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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

I. INTRODUCTION

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

A. My name is Heather Rosentrater and I am employed as the Senior Vice President of Energy Delivery and Shared Services for Avista Utilities (Avista or Company), at 1411 East Mission Avenue, Spokane, Washington.

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

A. I received a Bachelor of Science degree in Electrical Engineering from Gonzaga University, and hold a Professional Engineer (PE) credential. I joined Avista in 1996 as an electrical engineering student at the Company's former subsidiary, Avista Labs, where I developed electrical systems for fuel cells. I joined Avista in 2003 and have broad experience on both the electric and natural gas side of the business, having managed departments and projects in electric transmission, distribution, SCADA, supply chain, as well as business process improvement using LEAN and Six Sigma techniques. I was named Vice President of Energy Delivery in December 2015 and promoted to my current role in October 2019. In this role, I am responsible for electric and natural gas engineering, operations and shared services which includes fleet, facilities, and supply chain.

I currently serve on the board of directors for the Vanessa Behan Crisis Nursery and Second Harvest Food Bank in Spokane, Washington. In addition, I am a member of the Gonzaga University School of Engineering and Applied Science Executive Advisory Council.

Q. What is the scope of your testimony?

A. I will provide an overview of the Company's electric and natural gas energy delivery facilities, electric reliability trends and areas of focus, and explain the factors driving our continuing investment in electric distribution infrastructure. I will explain how our efforts to maintain the asset health and performance of our electric transmission system, including compliance with mandatory federal standards for transmission planning and operations, is driving a continuing demand for new investment. Further, I will describe why our investments in natural gas distribution are necessary in the time frames completed and why each capital investment in our operations facilities and fleet operations is needed to support the efficient delivery of service to our customers, today and into the future. Furthermore, I will address the electric and natural gas distribution, transmission, general plant and fleet related capital additions included in the Company's Two-Year Rate Plan filed in this case, for the periods 2020 through August 2023. A table of the contents for my testimony is as follows:

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following Schedules as a part of Exhibit No. 11:

- Schedule 1, Avista's Electric Distribution Infrastructure Plan for 2020
- Schedule 2, Avista's Substation Infrastructure Plan for 2020
- Schedule 3, Avista's Electric Transmission Infrastructure Plan for 2020
- Schedule 4, Avista's Natural Gas Infrastructure Plan for 2020
- Schedule 5, Avista's Priority Aldyl-A Protocol Report
- Schedule 6, Study of Aldyl-A Mainline Pipe Leaks - 2018 Update
- Schedule 7, Avista's Fleet Infrastructure Plan for 2020
- Schedule 8, Avista's Facilities Infrastructure Plan for 2020
- Schedule 9, Capital Business Case documents for each of the capital projects and programs described in my testimony

Q. Will you be providing an overview of Avista's Wildfire Resiliency Plan in your testimony?

A. While I am the officer responsible for our work in this important area, Company witness Mr. Howell will provide an overview of the strategy and actions comprising the Plan.

II. OVERVIEW OF AVISTA'S ENERGY DELIVERY SERVICE

Q. Please describe Avista's electric and natural gas utility operations.

A. Avista operates a vertically-integrated electric system in Idaho and Washington, and natural gas local distribution operations in Idaho, Washington and Oregon. In addition to the hydroelectric, renewable, and thermal generating resources described by Company witness Mr. Thackston, the Company has an electric transmission system comprised of 685 miles of 230 kV lines and 1,534 miles of 115 kV lines. Avista has approximately 18,300 miles of primary and secondary electric distribution lines. The Company owns and operates 7,650 miles of natural gas distribution lines, served from the Williams Northwest and Gas Transmission Northwest (GTN) pipelines. A map showing the Company's electric and natural gas service area in Idaho, Washington and Oregon is provided by Company witness Mr. Vermillion.

As detailed in the Company's 2020 Electric Integrated Resource Plan,[1] Avista expects retail electric sales growth to average 0.3% annually for the next ten years in our service territory, a decline from the 0.5% forecast in the 2017 IRP. Also, based on Avista's 2018

[1] A copy of the Company's 2020 Electric IRP has been provided by Company witness Mr. Thackston (Exhibit No. 7, Schedule 1).

Natural Gas Integrated Resource Plan,[2] in Idaho and Washington the number of natural gas customers is projected to increase at an average annual rate of 0.4%, with demand growing at a compounded average annual rate of 1.3%. What may occur in a post-pandemic timeframe is unknown at this point.

Q. How many customers are served by Avista in the State of Idaho?

A. Of the Company's approximate 392,000 electric and 362,000 natural gas customers (as of the December 31, 2019 test year), 135,422 and 81,143, respectively, were Idaho customers.

Q. Please list the Company's operations service centers that support electric and natural gas customers in Idaho.

A. The Company has construction offices in Coeur d'Alene, Sandpoint, St. Maries, Kellogg, Grangeville, and Lewiston/Clarkton. Avista's three customer contact centers, located in Coeur d'Alene and Lewiston, Idaho, and Spokane, Washington, are networked, allowing the full pool of regular and part-time employees in each location to respond to customer calls from all jurisdictions.

Q. Please describe the Company's Service Quality Measures Program?

A. Avista's Service Quality Measures Program was approved by the Commission in November 2018, and includes the following measures:[3]

- ✓ Reporting on two (2) measures of electric service reliability;
- ✓ Seven (7) individual service standards, where Avista provides customers a payment of bill credit in the event the Company does not deliver the required service level (Customer Service Guarantees), and

[2] A copy of the Company's 2018 Natural Gas IRP has been provided by Company witness Ms. Morehouse (Exhibit No. 14, Schedule 1).
[3] Order No. 34181 in Case Nos. AVU-E-18-10 and AVU-G-18-06

- ✓ Five (5) individual measures of the level of customer service and satisfaction the Company must achieve each year.

Q. Did Avista achieve its Service Quality Measures Program benchmarks for 2020?

A. The Company is pleased to report we exceeded all six Customer Service Measure benchmarks for our most recent reporting year in 2019, and noted a continuing relatively stable long-term trend in electric service reliability.[4] Avista experienced a slight decrease in the average occurrence of outages per customer for the year, and a decrease of two minutes in our five-year average for outage duration per customer. Results for Avista's 2019 Customer Service Measures are provided in Table No. 1:

<u>Table No. 1 – 2019 Results for Avista's Customer Service Measures</u>

Customer Service Measures	Benchmark	2019 Performance	Achieved
Percent of customers satisfied with our Contact Center services, based on survey results	At least 90%	94.4%	✓
Percent of customers satisfied with field services, based on survey results	At least 90%	94.4%	✓
Number of complaints to the WUTC per 1,000 customers, per year	Less than 0.40	0.13	✓
Percent of calls answered live within 60 seconds by our Contact Center	At least 80%	80.7%	✓
Average time from customer call to arrival of field technicians in response to electric system emergencies, per year	No more than 80 minutes	44.3 minutes	✓
Average time from customer call to arrival of field technicians in response to natural gas system emergencies, per year	No more than 55 minutes	43 minutes	✓

Electric System Reliability	5-Year Average (2015-2019)	2019 Result	Change in 5-Year Average
Frequency of non-major-storm power interruptions, per year, per customer (SAIFI)	0.97	0.94	-0.04
Length of power outages, per year, per customer (SAIDI)	151 minutes	137 minutes	2 minutes

Q. Please describe the approach used by Avista for evaluating and managing the energy delivery capital investments required to serve our customers?

A. Proposals for individual projects and programs are initially developed,

[4] Avista annually reports results for its Service Quality programs at the end of April for the prior reporting year. Accordingly, the Company will have complete results for 2020 by April 30, 2021.

reviewed and evaluated in each responsible business unit, often followed by review, evaluation and prioritization by higher-level review committees, such as Avista's Engineering Roundtable, the Aldyl A Pipe Advisory Group, and the Facilities Steering Committee. In this review, projects are evaluated for completeness of the problem statement, the identification and evaluation of reasonable alternatives, and applicable risks, and other elements. Refined and finalized proposals are submitted to the Company's Capital Planning Group for consideration and recommendation of funding (as described in the testimony of Company witness Mr. Thies). Once approved for funding, the Project Engineer or Manager identifies critical project milestones and the resources needed to achieve them. Major equipment with long lead times may be purchased in this phase, necessary permitting identified and completed, and contracting processes initiated.

During execution, the Company's Project Managers create a detailed work schedule and establish inspection, monitoring, safety, environmental, and invoicing protocols. Standard project management practices are employed to effectively guide the work, identify and manage project risks, recommend needed changes to scope and budget, and track and report out on overall status. Examples of tools that may be used to track budget and schedule, depending upon the size and scope of a project, include Earned Value Measurement, cost-loaded scheduling, Cost Performance Index (CPI) and Schedule Performance Index (SPI).[5] Project results are regularly reviewed with the responsible Department Manager, applicable committee, and/or Director which review includes budget allocations and variances, internal resource demands, customer care results and issues, and contractor performance.

[5] Cost Performance Index (CPI) is computed by Earned Value / Actual Cost. A value of above 1 means that the project is doing well against the budget. Schedule Performance Index (SPI) represents how close actual work is being completed compared to the schedule. SPI is computed by Earned Value / Planned Value.

Q. Are alternatives vetted for these projects before approvals are given?

A. Yes. Where there are reasonable alternatives, the evaluation of those is discussed in each business case (business case documents for the capital projects I am sponsoring have been included as Exhibit No. 11, Schedule 9).

Q. How is Avista's leadership informed of the program status?

A. As described above, project and program status and results are communicated up departmental lines, through various committees, and to me via my Director-level direct reports. Program and project results are also reported directly to Avista's Capital Planning Group, and the Company's senior leaders, including myself, through steering committees, various business meetings, and presentations.

<u>III. INVESTMENTS IN THE COMPANY'S ELECTRIC DISTRIBUTION SYSTEM</u>

Q. Please summarize the need for continuing investments in the <u>electric distribution</u> system.

A. Avista, like utilities across the country, continues to prudently fund the increasing demand for investment in electric distribution infrastructure. The pattern of our investments bears a striking resemblance to that of the industry, which should not be a surprise, since we are all responding to the same predominant needs: first, the need to replace an increasing amount of infrastructure each year that has reached the end of its useful life (based on asset condition), and second, responding to the need for technology investments required to build the integrated energy services grid of the future. To provide better visibility of the factors driving this need for investment, we continue to organize the Company's planned spending over the current five-year planning horizon by "Investment Driver" categories shown below, and as discussed by Mr. Thies.

1. Respond to customer requests for new service or enhancements;
2. Meet our customers' expectations for service quality and reliability;
3. Meet regulatory and other mandatory obligations;
4. Address system performance and capacity needs;
5. Replace infrastructure at the end of its useful life based on asset condition, and;
6. Replace equipment that is damaged or fails, and support field operations.

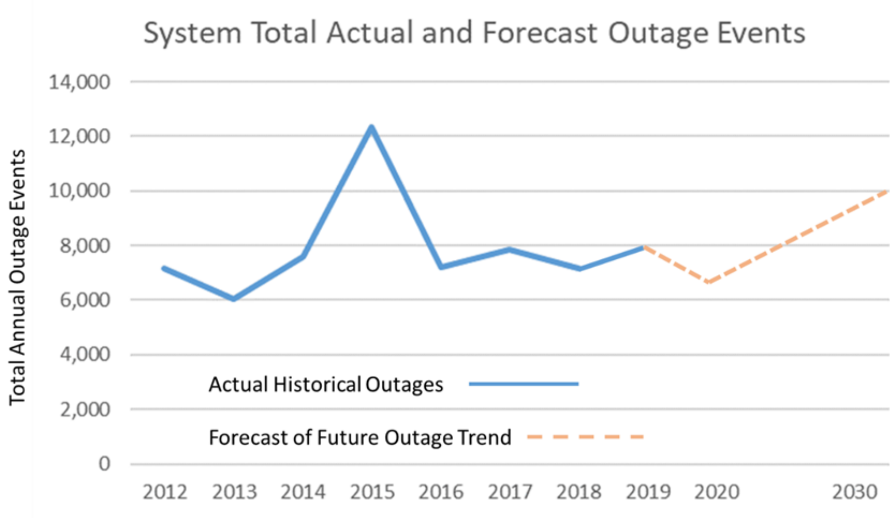
The need for major capital projects and programs supporting our electric distribution system is explained in detail in the Company's Electric Distribution Infrastructure Investment Plan for 2020, Exhibit No. 11, Schedule 1, and our enterprise-wide Infrastructure Investment Plan for 2020, Exhibit No. 2, Schedule 3.

Q. Would you describe the Company's current focus on electric service reliability?

A. Yes. In recent years, the Company has generally aimed to maintain and uphold its current overall reliability performance and we annually report on current-year and historic reliability trends. In 2019, Avista employees under my direction developed draft recommendations for a new electric service reliability strategy based on the aspects we believe are most important to our individual customers and the prudent long-term management of our system. While we will continue to report historic reliability performance, our new approach is forward-focused to better understand, evaluate and respond to long-term reliability trends. This work is based on intensive use of historic reliability data, infrastructure modeling and robust statistical forecasting. An example of this forecasting is shown below in Illustration No. 1, for the annual number of outage events.[6]

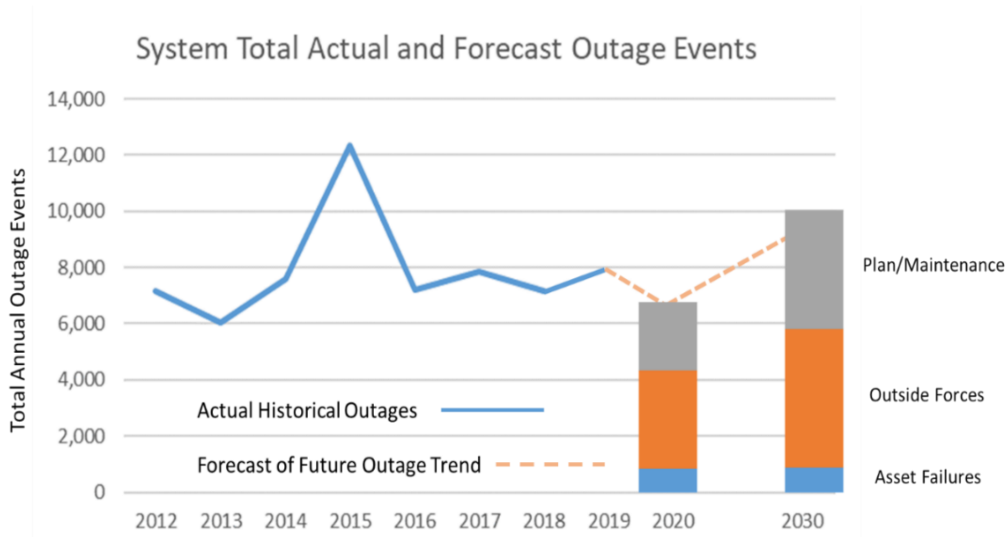
[6] Outage data shown excludes outage events for Major Event Days on the Company's electric system.

Illustration No. 1 – System Total Actual and Forecast Outage Events



The forecast trend shows a potential increase in the annual number outages, and the "outage types" contributing to the forecast are explained below in Illustration No. 2.

Illustration No. 2



In our modeling and forecasting the Company groups the cause of outage events into three categories: "Plan/Maintenance," "Outside Forces," and "Asset Failures." As implied by the title, plan/maintenance outages are those unavoidable outages required for Avista's maintenance, repair and upgrade of its electric distribution system. Outages associated with outside forces are those events beyond the Company's direct control, such as the 2020 Labor Day and January 2021 major windstorm events, heavy snow, ice, animal-caused or car-hit-pole. Outages associated with asset failures result from equipment that fails in service, which the Company has a greater degree of control over through our engineering standards, asset maintenance programs (e.g. Wood Pole Management), and Vegetation Management. Although the overall forecast shows a likely increasing trend, it is driven primarily by outages beyond our control (outside forces) and those required for maintenance on our system (plan/maintenance). Importantly, outages resulting from asset failures are expected to trend flat over the next decade.

Q. Would you please describe the extent of the service outages experienced by customers in Idaho's Silver Valley and other locales in the recent major windstorm event of January 2021?

A. On January 13, 2021, the Company experienced near-hurricane-force winds across its service territory that uprooted or snapped a significant number of trees that were blown into our electric transmission and distribution lines, taking them out of service. Not only were the windspeeds extreme but they coincided with conditions where the soil was unfrozen and highly saturated from rains, rendering conditions prime for the uprooting of conifers across our forested service area. Among the damage we experienced was the unprecedented loss of all six of our electric transmission lines serving communities in the Silver Valley. Much of the damage to these lines was in remote areas that were difficult to reach, both for locating the damage and performing repairs. The extent of repairs required to the transmission backbone, combined with extensive damage to our electric distribution lines, along with the major damage that occurred all across our Idaho and Washington service area, created a large and extended outage for many of our Silver Valley and other customers. Avista launched an all-out response to this storm by deploying all 60 of the Company's electric crews, putting on 44 additional crews from electric contractors, and receiving the mutual aid support of 22 electric crews from neighboring utilities. These electric crews were aided in tree removal by 19 vegetation management crews. All customers had their service restored by January 20, 2021. We are very proud of the efforts of our employees and contractors in restoring service and assisting customers in this unprecedented event.

Q. What's next in the continuing development of the Company's reliability strategy?

A. Avista has been evaluating asset maintenance options to cost-effectively reduce asset failures as one approach for better achieving our long-term reliability metrics. Over time, the strategy will integrate the reliability benefits and impacts of related efforts, such as the Company's Wildfire Resiliency Program, to ensure we're evaluating a broader range of alternatives for meeting our service reliability objectives. Avista is also in the early stages of assessing opportunities for expanding our communication with customers both before, during and following service outages on our system. The purpose of these communications is to create more visibility around our efforts to provide them reliable service, to acknowledge them in meaningful ways when they have experienced multiple outages in a year, and to continue to provide them timely, accurate and relevant information during service outages.

Q. Would you please summarize the capital investments in electric distribution plant completed in 2020 and planned for over the Two-Year Rate Plan?

A. Yes. As discussed by Company witnesses Ms. Schultz and Ms. Andrews, Avista's capital witnesses, including myself, describe the capital projects included in the Company's proposed Two-Year Rate Plan, reflecting pro forma capital additions for the period between January 1, 2020 and August 31, 2023. The completed and planned investments related to electric distribution, presented on a system basis and grouped by investment driver, are shown below in Table No. 2, and described below.

<u>Table No. 2 – Electric Distribution Capital Projects (System)</u>

Electric Distribution Capital Projects (System) In $(000's)				
Business Case Name	**2020**	**2021**	**2022**	**2023(1)**
Mandatory and Compliance				
Elec Relocation and Replacement Program	$ 2,915	$ 2,751	$ 3,638	$ 1,760
Joint Use	2,682	2,750	2,750	1,462
Saddle Mountain 230/115kV Station (New) Integration Project Phase 2	-	806	-	-
Failed Plant and Operations				
Electric Storm	5,169	2,145	2,118	1,412
Meter Minor Blanket	200	250	250	167
Asset Condition				
Distribution Grid Modernization	7,374	-	-	-
Distribution Minor Rebuild	11,315	10,046	10,300	6,578
Distribution Transformer Change Out Program	316	400		
LED Change-Out Program	400	400	400	267
Primary URD Cable Replacement	86	-	-	-
Substation - Station Rebuilds Program	9,945	1,182	28,468	667
Wood Pole Management	10,275	15,739	16,000	10,667
Customer Service Quality and Reliability				
Wildfire Resiliency Plan	3,033	13,317	21,330	17,053
Performance and Capacity				
Distribution System Enhancements	6,922	6,000	7,000	2,668
Misc. accrual reversals, corrections or additional TTP	13	-	-	-
Total Planned Electric Distribution Capital Projects(2)	**$ 60,646**	**$ 55,787**	**$ 92,254**	**$ 42,700**

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

(2) Totals exclude Washington and Oregon direct business cases from revenue requirement in this case

Electric Relocation and Replacement Program – 2020: $2,915,000, 2021: $2,751,000, 2022: $3,638,000, 2023: $1,760,000

Placement of the Company's electric facilities is generally located in easements provided in public rights of way that are governed by jurisdictional franchise agreements. When requested by the local jurisdiction, typically related to transportation projects, the Company must relocate its facilities in the right of way to accommodate these projects. Avista is obligated under terms of its franchise agreements to move its facilities at its own expense and within the timeframe specified by the local jurisdiction. Using public rights of way for our many thousands of miles of electric infrastructure provides a cost-effective way to serve our customers, even considering the costs associated with the periodic requirement for their relocation. Agreeing to move our facilities when requested is an important provision that allows the Company to negotiate favorable franchise agreements, which in turn, allows us to continue providing reasonable service to our customers at an affordable cost. The need for electric relocations and replacements is driven by the plans of our local jurisdictions, and as such, is not an activity that Avista can anticipate in definitive terms, plan for, or manage like a project internal to the Company. Accordingly, the annual spending levels can be quite variable so Avista budgets for this activity in coming years based on the spending levels experienced in the prior five-year period. The actual spending level each year is determined by the number and size of projects the Company is required to complete.

Joint Use Projects[7] - 2020: $2,682,000, 2021: $2,750,000, 2022: $2,750,000, 2023: $1,462,000

Joint Use is the regulated use of utility poles and other structures owned by Avista that are available for use by third-party telecommunications companies to provide their services to customers we have in common. Avista is reimbursed for this joint use by tariffs in each of our jurisdictions, which reimbursement serves to directly lower the cost our customers pay for their Avista service. These joint use projects, referred to 'make ready,' meet our obligation to provide adequate clearance for the attachment of third-party infrastructure by installing taller structures (typically wood poles) than would be required for Avista's facilities alone. These annual projects are part of a continuing program where the Company responds to the requests of third parties to make our facilities ready for their infrastructure. The Company is subject to regulatory action, penalties, and/or civil litigation if it does not timely perform the mandated make ready work when requested. Our customers benefit from the shared use of facilities because it helps reduce the cost they pay for both their telecom and electric services. The need for joint use projects is driven by the plans and requests of third parties and is beyond the control of the Company. The amount of work performed each year and the resulting spending is therefore variable year-to-year. Historically, the Company included investments supporting joint use as part of the electric Distribution Minor Rebuild program. The level of investment required recently, however, signaled the need to present these activities in a separate business case.

[7] Joint Use is a new business case in 2020. Costs for this project were previously embedded in the Distribution Minor Rebuild business case.

Saddle Mountain 230/115kV Station (New) Integration Project Phase 2 – 2021: $806,000

The Saddle Mountain Project was initiated as primarily an electric transmission substation project, however, it has multiple parts and phases which include transmission line investments needed to integrate the new substation as well as integrating distribution facilities. This portion of the project includes transmission system upgrades that are needed to integrate the Company's new Othello city distribution substation with the new Saddle Mountain substation. Integration of these two new substations is critical to providing our customers adequate service reliability at the distribution level and the flexibility needed for the operation and maintenance of our overall transmission system.

Electric Storm – 2020: $5,169,000, 2021: $2,145,000, 2022: $2,118,000, 2023: $1,412,000

The Electric Storm investments cover the cost of restoring Avista's electric transmission, substation, and distribution systems to serviceable condition when damaged during a significant weather (storm) event or other natural disaster. These storm events include high winds, heavy wet snow, ice, lightning strikes, flooding, and wildfire, and various combinations of them, to name a few. Most of this damage typically occurs on the Company's extensive electric distribution system, however, some storm events also impact our electric transmission system. Significant storm events are best understood as random forces[8] that often occur with short notice, and that are beyond the control of the Company[9] to prepare for or prevent. Avista recently experienced two such major storm events, the first occurring on Labor Day 2020 and the second on January 13, 2021. Like many of the region's electric utilities, the Company suffered catastrophic damage as a result of high winds and wildfires over the 2020 Labor Day weekend. The greatest damage was caused by wildfire that burned several structures on our Lind-Shawnee 115kV line, a structure on our Shawnee-Sunset Line, and approximately 160 structures covering 13 miles of our Chelan-Stratford 115kV transmission line. The Company experienced even greater damage to its system in the January 2021 windstorm, as the near-hurricane-force winds uprooted trees across our electric service territory taking huge portions of both our electric transmission and distribution systems out of service.

Investments made to restore our electric system after these major events include replacement of wood poles, crossarms, conductor, transformers and customers' secondary service lines. Making the area safe after an event, and quickly replacing damaged equipment is crucial to promptly restoring service to our customers. The need for investments in infrastructure restoration is difficult to predict year-to-year, requiring the Company to consider recent history and long-term trends in setting forecast budgets for these types of investments.

[8] Though the incidence of major storm events can follow cyclical patterns based on season of the year, we refer to them as random events because their occurrence, timing and magnitude cannot be predicted, such as the wind event that recently occurred in our service territory on January 13, 2021.

[9] Beyond the control of the Company refers to the fact that these "outside forces" exceed the ability of our system to withstand them without some resulting failures. While it is possible to have a system capable of better withstanding these events it would require a substantial redesign of our system and massive capital investments to rebuild it. One example of 'system redesign' would be to convert substantial portions of our electric distribution system from overhead to underground service where it would be relatively more immune to these outside forces.

Meter Minor Blanket – 2020: $200,000, 2021: $250,000, 2022: $250,000, 2023: $167,000

Utilities regularly plan for the replacement of assets that have reached the end of useful life, which includes the replacement of slow, failing or stopped meters. When meters fail to read accurately (typically more the case with analog electro-mechanical meters) or stop reading altogether, Avista quickly replaces the meter to avoid having to estimate a substantial portion of the customers' usage. Expected capital spending for replacement of meters is based on the Company's experienced failure rates for its population of meters in service.

Distribution Grid Modernization – 2020: $7,374,000

The purpose of this program is to cyclically rebuild and upgrade every electric feeder in Avista's distribution system, with the objectives of replacing end of life assets, while evaluating improvements in feeder design to bolster service reliability, capture energy efficiency savings, and improve operational ability, code compliance and safety.[10] These objectives are accomplished through the systematic replacement of end-of-life equipment, such as old poles, conductor, and transformers, with new and more energy-efficient equipment that ensures the long-term, efficient operability of the system. Other issues addressed on each feeder include pole realignment to address accessibility issues and rights of way concerns, potential feeder undergrounding, coordination of joint use facilities, and clear zone compliance. On qualifying feeders, additional system reliability value is captured by installing distribution line automation devices to help isolate outages and reduce the number of customers that experience a sustained outage (also known as feeder automation).[11]

The primary alternatives to this program are to replace distribution poles and attached equipment as they fail in service or to continue funding work under the various operational initiatives designed to treat individual aspects of each feeder, including the wood pole management program, polychlorinated biphenyls (PCB) transformer change-out program, vegetation management program, segment reconductor and feeder tie program, overhead to underground conversion, and various other budgeted maintenance programs. Combining the work of these individual programs into one is not only more efficient, but it also enables the entire feeder to be evaluated for beneficial changes in design, alignment, and in other ways not possible when individual elements of the line are simply replaced in an "as is" configuration. Absent this program, the Company would continue to treat every feeder in its system under individual maintenance programs. The value created by opportunities to improve the design, construction and operation of the feeder would be missed. Further, bundling the work of these individual programs for targeted feeders into one coordinated effort improves the cost efficiency by reducing redundant travel costs and capturing labor productivity. In short, customers would experience higher costs for a less robust system absent this program.

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[10] Instead of simply replacing equipment like poles in place and in kind, Grid Modernization looks at the overall feeder design to evaluate the opportunity for gains captured through new designs, feeder alignment, dividing feeders, and the application of new technology.

[11] For a more in-depth description of this program, please see pages 12 of Avista's Electric Distribution Infrastructure Plan for 2020, provided as Exhibit No. 11, Schedule 1.

Distribution Minor Rebuild – 2020: $11,315,000, 2021: $10,046,000, 2022: $10,300,000, 2023: $6,578,000

The purpose of this program is to replace end-of-life assets and respond to a range of operations needs in order to provide public and employee safety and the continuity and adequacy of service to our customers. In addition to needed work that is ancillary to customer-requested service, minor rebuilds, and replacement of individual assets are required across the distribution system as issues are identified to maintain system integrity, reliability, and safety.[12]

There are no traditional alternatives to the work completed under this program since it consists of many, small unplanned projects[13] across the entire electric distribution system. These small, unplanned projects are responsive to a range of factors generally beyond the control of the Company. Examples include ancillary work required by customer-requested rebuilds,[14] "trouble work" – like the repair of damage from a car-hit-pole, investments needed to support joint use of our facilities, replacement of deteriorated or failed equipment that is not scheduled for planned asset condition replacement, and small general rebuilds required to meet National Electric Safety Code (NESC) requirements, remediate failed, under-sized or unsafe equipment, and install needed switches, regulators, line reclosers, etc. There are instances among the small rebuild projects where limited alternatives are evaluated in the design phase by the individual project designer. In general, however, there is no reasonable alternative to timely making these investments once the need has been identified.

Transformer Change Out Program – 2020: $316,000, 2021: $400,000

Between 1929 and 1979, a family of synthetic organic compounds known as Polychlorinated Biphenyls (PCBs) were commonly used in the oil that fills electrical transformers, beneficial because of their high dielectric strength[15] and resistance to fire. Studies conducted in the 1960s and 70s revealed, however, that these compounds are also toxic, carcinogenic and highly resistant to biodegradation in the environment. Their production was banned in the United States in 1979.[16] As a result of growing concern over time and our experience with the risk of aging transformers leaking or breaking open when striking the ground as a result of damage to the feeder, Avista analyzed alternatives to remediate its distribution transformers containing PCBs. When the program began in 2011, Avista targeted over 12,000 transformers in its system for replacement. Because most of these transformers were already 30 years of age and older, the program, irrespective of eliminating PCBs, was predominantly based on replacements for asset age and condition. Another significant benefit of the program to replace aging transformers is the energy savings captured by replacing energy-inefficient transformers

[12] For a more in-depth description of this program, please see pages 12-13 of Avista's Electric Distribution Infrastructure Plan for 2020, provided as Exhibit No. 11, Schedule 1.

[13] For example, the average cost of each of these small projects is approximately $4,500, which translates to over 2,000 individual projects in a given budget year.

[14] These investments include work required to properly maintain the system, but that are not reasonably covered by the tariffed financial contribution required of the customer.

[15] Dielectric strength refers to the ability of a material to resist carrying an electrical current, which is a measure of its potential to insulate against electric short circuit or fault.

[16] "PCBs Questions & Answers," United States Environmental Protection Agency bulletin https://www3.epa.gov/region9/pcbs/faq.html.

with new energy-efficient units. In 2020, there were 284 targeted transformers remaining, however, the replacement of transformers based on asset condition and energy efficiency savings is continuing as part of the Grid Modernization and Wood Pole Management programs.

Light Emitting Diode (LED) Change Out Program – 2020: $400,000, 2021: $400,000, 2022: $400,000, 2023: $267,000

Avista operates approximately 35,000 streetlights we have installed for many public jurisdictions across our service territory as well as area lights requested and paid for by individual customers. In 2013, in response to the superior safety performance of LED lighting, the energy savings potential, and the opportunity to reduce long-term energy costs, Avista evaluated the potential benefit of converting streetlights from conventional High-Pressure Sodium (HPS) to LED fixtures. LED bulbs cut electricity use by up to 85% compared with incandescent bulbs, and 40% compared with fluorescent lighting.[17] After careful evaluation the program was launched in 2015 and focused initially on replacing our predominant 100 watt "cobrahead" streetlights. The program was expanded to include higher wattage lights (200 and 400 watts) as subsequent price reductions for these fixtures made it cost effective for customers. Under our current program, as conventional streetlight bulbs fail in service, fixtures are replaced with LED lighting. Forecasted expenditures are based on the annual expected failure rate of our conventional streetlights in service.

Primary Underground Residential Development Cable Replacement – 2020: $86,000

Underground Residential District Cable (underground cable or URD) has been used by the utility industry since the 1930s, though Avista did not begin installing the cable until the late 1960s. During the 1990s the industry began to recognize that earlier generations of cable were beginning to fail in service at an increasing rate. By this point Avista had installed over 6,000,000 feet of earlier-generation cable installed from 1971 to 1982. And by the mid-1990s, customers began to experience more prevalent outages as the cable aged and continued to deteriorate at an accelerated rate. Avista's asset management group analyzed options for the replacement of this failing cable and recommended a replacement horizon of four years. The majority of the known vintage cable had been replaced by 2013 and the systematic replacement program was ramped down to an annual investment of approximately one million dollars, which provides for the removal and replacement of this vintage cable as we find it on the system (usually through responding to an underground fault). The planned annual capital investment for this program is based on the Company's recent experience locating and replacing sections of this vintage cable.

Substation – Station Rebuilds – 2020: $9,945,000, 2021: $1,182,000, 2022: $28,468,000, 2023: $667,000

Projects to rebuild the Company's aging electric substations involve replacing and upgrading structures, fencing, grounding, apparatus and equipment at end-of-life, when obsolete, or is otherwise necessary to maintain safe and reliable operation of Avista's transmission and distribution systems. While asset condition of the overall substation including major apparatus

[17] https://thinkprogress.org/5-charts-that-illustrate-the-remarkable-led-lighting-revolution-83ecb6c1f472.

and equipment is the primary driver for these investments, additional factors may broaden the scope of a station rebuild project. These factors include operational and maintenance requirements, updated design and construction standards, SCADA communications, future customer load-service needs, and other programs such as Grid Modernization. This program (Substation Rebuilds) differs from Avista's Substation Asset Management program in that the latter is focused on replacing only aging apparatus and equipment, and not rebuilding or refurbishing the entire substation. In some instances, instead of replacing or rebuilding aging substations, Avista could continue to manage stations under the Substation Asset Management Program, however, this alternative is not reasonable by the time the Company has identified the need for substantial rebuild or replacement. This is because aged equipment is often obsolete and replacements are unavailable, because some structures such as the grounding pad, cannot be replaced once failed, and because a station might have to be taken out of service for an extended period of time for major work on structures and equipment. When aging substations reach this point in their lifecycle, the only reasonable alternative is to completely refurbish or rebuild them.[18] For a complete description of the Company's management of its electric substations please see Avista's Substation Infrastructure Plan for 2020, Exhibit No. 11, Schedule 2.

Distribution Wood Pole Management – 2020: $10,275,000, 2021: $15,739,000, 2022: $16,000,000, 2023: $10,667,000

Avista has approximately 230,000 to 240,000 wood poles[19] in its electric distribution system and a portion of these must be replaced each year based on asset condition, i.e., replacement of poles and attachments that have reached the end of their useful service life. Our wood poles are inspected on a 20-year cycle, resulting in our inspection of approximately 12,000 poles each year.[20] Individual poles or attached equipment that don't meet our inspection criteria are replaced as part of capital follow-up work. Attached equipment includes overhead distribution transformers, cutouts, insulators and pins, wildlife guards, lighting arresters, cross arms, pole guying, and grounds.[21] The primary alternative to this proactive inspection and replacement program is to simply replace poles as they fail in service and fall down (asset strategy known as "run to fail"). Sub-alternatives evaluated include inspecting the pole population on a cycle time either shorter or longer than the current 20-year cycle.

Avista analyzed the option of replacing poles as they fail, as well as a range of inspection cycle intervals ranging from 5 to 25 years. The customer value of the 20-year cycle, as measured by customer rates of return, is superior to both the run-to-fail option and the 25-year cycle time. Perhaps even more importantly in today's world, <u>a run to fail strategy would also increase wildfire risk</u>. Cycle intervals shorter than 20 years do produce slightly better results

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[18] When replacing a substation, the new substation is often placed adjacent to the existing substation, which remains in service until the new substation is completed, ensuring minimal outages to the customers served on from the station.

[19] Under the current inspection program individual poles are validated by location, age and material in our geographic information system, leading to an overall refinement in the population size.

[20] Avista's Wood Pole Inspection Program is funded as an expense.

[21] For a more in-depth description of this program, please see pages 16-17 of Avista's Electric Distribution Infrastructure Plan for 2020, provided as Exhibit No. 11, Schedule 1.

as measured by their respective rates of return. This incremental increase in value is the result of avoiding failures in poles and attached equipment that would otherwise occur with longer inspection cycles.[22] Importantly, any reduction in cycle time requires an up-front increase in expenses to pay for the increased number of poles inspected each year, and a corresponding increase in requirements for capital replacements, at least through the first complete inspection cycle. Avista believes this incremental increase in costs would put too much near-term price pressure on our customers, considered in combination with the margin of benefit and Avista's many other infrastructure investment needs.[23] The Company is continuing with its 20-year inspection cycle.

Wildfire Resiliency Plan – 2020: $3,033,000, 2021: $13,317,000, 2022: $21,330,000, 2023: $17,053,000

While I provide a high-level summary of the Company's Wildfire Resiliency Plan here, please see the direct testimony of Mr. Howell for a detailed description and discussion of this important topic. The increasing threat of wildfires poses a significant risk to utilities across the western United States, prompting many to develop detailed plans for better assessing and managing this growing risk. In May of this year Avista published its "2020 Wildfire Resiliency Plan" (see Exhibit No. 12, Schedule 1) detailing twenty-eight actions to mitigate the risk of wildfire on our system. These actions include upgrades to infrastructure aimed at reducing spark-ignition events and protecting critical infrastructure from the threat of wildfires. Avista's Plan covers a 10-year operating horizon and includes a planned investment of $268,965,000 grouped in the four categories:

- Enhanced Vegetation Management
  - Widen electric transmission rights of way ($5,000,000)
  - Vegetation management factored into design of customer facilities ($100,000)
- Situational Awareness
  - Fire-weather dashboard & data-driven risk analysis ($425,000)
  - New midline reclosers with feeder communications ($540,000)
  - Target 100% of substations with SCADA[24] communications ($17,000,000)
- Operations and Emergency Response
  - Transmission design review of major events ($100,000)
  - Fire ignition tracking system ($200,000)
- Grid Hardening & Dry Land Mode Operations
  - Transmission fire inspection ($3,000,000)
  - Transmission grid hardening ($44,000,000)
  - Midline reclosers ($5,400,000)
  - Distribution grid hardening (193,200,000)
- Wildfire Plan Planned Capital Expenditures (2020 – 2029) $268,965,000

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[22] On average, under its current 20-year inspection cycle interval, Avista experiences approximately 12 pole failures each year out of its population of 230,000 wood poles.

[23] See Avista Utilities Infrastructure Investment Plan, Exhibit No. 2, Schedule 3.

[24] Supervisory Control and Data Acquisition (or SCADA).

Avista has estimated the 10-year accumulated inherent risk of wildfire to be between $8.1 and $18.2 billion dollars. The mitigated risk (under the Company's proposed 10-year Plan) is estimated between $0.5 and $2.3 billion dollars. This represents a risk reduction between 8X and 16X with a cost-benefit ratio ranging between 22.9 and 48.6, including $60 million dollars of O&M expense.

Distribution System Enhancements – 2020: $6,922,000, 2021: $6,000,000, 2022: $7,000,000, 2023: $2,668,000

Avista's electric distribution system is composed of 347 individual 'feeder' lines that carry primary electric power to customers across our service area in Idaho and Washington. As new customers are added to these feeders, and as existing customers add new and different types of loads to their service, the carrying capacity of feeders, and often segments of feeders, is reached or exceeded. When the capacity of a circuit has been exceeded it creates excess heat in the conductor and components resulting in the conductor sagging closer to the earth than designed, creating a violation of NESC prescribed safety limits. In extreme situations the conductor itself can melt and fail, dropping energized lines to the ground and creating a very significant safety and fire hazard. Avista determines the carrying capacity margin for its feeders based on SCADA monitoring, where it is available, and system load modeling and analysis using the Synergee load flow computer program. When the Company identifies a feeder or segment with capacity limitations the local engineer evaluates alternatives for solving the problem, which most often include the installation of larger, higher-capacity conductor on the target segment(s) or construction of a "tie" line to an adjacent feeder that has sufficient capacity to carry a portion of the customer load of the first feeder. Managing our electric distribution system in a manner that ensures our service is adequate, safe, reliable and compliant, and at a reasonable cost, is in the interest of our electric system customers. Investments made under this program were included in the former program titled Segment Reconductor and Feeder Tie program.

IV. INVESTMENTS IN THE COMPANY'S ELECTRIC TRANSMISSION SYSTEM

Q. Would you please summarize the need for continuing investments in electric transmission infrastructure?

A. As highlighted in Avista's Electric Transmission Infrastructure Plan for 2020 (Exhibit No. 11, Schedule 3), the nation's electric utilities are facing unprecedented challenge from forces driving the continuing need for new investment in transmission infrastructure, and Avista is no different. This rapidly growing demand for new investment has challenged our ability to fund all our high-priority needs for electric transmission, which, themselves, are out of proportion to the investment requirements of our other infrastructure. Drivers for new investment include:

- System improvements required to meet the myriad and expanding federal regulations governing nearly every aspect of our transmission business. Chief among these are the tightening requirements to meet ever-more restrictive transmission operations and planning standards, driven by the assessment of financial penalties for noncompliance.

- Timely replacement of end-of-life assets based on condition. This need is at an all-time high across the industry and will continue to increase year-over-year for at least the next two decades. This need is tied to the major expansion of new electric infrastructure built during the economic boom following the end of World War II. Because these assets are now at or near the end of their useful lives, a substantial boost in new investment is required, compared with previous years, just to maintain existing systems.

- External demands on our transmission system, including new transmission interconnections required for third parties to integrate new, variable energy resources, particularly wind and solar. These interconnections require significant capital investment to extend or reinforce our transmission system and often take priority over investments required to provide for native load service on our system.

- A further driver is related to supporting development of the new energy services grid of the future. Emerging technologies are driving increasing digitization, distributed generation, energy storage, and other technologies that require adapting and upgrading the existing system, including new ways of engaging with our customers. Though primarily focused at the distribution level, these changes in our energy delivery business model also impact transmission investments. This increased digitalization brings with it the potential for greater cyber vulnerability and the need for continuing investment to provide for the safety and security of our bulk power system.

- Siting, permitting and constructing transmission assets has become more complex, time-consuming, and expensive due in part to increasing environmental, property rights, and land-use requirements. Permitting can extend over several years and typically includes conditions constraining how utilities site, design, construct and maintain these assets.

When it comes to the impact for our customers, who must ultimately pay for these requirements and investments, an exacerbating factor is our relatively stagnant load growth due to relatively low increases in population and declining use-per-customer. This translates into nearly flat revenues, which means that new capital investments must be covered by higher customer rates. Historically, annual increases in customer loads produced new revenues that were often sufficient to cover the costs for new investment and inflation without the need to increase rates.

Q. Please describe the Company's process for ensuring it is making timely investments in electric transmission to maintain compliance with mandatory federal standards.

A. The Company's process for determining which projects should be recommended for funding each year includes results of comprehensive planning studies, engineering and asset management analyses, and scheduled upgrades and replacements identified in our operations districts and Transmission Engineering. These projects undergo internal review by multiple stakeholders, who help ensure all system needs and alternatives have been identified and evaluated.

Projects advanced for funding enter a formal review process referred to as the "Engineering Roundtable" (ERT). This group carefully reviews the need for each project, the primary business driver, the alternatives considered, and the justification for the approach recommended. During the review, the potential benefits of any cross-business-unit synergies that could better optimize project benefits and scope are also identified and evaluated. The result of this process is a prioritized list of recommended projects that serves as a roadmap of investments sequenced by year for at least a ten-year time horizon. Using this roadmap, each department can plan ahead for the work they will be responsible to execute once projects are approved for funding and implementation. Once evaluated, prioritized and sequenced, these projects are recommended to the Capital Planning Group (as described in the testimony of Mr.

Thies) for final review and funding allocation. Representatives from eleven business units participate in the ERT process.

Q. Would you please summarize the capital investments in electric transmission plant completed in 2020 and planned for over the Two-Year Rate Plan?

A. Yes, the completed and planned investments related to transmission investment, presented on a system basis and grouped by investment driver, are shown in Table No. 3, and described below.

Table No. 3 – Electric Transmission Capital Projects (System)

Electric Transmission Capital Projects (System) In $(000's)				
Business Case Name	**2020**	**2021**	**2022**	**2023(1)**
Customer Requested				
Rattlesnake Flat Wind Farm Project 115kV Integration Project	$ 9,480	-	-	-
Mandatory and Compliance				
Clearwater Wind Generation Interconnection	28	460	-	-
Colstrip Transmission	520	724	360	226
Protection System Upgrade for PRC-002	2,231	-	10,030	-
Saddle Mountain 230/115kV Station (New) Integration Project Phase 1	28,639	-	-	-
Transmission Construction - Compliance	9,502	2,101	2,262	1,544
Transmission NERC Low-Risk Priority Lines Mitigation	4,817	1,023	2,900	
Tribal Permits & Settlements	124	-	-	-
Use Permits	27	50	50	33
West Plains New 230kV Substation	31	-	8,650	-
Westside 230/115kV Station Brownfield Rebuild Project	2,746	-	11,110	-
Saddle Mountain 230/115kV Station (New) Integration Project Phase 2	-	10,999	17,295	-
Spokane Valley Transmission Reinforcement Project	-	13,526	-	-
Failed Plant and Operations				
Electric Storm	8,803	1,278	1,082	721
Asset Condition				
SCADA - SOO and BuCC	2,003	1,352	897	159
Substation - Station Rebuilds Program	4,180	5,457	7,221	4,814
Transmission - Minor Rebuild	2,534	3,343	3,630	2,192
Transmission Major Rebuild - Asset Condition	-	17,900	9,750	9,800
Customer Service Quality and Reliability				
Wildfire Resiliency Plan	477	3,800	5,800	313
Performance and Capacity				
Substation - New Distribution Station Capacity Program	7,937	861	7,200	-
Misc. accrual reversals, corrections or additional TTP	(146)	-	-	-
Total Planned Electric Transmission Capital Projects	**$ 83,932**	**$ 62,874**	**$ 88,236**	**$ 19,802**

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

Rattlesnake Flat Wind Farm Project – 2020: $9,480,000

As mandated by the Federal Energy Regulatory Commission, Avista must accept and analyze third-party requests to interconnect and integrate generating resources with the Company's electric transmission and distribution system. Such interconnection was requested for the proposed 144MW Rattlesnake Flat Wind Farm southeast of Lind, Washington. From the alternatives studied by the Company's transmission planning group the developer chose a point of interconnection to Avista's Lind-Washtucna 115kV transmission line at a new 3-position ring bus Neilson substation with a line position dedicated to the interconnection customer. The project consists of a number of individual new construction and upgrade projects to accommodate the required interconnection and meet load service capabilities. This project, as required under the interconnection agreement, was completed in September 2020.

Clearwater Wind Generation Interconnection – 2020: $28,000, 2021: $460,000

Avista is joint owner in the 500kV Colstrip Transmission System and party to the Colstrip Project Transmission Agreement ("Agreement") (Avista owns a 10.2% share in the Colstrip-Broadview segment and a 12.1% share in the Broadview-Townsend segment). Under rules of the Federal Energy Regulatory Commission ("FERC") and those in the Agreement, all joint owners, including Avista, must comply with rules governing the interconnection of new generation facilities with the Colstrip Transmission System. In accordance with those rules, Clearwater Energy Resources, LLC, requested interconnection of a 750MW wind project known as the "Clearwater Wind Project." All required studies have been completed and Avista executed a Large Generator Interconnection Agreement with Clearwater Energy on May 22, 2019 ("LGIA"). Avista and the other joint owners are obligated to fund their respective shares of the Transmission Provider Interconnection Facilities and Network Upgrades applicable to the interconnection agreement. Avista's allocation of the required construction cost was originally estimated to be $650,600, the approved cost was subsequently reduced to $570,000.

Colstrip Transmission Operation and Maintenance – 2020: $520,000, 2021: $724,000, 2022: $360,000, 2023: $226,000

As noted in the business case just above, Avista is a joint owner in the 500kV Colstrip Transmission System and is obligated under the Agreement to fund its commensurate share of necessary construction and maintenance programs. Examples of recent and pending capital expenditures in the Colstrip Transmission System include end-of-life replacement of 500kV power circuit breakers at the Colstrip 500/230kV Station and 500kV structure relocation to mitigate erosion risk caused by high runoff in the Little Big Horn River. Avista's share of these expenditures has averaged $348,000 over the past ten years. The most-recent operation and maintenance plan (July 2020) forecasts Avista's five-year (2020-2024) average program expense at $516,000.

Protection System Upgrade for PRC-002 – 2020: $2,231,000, 2021: $0, 2022: $10,030,000, 2023: $0

As noted in numerous previous places in my testimony, Avista is subject to a range of planning and operating standards established by NERC, including the standard PRC-002-2, which establishes disturbance monitoring and reporting requirements on our bulk electric transmission system. Each year Avista evaluates every one of its electric transmission busses[25] to determine our obligations under bulk electric system requirements and standards. The subject standard mandates the Company have suitable protection systems to monitor and record all electric disturbances occurring on each portion of our electric transmission system that is within the bulk electric system. The protection systems must have the capability to record electrical quantities for each element connected to every bus identified as being part of the bulk electric system.

Saddle Mountain 230/115kV Station (New) Integration Project Phase 1 – 2020: $28,639,000

Avista learned in 2013 of grid performance issues on Grant County Public Utility District's electric system that were exacerbated by Avista's load service in our Othello service area. The issue was subsequently advanced to Columbia Grid through the regional planning process, which along with Avista's own system planning analysis, determined our system could not meet several NERC performance requirements during periods of summer heavy load and some categories of winter loading. The Saddle Mountain project was developed as the selected solution to mitigate this issue and to ensure Avista's compliance with mandatory NERC performance standards. Avista considered constructing a new 115kV line to serve the area but found through planning analysis that it would not mitigate the low voltage issues in the Othello area. Another alternative was considered, which would add a neutral or 'star point' to the associated transmission circuits, and then closing these star points to better manage unbalanced power and voltage issues. This alternative would require very costly (anticipated to be $75 million) reconductoring of the lines to mitigate potential violations. The Company also considered installing distributed generation in the affected area to mitigate the grid performance issues but this option was considered too costly and with potential lead times that were prohibitive. Finally, Avista identified the selected alternative to construct the new Saddle Mountain station, combined with identified upgrades to several existing transmission line segments, as the most cost-effective option to provide the voltage support needed today, and for the foreseeable planning horizon.

Transmission Construction – Compliance – 2020: $9,502,000, 2021: $2,101,000, 2022: $2,262,000, 2023: $1,544,000

This program funds the transmission rebuild and reconductor work identified by the Company as necessary to maintain compliance with NERC reliability standards.[26] The applicable standard requires Avista to complete an annual planning assessment, to identify shortfalls and

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[25] The transmission bus, or more technically 'busbar,' is the heavy electrical conductor used in electric substations that connect high voltage equipment, switch gear, low voltage equipment, etc. In evaluating power flows on the electric transmission system, the bus refers to any graph node of a single-line diagram at which voltage, current, power flow and other quantities are measured and evaluated. The NERC determination of what portions of Avista's electric transmission infrastructure (lines, circuits, substations, and individual busses and pieces of equipment) are part of the "bulk electric system" is based on analysis of our transmission system one-line diagrams.

[26] NERC Reliability Standard TPL-001-4 – Transmission System Planning Performance Requirements ("Standard"), has 8 requirements and 57 sub-requirements related to planning and analysis, including the requirement for robust system models to determine system stability, voltage levels and system performance under various scenarios.

corrective actions, and for those actions to be timely implemented within specific timeframes to remedy identified system performance deficiencies. Avista's transmission construction - compliance program identifies funding needed to mitigate identified reliability issues, ensuring our compliance with NERC requirements. In addition to meeting NERC standards, this program also includes construction to remedy issues on any transmission line that is not compliant with the current capacity criteria under the National Electric Safety Code (NESC). Avista is subject to substantial financial penalties for non-compliance with NERC standards, and the risk of not meeting NESC minimum requirements. Given what is presently known about NERC planning standards and requirements, in addition to current NESC requirements, this program is expected to complete in 2025.

Transmission – NERC Low-Risk Priority Lines Mitigation – 2020: $4,817,000, 2021: $1,023,000, 2022: $2,900,000

Avista's compliance with this mandatory standard requires that we conduct LiDAR surveys[27] on all subject transmission circuits to determine any discrepancies between the design specifications and field measurements for conductor sag.[28] While the subject NERC standard was offered as a recommendation to the industry, our compliance with minimum clearance requirements is also required by the National Electric Safety Code. NERC, however, is also closely monitoring the progress made by each utility in complying with these requirements, via a required status report filed with them every six months by each subject utility. When Avista identifies discrepancies through the surveys it evaluates a range of actions to be taken to ensure we meet the stated clearance requirements. The actions include reconfiguring insulator attachments, rebuilding or replacing structures and removing earth below the span of line in question.

Tribal Permits and Settlements – 2020: $124,000

Similar to the business case just above, approximately 82 miles of the Company's electric transmission facilities are located on the reserved lands of neighboring Native American Tribes. The capital costs in this business case fund easement agreements that require us to pay fees and/or undertake other actions in order to occupy these trust lands.

Use Permits – 2020: $27,000, 2021: $50,000, 2022: $50,000, 2023: $33,000

Avista owns and maintains electric transmission, distribution, and natural gas facilities whose rights of way invariably cross public lands owned and managed by a variety of state, federal and local agencies, as well as extensive private lands, such as those held by railroad companies. Traditionally, our access to these rights-of-way were secured by long-term agreements but as these permits have been renewed, provisions often require the Company to pay annual fees as a condition. Many of these historic long-term permits have reverted to

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[27] Light Detection and Ranging (LiDAR) is a method of measuring distances (ranging) by illuminating a target with laser light and measuring the reflection with a sensor. Differences in in laser light return times to the sensor and wavelengths are used to create a digital three-dimension representation of the target. Typically conducted on electric transmission by aerial flights.

[28] Sag refers to the lowest point (closest to the earth) of the electrical conductor between any two supporting structures (poles), measured as the vertical distance from the top of the supports to the lowest hanging point of the conductor between them.

annual permits, with annual payments that have typically increased each year, ranging from 3% to 10% annually, depending on the agency. The increase in permit costs is also accompanied by increased administrative expenses for tracking, research, and processing these annual permits. To better manage and control the long-term costs our customers bear for these permits Avista is pursuing long-term agreements to replace the annual permits and payments with one-time lump-sum payments. The investments in this business case fund the lump sum payments associated with new long-term easement agreements.

West Plains New 230kV Substation – 2020: $31,000, 2021: $0, 2022: $8,650,000

The need for this new transmission substation was identified in Company planning studies as early as 2010, which revealed issues related to the growing inadequacy of transmission capacity in this part of our system. In addition to capacity issues, Avista's distribution substations in this area are served by radial transmission lines.[29] In this configuration the system must be manually operated in order to restore service to customers following automatic circuit breaker operation to isolate a fault. Again, in addition to remedying capacity issues, this new station will provide the Company flexibility in accommodating planned outages for system maintenance and equipment replacement without having to disconnect customers in order to safely perform the work.

Westside 230/115kV Station Rebuild – 2020: $2,746,000, 2021: $0, 2022: $11,110,000

The Westside project was scheduled to be completed over two years based on one of the power transformers (number 1) exceeding its nameplate rating under certain NERC planning contingencies for heavy summer loads. This project was mandatory to meet NERC compliance obligations to not exceed facility and equipment ratings. The work included extension of the existing 115 kV and 230 kV buses in the station to allow for replacement of the 250 MVA autotransformer number 1, and replacing autotransformer number 2 with a new, higher capacity 250 MVA unit. The station was also reconfigured to a double-bus/double-breaker design. The primary alternative to this project would have been the shedding of non-consequential customer load during peak conditions to prevent overloading on transformer 1, however, this option failed to meet Avista's objective to provide its customers reliable electric service, and load shedding would ultimately represent a violation of NERC transmission standards.

Saddle Mountain 230/115kV Station (New) Integration Project Phase 2 – 2021: $10,999,000, 2022: $17,295,000

The Company's need to construct a new Saddle Mountain substation is described above in this section of my testimony. Construction of the new substation, however, required a range of other work to be completed in phases in order to integrate it into electric system. One of these phases that I explained above under our electric distribution plant investments is focused on electric transmission system improvements required to integrate the new Saddle Mountain substation with our new Othello city substation. The investments I refer to in this project

[29] Radial lines refer to service that is provided by a single line or source rather than a 'network' source that is supported by two or more connecting transmission lines. Network service is inherently more reliable for customers than a radial source.

description represent improvements to our electric transmission system that are needed to effectively integrate the new Saddle Mountain substation into our bulk transmission system.

Spokane Valley Transmission Reinforcement Project – 2021: $13,526,000

Load growth in Spokane Valley, combined with our growing inability to meet certain NERC planning criteria, required the Company to take steps over time to meet our load service and compliance obligations. Initially, Avista developed operating procedures to help mitigate deficiencies in this portion of our electric transmission system and has already completed system investments as part of a long-term plan to meet our obligations. The remaining portions of this project consist of constructing a new substation (Irvin substation) and rebuilding a portion of the Beacon – Boulder #2 115 kV Transmission Line. These investments will complete the overall reinforcement project, which will provide Avista the needed operational flexibility to adequately serve our current and expected customer loads and meet our federal compliance requirements.

Electric Storm – 2020: $8,803,000, 2021: $1,278,000, 2022: $1,082,000, 2023: $721,000

Please see this program above (titled the same) under electric distribution plant for the description of the Company's investments under the category of electric storms. This capital business case is similar in all respects to the program for electric distribution repair except it is focused on repairs to our electric transmission system.

SCADA – System Operations Office & Backup Control Center – 2020: $2,003,000, 2021: $1,352,000 2022: $897,000, 2023: $159,000

The Company increasingly relies on comprehensive digital monitoring of critical power system infrastructure and communication interconnectivity that provides real-time visibility, status, alarms, and the ability for remote and automated operations. Avista relies on the industry-standard system known as Supervisory Control and Data Acquisition (or SCADA) to provide this functionality.[30] The Company is required to continuously upgrade and enhance its SCADA systems to replace end-of-life technology and to meet constantly-expanding regulatory requirements and the current and long-term needs of our business. This particular project, the System Operations Office (SOO) and Backup Control Center (BuCC) is replacing and upgrading existing SCADA communications for our electric and natural gas control centers. Business groups who rely on these systems include Avista's system operators, power schedulers, distribution dispatchers, gas controllers, energy accounting and risk management, Protection Engineering, Substation Engineering, Generation Engineering, Distribution System Operations, Oracle database administration, Security Engineering, Network Engineering and Network Operations. Additionally, organizations outside Avista who also rely on these systems include the control centers of our neighboring electric and natural gas utilities, and our regional reliability coordinator. The investments made in our SCADA systems ensure we can continue to operate our energy delivery systems safely and remain in compliance with a broad range of NERC standards and federal pipeline safety requirements under PHMSA.

[30] SCADA, and extension of industrial process control, has been around since the early 1960s, and the term "SCADA" became commonly used by the mid-1970s. SCADA systems, naturally, have evolved through several major generations as computing and communications technologies have evolved and advanced.

Substation – Station Rebuilds – 2020: $4,180,000, 2021: $5,457,000, 2022: $7,221,000, 2023: $4,814,000

Please see the business case above under electric distribution investments for the description of the Company's substation rebuilds program. This capital business case is similar in all respects to the program for distribution stations except it funds investments in substations that have a primary function supporting our electric transmission system.

Transmission Minor Rebuild – 2020: $2,534,000, 2021: $3,343,000, 2022: $3,630,000, 2023: $2,192,000

This program provides for the major rebuild of electric transmission lines that are nearing the end of their useful service life based on overall condition of the assets, and the rating for likelihood of a failure and magnitude of the consequence. Factors such as operational issues, ease of access during outages and potential benefits of communications build-out are also considered in prioritizing the work to be completed in the planning horizon. The primary alternative to this proactive inspection and replacement would be to replace poles, cross arms, conductor and other attached equipment upon failure. This alternative is not practical or reasonable, however, since the consequences would be a greater overall cost to customers, an increasing risk of large and lengthy service outages, much greater wildfire risk, and the likelihood of penalties for non-compliance with NERC operating standards. The only way Avista can properly maintain its service levels for customers and shield them from a range of financial and other risks is to systematically rebuild end-of-life transmission facilities.

Transmission Major Rebuild - Asset Condition – 2021: $17,900,000, 2022: $9,750,000, 2023: $9,800,000

This program provides for the major rebuild of electric transmission lines that are nearing the end of their useful service life based on overall condition of the assets, and the rating for probability of a failure and magnitude of the consequence. Factors such as operational issues, ease of access during outages and potential benefits of communications build-out are also considered in prioritizing the work to be completed in the planning horizon. The primary alternative to this proactive inspection and replacement would be to replace poles, cross arms, conductor and other attached equipment upon failure. This alternative is not practical or reasonable, however, since the consequences would be a greater overall cost to customers, an increasing risk of large and lengthy service outages, much greater wildfire risk, and the likelihood of penalties for non-compliance with NERC operating standards. The only way Avista can properly maintain its service levels for customers and shield them from a range of financial and other risks is to systematically rebuild end-of-life transmission facilities.

Wildfire Resiliency Plan – 2020: $477,000, 2021: $3,800,000, 2022: $5,800,000, 2023: $313,000

Please see the business case above under electric distribution investments for the description of the Company's investments under the category of wildfire resiliency. This capital business case is similar to our program for the distribution system except it is focused on treatments to our electric transmission system.

Substation – New Distribution Station Capacity Program – 2020: $7,937,000, 2021: $861,000, 2022: $7,200,000

As I've noted in several areas of my above testimony, Avista actively monitors the customer loads placed on its energy delivery systems, identifies portions of its infrastructure where capacity has been reached or exceeded, evaluates options for best addressing these priority capacity constraints and invests in solutions to ensure we meet current and long-term customer needs. This program is focused on investments needed to add new electrical capacity to our distribution substations in response to growth in demand on the feeders supported by these stations. Beyond just meeting capacity requirements these investments provide the Company greater operational flexibility, ease of maintenance, and electric service reliability for our customers. The Company's Substation Engineering group evaluates the hypothetical alternative of not adding new capacity when needed and repairing and replacing equipment on an emergency basis only as it failed in service. I say 'hypothetical' because some obsolete equipment in its present configuration could neither be repaired or replaced. Under this alternative, our customers would experience more frequent and much longer service outages and they would pay higher rates because Avista would be unable to provide service at an optimized lifecycle cost. Another alternative would be to extend feeders from adjacent substations and tie them into feeders served from the overloaded station as way to relieve some of the capacity constraint. Naturally, this alternative assumes the adjacent station has the needed capacity to meet current and near-term customer loads without having to be upgraded. Clearly, there are circumstances where this approach is practical (see Segment Reconductor and Feeder Tie Program, above) for relieving overloading <u>on a single feeder</u>, but as strategy for meeting new capacity needs for an entire substation, it is very limited and would tend to de-optimize our distribution system. It would also result in reduced service reliability for our customers,[31] reduced operational flexibility and increased maintenance costs. The approach selected by the Company ensures we have the capacity to serve our customers' current and long-term electric loads in an efficient and cost-effective manner.

<u>IV. INVESTMENTS IN THE COMPANY'S NATURAL GAS SYSTEM</u>

Q. Please summarize the need for ongoing investment in Avista's <u>natural gas distribution</u> system.

A. Natural gas is a foundational energy resource for Avista's customers, as shown in the Company's Natural Gas Infrastructure Plan for 2020 (Exhibit No. 11, Schedule 4), and it plays a critical role in our achievement of a clean energy future. It provides the clean fuel

[31] This would occur because you would now have feeders of greater overall length and feeder length is negatively correlated with service reliability performance.

for 36% of the nation's electric generation fleet (and growing), heats more than half of America's homes, and provides the vital feedstock and energy for cooling, heating and industrial processes, commerce, and industry. The Company has experienced steady growth in natural gas customers in the prior decade where the annual number of new connects more than doubled between 2010 and 2019.[32] New services are expected to peak in 2020 at approximately 6,800 and to decline somewhat and levelize near 5,500 in the current five-year planning horizon. This increase in new customers has required continuing investment in new connects, in addition to investments to provide the capacity requirements needed to serve increasing loads. Another substantial driver for new investments is maintaining compliance with federal and state regulatory requirements and effectively managing the continuing safety risks associated with our natural gas distribution system. Over the last decade, the Company's investments to meet customer requests for new service and to comply with a range of growing regulatory obligations has grown from approximately $15.5 million in 2010 to approximately $67 million in 2019. Avista's allocation of capital investment in its natural gas system from 2009 through 2019 ranged from 6% for investments based on asset condition, 10% to meet performance and capacity needs, 11% to provide for failed plant and operations, 36% to meet customer requests, and 37% for mandatory and compliance requirements.[33]

Q. Would you please summarize the capital investments in natural gas infrastructure completed in 2020 and planned for over the Two-Year Rate Plan?

[32] See Exhibit No. 11, Schedule 4, Figure 1, page 3.
[33] See Exhibit No. 11, Schedule 4, Figure 2, page 4.

A. Yes, the completed and planned investments related to natural gas infrastructure, presented on a system basis and grouped by investment driver, are shown in Table No. 4, and described below.

Table No. 4 – Natural Gas Capital Projects (System)

Natural Gas Distribution Capital Projects (System) In $(000's)				
Business Case Name	**2020**	**2021**	**2022**	**2023[1]**
Mandatory and Compliance				
Gas Cathodic Protection Program	$ 678	$ 801	$ 715	$ 484
Gas Facility Replacement Program (GFRP) Aldyl A Pipe Replacement	20,708	22,832	23,357	15,319
Gas Isolated Steel Replacement Program	1,058	1,400	850	503
Gas Overbuilt Pipe Replacement Program	215	460	420	236
Gas PMC Program	1,710	2,950	1,500	1,033
Gas Replacement Street and Highway Program	2,641	3,418	3,500	2,333
Gas HP Pipeline Remediation Program	-	700	-	-
Failed Plant and Operations				
Gas Non-Revenue Program	8,203	8,000	8,000	5,320
Asset Condition				
Gas Regulator Station Replacement Program	1,004	1,462	1,000	750
Performance and Capacity				
Gas Rathdrum Prairie HP Main Reinforcement	72	-	-	-
Gas Reinforcement Program	1,313	1,300	1,300	783
Gas Telemetry Program	253	174	181	138
Jackson Prairie Joint Project	2,205	2,377	2,378	1,580
Total Planned Natural Gas Distribution Capital Projects[2]	**$ 40,062**	**$ 45,873**	**$ 43,200**	**$ 28,478**

(1) Includes system pro forma capital for the period of January 1, 2023 through August 31, 2023.
(2) Totals exclude Washington and Oregon direct business cases from revenue requirement in this case

Gas Cathodic Protection Program – 2020: $678,000, 2021: $801,000, 2022: $715,000, 2023: $484,000

The purpose of the cathodic protection program is to provide an additional level of protection[34] to the Company's buried steel natural gas piping from the effects of natural corrosion. The protection is provided by applying a low-voltage direct current to the subject pipe that creates a corrosion free zone at the surface of the pipe. Providing cathodic protection for our steel natural gas piping protects our customers and others from the potential consequence of leaks on our system and helps ensure they also receive the full lifecycle value of the investments made in our natural gas system by avoiding the need to prematurely replace the pipe due to

[34] This is in addition to providing proper protective coatings to the steel pipe. These provide the primary protection and the cathodic system serves to protect the pipe if the coating deteriorates or is damaged.

excessive corrosion. Besides a prudent business practice, Avista is mandated by the U.S. Department of Transportation to provide effective cathodic protection for its steel natural gas pipelines. The Company's Cathodic Protection Group is responsible for the monitoring and annual testing of our cathodic systems. The need for capital investments in our cathodic protection systems is driven by the results of annual monitoring and testing. Because cathodic systems can have variable service lives, depending on local soil conditions and the propensity for corrosion, and because all the component parts are buried in the earth, the only way to determine whether a system needs to be replaced is through annual performance monitoring. It is often difficult to predict in advance when a specific replacement will be required so the amount of replacement work experienced each year across our system can be somewhat variable. Therefore, the annual funding for this program in future years is based on Avista's experience in prior years.

Gas Facility Replacement Program (GFRP) Aldyl A Pipe Replacement – 2020: $20,708,000, 2021: $22,832,000, 2023: $23,357,000, 2023: $15,319,000

The Aldyl A Pipe Replacement Program[35] is a 20-year structured pipe replacement effort with dedicated internal and external resources focused on reducing natural gas system risk, on a prioritized basis, by replacing priority Aldyl A pipe throughout Avista's natural gas distribution system. The program was initiated in 2011 and is slated to be completed by year 2032.[36] The primary alternative to this proactive replacement program was to simply replace sections of the subject pipe as it failed in service over time. The Company's asset management analysis, however, revealed that this approach would eventually lead to a failure rate and consequences that would be unacceptable to Avista, our customers, the general public, and regulators.[37] The question, then, was to determine the time horizon over which a replacement program should be conducted. The analysis showed that a replacement interval in the range of 25 to 30 years would likely still result in an unacceptable increase in the number of annual leaks, while an interval in the range of 10 to 15 years would result in substantially-greater cost pressure on customers, exacerbate the complexities and demands of the project, and fail to produce enough of a reduction in annual leaks to overcome these burdens. A time interval in the range of 20 years was determined to be optimal. The Company has continued to re-evaluate the analysis since the initial work was completed, which has confirmed Avista's approach and timeline for managing this issue. I have provided the most recent report updating this analysis, conducted in 2018, as Exhibit No. 11, Schedule 6. Replacing this pipe in our system in the manner undertaken will help the Company shield our customers from this

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[35] This pipe replacement program is managed by the Company's Gas Facility Replacement Program, which is the organizational program responsible for managing all aspects of replacement planning and execution of all individual replacement projects. Multiple individual projects are carried out across our natural gas service area each year.

[36] For a detailed description of this program, please see Avista's Priority Aldyl A Protocol Report, provided as Exhibit No. 11, Schedule 5.

[37] As described in Exhibit No. 11, Schedule 5, in February 2012 Avista's Asset Management Group released its findings in the report titled "Avista's Proposed Protocol for Managing Select Aldyl A Pipe in Avista Utility's Natural Gas System." The report documents specific Aldyl A pipe in Avista's natural gas pipe system, describes the analysis of the types of failures observed, and the evaluation of its expected long-term integrity. The report proposed the undertaking of a 20-year program to systematically replace select portions of Aldyl A medium density pipe within its natural gas distribution system in the States of Washington, Oregon, and Idaho.

unreasonable risk and minimize, optimize and levelize the costs they pay for the work to be done.

Gas Isolated Steel Replacement Program – 2020: $1,058,000, 2021: $1,400,000, 2022: $850,000, 2023: $503,000

Related to my description of our cathodic protection systems above, the Company is required to identify portions of its natural gas system where we have "cathodically isolated" sections of steel piping, including natural gas service risers, and to replace them with non-corrosive pipe within a specified timeframe. Isolated steel sections are just that, they are electrically separated from the cathodic protection system by sections of non-corrosive (plastic) pipe. Because these sections are not connected to the cathodic protection system, they are not afforded the extra level of protection beyond their protective coating. Replacing isolated steel sections protects our customers and others from the potential consequence of leaks on our system and helps ensure customers also receive the full lifecycle value of the investments made by avoiding the need to prematurely replace pipe due to excessive corrosion. Identifying and replacing isolated steel sections of pipe is required by federal regulations and by agreement for our system in Washington. The need for capital investments in our isolated steel replacement program is driven by the results of our annual surveys of the system and the amount of piping that needs to be replaced each year. It can be difficult to predict in advance the amount of replacements that will be required each year so the annual funding for this program in future years is based on Avista's recent historic experience.

Gas Overbuilt Pipe Replacement Program – 2020: $215,000, 2021: $460,000, 2022: $420,000, 2023: $236,000

As a natural gas distribution system operator, Avista is required to operate within the minimum safety standards outlined in Part 192 of the Department of Transportation's Code of Federal Regulations (CFR). These regulations define the laws that all operators must legally comply with in the operation of natural gas distribution systems. There are sections of existing gas piping within Avista's gas distribution system that have experienced encroachment or have been overbuilt by customer-constructed improvements (e.g. living structures, sheds, decks, etc.) and were not designed for these conditions. Overbuilt facilities restrict company access to the pipe resulting in accessibility issues that interfere with our ability to perform certain maintenance activities required by the federal regulations, such as meter inspections or leak survey. These encroachments also impair our ability to safely operate and maintain these facilities, which can become impossible if access to the ground above the piping is restricted. More importantly, overbuilds present an increased risk to customers due to the threat that leaking gas may be trapped inside a structure, increasing the possibility of potentially catastrophic accidents. Unless our system was originally designed to be overbuilt these situations represent a violation of the federal regulations.

Gas PMC Program – 2020: $1,710,000, 2021: $2,950,000, 2022: $1,500,000, 2023: $1,033,000

Avista is required by Commission rules and tariffs in its three state jurisdictions to annually test a portion of its natural gas meters for accuracy and to ensure overall meter performance. This program is known as the Planned Meter Changeout Program (PMC) and uses a statistical sampling methodology[38] to determine the number of meters changeouts that must be completed each year. If samples from a meter "family" are not meeting accuracy standards, then the Company will remove that population of meters from service. Conversely, if the results meet our standards of accuracy then the sample size in the future for that meter family may be reduced. These analytics help control costs and remove meters quickly when not performing well. Ensuring the accuracy and overall performance of our natural gas meters is in the interest of all customers and helps us minimize the overall cost of maintaining a high standard of service. The annual volume of periodic meter changeouts is driven by the determination of sample sizes, as noted above, so there is some year-to-year variability in spending due to the natural change in number of units replaced each year.

Gas Replacement Street and Highway Program – 2020: $2,641,000, 2021: $3,418,000, 2022: $3,500,000, 2023: $2,333,000

Nearly all Avista's natural gas pipelines are located in public utility easements set aside for this purpose, which are controlled by jurisdictional franchise agreements. Avista is required under these agreements to relocate its facilities, at our cost, when local jurisdictional projects, typically transportation, require the move. Avista relies on its natural gas infrastructure to provide service to its customers and uses public utility easements as a cost-effective way to reduce the costs of placing new infrastructure into service. In cases where we must relocate our facilities, even though there is a new incremental cost for doing so, it still represents the least-cost approach for continuing to provide reliable and affordable natural gas service. In some instances, the Company will have a substantial lead time to plan for, budget, design and permit for the move, but in most cases, we're notified of the need to move during the year the jurisdictional project must be completed. Because these jurisdictional projects are outside Avista's control, and because it's impossible to forecast the year-to-year costs, this program and its ultimate costs are subject to considerable variability. There is no alternative to this program since the Company is required to move its facilities, within a specified time frame, when notified by local jurisdictions pursuant to our franchise agreements. Within each project, however, there are sometimes opportunities to evaluate alternative ways to continue providing service, and the Company always looks for opportunities to leverage these projects to capture other system benefits.

Natural Gas High Pressure Pipeline Remediation Program – 2021: $700,000

Current natural gas industry Pipeline Safety code requires pipeline operators to have pressure test documentation and material specifications for pipelines distributing natural gas. The Company is working to convert documentation from paper to electronic, as well as confirm that "traceable, verifiable, and complete" Maximum Allowable Operating Pressure (MAOP) records are available for its high-pressure natural gas facilities. Like many other natural gas utilities, Avista does not have such records available for every segment of subject pipe because there were no such code requirements in effect at the time many facilities were installed, in addition to cases where the Company acquired the facilities of other natural gas operators and did not have control over their testing practices and record keeping prior to the acquisition. The investments made under this program are required to field-verify some segments of

[38] ANSI Z1.9 "Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming."

installed pipe after performing a thorough review of Avista's existing records to determine where testing documentation is still needed, and to perform the field pressure testing or material verification/replacement required to complete our records.

Gas Non-Revenue Program – 2020: $8,203,000, 2021: $8,000,000, 2022: $8,000,000, 2023: $5,320,000

This annual program, which is under the Company's Failed Plant and Operations capital investment driver, includes investments to replace obsolete facilities, pipe and equipment at the end of their useful life or that have failed, equipment and/or technology to enhance gas system operation and/or maintenance, projects to improve public safety, and improvements ancillary to customer requested work.[39] These investments, while necessary for safe and reliable operation of our system, <u>are not</u> part of our programs to fund new customer connects, increase performance or capacity, or make systematic replacements based on asset condition.[40] Like the electric distribution minor rebuild program I described earlier in my testimony, there is no traditional alternative to the work completed under this program since it consists of many, small unplanned projects across the entire natural gas distribution system. These small, unplanned projects are responsive to a range of factors generally beyond the control of the Company. Examples include ancillary work required by customer-requested service,[41] repair of damage from a dig-in of our facilities, investments needed relocate facilities, repair of leaks, deepening pipeline sections that are too shallow, remediating failed, under-sized or unsafe equipment, and correcting overbuild issues. There are instances among the small rebuild projects where limited alternatives are evaluated in the design phase by the individual project designer. In general, however, there is no reasonable alternative to timely making these investments once the need has been identified.

Gas Regulator Station Replacement Program – 2020: $1,004,000, 2021: $1,462,000, 2022: $1,000,000, $2023: $750,000

This program addresses needed replacements of existing 'at-risk' natural gas gate stations, regulator stations and industrial customer meter sets ("stations") located across Avista's natural gas service territory. These stations to be replaced have reached the end of their useful service life, fail to meet the Company's current natural gas standards, and can no longer be properly maintained because of obsolete equipment. These replacements improve system operating performance, enhance operating safety, remove operating equipment that is no longer supported (obsolescence), and ensure the reliable operation of metering and regulating equipment. There are no practical alternatives to providing for the compliant, safe and reliable operation of our natural gas stations. As a hypothetical, the Company did consider the option of responding to station needs only when equipment failed in service, however, this approach

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[39] Work requested by customers is generally, by tariff, performed at the customer's expense. Under certain circumstances, however, Avista may choose to perform additional work needed on the system not related to the customer's request. An example is to replace an existing steel service with polyethylene pipe to eliminate the possibility of future deficiencies in cathodic protection and to reduce future maintenance related to that steel service. The cost of this conversion is assigned to this Program.

[40] For additional information on this program, please see pages 12-13 in Avista's Natural Gas Infrastructure Plan for 2020, provided as Exhibit No. 11, Schedule 4.

[41] These investments include work required to properly maintain the system, but that are not reasonably covered by the tariffed financial contribution required of the customer.

would expose our customers to greater risk, would expose Avista to compliance violations and financial penalties for failure to properly maintain station equipment, and would cost our customers substantially more than the cost associated with our current proper lifecycle management. Our Gas Engineering department also considered the options of not replacing end-of-life stations, but only replacing obsolete and failed components. This option would result in higher lifecycle costs for our stations because we would be making many more service calls to each station, and eventually, would be required to replace an increasing number of stations on a crisis basis each year as the backlog of required work became unsustainable. This option, too, would drive up the lifecycle cost of our stations, result in an increasing service and regulatory risk, and would increase our customers' cost of natural gas service.

Gas Rathdrum Prairie HP Main Reinforcement – 2020: $72,000

In the manner I described above for the natural gas reinforcement program, Avista's load studies demonstrate the need to reinforce high pressure main pipe capacity in the Rathdrum Prairie area of our system. Growth on the Williams Northwest Pipeline (NWP) - Coeur d'Alene Lateral pipeline has exceeded both Avista's contractual delivery amounts as well as the physical capacity of the NWP - Coeur d'Alene Lateral pipeline. In addition to these supply constraints, the distribution system in the area of Hayden Lake, Idaho will not have sufficient pressure to carry our firm customer loads during the peak demand of our design day. In addition to the insufficiencies in the Hayden Lake area, the Company also lacks the capacity to serve firm design day loads in the areas of the City of Coeur d'Alene and the corridor through Kellogg without this reinforcement project. There is no alternative to reinforcing our natural gas system to meet this array of design day firm customer loads.

Gas Reinforcement Program – 2020: $1,313,000, 2021: $1,300,000, 2022: $1,300,000, 2023: $783,000

Avista systematically monitors and models natural gas operating pressures throughout our system in an ongoing effort to ensure we have the capacity needed to serve our firm customer loads on our coldest expected winter "design days." Areas identified as having insufficient capacity to meet design day requirements are prioritized based on the severity of the risk associated with the potential inability to serve firm loads. Investments made under this program provide supply reinforcement to these capacity-constrained areas. There is no alternative to providing for the capacity needs of our firm natural gas customers who rely on Avista to ensure they have the supply needed to heat their homes and businesses and supply a range of industrial needs, most especially during extreme weather conditions. The natural gas reinforcement program helps ensure the Company meets this need, and to deliver an adequate supply at the most reasonable cost.

Gas Telemetry Program – 2020: $253,000, 2021: $174,000, 2022: $181,000, 2023: $138,000

Avista's commitment to safety and reliability dictates we monitor our gas system to ensure its safe and reliable operation and to accurately meter and account for natural gas purchased and sold. In addition to sound business practices, this monitoring is required by federal and state rules for "Natural Gas Control Room Management." Telemetry provides the visibility and data needed to pro-actively detect abnormal operating conditions - before they can become major problems that could impact safety or natural gas delivery. Additionally, telemetry is used to remotely monitor system pressures, volumes, and flows from areas of special interest such as gate stations, supply to natural gas transportation customers, regulator stations, select large industrial customers, and end of line pressures. Alarm set points in field instruments such as flow computers, electronic volume correctors, and electronic pressure monitors are used to alert the Gas Control Room of abnormal operating conditions such as low or high pressure, high flow, or high or low gas temperatures that could indicate problems with gas heaters at gate stations or sensing equipment failures. By proactively monitoring these sites, Avista can dispatch field personnel during normal business hours instead of responding to a conventional alarm that could occur at any time. Telemetry also allows us to identify low pressure on the system and to take quick action to avoid our customers potentially losing their natural gas service. Additionally, data from these telemetry sites is used to validate the system modeling tool used by our Natural Gas Planning group. Over the last several years, costs have averaged approximately 45% spent in OR, 35% in WA, and 20% in ID.

Jackson Prairie Joint Project – 2020: $2,205,000, 2021: $2,377,000, 2022: $2,378,000, 2023: $1,580,000

Avista is a one third joint owner in the Jackson Prairie Natural Gas Storage Project and has long relied on this asset to optimize gas prices and supply for the benefit of its customers. As one example of the benefit of this asset, over the natural gas procurement year of 2016-2017, the storage optimization provided by Jackson Prairie saved our natural gas customers over $20 million. Like any asset, investments must be made in the facility each year to ensure the integrity of its safe, efficient and cost-effective operation. Avista participates with its joint owners to identify and vet upcoming capital needs and to approve annual investments to be made. Company witness Ms. Morehouse provides further information regarding Avista's ownership in Jackson Prairie. The Company periodically evaluates the practicality of acquiring alternative natural gas storage capacity that includes leased pipeline capacity and storage for replacing the Jackson Prairie and the option of constructing a new stand-alone compressed natural gas storage facility. Both the leasing of natural gas pipeline capacity and leased storage capacity would provide only part of the flexibility provided by Jackson Prairie and at a much greater cost. The alternative of constructing a new compressed natural gas facility is very cost prohibitive. Maintaining Avista's ownership in Jackson Prairie, including investments to maintain the integrity and safe operation of the facility, provides our customers the least cost solution to meeting our natural gas storage needs.

IV. INVESTMENTS IN THE COMPANY'S OPERATIONS, FACILITIES AND FLEET RESOURCES

Q. Please summarize the need for ongoing investment in Avista's operations, facilities and fleet resources.

A. Adequate operating facilities are a critical ingredient to the success of all organizations, especially those like Avista that are office facility, information technology, heavy asset and field-operations intensive. As described in Avista's Fleet Infrastructure Plan for 2020 (Exhibit No. 11, Schedule 7), our fleet infrastructure includes a wide range of light to heavy trucks specialized for electric and natural gas operations, diverse and specialized equipment, all manner of tools, and extensive material and supply storage areas. Though it is easy to take for granted, our office and operations facilities are at the heart of our ability to effectively and efficiently serve customers, as described in Avista's Facilities Infrastructure Plan for 2020 (Exhibit No. 11, Schedule 8). In addition to employees supporting our field operations, our facilities are required to support a broad range of technical and administrative staff, including accountants, engineers, attorneys, customer service representatives, and information technology experts. Besides the facilities themselves, our operations depend on extensive information technology infrastructure, diverse and stand-alone communication networks, and myriad other support systems (including supporting the great majority of our employees who are connecting remotely to the Company's systems during the COVID-19 pandemic).

As would be expected for a Company that has been in business over 130 years, many of our facilities have been kept in operation well beyond their useful service life. A few remaining structures were built in our early years of service, while many, like our energy delivery infrastructure, were built during the economic expansion of the 1950s, placing them now in the range of 60 to 70 years old. Common sense and good stewardship require caring for old buildings that need increasing levels of maintenance or retrofits to keep them serviceable. Even so, over the years many of these facilities became inadequate to meet the

Company's growing needs given their age and condition and the increasing levels of maintenance required to keep them serviceable. To better extend their life, these facilities were often upgraded and updated to meet contemporary operating requirements, which included a steady increase in the number of customers served, the growing regulatory and technology complexity in our business, and the need to care for aging infrastructure, to name a few.

These same factors also contributed to the need for more employees and workspace, supporting infrastructure and related equipment. Trucks and vehicles also increased in size and complexity over time requiring larger service space and specialized maintenance requirements. To meet these demands, older facilities were continuously upgraded, expanded, remodeled and extensively repaired to keep them minimally serviceable. These efforts helped the Company reach the point where we could embark on a comprehensive planning initiative focused on replacing a wide range of facilities well beyond their useful service life, and their cost-effective capability to be further adapted to the future. Over the prior 15 years Avista has been systematically replacing facilities that were simply inadequate to meet the Company's current and future needs.

In addition to replacing end-of-life facilities, we have also reorganized our business to improve the service we provide our customers by responding more quickly to outages and equipment failures. We have accomplished this by locating stocks and supplies in closer proximity to crews and the geographic areas they will be used, and storing parts and equipment in more organized and efficient spaces for quick access. The Company goes through systematic procedures and protocols to determine how to best manage its facilities as well as determining when they should be replaced. Part of this evaluation includes industry best practices by national organizations that specialize in this area, including Building Owners and

Managers Association (BOMA) and the International Facility Management Association (IFMA). These investments are needed not only to keep up with current service requirements, but they also save money for our customers by lowering the overall cost of service over the long term.

Q. Would you please summarize the capital investments in general plant, fleet and facilities resources completed in 2020 and planned for over the Two-Year Rate Plan?

A. Yes, the completed and planned investments related to general plant, fleet and facilities resources, presented on a system basis and grouped by investment driver, are shown in Table No. 5, and described below.

Table No. 5 – General Plant Capital Projects (System)

General Plant & Fleet Investment Capital Projects (System) In $(000's)

Business Case Name	2020	2021	2022	2023[1]
Mandatory and Compliance				
Apprentice/Craft Training	$ 69	$ 62	$ 65	$ 14
Asset Condition				
Capital Tools & Stores	1,737	2,754	2,500	1,665
Fleet Services Capital Plan	6,814	6,873	5,893	4,148
Structures and Improvements/Furniture	2,258	3,552	3,001	2,000
Telematics 2025	-	1,100	338	-
Oil Storage Improvements	-	-	1,500	-
Performance and Capacity				
Campus Repurposing Phase 2	2,746	-	-	-
Gas Operator Qualification Compliance	65	65	120	5
Strategic Initiatives	5,441	2,000	-	-
Misc. accrual reversals, corrections or additional TTP	(7)	-	-	-
Total Planned General Plant and Fleet Investment Capital Projects[2]	**$ 19,123**	**$ 16,405**	**$ 13,417**	**$ 7,832**

(1) Includes system pro forma capital for the period of January 1, 2023 through August 31, 2023.
(2) Totals exclude Washington and Oregon direct business cases from revenue requirement in this case

Apprentice Craft Training – 2020: $69,000, 2021: $62,000, 2022: $65,000, 2023: $14,000

Avista manages 11 Federally regulated apprenticeships that require instructional aides and equipment deemed necessary to provide quality instruction.[42] The Company's Joint Apprenticeship Training Committee (JATC) administers these apprenticeships and capital funds are used to purchase tools, materials and equipment for training apprentices and journey workers in all crafts. The trained and competent workforce produced through the various apprenticeships benefits customers in all aspects of our service across all Avista service territories. Support of apprenticeship training at Avista through this capital program aligns with Avista's mission and focus areas, allowing us to deliver innovative energy solutions safely, responsibly, and affordably. Absent this capital funding, Avista would lack the ability to train craft workers, likely resulting in our inability to fill many critical positions in crafts ranging from meter and SCADA technicians, generation mechanics and electricians, natural gas pressure control and service personnel and microwave and radio communications systems, to name just a few of our many specialized and highly-trained positions. Our inability to train craft employees would also add significant cost to our business as we would be forced to pay premium labor costs in order to attract employees trained and employed at other utilities and to outsource the specialized training required to maintain our many skillsets. This is not a viable alternative for cost-effectively, safely and efficiently serving the needs of our customers.

Capital Tools & Stores – 2020: $1,737,000, 2021: $2,754,000, 2022: $2,500,000, 2023: $1,665,000

This program funds the tools and equipment needed by our employees to safely and efficiently perform new construction, conduct system monitoring, ensure system integrity, and the repair and maintenance of our facilities. This equipment, which needs to be in adequate supply and fully available for both planned work and emergency response, supports the work of our electric, natural gas, communications, fleet, facilities and generation crews and infrastructure. There are no alternatives to having the specialized tools required to perform the work of providing safe, reliable and affordable service to our customers. The Company, does, however, promote the continuous improvement process of always exploring more efficient and cost-effective ways of performing our work, including its application to the tools and equipment necessary for the tasks.

Fleet Services Capital Plan – 2020: $6,814,000, 2021: $6,873,000, 2022: $5,893,000, 2023: $4,148,000

Fleet vehicles and equipment simply do not age well, as they are subject to a duty cycle that most vehicle owners would not imagine for their personal car or truck. Avista's fleet of vehicles operate in environments that are often at the extreme; the hottest or the coldest, the dustiest, constant in and out, starting and stopping, high idle time and high loads. These factors lead to substantial wear and tear on our vehicles, <u>even under our prudent and proper use</u>, which over time leads to substantial maintenance and repair costs, and reduced availability and reliability. The Company's fleet replacement program optimizes the life of each vehicle allowing us to extract the right amount of useful value from our vehicles before they experience an accelerating rate of repair expenses. The investments made under this plan represent the annual investments needed to

[42] Regulated by 29 CFR 29 & 30.

replace a portion of our service fleet each year based on asset condition (replacement at end-of-life). Avista's fleet group uses industry best practices, data, and a proprietary, third-party asset management system[43] to identify when to replace equipment in order to achieve the lowest total cost of ownership for our customers. The analysis is based on the initial cost of each fleet unit, actual maintenance and repair costs, depreciation expense and salvage/resale value to establish the lowest lifecycle cost for each class of vehicle in the Company's fleet. In addition to achieving the lowest cost for customers, this strategy allows our fleet services group to achieve an equipment reliability/availability of 96%. Having equipment that is available when needed allows Avista to provide efficient, timely and cost-effective service to our customers.

In the absence of good data and analytics, it can be tempting to keep equipment in service beyond its optimum service life. After all, the equipment can appear to be in relatively good shape, and the repair and maintenance costs may not yet have begun to accelerate. In years past, Avista, like many organizations, did not have access to good data and analytical tools for determining the optimum replacement strategy. And, we often kept equipment in service because it represented the lowest incremental cost for operating 'the next day.' Once the Company had better access to good data and analytics, and the asset management culture and focus on lifecycle cost management, we became better at recognizing the value of replacing fleet assets based on condition and developing the capital budgets needed to support that philosophy and practice. The optimized lifecycle cost strategy employed by the Company ensures we're investing the right amount of capital at the right time to achieve the lowest cost of service for our customers.

Structures and Improvements/Furniture – 2020: $2,258,000, 2021: $3,552,000, 2022: $3,001,000, 2023: $2,000,000

These investments fund the capital maintenance, site improvement, security, and related needs for the Company's 40 building facilities providing office space, operations, storage and other core business functions. The capital maintenance projects include roofing, siding, asphalt, electrical and plumbing work, remodeling, furniture replacements and new furniture for replacements and growth in operations. Approximately half the investments fund asset replacements based on end-of-life condition and the Company's facilities management group uses a specialized application to help determine the optimum timing for these replacements. Approximately 30% of the annual funding supports immediate needs identified by the Avista work groups with responsibility for each facility, and the remainder funds emergent needs that could not be anticipated in the planning process. The level of funding approved to meet these needs in prior years has only been adequate to address the highest priority projects, which has required the facilities group to keep beyond end-of-life assets in service in a manner to minimize the impact on overall lifecycle cost. The primary alternative to making these investments is to keep end-of-life assets in service and to perform emergency repairs and replacements as components fail. This is similar to the alternative I described above for fleet services where it is possible to keep beyond end-of-life assets in service with the consequence of building a 'bow wave' of deferred investment that must be addressed in the future, while

[43] Avista uses the services of Utilimarc, a utility focused data analytics company that benchmarks and performs similar analysis for over 50 investor-owned utility fleets nationwide. https://www.utilimarc.com/

driving higher long-term lifecycle costs for our customers. Another alternative would be to fully fund this program to replace all assets at end of life and meet all other identified business needs. The selected alternative is to fund only the highest priority needs, which allows the Company's Capital Planning Group to allocate funding to other highest-priority projects that have greater risk if not adequately funded. This approach, as I noted just above, requires Avista's facilities group manage the backlog of unfunded needs in a way that minimizes the long-term lifecycle cost impact to our customers.

Telematics 2025 – 2021: $1,100,000, 2022: $338,000

Since 2012, Avista has used Zonar[44] telematics systems to track and record key operational data on the Company's fleet vehicles.[45] The first generation of telematics was implemented to streamline, track and administer the state and federally-required inspections of trucks and mounted equipment, which proved to be very successful for the Company. We have since expanded the use of telematics data and expanded the vehicles covered to include contractors working for Avista and Company employees using their personal vehicles while in service of our customers. Our current provider has notified the Company that the scheduled shutdown of AT&T 3G networks in February 2022, which are used to interconnect our vehicle-mounted devices, will render them no longer usable. In planning for the replacement of our current system Avista is considering moving to a contemporary cloud-platform application that will integrate geographic location data to improve our operations efficiency or provide our customers more-accurate information about our response to their service needs, among other uses. In the future, the Company plans to further leverage vehicle location and other data to provide coaching to drivers as well as collecting and analyzing leading indicators on decisions fleet drivers are making in the field. Selection and implementation of a new telematics system must begin in 2021 to provide ample time before the planned 3G network retirement.

Oil Storage Improvements – 2022: $1,500,000

Historically, Avista operated several oil storage tanks contained in an underground vault on the Mission campus. These tanks, which were interconnected with several facilities by underground piping and pumps, contained new oil products, used, but still viable oil, and spent scrap oil, all related to our substation maintenance and electric distribution operations. Over time, the Company experienced spill incidents and leaks in this underground system, and in 2014, we installed two new above-ground scrap oil storage tanks as part a new Waste and Asset Recovery building. Installation of the new above ground tanks allowed the Company to decommission two of the tanks in the underground vault, however, four of the underground tanks and their associated piping still remain in service. As I noted above, this underground infrastructure poses a continuing risk of undetected leaks, in addition to access issues that have compounded as we have redeveloped the Mission campus. The vault itself similarly limits use of the area for other purposes. Finally, the vault has been infiltrated by water and maintenance costs to ensure the vault provides proper containment are increasing. The selected alternative to eliminate the risks and issues related to the underground vault, tanks and piping is to build two additional oil storage tanks above ground

[44] https://www.zonarsystems.com/

[45] Telematics systems include transmitting/receiving/data storage device installed in a vehicle that captures can include location, speed, idling time, harsh acceleration or braking, fuel consumption, **vehicle** faults, and more.

adjacent to the new above-ground tanks, accompanied by several smaller 'day containers' located in the electric shop.

Campus Repurposing Phase 2 – 2020: $2,746,000

Avista embraced a holistic, long-term approach to address wide-ranging needs at its Central Office Facility, included under the "Campus Repurposing Phase 2" Business Case. Primary among the needs addressed were: 1) create needed workspace for an increasing employee population; 2) improve the safety and efficiency of employee, service-related and service provider traffic on campus; 3) create new fleet management and maintenance facilities to replace outdated and inadequate work space and processes; 4) provide adequate materials storage space and create more flexibility in space for emergency operations; and 5) provide safe and adequate parking for our customers, visitors, and our employees. The Avista Central Office Facility or "corporate campus" was developed in the 1950s to consolidate dispersed and inefficient utility operations. At the time Avista constructed its Central Office Facility, the Company served a total of 102,685 electric, and 9,962 natural gas customers. While the original footprint of the campus was adequate at the time it was built, there has been a nearly continuous need to expand its size to keep up with the growing needs of our business. From the late 1980s through 2014, the Company strategically acquired parcels of land as they became available to the north of the campus. Today, the campus encompasses 36 acres, constrained on the east by the Spokane River, to the west and south by Mission Park, the Burlington Northern Railroad, and developed residential neighborhoods, and to the north by residential housing and assisted living facilities. Today, the Company serves approximately 392,000 electric and 362,000 natural gas customers.

As I noted above, Avista made the decision in 2011 to approach its current and future central facility needs through a comprehensive planning process that anticipated and planned for our service needs for the next 50 years. Our focus was to minimize the need to provide reactive solutions to emerging service needs and to invest in the best long-term plan for the benefit of our customers. In the prior phase of this major project the Company completed a new fleet services building to support field operations at our central office facility. In the current phase, Avista recently completed construction of a Campus Parking Structure needed to accommodate vehicle parking for employees working at the Company's central office. Nearly 1,300 employees currently report to work at the main campus, which had a parking capacity of 728 dedicated spaces that were available to employees.[46] The new structure added approximately 500 additional parking spaces in a relatively small footprint (0.71 acres) compared with the 10 acres that would have been required for equivalent surface-level parking. This solution freed up valuable campus space for other uses with no alternatives, such as equipment and material storage, staging areas, truck parking and maneuvering, and future growth.[47] A primary concern for Avista in determining how to address the need for

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[46] This number does not include gravel parking areas used by employees on the right-of-way of the Burlington Northern Railroad across the tracks from the campus.

[47] Initially, the Company took incremental steps over several years to increase parking spaces available to employees working at our central office. These included adding spaces to our south Mission parking lot and creating new spaces in our transformer storage area in 2009, expanding employee parking in our north wood pole storage area in 2012, and adding remote parking spaces in our north Ross Court area, also in 2012.

more employee parking was the safety of employees themselves. According to the National Safety Council, potholes or cracks in parking lot surfaces, debris, poor lighting, puddles, snow, and ice can lead to pedestrian injuries (not to mention crossing active railroad tracks and right-of-way during the darkness). Slips, trips and falls are common in parking lots, and they are also highly-vulnerable areas for crime, according to the Urban Institute Justice Policy Center.[48] Avista employees experience these issues, having been confronted, chased and threatened and having their vehicles vandalized, burglarized or stolen from Company parking areas. Having to search for twenty minutes for a parking space, walk a mile or more to get to the office building from remote parking (potentially in icy and snowy conditions), or fear the potential of threats related to parking in risky areas had a very negative impact not only on safety and productivity, but also on the morale and job satisfaction of our employees.

Gas Operator Qualification Compliance – 2020: $65,000, 2021: $65,000, 2022: $120,000, 2023: $5,000

Similar to the apprenticeship training I described just above, as an operator of natural gas infrastructure, Avista Utilities is required by federal regulation to minimize safety and integrity risks that could result from an employee's lack of knowledge, skills, or abilities during the performance of required activities and tasks. Craft Training and Gas Operations are responsible for ensuring we can field a qualified and competent workforce, accomplished by evaluating and qualifying internal and contract employees on Operator Qualification tasks specific to Avista's natural gas infrastructure. The capital investments in this business case provide the tools, vehicles, and equipment necessary to meet the PHMSA regulations for Operator Qualification. The alternative of not providing the resources to support the qualification is not viable and would ultimately result in regulatory penalties and the potential for incidents impacting Avista's employees, customers and the public. These investments support Avista's natural gas operations in Idaho, Washington and Oregon.

Collectively, these efforts created 275 additional parking spaces for our employees. Creating these new spaces did come at a cost, however, as it required Avista to move operations vehicles and materials storage offsite to our Beacon Substation, increasing crew time and resources to access vehicles and materials each day. And, we were still 425 spaces short of providing adequate parking for our employees. As I noted above, Avista considered three alternatives for meeting our current and long-term parking needs at our central office facility. The first involved potential development of the Ross Court parcel of four acres into a dedicated, paved parking lot. The development would have to meet all applicable Spokane City codes including sidewalks, drainage and parking island vegetation. Pursuing this alternative would impact the then-pending construction of a new fleet services building and would net only 175 of the needed 425 parking spaces. The second alternative would require the Company to purchase adjacent residential properties to the east of the central office, in the cumulative area of approximately 10 acres, clear the land of homes and improvements, and develop the parcels into a parking lot with 500 spaces. Besides the high cost of development there were risks such as not all of the needed property owners being willing to sell their homes, and we still faced street and railroad crossings in addition to higher long-term maintenance costs. The selected alternative was to build a multi-story parking garage on 0.71 acres of land just adjacent to the central office. This option was the least cost and best optimized alternative to meeting the Company's current and long-term parking needs at our central office complex.

[48] Urban Institute Justice Policy Center, https://www.urban.org/sites/default/files/publication/31261/1001193-Preventing-Car-Crimes.PDF

Strategic Initiatives – 2020: $5,441,000, 2021: $2,000,000

Avista's leadership has set aside a limited amount of capital funding to support individual projects that align with the Company's strategic plan.[49] Projects funded under this business case often need greater flexibility and more rapid response than can be afforded in our normal capital planning cycle. For instance, an agency such as the U.S. Department of Energy may issue a grant request for projects like our smart grid or battery demonstration projects that align with Avista's strategic direction. These often have a brief response time within which the company must prepare and file a responsive proposal. A recent example of this type of investment is our Clean Energy Fund 2 battery storage project. The annual capital funding made available in each year for Strategic projects is $5 million allocated across our entire service area.

Q. Does this conclude your direct testimony?

A. Yes.

[49] The numbers above, $5,441,000 and $2,000,000 respectively, represent system totals for the strategic overall business case, and excludes the 2020 pro forma amount related to the Customer Experience Platform discussed by Mr. Magalsky. There are several sub-business cases within the strategic business case, including some directly assigned business cases (i.e.; Electric Vehicle Pilot Program in Washington). Business cases that are directly assigned to Washington have not been provided in this filing and have not been included in the Company's revenue requirement request.