many other equipment upgrades are underway at Cabinet Gorge, the timing of these Station Service replacements has been coordinated to reduce plant outages. In terms of risk, if this equipment is not upgraded, failure poses substantial hazards not only to the plant's operation but also to plant personnel as failed equipment can cause significant bodily injury and fire danger. Please see Exh. JRT-4, pp. 178-183 for additional information about this project, demonstrating that there are no reasonable alternatives and no offsetting direct benefits.

Project # 26 - Cabinet Gorge Stop Log Replacement ($1,200,000 in 2023)

Cabinet Gorge spill gates are early 1950s vintage and are original to the project. The spill gates are old and in need of replacement. Without a set of reliable stop logs, the Company cannot accomplish the spill gate work that is expected to take place over the next several years. Stop logs are used to isolate spillway gates from the reservoir for the Cabinet Gorge Hydroelectric project. Each stop log assembly comprises nine individual stop log elements or units, which when combined, allow dewatering of one spillway gate. Each stop log unit is a welded steel structure designed to fit inside stop log guides embedded inside a large concrete structure with a rubber seal that is compressed under the unit's weight and hydrostatic forces to minimize water seepage. Without these structures, Avista cannot efficiently and safely perform the upcoming spill gate work. The existing Cabinet Gorge spill gates need repair due to missing rivets, bent members, worn-out seals and heavy corrosion. If the repairs are not made, we pose the risk of a spill gate being out of operational use or a possible gate failure, which could result in an uncontrolled release of water. It is critical that this project is completed prior to the planned Cabinet Gorge Spill gate upgrade expected to be starting in 2024. Please see Exh. JRT-4, pp. 184-191 for additional information about this project, demonstrating that there are no reasonable alternatives and no offsetting direct benefits.

Project # 28 - Cabinet Gorge Unwatering Pumps ($395,000 in 2022 and $395,016 in 2023)

Cabinet Gorge Hydroelectric Development (HED), built in 1952, has retained most of its original equipment which is now aging and 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 generation, to changing customer loads and other regulating services needed to balance the system load requirement and assure transmission system reliability. One of those critical systems is the unwatering pumps. The unwatering system at Cabinet Gorge consists of two unwatering sumps, each housing three pumps, one 50HP and two 200HP pumps. The 50HP (1,000 GPM) pumps are used to pump out water from normal plant leakage. The 200HP (5,000 GPM) pumps are used to drain out generating units when performing routine maintenance. The original pumps are requiring increasing maintenance. Replacing all six pumps with new pumps at a cost of $800,000 is recommended. Timing for this work is related to Avista's entrance into the Energy Imbalance Market (EIM). The risks for not completing these upgrades include an inability to perform critical maintenance, potentially flooding the plant, and thereby jeopardizing Avista's ability to serve its customers. Please see Exh. JRT-4, pp. 192-197 for additional information about this project, demonstrating that there are no reasonable alternatives and no offsetting direct benefits.

Project # 30 - Generation Masonry Building Rehabilitation ($493,993 in 2022, $493,995 in 2023 and $493,990 in 2024)

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. This project funds a comprehensive inspection of each building to create a refurbishment plan which will remedy the issue long term ay each facility. Please see Exh. JRT-4, pp. 198-204 for additional information about this project, demonstrating that there are no reasonable alternatives and no offsetting direct benefits.

Project # 31 - Generation Protection Upgrades ($587,500 in 2024)

The purpose of this program is to replace existing obsolete protection relays at generating facilities with Avista standard digital multifunction protective relays. Protective relays in generation facilities must quickly detect high energy faults and isolate equipment to ensure personnel safety and avoid major equipment damage. Multiple generation sites currently operate with obsolete electromechanical and solid-state protection relays. Electromechanical relays are subject to mechanical drifting of settings that decrease relay operation reliability and require additional maintenance. Aging solid state relays are subject to sudden electronic failures and are difficult to accurately maintain settings. The like replacement options for both types of relays are very limited and failure could result in an extended unplanned outage. Also, older relays do not have the communication, metering, and event reporting functions standard in modern digital multifunction relays. These features are essential to effectively monitoring system operation and troubleshooting faults. Upgrading protection relays will improve reliability by reducing the risk of serious damage to major generation equipment, reduce outage time to troubleshoot protection events, and improve the safety of personnel in Avista's generating facilities. If this work is not approved or is deferred, operation and maintenance of these systems will become more costly, less reliable and increasingly dangerous. This program funds generator protection relay replacements at Rathdrum Combustion Turbine, Monroe Street HED, Boulder Park Generating Station, and Northeast Combustion Turbine. Please see Exh. JRT-4, pp. 205-213 for additional information about this project, demonstrating that there are no reasonable alternatives and no offsetting direct benefits.

Project # 32 - Kettle Falls Fuel Yard Equipment Replacement ($30,367,127 in 2023)

The Kettle Falls Generating Station, constructed in 1983, generates 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 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 2013 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. Please see Exh. JRT-4, pp. 214-225 for additional information about this project, demonstrating that there are no reasonable alternatives and no offsetting direct benefits.

Project # 34 - Monroe Street Abandoned Penstock Stabilization ($899,992 in 2023)

The Monroe Street Powerhouse was initially constructed in 1890 and has undergone several modernizations. During the 1972 modernization, three of the original penstock intakes were plugged with concrete and sealed with a layer of shot-crete. The three 10 ft. diameter steel penstocks were only partially removed, leaving an approximate 250 ft. length of each buried under what is now Huntington Park. It is unknown if the penstocks were also backfilled with material, posing a risk of implosion. These penstocks run underneath parts of the access road, crane staging area, and walking path through the park. The park is open to the public, and the access road and crane areas are critical to maintaining the safe and efficient operation of the Monroe Street Hydroelectric Development. During the 2018 Maintenance Assessment, these penstocks were identified as a high risk due to their location, unknown condition, and observed groundwater. The recommended solution includes further investigation of the intake dam and penstocks to better quantify the risk and implementation of a plan to mitigate those risks. The scope of this work would likely include an initial engineering evaluation, including investigatory drilling, with stabilization efforts likely to include grouting of the intake and penstock. Please see Exh. JRT-4, pp. 226-233 for additional information about this project, demonstrating that there are no reasonable alternatives and no offsetting direct benefits.

Project # 35 - Nine Mile HED Battery Building ($800,001 in 2022)

The purpose of this project is to build a battery storage building for the batteries supplying the Nine Mile Falls HED's critical power system to improve reliability and safety. The battery room will be located near the switchyard and underground conduit will be installed to the powerhouse containing power and control cables. During emergency situations, the critical power system is required to continually monitor and control the turbine generators and spillway for safe operations of the river and its flow. The 125 VDC battery banks are the most essential component of the critical power system and the health of the batteries needs to be closely monitored. The existing location of batteries on the switchgear floor is susceptible to extreme temperatures that greatly reduce the reliability and performance of the system. The location of the batteries is also a safety issue because they contain hazardous material and expel potentially explosive hydrogen gases during discharge. In addition to the reliability and safety concerns, the structural integrity of the existing floor needs to be reinforced as equipment is added or replaced. A new building with climate control and hydrogen monitoring dedicated to battery storage will greatly enhance the critical power system reliability and eliminate unnecessary safety hazards. The design and construction must be completed by the end of 2022 before major overhauls to Units 3 and 4 begin. Please see Exh. JRT-4, pp. 234-242 for additional information about this project, demonstrating that there are no reasonable alternatives and no offsetting direct benefits.

Project # 36 - Nine Mile Powerhouse Crane Rehab ($1,699,988 in 2022)

The Nine Mile Falls Generator Bay and Access Bay bridge cranes were replaced in 1993 prior to the Units 3 and 4 replacement project. Both cranes are Kone brand 35ton cranes with service class for both cranes being H1 – light duty. The Nine Mile powerhouse cranes are now beyond their useful life. Their duty cycle is too low to support continuous work during future unit overhauls with both replacement controls and mechanical parts no longer supported by the manufacturer and must be custom fabricated. The Generator floor crane trolley is now out of service, limiting Avista's capability to respond to a turbine generator failure. During the 2018 Maintenance Assessment, the cranes were identified as high risk due to their current condition. The project includes replacement of each crane's hoist and trolley system and installing a modern hoist and trolley. This is a modern in-kind replacement of the current powerhouse cranes and would provide a lasting solution to meet current and future crane demands. Please see Exh. JRT-4, pp. 243-250 for additional information about this project, demonstrating that there are no reasonable alternatives and no offsetting direct benefits.

Project # 37 - Nine Mile Units 3 & 4 Control Upgrade ($2,000,000 in 2023 and $1,999,999 in 2024)

Nine Mile Units 3 and 4 controls were installed in the early 1990s and are at the end of their intended life. As such, there is an increased likelihood of forced outages and subsequent loss of revenue and reliability from the plant. A controls upgrade including speed controllers (governors), voltage controls (automatic voltage regulator a.k.a. AVR), primary unit control system (i.e. PLC), and the protective relay system is needed on units 3 and 4. During the 2018 Maintenance Assessment, the Unit controls were rated in poor condition and high in risk due their age and current condition. Upgrading the controls, monitoring, and protection will reduce unplanned outages. This solution will address issues of obsolescence, increased likelihood of unplanned outages, and performance needs to work with the new dynamics of modern systems. This includes integration of intermittent resources, reserves, frequency and voltage response, and the ability to adapt these controls and protection devices as the larger grid continues to evolve. Please see Exh. JRT-4, pp. 251-258 for additional information about this project, demonstrating that there are no reasonable alternatives and no offsetting direct benefits.

Project # 38 - Noxon Rapids HVAC ($1,250,002 in 2024)

This project is similar to the Cabinet Gorge HVAC project (Project #24). The current ventilation system in the powerhouse at the Noxon Rapids Hydroelectric Development is not operational. The system was installed in 1959 and parts are no longer available. The system needs to be replaced because the original ventilation system controls are no longer functional and have been removed. There is no cooling or heating capacity with the current ventilation system and the current air handling system can only be operated manually for ventilating and exhausting powerhouse air. There is no filter system for plant make up air which results in outside smoke from wildfires and dust in the outside air from entering the plant. It is critical that this project is completed prior to the completion of the planned Noxon Rapids Generator excitation upgrade which is expected to be completed within the next 7 years. This new HVAC system will provide the needed plant cooling of this new equipment and provide sufficient heating, filtered ventilation and air conditioning in support of normal operations of the plant. Without this system replacement, plant personnel will be subjected to unacceptably high internal powerhouse temperatures and critical electrical equipment will fail due to inadequate cooling. Please see Exh. JRT-4, pp. 259-265 for additional information about this project, demonstrating that there are no reasonable alternatives and no offsetting direct benefits.

Project # 40 - Post Falls North Channel Spillway Rehabilitation ($18,499,999 in 2024)
The North Channel spillway at Post Falls HED is comprised of nine total spill gates – one large rolling sector gate and 8 Tainter-style radial gates. The North Channel spillway is a critical asset to Post Falls, being that it is a main spillway to divert water downstream once plant capacity is reached. The North Channel spillway continues to show its age, with continuing concrete deterioration, failing mechanical gate hoist equipment, and gate issues. Seepage through the left abutment has also been monitored by the Dam Safety team for years. In addition to normal maintenance activities, the North Channel Dam has undergone several major projects since the 1990's to keep it functional and reliable. These projects included at least two grouting projects to attempt to improve the internal integrity of the primary dam. The large sector gate has been structurally modified to address its design deficiencies and the Tainter gates have been painted and lift mechanisms have been refurbished. Even with these efforts, the current condition of the 110 plus year old structure raises questions about its ability to continue to provide the functions needed at the site.

If this project continues to be delayed, any unplanned failure of this structure could be a serious and costly unplanned contingency in the Powerhouse Redevelopment. Of even more criticality is the impact to upstream, downstream, and aesthetics required of the project. Avista's Spokane River license could be affected and our relationship with state and federal regulators would be in jeopardy should a portion of the spillway fail. Please see Exh. JRT-4, pp. 296-304 for additional information about this project, demonstrating that there are no reasonable alternatives and no offsetting direct benefits.

Project # 41 - Upper Falls Trash Rake Replacement ($1,500,000 in 2023)
The trash rake has, since its installation, presented an environmental risk due to the hydraulic system that it utilizes to function. When in use, the hydraulic system is suspended over the Upper Falls' unit intake and the Spokane River. If a hydraulic line failed during raking operations, some amount of hydraulic fluid would end up in the river, leading to an environmental cleanup exercise. The current trash rake is also undersized, leading to issues during raking operations. Often, the rake stalls out mid-operation due to the weight of

accumulated debris it is trying to recover. The rake is also limited in its ability to lift logs and tress which can accumulate in front of the rakes, leading to potential personnel safety issues with operators being required to cut up the logs and trees while in very close proximity to the river's edge. This often requires an operator leaning out over the handrail to address the problem. A safety action item was identified in 2016 related to the conveyor system that the trash rake utilizes to accumulate cleaned debris into a dumpster. This conveyor system, at the time posed a personnel safety threat due to its open operating nature. The risk of someone becoming entangled in the operating conveyor system drove a safety switch to be installed. This project replaces the trash rake with an appropriately sized system that will allow full reach of the intake racks and accommodate large sized trees and logs to be safely removed from the river. Please see Exh. JRT-4, pp. 275-282 for additional information about this project, demonstrating that there are no reasonable alternatives and no offsetting direct benefits.

V. COLSTRIP GENERATION CAPITAL PROJECTS

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

A. I will discuss the prudency of Colstrip capital additions for ongoing routine maintenance and environmental compliance projects from 2021 through 2024. The 2021 and 2022 Colstrip capital projects discussed below are included in approved budgets for those years and are meant to allow for continued operation of the plant through 2025. Certain capital additions identified for 2023 and 2024 are related to major outage work associated with an overhaul of Unit 4 in 2024 and an overhaul of Unit 3 in 2025. These projects do not officially come up for budget approval until November of 2022 (for budget year 2023) and November of 2023 (for budget year 2024). Avista has not received the hurdle rate sheets or other background specifics to these projects necessary to make a final approval determination, however based on our initial review, it is possible that some of these projects will not be necessary for the purpose of maintaining operations through 2025; accordingly, we will not vote in favor of budgets that include such projects, based on current information. Nevertheless, even if Avista votes "no" on these future budgets, we are subject to costs associated with these projects if we are outvoted in accordance with the terms of the Ownership Agreement. For these reasons, the costs are included in the revenue requirement of this case to cover the possibility that Avista may still be required to pick up its share. The revenue requirement associated with these disputed budget items for 2023 and 2024 will be refunded to customers, however, with interest, if Avista is successful in voting down a budget containing these disputed items.

Q. Would you provide some background about how Colstrip capital decisions are made and managed by the Company?

A. Yes. Talen, the plant operator, makes ongoing assessments regarding the conditions of the equipment at the plant during operation, 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 proposed budget after consideration of different options and the 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% 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, although as only a 15% owner it cannot dictate the result. 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 and also as part of 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.

It should also be recognized that 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.

Q. What is the overall reason for the on-going capital projects, in general, at Colstrip if the plant is not going to continue to serve Avista's Washington customers beyond 2025?

A. Some capital projects at Colstrip are necessary to maintain existing operations which are required by the owners to meet their anticipated load demands. The Colstrip Generating Station consists of Units 1 and 2 (333 MW each, that operated from 1975 until their retirement in January 2020), and Units 3 and 4 (740 MW each operating since 1983 and 1986), which are currently assumed to operate through 2025 to serve Avista's Washington customers. An actual retirement date for Units 3 and 4, however, has not been determined by the collective owners at this time. Avista, however, has removed it from its production portfolio for

Washington at the end of 2025.

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

A. Yes. For example, the owners will have to complete all projects associated with environmental mitigation and long-term closure of the facility. Additionally, certain prudent investments will be economically justified and required to reliably operate the facility even through December of 2025. Others, such as the Dry Waste Disposal project that is scheduled to be complete and transfer to plant in 2022, are legally required for continued operation of the facility. (The Dry Waste Disposal project is legally required to be operational in 2022.)

Q. What role does Avista play in the development of capital budgets for the Plants?

A. As mentioned, Avista is a 15% owner of the Plants and serves on an Ownership Committee with the other plant owners, which include NorthWestern Energy, PacifiCorp, Portland General Electric, Puget Sound Energy, and Talen. As such, as a minority owner, it does not have veto power over decisions generally, or line items in the budget. That does not suggest, however, that it is a passive owner. Quite the contrary, it can and does express its views and enlists the support of other owners to oppose any capital budget items proposed by Talen, the Project Operator, that it believes are inappropriate.

Q. Has Avista demonstrated its willingness to be heard?

A. Yes. Avista and other minority owners banded together to initially oppose the 2021 Capital Budget for Colstrip, originally proposed by Talen. Avista made it clear that it would not support any capital projects that were not necessary for continued operation of the Plants through 2025. As a result, the 2021 Capital Budget as finally approved by the Owners only reflected items that were necessary for continued operation of the Plants through 2025.

Q How have you documented this?

A. Confidential Exh. JRT-5C include a letter from the Pacific Northwest Owners requesting that Talen exclude certain projects and reduce in scope others to only do those projects necessary for operation through the end of 2025. Also included in Confidential Exh. JRT-5C is the response letter from Talen agreeing to the changes, as well as a line-by-line spreadsheet showing the need for each of the proposed capital items. This letter from Talen notes the reduction in budget for the 2021 overhaul (capital & O&M) of $10.3 million, which represented a reduction of more than 18% from the proposed budget.

Q. Did Avista and the other owners exercise similar oversight over the 2022 budget?

A. Yes, however since 2022 is a non-outage year (generally speaking, most capital work occurs during unit outages), there are very few material capital projects planned for 2022. In fact, the only material capital project planned for 2022 is the Dry Waste Disposal Project, a legally required installation begun earlier. The only new projects are the Common Effluent/Pond Return Project and the 2022 Scrubber Lime Slaker Replacement. Exhibit JRT-6C contains Talen's 2022 hurdle rate sheets describing the projects and why they are needed. Additionally, Exhibit JRT-6C, pp. 27 documents Avista's review and approval of the Common Effluent/Pond Return Project. These projects and their justification are described in more detail below.

Q. Please describe the capital projects slated to occur in 2022.

A. There are only five projects with expenditure or transfer to plant (TTP) activity in 2022. The biggest item in 2022, representing 78% of the annual spend and 94% of the transfer-to-plant activity is the Dry Waste Disposal project (TTP 2022, $5,755,329) which, as discussed previously, is a legally required installation. Additional detail on this project follows below.

The second project (TTP 2022, $120,000) is the 4-5 Feedwater Heater Replacement project which is a multi-year project that was approved as part of the 2021 budget process.

The third project is the Common Effluent/Pond Return Backup Line (TTP 2022, $188,000). Avista considered this project necessary because installation of this line restores important redundancy for transportation of scrubber effluent that will be lost when the Plantside B pond is removed from service July 1, 2022. The 2022 Hurdle Rate Package, provided as Exh. JRT-6C, pp. 5, lists the details for this project. In the event of a primary pipeline failure, the Plant has estimated a $320,000 (Avista share) per incident impact to power supply expense if the line was not installed (assuming a conservative market electric price of $22/MWh). Another option was considered, but that option would have cost almost four times as much and it would have provided less protection.

The fourth project is a Lime Slaker Replacement (TTP 2022, $52,000 Avista Share). Lime slakers provide lime to the scrubber system and reliable operation of this component is needed for SO_2 environmental compliance. Project information can be found in the 2022 Hurdle Rate Package; please see Exh. JRT-6C, pp. 9.

The fifth project is a PLC (Programmable Logic Controller) to DCS (Distributed Control System) retrofit project ($5,000) which is a carry-over from a 2021 project.

Q. Would you please provide a table that summarizes Avista's share of Colstrip capital transfer-to-plant in 2021-2024, that undergirds its revenue requirement in this case?

A. Yes. Table No. 6 provides an overview of the Colstrip capital projects and costs that are planned to transfer-to-plant in 2021 through 2024. The business case for the planned capital projects at Colstrip, showing Avista's share of amounts on a spend basis for the period 2022-2024, is provided as Confidential Exh. JRT-7C. Whereas, Confidential Exh. JRT-8C provides detail of Avista's share of Colstrip projects by year, spend and transfers-to-plant. Table No. 6 below provides the annual Avista share (WA/ID) of transfers-to-plant by year for 2021 through 2024.

Table No. 6: Colstrip Capital Projects 2021-2024

Transfer-To-Plant Colstrip Capital Projects - WA System Costs (WA/ID)					
Project #	**Project Description**	**2021**	**2022**	**2023***	**2024***
10027258	Cooling Tower Fill Unit 3	$ 503,172			
10027022	Design/Build Dry Waste Disposal System		$ 5,755,329		
99992416	Final Superheat Section Replacement*				$ 3,342,750
99992404	Condenser Tube Replacement*				$ 1,893,900
	Cooling Tower Fill Unit 4*				$ 577,500
	Projects Less than $500,000	$ 2,934,680	$ 364,200	$ 579,008	$ 3,574,648
	Total Colstrip Capital Projects TTP	$ 3,437,852	$ 6,119,529	$ 579,008	$ 9,388,798

* After completion of the Company's revenue requirement in this proceeding, it was determined that portions of the 2023 and 2024 capital additions included by the Company as transferring to plant in 2023 and 2024 (while amounts would be spent in those years), would not actually transfer to plant (be used and useful), until 2024 and 2025. The table above recognizes this and is corrected based on transfer to plant, not spend. The Company will correct its transfer to plant as included in its Colstrip Adjustments for 2023 (Rate Year 1) and 2024 (Rate Year 2) revenue requirement amounts associated with this change during the process of the case.

Q. How do the figures shown in Table No. 6 above, reflecting transfers-to-plant, compare with figures contained in the accompanying Business Case, in exhibit JRT-7C?

A. As discussed above, the Business Case shows budgeted annual spend amounts while the figures in Table No. 6 show expected transfers to plant for each of these years. Confidential Exh JRT-8C reconciles the Business Case annual spending with the transfer-to-plant data.

Q. Please discuss each of the entries in Table No. 6 by year.

A. For 2021, the only project with a TTP amount in excess of $500,000 is the Cooling Tower Fill Project Unit 3. The cooling tower fill[3] ("Fill") was in place for over ten years and was beyond its recommended life span. The Fill is typically replaced every 10 years, as per the manufacturer's recommendations. The existing Fill was becoming brittle, as expected with increasing age; additionally, it 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 structural members support to also fail, and the brittle remnants of the failed cooling tower Fill cause the circulating water system to plug up. This project was the first of two staged projects to restore the cooling tower. During the 2021 outage, high priority beams and the Fill above those beams was replaced, amounting to approximately 50% of the beams and Fill in the cooling tower. The balance of the work on this cooling tower is planned for 2025.

Q. Did Avista/Talen consider alternatives to the project?

A. Yes, the original recommendation was to remove and replace all of the weak structural members and associated Fill, but this option was not selected in order to reduce 2021 capital costs. A "do nothing" approach was also considered but rejected based on the risk of catastrophic failures and personnel safety concerns as well as increased likelihood of plant outages, even before 2025.

Q. Is this project necessary to extend the safe and reliable operation through 2025?

A. Yes, for the reasons discussed above.

[3] The Fill project replaces worn out evaporative media and some structural components of the cooling tower.

Q. What was the expected final cost of the project?

A. Total 2021 final cost for the Unit 3 Cooling Tower Fill project was $503,172 (Avista share).

Q. Please explain the $2,934,680 aggregation of 2021 projects less than $500,000.

A. Avista, as well as the other Pacific Northwest Owners, reviewed all of the capital projects proposed by Talen for 2021. The $2,934,680 that transferred to plant for 2021 includes those projects that were determined to be necessary for reliable and safe operations through 2025. Not all of the projects originally proposed by Talen for 2021 were acceptable to Avista or the other Pacific Northwest Owners because they were not, in our view, essential for safe and reliable operation through December 31, 2025. As mentioned previously, this scrutiny resulted in an 18% reduction in overhaul expense in 2021. Please see Exh. JRT-5C and Exh. JRT-6C for 2021 budget revisions and Hurdle Rate Sheets, respectively.

Q. Please describe the capital expenditures and transfers-to-plant listed in Table No. 6 <u>for 2022</u>.

A. 2022 is a year in which no scheduled outages are planned. The single largest project under way in 2022 is the previously discussed multi-year Dry Waste Disposal project. It will be complete in 2022, as required, and it has a forecast transfer-to-plant value of $5,755,329 (Avista share). Besides that project, there are only five additional small projects that transfer to plant in 2022, for a total cost of $364,200 (excludes Asset Retirement Obligation (ARO) projects which are addressed elsewhere in these proceedings). These projects were listed and discussed previously in this testimony.

Q. For 2023 and 2024, what is shown in Table No. 6?

A. For 2023, the largest item is the start of the "Superheat Section Replacement", for a budgeted amount of $1,182,150. For 2024, the largest projects are the completion of the "Superheat Section Replacement" for TTP of $3,342,750, the "Condenser Tube Replacement" for $1,893,900, and the "Cooling Tower Fill Unit 4" project for $577,500. All of the projects for 2023 and 2024 are shown in Confidential Exh JRT-7C. Those items shown in Exh. JRT-7C in italics are projects that Avista has preliminarily identified as being likely to require additional scrutiny to determine if they are required for safe and reliable operation through December 31, 2025. As previously stated, if Avista determines that any of these projects are not necessary in that regard, Avista will not vote to approve the Budget.

Q. For the 2023 and 2024 capital budgets, is it possible that Avista may learn more about these items, thereby changing its point of view?

A. Of course. New or additional information will always be considered by Avista and others in that regard, which may change its thinking, which one would only expect to be the case. Nevertheless, our current intention is to oppose any budget that contains capital projects that are not specifically necessary to provide safe and reliable operation through 2025.

Q. Please describe the Design/Build Dry Waste Disposal System project in 2022.

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 related litigation settlement.[4] 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

[4] The AOC defines the legally required and agreed upon steps to address groundwater contamination at Colstrip from leaking ash ponds.

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. This project is considered an Environmental “Must Do” project because of the AOC and AOC Settlement requirements. The AOC, developed by the Montana Department of Environmental Quality (MDEQ), sets out an evaluation process that includes site characterization, clean-up criteria, and risk assessment related to groundwater mitigation. The draft and finalized documents can be found on the MDEQ website specific to the Plant groundwater clean-up.[5]

Q. Did Avista/Talen consider alternatives to the project?

A. The Dry Waste Disposal system is legally required as a result of the AOC litigation settlement. The technology itself was chosen after completion of a successful pilot test. Not completing this project would result in a violation of the Colstrip Wastewater AOC and AOC Settlement. This alternative would result in a Notice of Violation (NOV) and a high risk of litigation along with fines and penalties.

Q. What is the timeline for completion?

A. The work on this item began with design efforts in 2020, construction started in 2021 and estimated completion is expected in mid-2022, as required.

Q. What is the expected final cost of the project?

A. Avista’s share of the 2022 project costs are $5,755,329.

Q. Please describe the Company’s investment in the <u>Final Superheat Section Replacement</u> in 2023.

A. The purpose of this project is to replace the Final Superheat Section that is

[5] https://deq.mt.gov/cleanupandrec/Programs/colstrip.

approaching the end of its engineered life to improve reliability and efficiency on Unit 4. This project includes removing some radiant reheat tubes to balance Superheat and Reheat surfaces so that design temperatures can be achieved.

Q. Did Avista/Talen consider alternatives to the project?

A. Yes. The alternative is to do nothing and repair tube failures as they occur. This project was originally proposed to be completed in 2020. Avista and other owners believed that the reliability risk did not yet justify the work and the original proposal was ultimately rejected. At this time, we do not yet know for sure whether or not installation in 2024 would be required for continued safe and reliable operation through December 31, 2025. However as previously stated, as we learn more, Avista will not approve a budget that contains projects that do not meet the criteria.

Q. What is the timeline for completion?

A. The work on the final Superheat Section Replacement Project would be expected to be started in 2023 and completed in 2024.

Q. What is the expected final cost of the project?

A. Avista's share of the 2023 and 2024 project costs are $1,182,150 and $2,160,600, respectively.

Q. Please describe the Company's investments in the <u>Condenser Tube Replacement</u> project in 2024.

A. The condenser tubes in Colstrip Units 3 and 4 are original to the plant and are a necessary component for operation of the plant. Normal wear and tear during forty years of operation has led to thinning of the metal to the point where individual tubes have begun to leak. As individual tubes fail and begin to leak, they need to be plugged. Many of the tubes have already failed, been plugged and are no longer operational. While plugging individual tubes is effective at stopping leaks, once a high percentage of tubes are plugged, the heat transfer degrades enough so that the unit performs poorly. Additionally, a big leak may result in a shutdown and lost generation. There is also a high percentage of tube wall loss in the remaining operational tubes. This project will replace the condenser tubes beginning with Unit 4 and then on Unit 3.

Q. Did Avista/Talen consider alternatives to the project?

A. This is a "Must Do" project to maintain the reliable operation of the plant. There are no real alternatives to be considered for this type of project. Additionally, Avista has not received the Hurdle Rate Sheets and associated operational data to make a final determination, at this time, regarding approval of this project.

Q. What is the timeline for completion?

A. The Condenser Tube Replacement Project is scheduled for completion in 2024.

Q. What is the expected final cost of this project?

A. Avista's share of the expected total cost of this project is $1,893,900.

Q. Are there any offsetting benefits associated with the Colstrip capital investments in this case?

A. Yes, there are total direct savings of $218,185, on a system basis related to Colstrip capital additions. These include $214,479 related to 2021 additions and $3,706 related to 2022 additions. These relate to the direct savings identified in Ms. Andrew's testimony and supporting documentation. Given the minor amount of the 2022 savings, these savings were included in total as $218,000 (Avista system), or $143,000 Washington share in electric pro forma adjustment (3.19) in Exh. EMA-2. Please see Ms. Andrews Exhibit EMA-5 for details.

Q. You mentioned Avista's continued review of 2023 and 2024 items. Will that review and any final budget determinations on disputed items be completed in time for the subsequent review by the parties of Rate Year 1 and Rate Year 2 expenditures, and amounts refunded to customers, if necessary?

A. Yes. Any dispute over budgeted 2023 and 2024 capital items will be resolved by year-end 2022 and year-end 2023 respectively. The future review of Rate Year 1 and Rate Year 2 expenditures will occur by the parties during mid-2024 for 2023 capital and mid-2025 for 2024 capital, well after budgets are determined and transfers to plant occur. All subject to refund of course.

VI. CHELAN PUD HYDRO POWER PURCHASE AGREEMENT

Q. Would you please explain the Chelan PUD Hydro Slice Power Purchase Agreement?

A. Avista's 2020 Integrated Resource Plan (IRP) identified the need for additional renewable resources in support of progress towards meeting clean energy goals of carbon neutrality by 2027 and 100 percent clean electricity by 2045. In order to fulfill these needs, on June 26, 2020 Avista issued a "Request For Proposals" (RFP) soliciting bids for renewable energy, capacity, and associated environmental attributes. The goal of the RFP process was to acquire resources that met Avista's renewable energy goals, and which were less than the avoided costs and the social cost of carbon. Any long-term resource acquisition below these costs would deliver net-value in Washington. Bids received on July 22, 2020 included over 40 wind, solar, hydro and biomass offers (many with storage options), for a total of over 4,300 MW. Avista evaluated these bids, as discussed below, and began contract negotiations with two parties: Chelan County Public Utility District ("Chelan") and a biomass facility. The biomass facility pulled their bid from consideration in early 2021, and Chelan was awarded a contract with an execution date of March 25, 2021. A full timeline of events for the 2020 RFP is included in the 2020 Renewable RFP Summary Report, provided in Confidential Exh. JRT-9C. The contract with Chelan is provided as Confidential Exh. JRT-10C.

Q. What are the terms of the contract with Chelan?

A. The terms of this contract resulted in the acquisition of a 5% Fixed Cost Slice (88 MW / 51 aMW) of Chelan's "Chelan Power System" (CPS) consisting of Rocky Reach and Rock Island hydro projects located on the Columbia River. The contract will supply Avista with output from the combined operation of Chelan's Rocky Reach and Rock Island hydro-electric projects with planned delivery of renewable energy and capacity to Avista for 10 years, beginning on January 1, 2024 and continuing through December 31, 2033.

A full summary of the RFP process and justifications for signing the Chelan PPA is provided as Confidential Exh. JRT-9C – 2020 Renewable RFP Report which contains the following supplemental documentation in addition to the main summary report:

- Exhibit A – Evaluation Methodology
- Exhibit B – Avista 2020 Renewables RFP Instructions and Preliminary Proposal Information
- Exhibit C – Avista 2020 Renewable RFP Document
- Exhibit D.1 – Evaluation Matrix 9/8/20
- Exhibit D.2 – Financial Analysis 9/14/20
- Exhibit E.1 – Short List Bid Scoring Summary 9/4/20
- Exhibit E.2 – Financial Analysis 9/30/20
- Exhibit F – Commission Staffs Update 9/22/20
- Exhibit G.1 – Evaluation Matrix Short List Bids 10/14/20
- Exhibit G.2 – Financial Analysis Summary 10/14/20
- Exhibit H – Management Approvals
- Exhibit I – Updated Presentation 3/12/21

Q. Would you provide additional background concerning the timing of the RFP?

A. Yes. Based on needs identified in the 2020 IRP, and considering industry indicators, Avista determined the opportune time to solicit bids for new renewable resources through the RFP was in the Summer 2020. These indicators included the continued sunsetting of the Production Tax Credit (PTC), pricing and developer activity, competition for preferred projects and locations, technology advancements. and competition for least cost resources. The 2020 Renewable RFP resulted in competitively-priced proposals that delivered the renewable benefit; additionally some proposals provided significant flexible and dispatchable energy benefits from existing projects with known performance.

Q. At the time of the 2020 Renewables RFP, please explain how the Company determined that a new resource was necessary.

A. As previously described, the need for additional renewable energy resources was identified in the 2020 IRP. The goal was to acquire resources that met Avista's renewable energy goals and were less than avoided costs and societal cost of carbon. As such, taking into consideration industry indicators and project lead times, Avista determined it was the opportune time to solicit pricing for new renewable resources through an RFP in the Summer of 2020. The Company's Board of Directors was apprised of the 2020 Renewables RFP and the evaluation process that was used to compare project bids from which the Chelan PPA was selected.

Q. How did Avista evaluate and consider alternatives to the Chelan PUD Hydro PPA?

A. The RFP was open to parties who owned, proposed to develop, or held rights to new renewable resource generating facilities. The 2020 RFP utilized similar methodologies as the 2018 RFP. Avista had engaged a third-party consultant for the 2018 RFP to gain an outside perspective as it related to the RFP. For the 2020 RFP, Avista utilized similar methodologies proven out in the 2018 RFP. Finally, Avista did not accept proposals for renewable energy certificates only.

As specified in the RFP, Avista sought proposals from eligible renewable resources as defined by RCW 19.285. The proposals were required to outline the acquisition of approximately 120 MW (alternating current, or AC) with a minimum net annual output of 5 MW AC that satisfied the requirements of the RFP. Bidders could submit more than one proposal or proposals with multiple developments, and projects could be new or existing eligible resources, including wind, solar, geothermal, biomass, hydroelectric or other eligible renewable resources. Avista also considered proposals that included storage. Avista's objective was to secure eligible renewable resource(s) under terms and conditions that were economical and favorable to Avista's customers. Bidders assumed the risks related to federal tax incentives.

The Company produced an evaluation criteria and methodology for scoring bids in consultation with Black & Veatch, a third-party independent evaluator, for the 2018 RFP. The 2020 RFP used a similar methodology with additional criteria on emerging issues such as identified community and vulnerable population impacts. The methodology provided in Exhibit A of Confidential Exh. JRT-9C was shared and discussed with the Staffs of both the Washington and Idaho Commissions.

The general qualifications for each proposal were evaluated and weighted on six characteristics listed in Table No. 7. The weightings for each characteristic were determined based on their importance in helping the Company meet its resource development goals stated in the 2020 IRP. Within each characteristic, points could be subtracted or added to the initial 100 points based on responses to the RFP and Avista's interpretation of the submitted data. Avista reserved the right to modify the scoring criteria in consultation with Commission Staff of Washington and Idaho if proposals were received that contained circumstances not considered in the original methodology.

Table No. 7: 2020 Renewables RFP Evaluation Criteria and Weightings

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

Avista utilized a two-step bid process. The first step included evaluating and ranking projects based on preliminary information by allowing developers to submit a condensed initial bid utilizing the template shown in Exhibit B of Confidential Exh. JRT-9C. The evaluation and ranking of the preliminary information focused on conformance of each bidder's submittal with the requirements of the RFP and the proposed net price, among other factors. The initial evaluation and ranking, performed in a fair and consistent manner, produced a short list of bids. Once the short list was compiled, short-listed bidders submitted detailed proposals in accordance with Exhibit C of Confidential Exh. JRT-9C. Each short-listed bidder's detailed proposal was evaluated against the other short-listed bidders' detailed proposals.

The two-step approach was well-received with 25 developers submitting over 40 responses to the RFP with projects in excess of 4,800 MW proposed. Potential projects were evaluated both quantitatively and qualitatively based on predetermined criteria shared with the Commission Staff of Washington and Idaho. Seven projects were selected for a short list and were asked to provide detailed responses to the proposal. The first screening began after preliminary information was received on July 22, 2020. This screen focused on removing from further consideration those 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 project 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) and a few projects were from existing generation resources. The complete evaluation matrix is found in Exhibit D.1 and the financial analysis is provided in Exhibit D.2 of Confidential Exh. JRT-9C

There was a clear break in the rankings after the top seven proposals. Out of the top eight ranked projects, three were wind projects, two were hydro and one each of solar and biomass. One was removed from further consideration as it only bid a 5-year term and did not meet the minimum PPA term requirements of the RFP. To help differentiate between the short-listed bids from round 1 to round 2, between August 21, 2020 through September 9, 2020, seven short-listed bidders were asked to provide detailed proposals. The short-listed bidders were further evaluated using the detailed information and additional due diligence was performed on each offering. The evaluation matrix for the detailed proposals is included in Exhibit E.1 and the financial analysis is included in Exhibit E.2 of Confidential Exh. JRT-9C. A presentation of the RFP process and short-listed bidders was made to the Washington Commission Staff on September 22, 2020 and is available in Exhibit F of Confidential Exh. JRT-9C.

Avista allowed shortlisted bidders to refresh their prices in early September 2020, 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. The complete evaluation matrix of the seven short-listed projects is provided in Exhibit G.1 and the financial analysis including re-pricing is provided in Exhibit G.2 of Confidential Exh. JRT-9C. Based on the financial and full evaluation matrix analysis Chelan PUD's 5% fixed cost hydro slice and a biomass project were selected for further negotiations (Chelan initially bid their 5% and 10% proposals as separate, either/or proposals). The biomass project pulled their bid from further consideration in early January 2021.

Q. Has the Company finalized the 2020 RFP?

A. Yes. With the biomass project pulling their bid from consideration, the Company re-engaged Chelan on their second bid which also ranked in the top three of the evaluation matrix. The Company closed out its 2020 RFP with a second contract with Chelan for an additional 5% (88 MW/51 aMW) with delivery starting on January 1, 2026. This contract increases to 10% on January 1, 2031, when an existing Chelan PUD contract expires on December 31, 2030, and continues until 2045. That second contract is not yet before the Commission but will be the subject of a future filing.

Q. Is the first contract for 5% Fixed Cost Slice Chelan contract starting in 2024 included in the power supply base sponsored by Company witness Mr. Kalich?

A. No, this contract is not included in the 2023 power supply base, as the Chelan 5% slice contract does not begin until January 2024. We are, however, including this contract for testimony in this case because of Mr. Kalich's proposal regarding the proposed 60-day Power Supply Update prior to Rate Year 2, if the proposed trigger is met. As Mr. Kalich states, if the proposed trigger is met, the same 60-day update methodology used for Rate Year 1 would be used for Rate Year 2. The only known modification would be inclusion of the new Chelan

Hydro contract that begins in 2024, which is close to the start of Rate Year 2. It would be appropriate, in the Company's view, to include this first Chelan contract in such an update, along with other pricing and contractual changes, as well as any refinement to EIM benefits.

Q. Is the 20-year Chelan deal (the second contract) that begins in 2026 included as part of this general rate case?

A. No, it is not. With a beginning date of January 1, 2026, this contract is outside of the test period 2023 or 2024, and would be outside the scope of the proposed Rate Year 2 60-day update. This contract will be evaluated for prudence in the Company's next general rate case, or in the 2026 Annual ERM filing. We have included brief testimony on this matter as the contract is directly tied to the same RFP that led to the first Chelan contract, and therefore providing that update in this testimony completes the discussion of the work and contracts related to that RFP.

Q. How was transmission considered in this decision?

A. The cost of transmission was considered for the all the bidders. No new transmission facilities needed to be developed for the 2024 or 2026 Chelan PPAs.

Q. What documentation for the analysis and decision-making process has the Company provided regarding the decision to enter into the Chelan contract?

A. Confidential Exh. JRT-9C includes the complete documentation concerning the RFP solicitation, and evaluation process that resulted in the selection and signing of the Chelan PUD Hydro Power Purchase Agreement, Confidential Exh. JRT-10C. My testimony and exhibits provide the documentation necessary to demonstrate the long-term economic benefit to customers for the Chelan contract and provides specific supporting details regarding the Company's analysis and decision. The executed PPA will also help meet the renewable and clean energy goals under Washington's Energy Independence Act, the Clean Energy Transformation Act, as well as support the Company's own clean energy goals. The Chelan contract also fits within the analysis performed under the Company's IRP. 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 Washington and Idaho Commission Staffs in the entire RPF process.

Q. Does the PPA with Chelan PUD for hydro power comply with RCW 80.80, the emissions performance standard?

A. Yes, it does. This PPA automatically complies with RCW 80.80 under WAC 173-407-120 (c) because it is powered exclusively by renewable water resources.

Q. Does this conclude your pre filed direct testimony?

A. Yes, it does.