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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	))))))))	CASE NO. AVU-E-25-01 CASE NO. AVU-G-25-01 DIRECT TESTIMONY OF JOSHUA D. DILUCIANO

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

I. INTRODUCTION

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

A. My name is Joshua D. DiLuciano and I am employed as the Vice President of Energy Delivery 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. Yes. I am a graduate of Washington State University (WSU), from which I earned a Bachelor of Science degree in Electrical Engineering. I also earned a Master of Science degree in Management and Leadership from Western Governors University and am a licensed electrical engineer in Washington State. I joined Avista in 2006 as an Engineer and have held a variety of technical engineering roles since. I have managed several groups, most recently as Director of Electrical Engineering where I had responsibility for Washington Advanced Metering Infrastructure (AMI), the Company's geographic information system (GIS) Refresh, Transmission Engineering, Distribution Engineering, Protection Engineering, Substation Engineering, Drafting and Edit, Maximo, and Engineering Technical Services. I was awarded my current position in September 2022, where I have responsibility for electric and natural gas engineering, operations, transmission operations and system planning, and shared services.

Additionally, I am a U.S. Navy veteran, and I currently serve on the board of the West Central Community Center.

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 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. I will also 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 July 1, 2024, through August 31, 2027. A table of the contents for my testimony is as follows:

Description	Page
I. INTRODUCTION	1
II. OVERVIEW OF AVISTA'S ENERGY DELIVERY SERVICE	3
III. INVESTMENTS IN THE COMPANY'S ELECTRIC DISTRIBUTION SYSTEM	6
IV. INVESTMENTS IN THE COMPANY'S ELECTRIC TRANSMISSION SYSTEM	13
V. INVESTMENTS IN THE COMPANY'S NATURAL GAS SYSTEM	20
VI. INVESTMENTS IN THE COMPANY'S OPERATIONS, FACILITIES AND FLEET SERVICES	25

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following Schedules as a part of Exhibit No. 10:

- Schedule 1, Avista's Priority Aldyl-A Protocol Report
- Schedule 2, Study of Aldyl-A Mainline Pipe Leaks - 2024 Update
- Schedule 3, 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. Malensky will provide an overview of the strategy and actions comprising the plan, including the investments the Company is making under 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 Washington and Idaho, and natural gas local distribution operations in Washington, Idaho, and Oregon. In addition to the hydroelectric, renewable, and thermal generating resources, the Company has an electric transmission system comprised of approximately 700 miles of 230 kV lines and 1,600 miles of 115 kV lines and approximately 19,300 miles of primary and secondary electric distribution lines. Additionally, the Company owns and operates approximately 8,000 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 Washington, Idaho and Oregon is provided by Company witness Ms. Rosentrater.

As detailed in the Company's 2023 Electric Integrated Resource Plan (IRP),[1] Avista expects retail electric sales growth to average 0.33% annually for the next ten years in our service territory, a small increase from our 2023 IRP. Also, based on Avista's 2023 Natural Gas IRP,[2] in Idaho and Washington the number of natural gas customers is projected to increase at an average annual rate of 1.1% between 2023 and 2045, with demand growing at a compounded average annual rate of 0.52%.

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

A. Of the Company's approximate 422,000 electric and 383,000 natural gas

[1] The Company's 2025 Electric IRP has been provided by Mr. Kinney (Exhibit No. 6, Schedule 1).
[2] The Company's 2023 Natural Gas IRP has been provided by Mr. Kinney (Exhibit No. 6, Schedule 3).

customers, approximately 148,000 and 97,000, respectively, are 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, Moscow/Pullman, and Lewiston/Clarkston.

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

A. Avista's Service Quality Measures (SQM) 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
- ✓ Five (5) individual measures of the level of customer service and satisfaction the Company must achieve each year.

The Company is pleased to report we exceeded all six Customer Service Measure benchmarks for our most recent reporting year in 2023 and noted a continuing, relatively stable, long-term trend in electric service reliability.[4] Results for Avista's 2023 Customer Service Measures are provided in Table No. 1:

[3] Order No. 34181 in Case Nos. AVU-E-18-10 and AVU-G-18-06.

[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 2024 by April 30, 2025.

Table No. 1 – 2023 Results for Avista's Customer Service Measures

Customer Service Measures	Benchmark	2023 Performance	Achieved
Percent of customers satisfied with our Contact Center services, based on survey results	At least 90%	96%	✓
Percent of customers satisfied with field services, based on survey results	At least 90%	97%	✓
Number of complaints to the WUTC per 1,000 customers, per year	Less than 0.40	0.04	✓
Percent of calls answered live within 60 seconds by our Contact Center	At least 80%	83%	✓
Average time from customer call to arrival of field technicians in response to electric system emergencies, per year	No more than 80 minutes	47 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	50 minutes	✓

Electric System Reliability	5-Year Average (2019-2023)	2023 Result	Change in 5-Year Average
Frequency of non-major-storm power interruptions, per year, per customer (SAIFI)	0.96	0.79	-0.004
Length of power outages, per year, per customer (SAIDI)	138 minutes	113 minutes	-2.6 minutes

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

A. The Company's process for determining which projects should be recommended for funding each year includes reviewing comprehensive planning studies, engineering and asset management analyses, and scheduled upgrades and replacements identified across 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.

As discussed by Company witness Mr. Christie, projects advanced for funding enter a formal review process and are reviewed and prioritized by higher-level committees, such as Avista's Engineering Round Table (ERT), the Aldyl A Pipe Advisory Group, and the Facilities Steering Committee. These groups carefully review 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. 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 (discussed by Mr. Christie) for final review and funding allocation.

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. 10, Schedule 3).

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 by my director-level direct reports. Program and project results are also reported directly to the Company's senior leaders, including myself, through steering committees, various business meetings, and presentations.

III. INVESTMENTS IN THE COMPANY'S ELECTRIC DISTRIBUTION SYSTEM

Q. Please summarize the need for continuing investments in the electric distribution 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 supply our customers with safe and reliable electricity, which creates the need to annually replace an increasing amount of infrastructure that has reached the end of its useful life (based on asset

conditions). Second, we are responding to the need for technology investments required to build an integrated energy services grid. 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. Christie.

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.

Q. Would you please summarize the capital investments in electric distribution plant completed in 2024 and planned for over the Two-Year Rate Plan?

A. Yes. As discussed by Company witnesses Ms. Schultz and Ms. Benjamin, 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 July 1, 2024 and August 31, 2027. The completed and planned investments related to electric distribution, presented on a system basis, are shown below in Table No. 2, and described below. See also the detailed narrative for each electric distribution Business Case at Exhibit No. 10, Schedule 3, pages 3 – 170.

Table No. 2 – Electric Distribution Capital Projects (System)

Electric Distribution Capital Projects (System) In $(000's)					
Line #	Business Case Name	Investment Driver	July 2024 - August 2025	Rate Year 1 Sept 2025 - Aug 2026	Rate Year 2 Sept 2026 - Aug 2027
1	Distribution Grid Modernization	Asset Condition	$ 451	$ 799	$ 1,411
2	Distribution Minor Rebuild	Asset Condition	14,562	13,833	14,657
3	Distribution System Enhancements	Performance & Capacity	11,399	10,063	10,719
4	East CDA Lake Reinforcement Program	Performance & Capacity	243	694	-
5	Elec Relocation and Replacement Program	Mandatory & Compliance	9,968	6,960	7,020
6	Electric Storm	Failed Plant & Operations	2,836	2,529	2,529
7	Joint Use	Mandatory & Compliance	4,530	4,167	3,667
8	Meter Minor Blanket	Failed Plant & Operations	274	250	250
9	Metro 115kV Substation	Asset Condition	3,990	-	9,315
10	New Revenue - Growth	Customer Requested	78,190	62,629	66,746
11	Substation - Asset Condition	Asset Condition	26,781	19,003	6,895
12	Substation - Performance and Capacity	Performance & Capacity	15,594	11,517	14,660
13	Substation Failed Plant	Failed Plant & Operations	1,000	1,500	1,500
14	Wood Pole Management	Asset Condition	8,797	11,573	12,577
Total Planned Electric Distribution Capital Projects			**$ 178,616**	**$ 145,517**	**$ 151,946**

Distribution Grid Modernization (July 2024-August 2025: $451,000, RY1: $799,000, RY2: $1,411,000)

The purpose of this program is to rebuild and upgrade every electric feeder in Avista's distribution system. Some objectives within this program are 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.[5] 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 right-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). This business case results in direct O&M offsets by reducing the number of service calls received. The annual system estimated value of these Direct Offsets is expected at $101,839 in 2025, $161,456 in 2026 and $198,726 in 2027. Idaho's share is prorated over the Two-Year Rate Plan and included in the Company's revenue requirement as a reduction in expense within pro forma Adjustments 3.10 (Rate Year 1) and 26.05 (Rate Year 2).

Distribution Minor Rebuild (July 2024-August 2025: $14,562,000, RY1: $13,833,000, RY2: $14,657,000)

Distribution Minor Rebuild is an ongoing program that focuses on keeping the distribution

[5] 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 new technology.

system in a safe and reliable condition for customers, ensuring responsiveness to unplanned damages on distribution assets (car hit pole, broken crossarm, burned up transformer, etc.) that are not related to weather events, as well as small customer driven rebuilds. Throughout the entire distribution system, minor rebuilds, or replacement of asset units are required to be completed to maintain system reliability and safety. The work includes failed asset replacements, small mandatory or compliance driven work, smaller performance and capacity improvements, or unplanned customer requests. Occasionally, larger projects with an identified need and short timeframe for implementation are constructed under the Distribution Minor Rebuild business case. Even though the work is unplanned, Minor Rebuild work occurs regularly due to the nature of the utility business and our numerous assets in the field spread over a wide geographical area. An adverse accumulation of unrepaired assets would greatly put line workers and the public at risk as minor asset failures begin to deteriorate pockets of the distribution system, as well as decreasing the reliability of the distribution system.

Distribution System Reinforcements (July 2024-August 2025: $11,399,000, RY1: $10,063,000, RY2: $10,719,000)

Avista's electric distribution system consists of 370 discrete primary electric circuits (feeders) encompassing over 19,300 circuit miles of overhead conductors and underground cables, along with the other equipment needed to operate an electric distribution system. Load demands on the grid are dynamic with load patterns changing due to factors such weather, temperature, economic conditions, conservation efforts, and seasonal variations. The distribution grid is managed by division or 'Operations Engineers' and centralized Distribution Planning. The performance and capacity needs of this system are constantly changing, and this business case is the main tool available to our Operations Engineers so that they can keep up with these system demands. Most of the work completed with this business case addresses capacity constraints driven by load growth, which we anticipate being higher in coming years than historical growth rates, throughout the system.

The main driver for this business case is load growth on our electric distribution system. It is primarily focused on ensuring that our electric distribution system can accommodate our load growth. Our engineers are looking at the system as a whole and identifying the projects needed that will keep the system operating within acceptable parameters. Other drivers for this business case include power quality investigations and subsequent mitigation projects which are initiated by customer inquiries or engineering analysis work. Work is also driven by reliability, system performance issues, and safety concerns that are identified by our engineers and/or operations personnel. Power quality, reliability and safety driven projects completed through this business case are meant to mitigate code violations and observed system issues that will help maintain adequate levels of service in these areas for our customers. Operational flexibility can also drive the need to upgrade electric circuits, install switching equipment, and other infrastructure as needed.

East CDA Lake Reinforcement Program (July 2024-August 2025: $243,000, RY1: $694,000, RY2: $0)

The East Lake Coeur d'Alene System Reinforcement project provides additional capacity to a system which is critical to serving our customers and unlocking pathways to growth. The population and load demand growth on the east side of Lake Coeur D'Alene has caused Avista concerns that we may not be able to reliably support new customers at the far-reaching end of

two distribution feeders. Currently, two distribution feeders serve the east shore of Lake Coeur D'Alene, one originating from the Blue Creek Substation, and the other from the O'Gara Substation. The feeders have reached their capacity and cannot support additional growth in the area. A 13.2kV distribution system is constrained in serving long distances due to protection coordination issues distinguishing fault current from load current. The consequence customers will experience as a result of protection coordination is increased outages due to fault detection devices tripping under heavy load conditions. Equipment capacity issues have emerged, including overloaded feeder cable, voltage drop, voltage imbalance, reduced fault current, overloaded fusing and feeder protection, and cold load pickup. To prevent overloading equipment, Avista would need to disrupt service to customers to reduce loading or risk the equipment becoming damaged, which would lead to longer outage duration for customers.

Electric Relocation and Replacement Program (July 2024-August 2025: $9,968,000, RY1: $6,960,000, RY2: $7,020,000)

Placement of the Company's electric facilities is generally located in easements provided in public right of ways 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 requirement for their periodic 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 reliable 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.

Electric Storm (July 2024-August 2025: $2,836,000, RY1: $2,529,000, RY2: $2,529,000)

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. 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[6] that often occur with short notice and are beyond the control of

[6] 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.

the Company.[7]

Investments made to restore our electric system after 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 for 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.

Joint Use Projects (July 2024-August 2025: $4,530,000, RY1: $4,167,000, RY2: $3,667,000)

Joint Use is the regulated use of utility poles and other structures by third-party telecommunications companies in order for them to provide their services to the customers we have in common. Avista licenses 73 unique entities that are attached to over 150,000 poles across Avista's service territory and is required by federal, state, and local laws to allow non-discriminatory access to those assets. Even though this relationship is mandated by law and is compliance driven, Avista agrees that this practice provides a direct benefit to our customers who desire those services. Part of this requirement includes the obligation of Avista to replace infrastructure to taller stronger structures in order to accommodate or "make ready" those facilities for new attachments. This make ready work falls under capital expense and Avista is allowed to recover the actual costs from the requesting party. Avista is also allowed to recover a portion of the cost of replacing & maintaining shared infrastructure via a regulated yearly pole rental fee. This benefits our customers by offsetting the cost of upgrading infrastructure, improving reliability, and ensuring telecommunications companies can provide their services to our shared customers.

Meter Minor Blanket (July 2024-August 2025: $274,000, RY1: $250,000, RY2: $250,000)

The meter minor blanket is used to charge the labor associated with new electric meter installations in Washington and Idaho, due to the replacement of failed plant (meters) that can no longer gather or communicate accurate consumption data. Failed plant can occur for various reasons including but not limited to, age, weather/environmental damage, hardware failure, or radio communication failures. A meter must be installed as soon as possible to accurately capture customer energy consumption data. For this reason, Avista must maintain a continuous stock of each electric meter type, and budget the required labor to install these meters. The Meter Minor Blanket is driven by tariff requirements that mandate Avista's obligation to serve existing customer load within our franchised area.

Metro 115kV Substation (July 2024-August 2025: $3,990,000, RY1: $0, RY2: $9,315,000)

The Metro 115kV Substation serves the urban core of downtown Spokane and has done so reliably for almost 50 years. Now this substation has components that are approaching the end of life, equipment that no longer meets present safety standards, and a unique site that imposes

[7] 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.

severe operational constraints. The existing transformers are 40+ years old, are unique and do not have spares, and lack the option of the mobile transformer at Metro. These constraints threaten to create significant and extended customer outages in the event of major equipment failure for a significant portion of the downtown area. This project will address both the equipment and site issues in the most efficient and affordable way possible, based on the alternatives and risk analysis performed for this substation that are detailed further in the included Business Case. The result of this project will be a flexible and reliable station that fulfills needs in multiple operating divisions. The new substation will provide safer equipment, necessary redundancy, increased capacity, and a design that enables a longer station lifespan where individual pieces of equipment can be safely serviced and upgraded without prohibitive site/outage constraints.

Electric New Revenue - Growth (July 2024-August 2025: $78,190,000, RY1: $62,629,000, RY2: $66,746,000)

Avista defines these investments as "customer requests for new service connections, line extensions, transmission interconnections, or system reinforcements to serve a single large customer." In the past we have referred to new service connects as "growth," which refers to growth in the number of customers Avista services. It's important to note that these investments are beyond the control of the Company, and as such they do not reflect a plan or strategy on the part of Avista. Typical projects include installing electric to new housing or commercial developments, installing or replacing electric meters, or adding street or area lights at the request of a customer, city, or county agency. As would be expected, fluctuation in the number of new customer connections is largely dependent on local economic conditions both in the housing and business sectors. The Company has included Idaho electric offsetting revenues of $3,296,000 in Rate Year 1 in Adjustments 3.10 and offsetting revenues of $1,716,000 in Rate Year 2 in Adjustment 26.05.

Substation – Asset Condition (July 2024-August 2025: $26,781,000, RY1: $19,003,000, RY2: $6,895,000)

The Substation Asset Condition Business Case is comprised of three Projects. The first includes major equipment spares (power transformers, high voltage breakers, etc.) that are held in stock until they are transferred to a location. The second includes major substation projects that contain multiple equipment asset condition issues, compliance updates and capacity upgrades. A substation rebuild is planned when several equipment types are at end of life. These projects also include significant Distribution system, Transmission system and Communication system work. The third includes small substation projects (single transformer replacements, regulator upgrades, etc.) that have been deemed necessary due to asset conditions, leading to imminent equipment failure. Equipment failures for capital items that have been run to failure are funded through this project. In the end, substation equipment needs to be replaced when it fails to fulfill its intended function and may also need to be replaced when it has become obsolete. Obsolete equipment is due to parts or software not being available to maintain a piece of equipment.

Substation – Performance and Capacity (July 2024-August 2025: $15,594,000, RY1: $11,517,000, RY2: $14,660,000)

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 Avista with greater operational flexibility, ease of maintenance, and electric service reliability for our customers.

Substation Failed Plant (July 2024-August 2025: $1,000,000, RY1: $1,500,000, RY2: $1,500,000)

The Substation – Failed Plant Business Case is focused on restoring Avista's substation systems into serviceable condition after equipment fails due to animal 'contact', lightning, or other sudden equipment failures. These equipment failure events are random and cannot be planned. This business case funds a rapid response to unexpected damage, so customer outages are minimized. In the past, these replacements were completed under the Substation – Asset Condition Business Case, but better overview and tracking was desired by Electrical Engineering. Therefore, a decision was made to create a separate business case for more visibility into any substation equipment failures or possible equipment manufacturer/model issues that occurred. Future maintenance practices and programs will also be reviewed in light of these equipment failures. The importance of quickly replacing damaged equipment is vital to supplying reliable service to our customers. This affects electrical customers in Washington, Idaho, and Montana.

Distribution Wood Pole Management (July 2024-August 2025: $8,797,000, RY1: $11,573,000, RY2: $12,577,000)

Avista has approximately 240,000 wood poles[8] in its electric distribution system and a portion of these must be replaced each year due to asset condition. These are replacement of poles and attachments that have reached the end of their useful service life. Our wood poles are inspected on an approximate 20-year cycle, resulting in the inspection of approximately 12,000 poles each year.[9] Individual poles or attached equipment that don't meet our inspection requirements are replaced as part of capital follow-up work. Attached equipment includes overhead distribution transformers, cutouts, insulators and pins, wildlife guards, lightning arresters, cross arms, pole guying, and grounds. 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.

IV. INVESTMENTS IN THE COMPANY'S ELECTRIC TRANSMISSION SYSTEM

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

[8] 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.

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

A. The nation's electric utilities are facing unprecedented challenges from many forces that are 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 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. Specifically, the tightening requirements to meet increasingly restrictive transmission operations and planning standards that could potentially result in 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 annually 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 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 the development of the new energy services grid of the future. Emerging technologies are driving an increase in 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 on 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. This is due, in part, to increasing environmental regulation, 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 on our customers, who must ultimately pay for these requirements and investments, an exacerbating factor is our relatively low load growth due to declining use-per-customer, over time. This translates into nearly flat revenues, which means that new capital investments must be covered by higher customer 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.

As discussed by Mr. Christie, projects advanced for funding enter a formal review process referred to as the Engineering Roundtable. 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 timeframe. 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 (discussed by Mr. Christie) for final review and funding allocation. Representatives from eleven business units

participate in the Engineering Roundtable process.

Q. Would you please summarize the capital investments in electric transmission plant completed in 2024 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, are shown in Table No. 3, and described below. See also the detailed narrative for each electric transmission Business Case at Exhibit No. 10, Schedule 3, pages 171 – 272.

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

Electric Transmission Capital Projects (System) In $(000's)

Line #	Business Case Name	Investment Driver	July 2024 - August 2025	Rate Year 1 Sept 2025 - Aug 2026	Rate Year 2 Sept 2026 - Aug 2027
1	Ambient-Adjusted Transmission Line Ratings	Mandatory & Compliance	$ -	$ 1,200	$ -
2	Colstrip Transmission	Mandatory & Compliance	1,251	1,094	588
3	Electric Storm	Failed Plant & Operations	1,931	1,471	1,471
4	SCADA - SOO and BuCC	Asset Condition	960	1,011	1,148
5	Substation - West Plains System Reinforcement Project	Mandatory & Compliance	1,667	3,592	37,992
6	Transmission - Minor Rebuild	Asset Condition	5,494	4,000	4,000
7	Transmission Construction - Compliance	Mandatory & Compliance	382	500	500
8	Transmission Critical Crossing Reinforcement	Asset Condition	500	-	-
9	Transmission Major Rebuild - Asset Condition	Asset Condition	7,817	4,303	3,789
10	Transmission NERC Low-Risk Priority Lines Mitigation	Mandatory & Compliance	3,051	-	-
11	Westside 230/115kV Station Brownfield Rebuild Project	Mandatory & Compliance	2,978	-	-
Total Planned Electric Transmission Capital Projects			**$ 26,030**	**$ 17,171**	**$ 49,489**

Ambient-Adjusted Transmission Line Ratings (July 2024-August 2025: $0, RY1: $1,200,000, RY2: $0)

This business case provides for engineering and deployment of new applications and technology as required to address FERC Order 881 regulatory and business requirements. FERC Order 881, issued on December 16, 2021, requires transmission providers to implement and use ambient-adjusted ratings (AARs) for transmission lines used in providing transmission service by 2025. These AARs ensure that line ratings align closely with actual operating conditions. The goal is to utilize the transmission grid and lower costs more efficiently for consumers by improving the accuracy and transparency of line ratings. Transmission providers were required to submit compliance filings within 120 days of the effective date of the rule, and all requirements in this rule were to be implemented no more than three years from the compliance filing due date.

Colstrip Transmission Operation and Maintenance (July 2024-August 2025: $1,251,000, RY1: $1,094,000, RY2: $588,000)

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 microwave communication upgrades, replacement of original remedial action scheme, and ballistic substation protection.

Electric Storm (July 2024-August 2025: $1,931,000, RY1: $1,471,000, RY2: $1,471,000)
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 (July 2024-August 2025: $960,000, RY1: $1,011,000, RY2: $1,148,000)
The Company increasingly relies on comprehensive digital monitoring of critical power system infrastructure and communication interconnectivity that provides real-time visibility, status, 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.[10] The Company is required to continuously upgrade and enhance its SCADA systems to replace end-of-life technology and to meet expanding regulatory requirements and business needs. This particular project is replacing and upgrading existing SCADA communications for our electric and natural gas control centers. The control systems addressed under this program provide real-time visibility, situational awareness, remote operation, and control of these systems. 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 FERC orders, NERC standards, and federal pipeline safety requirements under PHMSA.

Substation – West Plains System Reinforcement Project (July 2024-August 2025: $1,667,000, RY1: $3,592,000, RY2: $37,992,000)
The West Plains area load has increased in the past few years and continues to grow at a rate outpacing Avista's average service territory load growth rate. Between 2018-2022, a 3 - 3 ½% growth rate has been observed and is forecasted to continue for the next 5-10 years. The growth has strained the transmission system to the extent that system reliability cannot be maintained while accommodating system outages as required under applicable operational performance requirements and NERC TPL-001-5. Government, tribal, public, and private entities have invested significant time and money in the area and are working to establish area backbone infrastructure. Avista is being asked to join these efforts by readying and fortifying the electric grid to accommodate future expanding economic development. The West Plains area requires a new 230kV source into the area to support the system and improve reliability and operability while offloading existing 230/115kV transformers in Spokane. The new 230kV source will improve contingency situation results and give increased ability to meet existing and future customer demand. The project will reduce the potential of customer

[10] 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.

outages under heavy summer loading scenarios. Without the project, customers may have power turned off under certain outage combination conditions. The scope of the project includes a new 230/115kV station near the West Plains at Garden Springs, new 230kV station to interconnect with the Bonneville Power Administration called Bluebird, and a new 12-mile 230kV transmission line. The new infrastructure is major investment in the transmission system which is needed to serve our customers.

Transmission Minor Rebuild (July 2024-August 2025: $5,494,000, RY1: $4,000,000, RY2: $4,000,000)

This Business Case covers the Transmission rebuild and reconductor work necessary to maintain compliance with the North American Electric Reliability Corporation (NERC) Reliability Standard FAC-501-WECC-1 as applied through Avista's Transmission Maintenance Inspection Program (TMIP). These standard mandates that specific Transmission lines be inspected annually and assessed for corrective actions to be implemented to remedy any system performance deficiencies. During routinely scheduled inspections, issues are discovered regarding the condition of assets, including items such as rotten poles, broken/split/rotten crossarms, broken conductor or ground/shield wire, and air switches that no longer operate safely or reliably. The TMIP applies the same inspection methodology to the entire Avista system with the understanding that only a portion of the mitigation work is recognized as Mandatory and Compliance. The remaining work undertaken within this Business Case is recognized as Customer Requested, Failed Plant and Asset Condition.

Transmission Construction – Compliance (July 2024-August 2025: $382,000, RY1: $500,000, RY2: $500,000)

This program covers the transmission rebuild and reconductor work identified by the Company as necessary to maintain compliance with the NERC reliability standards.[11] The applicable standard requires Avista to complete an annual planning assessment, to identify shortfalls and 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).

Transmission – Critical Crossing Reinforcement (July 2024-August 2025: $500,000, RY1: $0, RY2: $0)

The Transmission Critical Crossing Reinforcements Business Case identifies high failure consequence asset/structure locations; that, if subject to failure, would create life loss or injury conditions. Avista is dedicated to providing safe and reliable service to our customers, ensuring failures that could lead to these conditions are avoided; and that trust with Avista's

[11]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.

service territory community remains. These locations are specifically highway, railway, and waterway crossings.

Transmission Major Rebuild - Asset Condition (July 2024-August 2025: $7,817,000, RY1: $4,303,000, RY2: $3,789,000)

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, the rating 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 considered when planning and prioritizing the work to be completed. This business case results in direct offsets to O&M by eliminating unplanned outages. The annual system estimated value of these Direct Offsets is expected at $10,000 beginning in 2025. Idaho's share is included in the Company's revenue requirement as a reduction in expense within pro forma Adjustment 3.10.

Transmission – NERC Low-Risk Priority Lines Mitigation (July 2024-August 2025: $3,051,000, RY1: $0, RY2: $0)

Avista's compliance with this mandatory standard requires that we conduct LiDAR surveys[12] on all subject transmission circuits to determine any discrepancies between the design specifications and field measurements for conductor sag.[13] 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.

Westside 230/115kV Station Rebuild (July 2024-August 2025: $2,978,000, RY1: $0, RY2: $0)

A P1 is a single element failure where we lose one of the two 230/115 kV autotransformers. The existing Westside #1 230/115 kV transformer exceeds its applicable facility rating for the P1 event of the Westside #2 230/115 kV transformer. System performance analysis indicated an inability of the system to meet the performance requirements in Table 1 of NERC TPL-001-4 in scenarios representing 2017 Heavy Summer for P1 events. The problem prior to construction at the Westside Substation was that a P1 resulted in another element exceeding its rated capacity, which is not allowable under NERC TPL-001-4. We mitigated this issue by replacing the transformers with larger-capacity units. In order to facilitate these replacements, construction in the surrounding station also took place. The end result included necessary adjacent upgrades to connect the autotransformers, including increased

[12] 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.

[13] 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.

switching/bus-work capacity, and more reliable and functional protection schemes. While the site is now technically in compliance with the NERC TPL standard, the adjacent construction work to match switching and bus capabilities to the new transformers is still finishing up in 2024.

IV. INVESTMENTS IN THE COMPANY'S NATURAL GAS SYSTEM

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

A. In 2023, natural gas was the top source and provided the fuel for approximately 43% of the nation's electric generation fleet,[14] it heats more than half of America's homes, and provides the vital energy for cooling, heating, industrial processes, commerce, and industry. The Company has experienced steady growth in natural gas customers in the prior decade. In recent years, the annual number of new connects has remained steady with an average of 4,644 over the last five years, with a five-year average of 1,979 in the State of Idaho. The 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 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 nearly $59 million in 2024.

Q. Would you please summarize the capital investments in natural gas infrastructure completed in 2024 and planned for over the Two-Year Rate Plan?

A. Yes, the completed and planned investments related to natural gas

[14] https://www.eia.gov/energyexplained/electricity/electricity-in-the-us.php

infrastructure, presented on a system basis, and grouped by investment driver, are shown in Table No. 4, and described below. See also the detailed narrative for each electric transmission Business Case at Exhibit No. 10, Schedule 3, pages 273 - 415.

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

Natural Gas Distribution Capital Projects (System) In $(000's)					
Line #	Business Case Name	Investment Driver	July 2024 - August 2025	Rate Year 1 Sept 2025 - Aug 2026	Rate Year 2 Sept 2026 - Aug 2027
1	Gas Above Grade Pipe Remediation Program	Mandatory & Compliance	$ 738	$ 657	$ 643
2	Gas Cathodic Protection Program	Mandatory & Compliance	757	1,002	600
3	Gas Facility Replacement Program (GFRP) Aldyl A Pipe Replacement	Mandatory & Compliance	30,530	28,265	29,682
4	Gas Isolated Steel Replacement Program	Mandatory & Compliance	2,440	2,000	2,000
5	Gas Non-Revenue Program	Failed Plant & Operations	11,419	10,850	11,437
6	Gas PMC Program	Mandatory & Compliance	4,205	3,810	3,670
7	Gas Regulator Station Replacement Program	Asset Condition	1,094	1,051	1,050
8	Gas Reinforcement Program	Performance & Capacity	5,020	1,115	1,025
9	Gas Replacement Street and Highway Program	Mandatory & Compliance	5,427	5,665	5,757
10	Gas Telemetry Program	Performance & Capacity	98	-	-
11	Gas Transient Voltage Mitigation Program	Mandatory & Compliance	1,165	154	313
12	Jackson Prairie Natural Gas Storage Facility	Performance & Capacity	2,256	2,386	2,376
13	New Revenue - Growth	Customer Requested	30,723	25,016	25,333
Total Planned Natural Gas Distribution Capital Projects			**$ 95,873**	**$ 81,971**	**$ 83,886**

Gas Above Grade Pipe Remediation Program (July 2024-August 2025: $738,000, RY1: $657,000, RY2: $643,000)

Within Avista's natural gas distribution system there are sections of gas pipelines located above grade at locations such as bridges, small ditches, irrigation canals, and other crossings where it is difficult to install buried pipelines. These above grade facilities vary in age, condition, design, compliance, and overall risk. The Company's investment in the Gas Above Grade Remediation Program provides capital funding for remediating the highest risk locations that cannot be sufficiently mitigated or resolved through O&M maintenance activities (e.g. pipe support replacement, coating/wrap repairs, etc.). This business case results in direct offsets to O&M due to the reduction in maintenance and patrols required. The annual natural gas system estimated value of these Direct Offsets is expected at $7,983 in 2024, $7,983 in 2025, $9,677 in 2026 and $11,371 in 2027. Idaho's share is prorated over the Two-Year Rate Plan and included in the Company's revenue requirement as a reduction in expense within pro forma Adjustments 3.10 (Rate Year 1) and 26.05 (Rate Year 2).

Gas Cathodic Protection Program (July 2024-August 2025: $757,000, RY1: $1,002,000, RY2: $600,000)

Avista uses cathodic protection anode systems to reduce corrosion on buried steel gas piping. There are approximately 250 anode systems in use throughout our service territory. The anodes used in these systems corrode over time and need to be replaced every 20 – 30 years. Additionally, as pipe coating degrades over time, additional anode systems must be added.

The investments made under this program include installing new and replacement anodes and electronic equipment used to remotely control and monitor the anode systems. Providing cathodic protection for our steel natural gas piping protects our community from the potential consequence of leaks on our system and helps ensure they receive the full lifecycle value of the investments made in our natural gas. 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. Since 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 (July 2024-August 2025: $30,530,000, RY1: $28,265,000, RY2: $29,682,000)

The Aldyl A Pipe Replacement Program[15] 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 was slated to be completed by 2032. However, this timeframe has been extended in Idaho to 2037 due to decreased risk in our most recent analysis. This is due in part to the reduction of slow crack growth failures in Idaho coupled with the number of failures in Washington remaining steady, despite nearly half of the Aldyl-A pipe having been replaced since the program's inception. Extending Avista's Aldyl-A replacement work in Idaho to 2037 will allow us the opportunity to balance affordability and overall impact to our customers with the more recent risk analysis. The work under this business case results in direct O&M offsets due to the reduction in necessary leak surveys. The annual natural gas system estimated value of these Direct Offsets is expected at $1,465 in 2024, $1,604 in 2025, $4,129 in 2026 and $7,495 in 2027. Idaho's share is prorated over the Two-Year Rate Plan and included in the Company's revenue requirement as a reduction in expense within pro forma Adjustments 3.10 (Rate Year 1) and 26.05 (Rate Year 2).

Gas Isolated Steel Replacement Program (July 2024-August 2025: $2,440,000, RY1: $2,000,000, RY2: $2,000,000)

Related to our cathodic protection systems, 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 or by fittings that are insulated and prohibit the transmission of cathodic protection. Because these sections are not connected to the cathodic protection system, they are not afforded the extra level of protection beyond

[15] 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. For a detailed description of this program, please see Avista's Priority Aldyl A Protocol Report, provided as Exhibit No. 10, Schedule 1.

their protective coating. Identifying and replacing isolated steel sections of pipe is required by federal and state regulations.[16]

Gas Non-Revenue Program (July 2024-August 2025: $11,419,000, RY1: $10,850,000, RY2: $11,437,000)

The work in this annual program is mostly reactionary, unscheduled work and is therefore difficult to predict aside from using historical trends. The following situations are typical triggers for such work: shallow facilities found by excavation (the excavation may or may not be related to gas construction), relocation of facilities as requested by customers (except for road and highway relocations), leak repairs on mains or services, remediation of cathodic protection (CP) issues, farm tap elimination, and overbuilds. Gas Engineering is responsible for projects under the Gas Non-Revenue program that require substantial design efforts such as farm tap retirements, highway, or river crossings, and replacing steel pipelines with plastic pipe, but it's the local districts that manage the work.

Gas PMC Program (July 2024-August 2025: $4,205,000, RY1: $3,810,000, RY2: $3,670,000)

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[17] to determine the number of meter 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 for that meter family may be reduced in the future. These analytics help control costs and remove meters quickly when not performing well.

Gas Regulator Station Replacement Program (July 2024-August 2025: $1,094,000, RY1: $1,051,000, RY2: $1,050,000)

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. The stations set to be replaced have reached the end of their useful service life, failed 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, and ensure the reliable operation of metering and regulating equipment. This business case results in direct offsets to O&M due to the reduction time needed for station maintenance. The annual natural gas system estimated value of these Direct Offsets is expected at $3,400 in 2024, $5,300 in 2025, $7,200 in 2026 and $9,300 in 2027. Idaho's share is prorated over the Two-Year Rate Plan and included in the Company's revenue requirement as a reduction in expense within pro forma Adjustments 3.10 (Rate Year 1) and 26.05 (Rate Year 2).

Gas Reinforcement Program (July 2024-August 2025: $5,020,000, RY1: $1,115,000,

[16] Docket PG-100049.

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

RY2: $1,025,000)

This annual program will identify and provide for necessary capacity reinforcements to the existing natural gas distribution system in Washington, Idaho, and Oregon. Avista has an obligation to serve existing gas customers by providing adequate capacity on design day weather conditions. The design day is defined as the 30-year coldest average daily temperature of a weather region, with 99% probability of happening. Periodic reinforcement of the system is required to reliably serve customers due to increased demand at existing service locations and new customers being added to the system. Execution of this program on an annual basis will ensure the continuation of reliable gas service that is of adequate pressure and capacity. This business case results in direct offsets to O&M due to the reduction in activation of the Cold Weather Action Plan. The annual natural gas system estimated value of these Direct Offsets is expected at $22,800 beginning in 2024. Idaho's share of is included in the Company's revenue requirement as a reduction in expense within pro forma Adjustment 3.10 (Rate Year 1).

Gas Replacement Street and Highway Program (July 2024-August 2025: $5,427,000, RY1: $5,665,000, RY2: $5,757,000)

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. In some instances, the Company will have a substantial lead time to plan, budget, design, and permit for the move, but in most cases, we're notified of the need to move during the year the project must be completed. Due to the unpredictability of this work, historical averages are used to determine the necessary budget.

Gas Telemetry Program (July 2024-August 2025: $98,000, RY1: $0, RY2: $0)

This investment provides funding for additions, improvements, and replacements to Avista's existing Gas Telemetry system. Telemetry facilities include flow computers, electronic volume correctors, and electronic pressure monitors. The Gas Telemetry System provides safety related pressure monitoring and alarms at gate stations, regulator stations, pipelines, odorizers, and transportation customers. This data is critical for gas procurement, billing, engineering analysis, system operations and compliance with Federal Codes.

Gas Transient Voltage Mitigation Program (July 2024-August 2025: $1,165,000, RY1: $154,000, RY2: $313,000)

Avista has experienced safety issues including fires at Gas Regulator Stations due to transient voltage spikes from faults on the adjacent electric transmission system. The purpose of this program will be to identify high pressure gas piping systems that are at risk of these conditions, identify systems that have high steady state voltage, and to then install mitigation measures to reduce both these scenarios on the pipelines. These efforts will protect the pipeline and equipment from being damaged and reduce the voltages exposure to below compliance limits keeping our employees safe. Common approaches to this include the installation of gradient mats, solid state decouplers (SSD), and copper counterpoise conductor. This business case results in direct offsets to O&M due to the reduction in labor for safety procedures and labor and materials for the response to fault damage events needing repairs. The annual natural gas system estimated value of these Direct Offsets is expected at $8,500 in 2024, $8,700 in 2025, $9,000 in 2026 and $9,300 in 2027. Idaho's share is prorated over the Two-Year Rate Plan

and included in the Company's revenue requirement as a reduction in expense within pro forma Adjustments 3.10 (Rate Year 1) and 26.05 (Rate Year 2).

Jackson Prairie Natural Gas Storage Facility (July 2024-August 2025: $2,256,000, RY1: $2,386,000, RY2: $2,376,000)

Avista is 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. 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 in the facility. Company witness Mr. Kinney provides further information regarding Avista's ownership in Jackson Prairie.

Gas New Revenue - Growth (July 2024-August 2025: $30,723,000, RY1: $25,016,000, RY2: $25,333,000)

Avista defines these investments as "customer requests for new service connections, line extensions, transmission interconnections, or system reinforcements to serve a single large customer." In the past we have referred to new service connects as "growth," which refers to growth in the number of customers Avista services. It's important to note that these investments are beyond the control of the Company, and as such they do not reflect a plan or strategy on the part of Avista. Typical projects include installing gas facilities to new housing or commercial developments or installing or replacing gas meters at the request of a customer, city, or county agency. As would be expected, fluctuation in the number of new customer connections is largely dependent on local economic conditions both in the housing and business sectors. The Company has included Idaho natural gas offsetting revenues of $1,384,000 in Rate Year 1 in Adjustment 3.10 and offsetting revenues of $732,000 in Rate Year 2 in Adjustment 26.05.

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 utilities like Avista. Avista's operating facilities encompass office space, critical information technology systems, generation facilities, and are the hub for field operations. 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 serve customers effectively and efficiently. 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 a myriad of other support systems (including supporting all the Company's workers who are connecting remotely into the Company's systems).

Q. Would you please summarize the capital investments in general plant, fleet and facilities resources completed in 2024 and planned 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, are shown in Table No. 5, and described below. See also the detailed narrative for each electric transmission Business Case at Exhibit No. 10, Schedule 3, pages 416 - 535.

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

General Plant & Fleet Investments Capital Projects (System) In $(000's)					
Line #	Business Case Name	Investment Driver	July 2024 - August 2025	Rate Year 1 Sept 2025 - Aug 2026	Rate Year 2 Sept 2026 - Aug 2027
1	Capital Equipment Program	Asset Condition	$ 2,486	$ 2,084	$ 2,090
2	Central 24 HR Operations Facility	Performance & Capacity	-	-	3,339
3	Fleet Services Capital Plan	Asset Condition	9,259	5,257	5,695
4	Palouse Service Center	Asset Condition	750	750	-
5	Right-of-Way Use Permits	Mandatory & Compliance	337	243	243
6	Sandpoint Service Center	Performance & Capacity	1,250	-	-
7	Structures and Improvements/Furniture	Asset Condition	7,197	5,494	5,670
8	Telematics 2025	Asset Condition	495	-	-
Total Planned General Plant & Fleet Investment Capital Projects			**$ 21,774**	**$ 13,827**	**$ 17,037**

Capital Equipment Program (July 2024-August 2025: $2,486,000, RY1: $2,084,000, RY2: $2,090,000)

This program provides funding for the tools and equipment needed for Avista's employees to

perform new construction, make repairs, complete essential maintenance, and ensure system integrity. This equipment, which needs to be adequate and fully available for both planned work and emergency response, has to meet the needs of our electric, natural gas, communications, fleet, facilities and generation crews, and infrastructure.

Central 24 HR Operations Facility (July 2024-August 2025: $0, RY1: $0, RY2: $3,339,000)

For decades, several of Avista's most critical operations have been located on the 4th floor of Avista's General Office Building on the Mission Campus. This includes departments such as Transmission System Operations, Supervisory Control and Data Acquisition, Distribution Operations, Gas Control, Network Operations, Security Operations, and 24-Hour Call Center Reps. Over time, as each of these departments experiences new growth due to ever-changing utility requirements and/or initiatives, capacity has been reached in their available square footage. Due to our current space constraints, we have handicapped our ability to manage storm events, narrowly meeting government regulations, and created an inaccessible and ergonomically unfriendly working environment.

Likewise, our Generation Control Center, which monitors the 5 dams along the Spokane River, is in a leased space at the Seehorn Building in downtown Spokane. The urban setting surrounding the control center has led to a heightened risk of criminality and unauthorized access for our Seehorn Building operations and employees. Located on the second floor of the commercial retail building, the control center only has one layer of defense in the form of a controlled access man door. Moving the Generation Control Center to a safe and secure Avista-owned space alongside the other critical operations group is imperative. The recommended solution at this time is to build a new greenfield building. This will allow for a purpose-built control center facility, with ample space for current needs and future growth, upgrading our technology to meet industry standards, and reducing security risks.

Fleet Services Capital Plan (July 2024-August 2025: $9,259,000, RY1: $5,257,000, RY2: $5,695,000)

Fleet vehicles and equipment simply do not age well, as they are subject to a duty cycle that most vehicle owners would not experience in 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, even under prudent and proper use. Over time this leads to substantial maintenance and repair costs and reduced reliability/availability. 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 accelerated rate of repair expenses. The investments made under this plan represent the annual investments needed to 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[18] to identify when to replace equipment in order to achieve the lowest total cost of ownership for our customers.

Palouse Service Center (July 2024-August 2025: $750,000, RY1: $750,000, RY2: $0)

[18] 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/

The Pullman building and the site have many critical systems that need replacement, including electrical, HVAC, plumbing and roof systems. There are many worn assets in dire need of replacement, as many of the capital projects have been put on hold until the future state of the site is known. Due to budget constraints we are moving forward with targeted transfers to plant for 2024 and 2025 to maintain the existing assets by addressing asset condition concerns and operational needs. As funds become available in the future there will be a design completed for the building of a New Pullman Service Center to transfer to plant in 2029-2030.

Right-of-Way Use Permits (July 2024-August 2025: $337,000, RY1: $243,000, RY2: $243,000)

Avista owns and maintains electric transmission, distribution, and natural gas facilities which cross public lands managed by a variety of state, federal and local agencies, as well as entities who own extensive tracts, such as railroads. Traditionally, we have secured long-term right-of-way permits for these facilities, but have been required to renew them through an annual billing process. The cost of renewing these permits continues to increase each year, ranging from 3% to 10% annually, depending on the agency/entity, thereby increasing annual O&M expenses to the company and our customers. This business case proposal is to secure long-term agreements with lump-sum payments to reduce overall labor expenses related to tracking, researching, and processing these annual permits. In some cases, we have been able to negotiate a lower annualized cost over the term of the permit by paying a lump sum up front. In either case, we reduce costs to the company and our customers. Making long-term lump sum payments allows us to capitalize these costs, as the permit is a long-term asset.

Sandpoint Service Center (July 2024-August 2025: $1,250,000, RY1: $0, RY2: $0)

The existing Sandpoint Service Center facility was acquired in 1995, but we believe the original construction year to be 1957. There are many improvements needed at the current facilities and the existing storage yard is becoming too small for ever-growing inventory, which has almost tripled in the last 10 years. There is unique voltage in the Sandpoint area, different than the rest of the company, so the local storekeeper must keep more material than most yards of a similar size. The property is too small for our needs, and we are unable to purchase any additional land adjacent to the existing property. While ultimately, we would like to see the Sandpoint Service Center, including the office, line dock, pole yard, and warehouse moved to a new parcel North of Sandpoint, this business case provides the funding to make more immediate improvements to the current location. Those improvements include new asphalt, storage areas and repairing building systems such as roofs, electrical, HVAC, and another property to the North that will provide additional storage.

Structures and Improvements/Furniture (July 2024-August 2025: $7,197,000, RY1: $5,494,000, RY2: $5,670,000)

These investments fund capital maintenance, site improvements, security, and other needs related to the Company's 72 building facilities that provide office, operations, storage space and other business functions. These capital maintenance projects can include roofing, siding, asphalt, electrical and plumbing work, remodeling, furniture replacements and new furniture for growth in operations. Approximately half the investments fund asset replacements based on end-of-life conditions 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

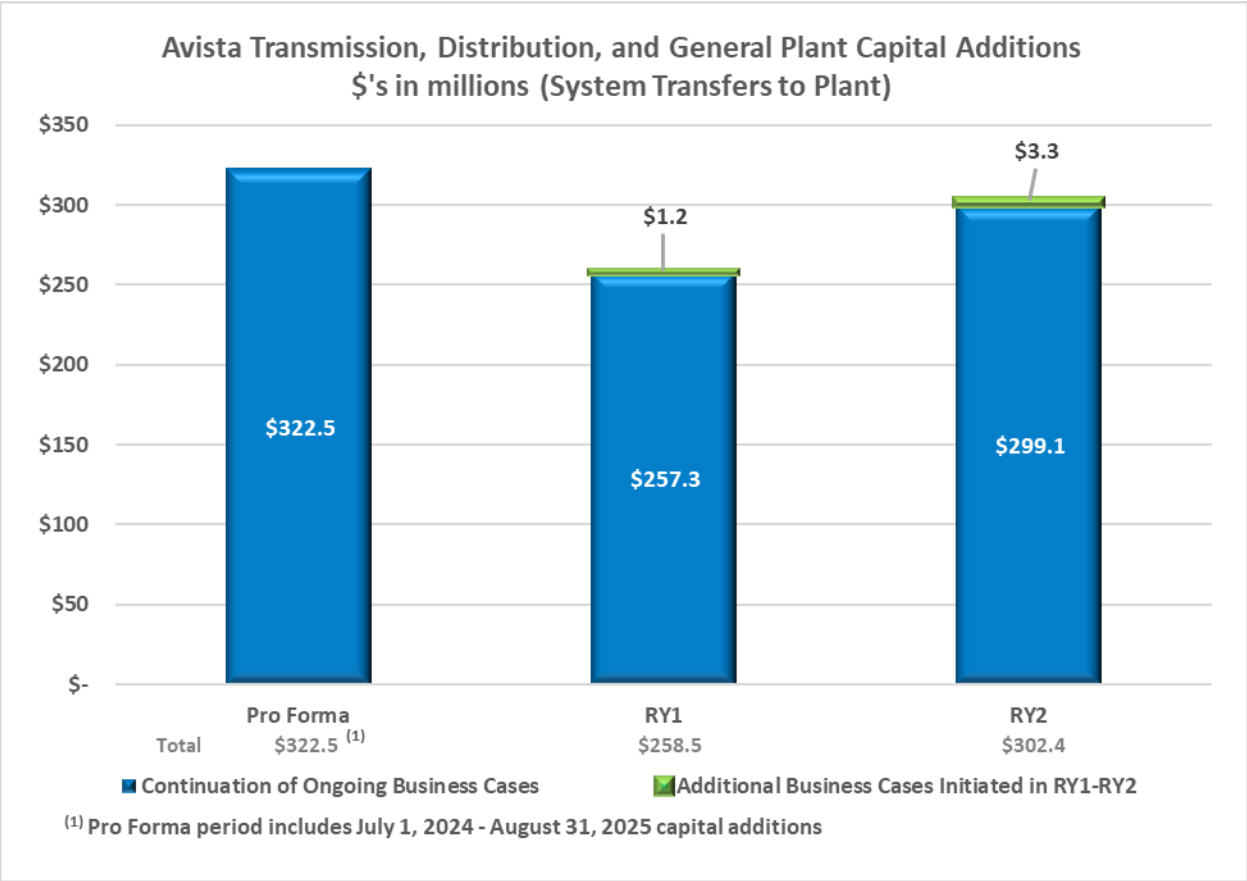
responsibility for each facility, and the remaining funds go to emergent needs that could not be anticipated in the planning process. This business case results in direct O&M offsets due to increased energy savings. The annual system estimated value of these Direct Offsets is expected at $11,000 in 2024, $11,330 in 2025, $11,670 in 2026 and $12,020 in 2027. Idaho's share is prorated over the Two-Year Rate Plan and included in the Company's revenue requirement as a reduction in Idaho electric and natural gas expense within pro forma Adjustments 3.10 (Rate Year 1) and 26.05 (Rate Year 2).

Telematics 2025 (July 2024-August 2025: $495,000, RY1: $0, RY2: $0)
Advances in technology, customer requirements and safety are driving the need to invest capital in our connected vehicle systems. Implementing the next generation of telematics in vehicles driving the roads in our communities on behalf of Avista have the opportunity to satisfy our customers, reduce our liability exposure and improve operational safety.

Q. Referring to the individual Table Nos. 1 through 5 above, what is the overall level of system capital additions for which you sponsor, and how does this capital investment compare between the Pro Forma and RY1 and RY2 periods?

A. Illustration No. 1 below shows overall system capital additions (transfers to plant) for transmission, distribution, and general plant for the Pro Forma, RY1 and RY2 periods, of $322.5 million, $258.5 million and $302.4 million, respectively. As also noted in the illustration, the "Pro Forma" period represents 14 months (or July 1, 2024 – August 31, 2025). Finally, this illustration distinguishes between what are ongoing projects or programs from the Pro Forma period ending August 2025, versus incremental projects that are estimated to transfer-to-plant from September 2025 through August 2027, representing $1.2 million in RY1 and $3.3 million in RY2.

Illustration No. 1– Transmission, Distribution and General Plant Investment (System Transfers to Plant)



Notably, as can be seen from this illustration, most of the capital investment (99.5% in RY1 and 98.9% in RY2) relates to ongoing, multi-year efforts that continue over time, at various funding levels. The rationale and justification for these ongoing projects or programs, however, does not change over time, only the funding levels. The additional Business Case of $1.2 million (system) in RY1 relates to the Ambient-Adjusted Transmission Line Ratings, whereas the additional Business Case of $3.3 million in RY2 relates to the Central 24 HR Operational Facility, that are both discussed earlier in my testimony.

Q. Does this conclude your direct testimony?

A. Yes.

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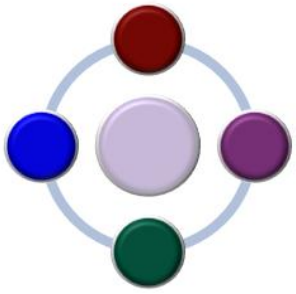
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)))))))	CASE NO. AVU-E-25-01 CASE NO. AVU-G-25-01 EXHIBIT NO. 10 OF JOSHUA D. DILUCIANO

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)



Avista Utilities Asset Management

Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System

May 2013

www.avistautilities.com

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 1 of 35

Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System

Executive Summary

Avista Utilities (Avista) protocol for managing select Aldyl A pipe proposes a twenty-year program to systematically remove and replace select portions of the DuPont Aldyl A medium density polyethylene pipe in its natural gas distribution system in the States of Washington, Oregon and Idaho. None of the subject pipe is "high pressure main pipe," but rather, consists of distribution mains at maximum operating pressures of 60 psi and pipe diameters ranging from 1¼ to 4 inches. Further, Avista notes that while there have been concerns with the integrity of steel pipe in other parts of the country in recent years, the steel pipe in its system, including steel service risers, is being managed to protect its long-term reliability and performance and is outside the scope of this program.

In recent years, Avista experienced two incidents on its natural gas system that prompted the Washington Utilities and Transportation Commission and the Company to better understand the potential long-term reliability of Aldyl A pipe. Results of these investigations, which were aided by new tools developed for Avista's Distribution Integrity Management Plan, corroborated reports for similar Aldyl A piping around the country as supporting the development of a protocol for the management of this gas facility. The following report highlights the history of DuPont's Aldyl A natural gas pipe and summarizes DuPont and Federal Agency communications that are relevant to this proposed program. The report documents the Aldyl A pipe in Avista's natural gas system and describes the analysis of the types of failures observed in this pipe, and the evaluation of its expected long-term integrity. Finally, the report describes the results of Avista's work to establish the framework for the proposed protocol for the management of Aldyl A pipe in its natural gas system.

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 2 of 35

Table of Contents

I. **History of DuPont Aldyl A Piping Systems 5**

DuPont Introduces Natural Gas Polyethylene Pipe – 1965 5
The Phenomenon of "Low Ductile Inner Wall" 5
DuPont Communicates Potential Issues to Aldyl A Customers 5
1982 Letter 5
1986 Letter 6
DuPont Substantially Improves Aldyl A Pipe 6
Common Classifications of Aldyl A Pipe 7

II. **Federal Bulletins on Brittle-Like Cracking in Plastic Pipe 8**

National Transportation Safety Board 8
Objectives of the Board's Investigation 8
Phenomenon of Premature Brittle-Like Cracking 9
Board Findings on the Three Identified Safety Issues 9
Pipeline and Hazardous Materials Safety Administration 12
1999 Bulletins 12
2002 Bulletin 12
2007 Bulletin 12

III. **2009 Distribution Integrity Management Program 12**

Objectives and Approach 12

IV. **2011 Call to Action – Transportation Secretary LaHood 13**

V. **Avista's Experience with DuPont Aldyl A Piping Systems 14**

Spokane and Odessa Incidents 14
Expert-Recommended Protocol for Managing Aldyl A Pipe in Relation to Reported Soil Conditions 15
Evaluation of Leak Survey Records 16
Pipe Replacement Projects in 2011 16
Avista Distribution Integrity Management Program 16

VI. **Analyzing Modes of Failure in Avista's Aldyl A Pipe 17**

Towers and Caps 18
Rock Contact and Squeeze-Off 19
Services Tapped from Steel Mains 20
Avista's Aldyl A Services 21
Understanding the Significance of Leaks in Aldyl A Pipe 21
Frequency and Potential Consequence 21
The Complication of Brittle Cracking in Aldyl A Pipe 22

VII. **Reliability Modeling of Avista's Aldyl A Piping 22**

Availability Workbench Software 22
Reliability Forecasting 23
Forecasting the Reliability of Aldyl A Piping 23
Forecasting Results 24
Forecast Piping Failures 24
Dependability of Forecasting Future Failures 24

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 3 of 35

Understanding the Significance of Cumulative Failure Curves 25
Prudent Failure Management 25
Priority Aldyl A Piping 26
VIII. **Formulation of a Management Program for Priority Aldyl A Pipe 26**
Priority Aldyl A Piping in Avista's System 27
IX. **Other Aldyl A Pipe Replacement Programs 28**
Aldyl A Pipe in the Pacific Northwest 28
Established and Emerging Programs for Aldyl A Pipe Replacement 28
Developments of Interest 29
X. **Designing Avista's Replacement Protocol for its Priority Aldyl A Pipe 30**
Systematic Replacement Program 30
Time Horizon 30
Prudent Management of Potential Risk 30
Prioritizing the Work 31
Twenty-Year Proposal 31
Initial Optimization 32
Responsive Replacement Program 33
Dr. Palermo's Assessment of the Proposed Protocol for Managing 33
Avista's Priority Aldyl A Piping 33
XI. **Application of Avista's Washington State Study Results to Aldyl A Pipe in the States of Oregon and Idaho 34**
XII. **Resource Requirements and Expected Cost 34**
Staffing 34
Capital Costs 35

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 4 of 35

History of DuPont Aldyl A Piping Systems

Modern polyethylene pipe products are corrosion-free, lightweight, cost-effective, highly-reliable, and can be installed quickly and efficiently. For these reasons, it has for decades been the 'standard for the industry' and is the predominant choice used in natural gas distribution systems. As with any revolutionary product line, polyethylene piping systems have undergone continuous and rigorous testing and product improvement. Such is the case with DuPont's Aldyl A piping systems, as very briefly summarized below.

DuPont Introduces Natural Gas Polyethylene Pipe – 1965

Along with other manufacturers, DuPont began to use polyethylene resin to produce plastic piping for a variety of purposes. The resin was produced from ethylene molecules combined together in repeating patterns to form larger molecules called 'polymers', hence the name 'polyethylene.' DuPont's product designed specifically for use in the natural gas industry was marketed under the name "Aldyl A." The initial resin used in production of Aldyl A pipe, Alathon 5040, was manufactured from 1965 to 1970. DuPont changed the resin in 1970 to improve Aldyl A's resistance to rupture during pressure testing. This improved formulation, known as Alathon 5043, was the primary resin used in DuPont's Aldyl A pipe from 1970 until 1984.

The Phenomenon of "Low Ductile Inner Wall"

Shortly after changing its polyethylene resin in 1970, DuPont detected a manufacturing issue highlighted during laboratory testing of Aldyl A pipe. DuPont learned that its manufacturing process was resulting in some of the pipe having a property described as "low ductile inner wall." "Ductility" is the ability of a material to withstand forces that alter its shape without it losing strength or breaking. A 'highly-ductile' material can be bent, flexed, pressed or stretched without cracking or losing strength because, unlike brittle materials, it can redistribute the forces of stress concentration. Low Ductile Inner Wall, or as it often appears "LDIW," results when the inner surface of the Aldyl A pipe becomes brittle, promoting the formation of cracks and premature failure. In early 1972, DuPont changed its manufacturing process to eliminate this phenomenon, but estimated that 30 – 40% of the pipe it produced in 1970, 1971 and early 1972 was affected, primarily in pipe diameters from 1¼ inches to 4 inches.

DuPont Communicates Potential Issues to Aldyl A Customers

1982 Letter

In 1982, DuPont sent a letter to its natural gas customers, noting that two of its gas utility customers had reported a low frequency of leaks in Aldyl A pipe manufactured prior to 1973. These leaks were reported as "slits" occurring where the pipe was in "point contact with rocks." DuPont noted these two utilities had increased the frequency of leak surveys where rock may have been part of the backfill around the pipe, and encouraged other Aldyl A customers to consider the same. This letter was the genesis of what would become a continuing focus on the pipe vintage known as "pre-1973 Aldyl A."

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 5 of 35

1986 Letter

DuPont's second letter to its Aldyl A pipe customers was sent in 1986, focusing again on pre-1973 Aldyl A pipe. The letter focused on results of newly-developed (elevated temperature) testing methods that allowed DuPont to more-accurately estimate the longevity of this vintage pipe, in diameters of 1¼ inches and larger. Test results showed that 'Aldyl A pipe manufactured prior to 1973 had certain limitations that were not previously-shown by then-available, state-of-the-art testing methods.' The limitations were described as a reduction in pipe service life caused by: 1) "rock impingement" or pressure from rock points directly on the pipe (as mentioned in their 1982 letter), and 2) the use of squeeze-off practices. The term "squeeze-off" refers to the current and long-standing construction practice of mechanically pressing in polyethylene pipe walls to temporarily stop the flow of gas during work on a line that is in service. DuPont further noted that average ground temperature surrounding the pipe, in the ranges of 60 to 70 degrees (F), had a major bearing on its ultimate expected service life. Finally, DuPont recommended that operators should reinforce the pipe, using clamps that surround the pipe at squeeze points, in order to extend the life of its Pre-1973 Aldyl A.

DuPont Substantially Improves Aldyl A Pipe

DuPont made a significant change to its Aldyl A resin formulation in 1984. The improved resin, known as Alathon 5046-C, was marketed as "Improved Aldyl A", and significantly improved the performance of Aldyl A pipe in its resistance to 'Slow Crack Growth' and overall long-term integrity. Slow Crack Growth, or as it's often abbreviated, SCG, describes the progression of a crack that begins with 'crack initiation' or the formation of a crack in the inner wall of the pipe. The crack then progresses through the pipe wall, usually over period of many years, until it finally breaks through the outer surface of the pipe, resulting in failure.

Again, in 1988, DuPont announced another advance in its Aldyl A pipe resin with the introduction of Alathon 5046-U. This change in resin formulation increased the resistance of the pipe to slow crack growth by another order of magnitude. In addition, because of the high 'molecular efficiency' of this new resin, its density was also reduced, which allowed for much greater ductility in the pipe. This product, the last of the DuPont Aldyl A materials that Avista would install, was also marketed as Improved Aldyl A. A summary of DuPont Aldyl A pipe produced between 1966 and 1992 is presented below in Table 1. Information includes the year of manufacture, resin formulation, relative resistance to slow crack growth (stress rupture testing at 80° C / 120 psig for accelerated life testing), and summary notes.

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 6 of 35

Table 1. DuPont Aldyl A Pipe 1965 - 1992

Years of Manufacture	Resin	Rupture Resistance*	Notes
1965 - 1970	Alathon 5040		Initial Product Marketed as "Aldyl A"
1970 - 1972	Alathon 5043	10 hours	Resin Improvement and Low Ductile Inner Wall
1970 - 1984	Alathon 5043	100 hours	Resin Improvement
1984 - 1988	Alathon 5046-C	1000 hours	Resin Improvement-- Sold as "Improved Aldyl A"
1988 - 1992	Alathon 5046-U	10,000 hours	Resin Improvement --"Improved Aldyl A"

*Illustrates the order of magnitude difference found from accelerated life testing of resins

Common Classifications of Aldyl A Pipe

Based on the characteristics of the different vintages of Aldyl A pipe, there would emerge over time, (from DuPont's 1982 letter going forward), three age-groupings recognized by the manufacturer, natural gas industry, and regulators as relevant in the reliability management of this pipe.

Pre-1973 Aldyl A – Pipe manufactured through 1972, from the first two resin formulations, and including pipe having low ductile inner wall.

Pre-1984 Aldyl A – Aldyl A pipe manufactured from Alathon 5043 resin, but only that pipe manufactured after 1972 and through 1983.

1984 and Later Aldyl A – Pipe manufactured from the improved Alathon 5046-C and 5046-U resins.

Aldyl A Service Pipe - Small-diameter (less than 1¼ inches) Aldyl A service piping is often treated or managed differently than larger-diameter Aldyl A pipe of the same vintage. This is because the small-diameter pipe has been assessed by industry experts as being more resistant to brittle-like cracking than larger-diameter pipe due to its greater flexibility. Further, small-diameter Aldyl A pipe has been confirmed as being free of the Low Ductile Inner Wall properties present in late 1970 through early 1972 vintage piping.

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 7 of 35

Federal Bulletins on Brittle-Like Cracking in Plastic Pipe

National Transportation Safety Board

In April 1998, twelve years after DuPont's second letter to customers, the National Transportation Safety Board (Board) published a comprehensive safety bulletin describing their investigation of natural gas pipeline accidents involving polyethylene pipe that had cracked in a "brittle-like" manner. The bulletin focused primarily on accidents related to an early plastic pipe manufactured by Century Utility Products (Century), produced from Union Carbide resin. In its review, findings, and in its Safety Recommendations, however, the Board concluded that in addition to the Century pipe, much of the polyethylene pipe produced for gas service from the 1960s through the early 1980s may be susceptible to brittle cracking and premature failure, further noting that vulnerability of this material to premature failure could represent a serious potential hazard to public safety.

The Board's bulletin represented a seminal work on the vulnerability of early plastic pipe to brittle-like cracking because it analyzed and integrated – for the first time – reports from the technical literature, manufacturers' communications, industry expert opinions, the experience of pipeline operators and regulators' accident reports. Because the bulletin provided a clear understanding of the drivers of failure in older polyethylene pipe, we have included a fairly detailed synopsis in this report.

Objectives of the Board's Investigation

Following the Board's investigation of over a dozen serious incidents, it undertook an effort to evaluate whether the existing pipeline accident data was sufficient for assessing the long-term performance of plastic piping. The office of Research and Special Programs Administration of the National Transportation Safety Board compiled the relevant accident data, but found it to be insufficient for this purpose. Lacking adequate data for the larger assessment, the Board instead focused on estimating the likely frequency of brittle-like cracking, focusing on published technical literature, industry expertise, and work with several gas system operators. From this review, the Board launched a special investigation with the objectives to address three safety issues related to polyethylene gas service pipe:

1. Vulnerability of plastic piping to brittle-like cracking
2. Adequacy of available guidance to pipeline operators regarding installation and protection of plastic pipe tapped to steel mains
3. Performance monitoring as a possible way to detect unacceptable performance in piping systems

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 8 of 35

Phenomenon of Premature Brittle-Like Cracking

The Board's survey suggested that early plastic piping may be "susceptible to premature brittle-like cracking under conditions of stress intensification." The term 'stress intensification' refers to localized pressure on the pipe wall created by such conditions as rock contact or significant bending of the pipe. The phenomenon of brittle-like cracking was characterized by the failure processes described above, beginning with the initiation of cracks on the inner wall of the pipe at the pressure or stress point, followed by slow crack growth that progressed under normal pipeline operating pressures (much lower than the pressure required to rupture the pipe). The process culminated with the crack reaching the outside wall of the pipe, showing up as a very tight, slit-like opening on the surface, running generally parallel with the length of the pipe. Premature brittle-like cracking was believed, at the time of the Board's safety bulletin, to require relatively high and localized stress on the pipe resulting from sharp or excessive bending, soil settling, rock "impingement" (point or contact pressure on the pipe) , improperly installed fittings, and dents or gouges to the pipe surface. The term 'brittle-like cracking' was used to describe this failure process because the pipe showed no signs of being bulged or deformed where the cracks occurred.

Board Findings on the Three Identified Safety Issues

Issue 1: Vulnerability of Plastic Piping to Brittle Cracking

Long-Term Strength of Early Pipe was Overrated - In the early 1960s the industry had very little long-term experience with plastic pipe, and consequently, developed laboratory testing procedures to forecast the expected service life of piping. Early testing results suggested that polyethylene pipe would exhibit a relatively constant, or 'straight line' gradual decline in strength over time. These tests and underlying assumptions were subsequently incorporated as standards for the industry and in related federal requirements.

As the industry gained experience, however, the straight-line assumptions of these early procedures began to be challenged through the development of new testing methods, where pipe strength was assessed under conditions of elevated temperature (such as the testing referenced in DuPont's 1986 letter to customers). Results of the elevated-temperature testing showed that the decline in strength of early plastic pipe was not gradual or linear as had been assumed, but instead, began to accelerate or drop below the straight line, especially after twelve years. The Board concluded that the early testing procedures may have overrated the strength and resistance to brittle-like cracking of the polyethylene pipe manufactured for the gas industry from the 1960s through the early 1980s.

Long-Term Ductility was Overrated - Another important assumption about early plastic pipe, based on short-term testing, was that it would retain its ductile properties long term. The assumption of long-term ductility had important safety ramifications since it allowed plastic pipe systems to be designed to withstand stresses generated primarily by internal pressure and to give less consideration to the impacts of external

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 9 of 35

stresses such as bending. Unfortunately, the early testing methods did not properly identify the evidence of the "ductile to brittle" transition that was occurring early in the life of the pipe. Consequently, the tests did not distinguish pipe failures resulting from a loss in ductility. The Board noted that this loss of ductility was also observed in the older piping of several manufacturers, those other than Century Utility Products.

Pipeline Operators had Insufficient Notification - The Board noted that premature brittle-like cracking was a complex phenomenon that had not been systematically communicated to the industry, and hence, had not been fully-appreciated by pipeline operators. The Board recognized pipe manufacturers as commonly offering technical and safety assistance to operators, and occasionally, formal reports on their materials. But, because the information on the potential weakness of their products was also mixed with information publicizing its best performance characteristics, the message was not clear. The Board also noted that the Federal Government had not provided relevant information to gas system operators, and concluded that operators had insufficient notification that much of their early polyethylene pipe may have been susceptible to premature brittle-like cracking. Finally, the Board went on to recommend that the polyethylene pipe manufacturers' organization, the Plastics Pipe Institute, advise its members to notify pipeline operators if any of their materials indicate poor resistance to brittle-like failure.

Issue 2: Adequacy of Guidance for Connecting Plastic Pipe to Steel Mains

Critical Understanding of Stress on Pipe - The Board observed that the premature transition of plastic piping from a ductile to a brittle state appeared to have little observable adverse impact on the serviceability of plastic pipe, *except* where the pipe was subjected to external stresses, such as excessive bending, earth settlement, dents or gouges to the pipe surface, and improper installation of fittings, etc. Of those sources of stress, a key factor identified in the Board's bulletin was earth settlement, but particularly in cases where plastic piping was connected to more rigidly anchored fittings, such as steel main pipe. Because the physical properties of plastic and steel respond differently under the same conditions, such as to temperature change and ground settlement, the slight movements of each type of pipe in the ground will be different. This difference in movement can result in significant stress at the point of connection between the plastic and steel piping.

Much of the Guidance to Operators was Insufficient or Ambiguous - In addition to pipeline operators having insufficient guidance on the overall issue of the vulnerability of plastic pipe to brittle cracking, as noted above, the Board also observed that much of the available guidance to operators on how to limit stress on the pipe during installation was inadequate or ambiguous. This was particularly the case with the stress associated with the tapping of plastic service piping to steel mains, where the Board concluded that many of those connections may have been installed without adequate protection from external stress. The Board went on to identify several instances where safety requirements did not fully incorporate safety recommendations, resulting in ambiguity for pipeline installers and regulators. Other highlights of the Board's findings were the many cases where the applicable regulations applying to pipeline installation lacked any performance measurement criteria. Noting that the Office of Pipeline Safety considered many of its

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 10 of 35

safety regulations to be performance-oriented requirements, the Board rebutted this in stating that "many are no more than general statements of required actions that do not establish any criteria against which the adequacy of the actions taken can be evaluated." A particular example was the regulation that "requires gas service lines to be installed so as to minimize anticipated piping strain and external loading," and yet it contained no performance measurement criteria for establishing compliance. Finally, the Board went on to note cases where the inadequacy of pipe manufacturers' instructions also contributed to the lack of a clear understanding of methods to limit stress on plastic pipe during installation.

Issue 3: Monitoring of Plastic Pipe to Determine Unacceptable Performance

The Board's final objective was focused on performance monitoring of pipeline systems as the key to effectively managing the vulnerable piping types identified in the bulletin. In this discussion, the Board focused on the accident in Waterloo, Iowa in 1994[1], in highlighting the very real challenges of designing effective pipeline monitoring programs. The Board stated that before the accident, the pipeline operator had developed a limited capability to monitor and analyze the condition of its system. It concluded however, that the systems the operator had developed for tracking, identifying, and statistically treating plastic piping failures did not permit an effective analysis of system failures and leak history, noting that their methods of handling of pipe data masked the high failure rates of the subject Century pipe. While the operator did re-evaluate its monitoring data after the accident, and subsequently identified the high failure rates of Century Pipe, the Board opined that the problem could have been detected earlier (before the accident) if the data had been properly analyzed in the first place. Finally, the Board concluded that an effective monitoring program would have allowed the operator to implement a pipe replacement program that might have prevented the accident.

In the second case, the Board noted that while the operator had added capabilities to its pipe-monitoring protocols, it had still not chosen parameters needed to provide adequate analysis of its plastic piping system failures and leak history. The bulletin went on to note examples of the many types of additional parameters needed to enable the effective tracking, identifying, and properly describing system failures and leak history.

The Board concluded that in light of the key findings in its bulletin, that gas system operators may need to be advised once again of the importance of complying with Federal requirements for piping system surveillance and analyses. Regarding the monitoring of older piping, the Board identified the necessity to analyze factors such as piping manufacturer, installation date, pipe diameter, operating pressure, leak history, geographical location, modes of failure, location of failure, etc. Finally, the Board noted that an effective monitoring program would require the evaluation of pipe material and installation practices to provide a basis for the planned and timely replacement of piping that indicates unacceptable performance.

[1] In October, 1994, a natural gas leak and explosion at Midwest Gas Company in Waterloo, Iowa, resulted in 6 fatalities and 7 injuries. The cause of the incident was identified as the failure of a ½ inch diameter service pipe cracking in a brittle-like manner at a connection to a steel main.

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 11 of 35

Pipeline and Hazardous Materials Safety Administration

1999 Bulletins

The first two of several advisory bulletins related to the Board's 1998 Safety Bulletin (above), were published by the Office of Pipeline Safety, now known as the Pipeline and Hazardous Materials Safety Administration (Administration), in March 1999. The bulletins, which were issued as advisories to pipeline owners and operators, provided an abstract of the findings of the Board's 1998 investigation and advised that much of the plastic pipe manufactured from the 1960s through the early 1980s may be susceptible to brittle-like cracking. The advisories concluded with the recommendation to owners and operators to identify all pre-1982 plastic pipe installations, analyze leak histories, evaluate potential stresses to pipe, and to develop appropriate remedial actions, including pipe replacement, to mitigate any risks to public safety.

2002 Bulletin

This bulletin, as with the prior advisories, reiterated to natural gas pipeline owners and operators the susceptibility of older plastic pipe to premature brittle-like cracking. But, for the first time, this advisory specifically named DuPont's pre-1973 Aldyl A pipe (low ductile inner wall) as being susceptible to brittle cracking. The bulletin also depicted several environmental and installation conditions that could lead to premature, brittle-like cracking failure of the subject pipe, and described recommended practices to aid operators in identifying and managing brittle-like cracking problems.

2007 Bulletin

This bulletin, again, served to review and recap the findings of the prior bulletins, advising natural gas system operators to review the earlier statements. In addition, the advisory recapped results of the ongoing effort of the American Gas Association to identify trends in the performance of older plastic pipe. The advisory reported that the data, at that point, could not assess failure rates of individual plastic pipe materials, but did support what was historically known about the susceptibility of older plastic piping to brittle-like failure, including the addition of specific materials to the list, such as Delrin insert tap tees.

2009 Distribution Integrity Management Program

The Administration published the final rule establishing integrity management requirements for gas distribution pipeline operators in December 2009. Though the effective date of the rule was February 2010, operators were given until August 2011 to write and implement their Distribution Integrity Management Plan (DIMP).

Objectives and Approach

Among other objectives, the program was intended to overcome two key weaknesses in pipeline safety management that were identified in the National Transportation Safety

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 12 of 35

Board's 1998 bulletin (above): 1) correct weaknesses in federal regulations, particularly in the Office of Pipeline Safety, by establishing true measurement criteria for establishing safety compliance, and 2) establish systematic protocols for pipeline data collection, analysis, and interpretation, that helps ensure accurate integrity assessment and appropriate remediation.

The concept of "Integrity Management" grew out of a demonstration project of the Office of Pipeline Safety designed to test whether allowing operators the flexibility to allocate safety resources through risk management was effective in improving pipeline safety and reliability. Integrity management requires operators, such as natural gas distribution companies, to write and implement Integrity Management Programs (IMPs) to assess, evaluate, repair and validate the integrity of pipeline segments. The program contains the following elements:

- Knowledge
- Identify Threats
- Evaluate and Rank Risks
- Identify and Implement Measures to Address Risks
- Measure Performance, Monitor Results, and Evaluate Effectiveness
- Periodically Evaluate and Improve Program
- Report Results

The Integrity Management approach uses historical leak data and other facility information, along with the input of subject-matter experts, to identify individual threats to a gas system. These threats are then analyzed to predict the likelihood and consequences of failure. Each threat is then ranked by priority, followed by the development of a plan to reduce or remove those risks as deemed necessary.

2011 Call to Action – Transportation Secretary LaHood

Finally, in April 2011, U.S. Transportation Secretary LaHood issued a Call to Action to all pipeline stakeholders in conjunction with the effective application of the Distribution Integrity Management Program. The Call to Action was aimed at the more than 2.5 million miles of liquid and gas pipelines of both federal and state jurisdiction, including transmission and distribution facilities, calling on owners and operators, the pipeline industry, utility regulators and state and federal partners to:

- Evaluate risks on pipeline systems;
- Take appropriate actions to address those risks, and
- Requalify subject pipeline systems as being fit for service.

The centerpiece of the Call to Action is the "Action Plan" of the Department of Transportation and the Pipeline and Hazardous Materials Safety Administration. The focus of the Action Plan is to accelerate the rehabilitation, repair, and replacement of high-risk pipeline infrastructure, calling on pipeline operators and owners to take

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 13 of 35

"aggressive efforts… to review their pipelines and quickly repair and replace sections in poor condition." To buttress this Call to Action, Secretary LaHood has asked Congress to increase maximum civil penalties for pipeline violations, to close regulatory loopholes, strengthen risk-management requirements, add more inspectors, improve data reporting and help identify potential pipeline safety risks early.

Avista's Experience with DuPont Aldyl A Piping Systems

Avista has approximately 12,500 miles of natural gas piping in its service territories in the States of Washington, Oregon and Idaho. Like dozens of other gas utilities, Avista adopted plastic pipe as an excellent alternative to steel, and consequently, the broad majority of Avista's pipe is polyethylene (about 8,500 miles) of various types, ages and brands, including DuPont's Aldyl A.

Avista began installing DuPont Aldyl A in 1968 and discontinued its use in 1990 when DuPont sold their production to Uponor. Of the various vintages and formulations of Aldyl A pipe in its system, Avista has estimated quantities in the following amounts, in diameters of ½" to 4":

Pre-1973 Aldyl A (1965-1972 resins)	190 Miles
1973-1984 resins	960 Miles
1985-1990 resins	919 Miles

Avista noted the advisory bulletins of the Board and Administration in 1998, 1999 and 2002, but since it had no documented trends in the types of failures highlighted, continued to manage its Aldyl A pipe according to established monitoring standards for leak survey and sound operations practices.

Spokane and Odessa Incidents

In recent years, however, Avista experienced two natural gas incidents[2] resulting in injuries and property damage that signaled possible changes in leak patterns in its Aldyl A piping. The first incident occurred in 2005 at a commercial site in Spokane. This event involved the failure of 1976-vintage Aldyl A pipe caused by bending-stress resulting from poor soil compaction around the pipe that was performed by a non-Avista excavator in 1993. The post-incident investigation judged the resulting leak to be an anomaly that could have been prevented with proper care by that 3rd party excavator.

The second incident, at a residence in the town of Odessa, Washington, in late 2008, was determined to be the result of rock pressure on the 1981-vintage Aldyl A pipe that occurred during the initial installation. Avista signed a settlement agreement with staff of

[2] The Pipeline and Hazardous Materials Safety Administration defines a natural gas "incident" as a release of gas that results in any of the following: a fatality or personal injury that requires in-patient hospitalization; property damage of $50,000 or greater, or the loss of greater than 3 million cubic feet of gas.

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 14 of 35

the Washington Utilities and Transportation Commission as an outcome of the investigation of this incident. Under terms of the agreement, which was subsequently approved by the Commission, Avista increased the frequency of its residential leak survey on pre-1984 resin (pre-1987 installed) Aldyl A natural gas mains in its Washington jurisdiction, from once every five years to annually. In addition, whenever it is excavating in the vicinity of Aldyl A natural gas mains in Washington, Avista will also report on the soil conditions surrounding the pipe, and identify appropriate and reasonable remedial measures, as necessary. Avista retained the consulting services of Dr. Gene Palermo to help develop its approach for managing Aldyl A pipe, in relation to the soil conditions reported.

Expert-Recommended Protocol for Managing Aldyl A Pipe in Relation to Reported Soil Conditions

Dr. Palermo is a nationally-recognized expert on the plastic pipe used in natural gas systems, and in particular, Aldyl A piping. He has worked in the plastic pipe industry for over 35 years, which includes 19 years with the DuPont Corporation in its Aldyl A natural gas pipe division.

Dr. Palermo also served as the Technical Director for the Plastics Pipe Institute from 1996 through 2003 and served on the Institute's Hydrostatic Stress Board for over 20 years. Dr. Palermo has served on a variety of gas industry committees, has trained gas industry practitioners and regulators, and has received numerous awards of merit for his outstanding individual contribution to the natural gas plastic-piping industry. He is the only person to receive both the American Society of Testing and Materials - Award of Merit, and the American Gas Association - Platinum Award of Merit. Dr. Palermo is president of his consulting firm, Palermo Plastics Pipe Consulting.

Dr. Palermo reviewed the content of Avista's agreement with the Commission to become familiar with its requirements, specifically with regard to managing Aldyl A piping found in soils that would currently not meet standard criteria for bedding and backfill. Dr. Palermo's review and expertise provided the basis for his recommended protocol for management of Avista's Aldyl A piping found in rocky soils.

1. All Aldyl A pipe manufactured prior to 1984 should be evaluated for replacement in the following manner:
    a. If the pipe has Low Ductile Inner Wall properties, Avista should immediately begin a prioritized pipe replacement program.
    b. If the pipe is installed in soil with rocks larger than ¾ inch, Avista should immediately begin a prioritized pipe replacement program.
    c. If the pipe is installed in sandy soil or in soil with rocks up to ¾ inch in size, the pipe should remain in service and normal leak surveys per DOT Part 192 should be followed.

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 15 of 35

2. All Aldyl A pipe manufactured during or after 1984 should also be evaluated.

    a. If the pipe is installed in soil with rocks larger than ¾ inch in size, Avista should evaluate the pipe and consider replacing it if they begin to experience rock impingement failures, and should conduct leak surveys more frequently than required by DOT Part 192, until replacement.
    b. If this pipe is installed in sandy soil or in soil with rocks up to ¾" in size, the pipe should remain in service and normal leak surveys should be followed.

Evaluation of Leak Survey Records

Following the Odessa incident, Avista was also asked to review five years of leak survey records in Washington State to look for possible emerging patterns in the health of its Aldyl A piping system. Avista organized the leak survey information and then conducted several evaluations, which were organized under three general objectives, listed below.

1. Analyze the modes or observed types of failures in Aldyl A pipe;
2. Forecast the expected long-term integrity of Aldyl A piping;
3. Identify potential patterns in the overall health of this piping to aid in the design of a more-focused management protocol for Aldyl A pipe.

Avista used newly-available asset-management tools to conduct these assessments, including its recently-implemented Distribution Integrity Management Program (Integrity Management) approach for identifying and analyzing potential threats to its natural gas system. This approach is suited for just such an analysis, having the capability to determine potential patterns in the overall health of a piping system that might not have been otherwise evident through conventional data review. The analysis of the historic leak survey data, including the observation of several new Aldyl A material failures and leaks, did point to the development of a possible trend.

Pipe Replacement Projects in 2011

Another outcome of this heightened focus on Aldyl A leaks was Avista's decision to replace several thousand feet of its Aldyl A main in 2011. In Odessa, Avista increased the frequency of leak surveys on its gas system to once per quarter and mobilized a pipe replacement program that removed all of the pre-1984 Aldyl A main pipe from the gas system in the town. During that project, which was conducted from June to December 2011, nearly 32,000 feet of Aldyl A main pipe were replaced. Other Aldyl A replacement projects in 2011 removed an additional 7,000 feet of this priority pipe. Together, these projects had a capital cost of approximately $2.7 million.

Avista Distribution Integrity Management Program

As described briefly above, the Integrity Management approach, now required by law, begins with the aggregation of historical leak-survey data and other facility information

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 16 of 35

relevant to Avista's natural gas piping system. Then, in conjunction with the input of subject matter experts, individual threats to Avista's gas system are identified. These threats are analyzed to predict the likelihood and consequences of failure associated with each threat, based on the specific operating environment, system makeup, and history of Avista's natural gas system. Each threat is then ranked relative to all others to identify, by priority, those with the greatest hazard potential. From that priority list, measures are developed to reduce or remove those risks as deemed necessary. These mitigating measures are often referred to as "accelerated actions" because they may be above and beyond the minimum requirements of applicable federal and state codes. These accelerated actions can range from increased frequency of maintenance and leak surveys to full replacement programs for certain gas facilities. Finally, the mitigating measures will be reviewed to evaluate their effectiveness in reducing threats to the gas system, and the program will then be adjusted as necessary based on those outcomes.

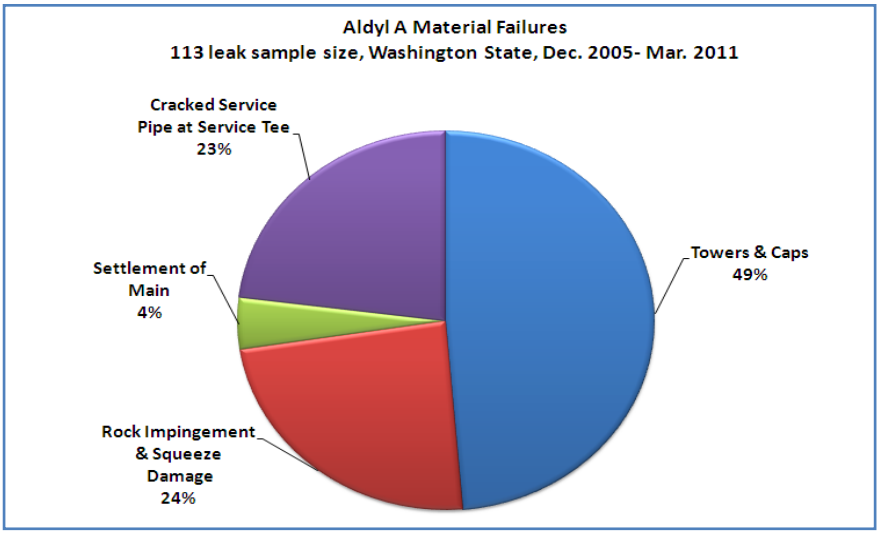
Integrity Management requires the use of geographically-based analytical software to complete many of the required program elements. Like many utilities, Avista is using the Geographic Information System (GIS) platform developed and supported by Environmental Systems Research, Inc. (ESRI), as the geographic and analytical engine for conducting its gas system evaluations under the Integrity Management program. ESRI is a pioneer and world leader in developing and supporting geographic software products for a broad range of global business sectors, including utilities. Since Avista had already created a comprehensive GIS layer, or database, for its gas facilities, it made sense to add analytical capabilities to this platform in complying with the Integrity Management program requirements.

Analyzing Modes of Failure in Avista's Aldyl A Pipe

In tackling the first objective of the assessment of its Aldyl A piping, Avista aggregated the gas leaks resulting from Aldyl A material failures found in its gas system in Washington State from late 2005 through March 2011. The sample included 113 material failures that were evaluated and summarized by component to offer an understanding of the specific failure modes for Aldyl A pipe. The 'modes' or types of material failures categorized are shown below in Figure 1.

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 17 of 35

Figure 1. Modes or types of material failures documented in a sample of 113 leaks in Avista's Aldyl A piping in Washington State, December 2005 through March 2011.

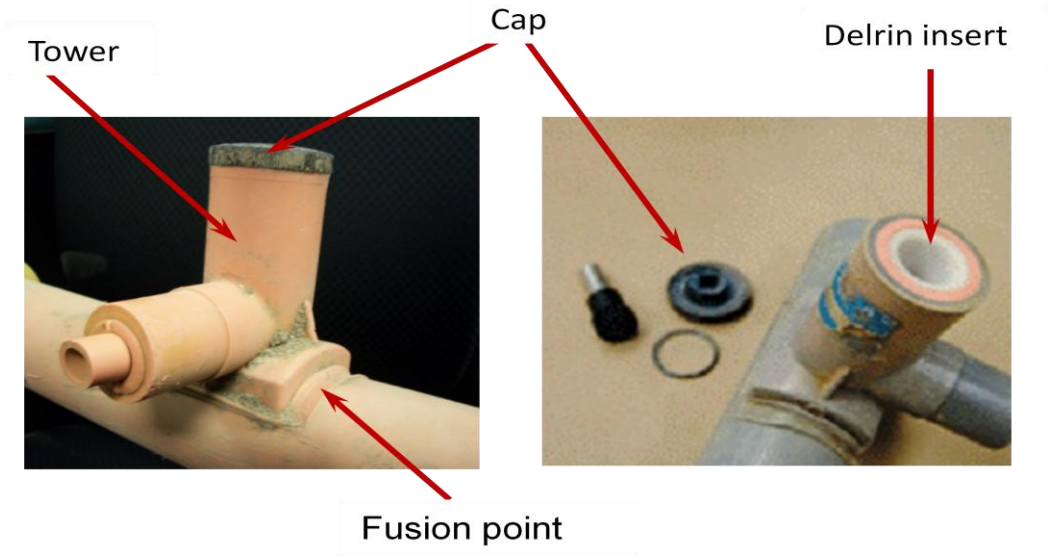


Towers and Caps

The largest percentage of material failures in the sample occurred in Towers and Caps, referring to failure of the service tapping tee itself, shown below in Figure 2. In these cases, the pressure applied to the tee as the cap was tightened onto the body during initial installation has resulted in slow crack growth and failure of the tower body, the cap, or the Delrin® insert many years later. Additionally, the saddle fusion point of the tower to the main pipe is another frequent point of failure in this assembly. The unavoidable stresses created during standard installation (using factory recommended procedures) have led to brittle cracking in these components many years later. This phenomenon clearly demonstrates the susceptibility of certain resins of Aldyl A piping to tend to fail by brittle cracking due to the slow crack growth initiated during installation.

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 18 of 35

Figure 2. External features and internal components of a typical Aldyl A service tee, as fused to Aldyl A main pipe.

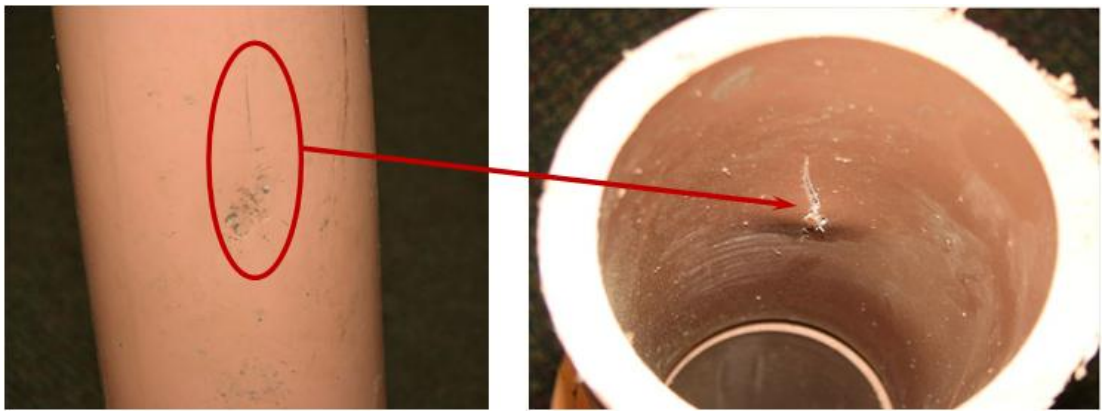


Rock Contact and Squeeze-Off

The second-most common material failure observed in Avista's Aldyl A pipe was due to localized, brittle cracking in Aldyl A mains that resulted from rock impingement – rock pressure directly on the pipe, or places where 'squeeze-off' was applied over the pipe's service life. These failures are very typical for certain resins of Aldyl A main pipe, having been consistently reported by other utilities since before the time of DuPont's 1986 letter. As described earlier, when these external stresses (rock impingement or squeeze-off) cause the pipe to fail, it always begins with crack initiation on the inside surface of the pipe wall, eventually resulting in slow crack growth that propagates toward the outer wall of the pipe, and finally, through-wall failure. These failures generally appear as short, tight cracks in the outer wall of the pipe that run either parallel, or slightly off-parallel with the length of the pipe. A typical failure in Aldyl A main pipe, showing a crack through the pipe wall as it appears on both the inner and outer surfaces, is shown below in Figure 3.

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 19 of 35

Figure 3. Typical brittle-like crack through the wall of Aldyl A pipe, resulting from rock contact directly on the pipe.



Although the duration of the stress caused by rock contact with the pipe is very different from that associated with squeeze-off, they both result the same pattern of crack initiation and slow crack growth leading to failure of the pipe. Other sources of external stress that can result in brittle failure of Aldyl A pipe, as mentioned earlier in the report, include bending of the pipe, soil settlement, dents or gouges to the pipe, and improper installation of fittings.

Services Tapped from Steel Mains

The third most-common failure in Avista's sample occurred where small diameter Aldyl A service pipe is tapped from steel main pipe. In this application, a steel service tee is welded to the steel main pipe and the small-diameter Aldyl A service pipe is then connected to a mechanical transition fitting on the tee, as pictured below in Figure 4.

Figure 4. Typical polyethylene service tapped from a steel main.

It is at this transition point, between the rigid steel fitting and the more-flexible Aldyl A service pipe, that brittle-like cracking has been observed. This failure mode in older plastic pipe is well understood, and was one of the three study objectives reported by the

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 20 of 35

National Transportation Safety Board in its 1998 bulletin, summarized earlier in this report.

Avista's Aldyl A Services

Avista believes its Aldyl A service piping (apart from cracking at the connection with the tee on steel main pipe) has no greater tendency to fail than its other polyethylene service piping , and at this point in time, should not be managed differently than other plastic service pipe (frequency of leak survey, etc.). Consequently, Avista is not planning to systematically replace Aldyl A service pipe as it replaces main pipe and rehabilitates service connections at steel tees. Avista is using the Integrity Management model, however, to track and analyze service leaks going forward to determine if the reliability of Aldyl A service piping changes in ways that warrant a different approach.

Understanding the Significance of Leaks in Aldyl A Pipe

Frequency and Potential Consequence

Analysis of the material failures of Aldyl A pipe provides the opportunity to put these leaks into perspective with other types of leaks on Avista's natural gas system. As part of the development of the Integrity Management Plan, five years of leak data were analyzed for Avista's three-state service territory. The data included nearly 17,000 individual leaks, which were categorized according to the underlying threats to the natural gas system as required under Integrity Management. As a point of comparison of the significance of leak types, the data included an excess of 2,000 leaks associated with the failure of gas system equipment, such as valves, fittings and meters. But only 153 leaks were identified as resulting from 'material failures' of Aldyl A piping in the three states. Looking simply at Aldyl A leaks as part of the aggregate of all system leaks, it could be easy to conclude that Aldyl A pipe failures pose a limited potential for hazard relative to the threat of other system leaks. In fact, while gas equipment leaks are more likely to occur, their potential consequence is often minimal. A thorough understanding of this difference is one of the most important requirements and outcomes of any effective Integrity Management Plan analysis.

Review of the leak-history data shows the vast majority of equipment leaks as occurring typically with shut-off valves and gas meters, located either above ground or in locations that allow free-venting of gas to the atmosphere. Consequently, these types of leaks have a low potential to result in an incident posing harm. Through public awareness programs, people have become familiar with the odor of venting gas and tend to quickly call Avista to make repairs; this is especially true if the venting gas can be associated with visible gas valves or meters. By contrast, Aldyl A failures and the associated leaks occur almost entirely underground, out of sight, often in populated areas, and occasionally in the proximity of buildings that are not actually connected to the natural gas system. Without visible facilities, natural gas may have an unexpected presence in the environment that allows people to dismiss slight gas odors. This reduced awareness allows gas from these undetected leaks to have the significant potential to migrate into buildings before it can

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 21 of 35

be identified and reported. This is especially true in winter when the ground is saturated, frozen or snow covered, and in areas of full pavement and concrete finishes. Of the roughly 2,000 equipment leaks reported in the five years of data reviewed, none resulted in gas incidents. By comparison, two of the relatively-small number of Aldyl A material failures resulted in gas migrating into buildings undetected, and upon accidental ignition, resulted in harmful incidents.

The Complication of Brittle Cracking in Aldyl A Pipe

The common mode of failure for Aldyl A materials, brittle-like cracking, can also present special problems compared with leaks in other gas piping, such as corrosion in steel gas pipe. Corrosion leaks tend to begin with the failure of a very minute area in the pipe wall, which then begins to release a very minute amount of natural gas. These leaks then tend to progress very slowly and in a stable and somewhat predicable way over time. These types of leaks, while never positive, are more likely to be detected by modern gas-detection equipment when they are at a stage where the release of gas is relatively minor. By contrast, leaks in Aldyl A piping tend to first appear as substantial (high gas volume) leaks that appear in a very short time period. This is due to the nature of brittle cracking, where the crack can progress very slowly from the inner wall of the pipe toward the outer wall without any release of gas, until the pipe finally splits open, resulting in a substantial failure. Additionally, unlike the prevention or even suspension of corrosion problems in steel pipe through effective protection methods, there is no way to halt undetected progress of slow crack growth in brittle Aldyl A pipe.

Reliability Modeling of Avista's Aldyl A Piping

Avista's Asset Management Group performed reliability modeling for several classes of its natural gas pipe in order to assess the long-term performance of its Aldyl A piping, compared with steel pipe and newer-vintage plastic pipe. Reliability analysis comes from the discipline of 'reliability engineering' and is a foundational asset management tool that provides a forecast or prediction of the future performance of a piece of equipment (pipe, in this instance). The predicted asset performance then provides the basis for the application of other asset management tools, allowing the development of the ultimate maintenance or replacement strategies that optimize asset cost with any number of other factors, such as availability for service or risk avoidance.

Availability Workbench Software

Avista developed reliability forecasts for its Aldyl A and other piping using Availability Workbench™ software. This 'off the shelf software' was introduced by Isograph, Ltd., the world's leader in reliability analysis software. Availability Workbench was first introduced in 1988, and is used to support asset decision making in over 7,000 sites around the world and across a range of industries, including Aerospace, Automotive, Chemical, Defense, Electronics, Manufacturing, Mining, Oil and Gas, Power Generation, Railways, and Utilities. Avista's version of the model was released in 2009.

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 22 of 35

Reliability Forecasting

Availability Workbench has four modules, one of which, the Weibull module, is used to create reliability forecasts (curves) for an asset. Reliability curves for gas piping are generated from input data that include pipe inventory (type, brand, footage, location, soil conditions, etc.), current age of piping, historic and current failure information and repair data. Avista uses predominantly its own historical data for these inputs, but when they must be estimated, they are vetted by subject matter experts within the company. The model integrates pipe age and failure and repair data, and then by applying a conventional Weibull-curve mathematical model, it produces probability curves that represent the expected failure rates over time for each failure mode, such as the brittle-like cracking associated with Aldyl A services tapped to steel mains. The reliability curves represent how quickly the rest of the pipe is at risk of failing, shown as the percentage of failures expected each year over time.

Forecasting the Reliability of Aldyl A Piping

The objective of Avista's reliability modeling was to forecast expected failures for elements of Avista's Aldyl A piping system, compared with that of steel and latest-generation polyethylene pipe. The observed Aldyl A failure modes, discussed above, including leak data for other types of gas pipe in Avista's system, provided high-quality leak and age information for the reliability modeling. Forecasting was performed for the following pipe 'classes' in Avista's system.

a. Aldyl A Main pipe of Pre-1984 manufacture (Alathon 5040 and 5043 resins, including low ductile inner wall pipe)
b. Aldyl A Main pipe manufactured during 1984 and after (Alathon 5046-C and 5046-U resins)
c. Aldyl A Services Tapped to Steel Main (Bending Stress Services)
d. Steel Main pipe
e. Newer Polyethylene Main pipe (1990 and later)

To perform the modeling, the data for these pipe classes must be input as discrete elements, which are described as follows:

Main Pipe - Analyzed using 50-foot segments as discrete modeling elements.

Services Tapped from Steel Mains - Avista identified 16,000 such services in its system, also referred to as 'bending stress tees.' For the reliability modeling, the individual service is the discrete element.

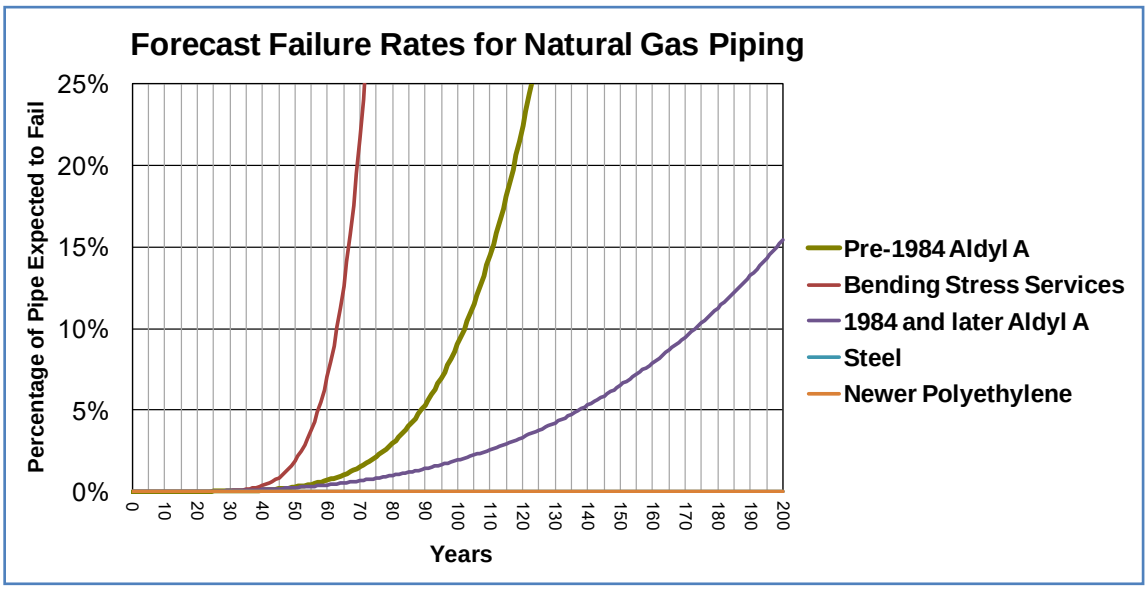
Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 23 of 35

Forecasting Results

Forecast Piping Failures

Results of the forecast modeling, for the pipe classes evaluated, are represented as 'curves' showing the percentage of the amount of each pipe class that is projected to fail in each year of the forecast time period. The resulting reliability curves are shown in the graph below in Figure 5.

Figure 5. The expected failure rates for several classes of pipe in Avista's system, as forecast by Availability Workbench Modeling. The "Steel" curve is obscured by the "Newer Polyethylene" curve, both of which are essentially flat lines.



The failure curves show dramatic differences in the expected life for the pipe classes evaluated. The difference in expected life between the Aldyl A products as a group, compared with that of steel and newer-generation plastic pipe, is particularly evident. Striking also, are the expected performance differences among the classes of Aldyl A pipe evaluated, providing some clear trends useful in designing remediation strategies.

Dependability of Forecasting Future Failures

The reliability forecast is essentially a mathematical calculation of the 'chance' of future failure and decisions of significant risk and financial magnitude are based, at least in part, on that result. Importantly though, the forecast has a 'real numbers' foundation in the actual leak data, records of material failure and repair, and the relationship of those events with time. For Aldyl A pipe, the model is using observed endpoints in the life of the pipe resulting from a loss in ductility and slow crack growth, for example, and integrating that with other data to forecast future expected failures. Comparatively, the relatively rare observed failures in steel pipe and newer-generation plastic pipe are

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 24 of 35

reflected in their nearly-flat cumulative failure curves. The value of using proven reliability forecasting approaches and widely-adopted software is derived from their ubiquitous application across reliability-critical industries, and their continuous testing, evaluation, and support. Finally, as Avista adds new data in coming years for pipe failures of all material classes, including Aldyl A, it serves to increase the statistical power of the forecast results.

Understanding the Significance of Cumulative Failure Curves

Although the failure curves for the different classes of pipe differ significantly over the long term, as mentioned, the failure rates also appear to be very close to zero for the first 40 years for Aldyl A services tapped to steel main, and for 75 years for Pre-1984 Aldyl A main pipe. Since the weighted average age for Aldyl A pipe in Avista's system is 32 years, it would appear that we might have ample time before the failure rate would start to rise substantially for Pre-1984 Aldyl A main pipe. The failure curve estimates that when the Pre-1984 Aldyl A main pipe is 80 years old that approximately three percent of it will fail in that single year. Given that Avista has 335 miles of this vintage pipe in Washington, that mileage equals about 35,000 discrete elements (50-ft sections) in the forecast model. The three percent failure, then, translates to 1,050 leaks in that 80th year. To put that failure rate into perspective, consider that Avista documented just 113 leaks over the past five years in Washington state, two of which resulted in injury and property incidents, and dozens more that were categorized as hazardous leaks[3], timely repaired. Since it is expected that the number of hazardous leaks and incidents would increase proportionally with the increase in total leaks, then it's easy to imagine just how unacceptable the pipe performance would be at an annual failure rate of three percent.

Prudent Failure Management

To carry this point further, if we "zoom-in" on the curves we can gauge the significance of the change in failure rate that is expected ten years from today. At that point the weighted average age of Aldyl A pipe in Avista's system will be 42 years, and the expected failure rate for that year is just over one-tenth of one percent (0.12%), or 42 leaks in that year. The failure rate in that year, then, will have nearly doubled over the average annual rate for the past five years (22.6). The critical point in this analysis is the understanding that failures in buried natural gas piping can be prudently managed only when they are occurring at very low rates. Otherwise new leaks in the system occur too frequently to be detected by even annual leak surveys of the entire system, resulting in an increase in the likelihood of hazardous leaks and the potential for harmful incidents.

[3] The Pipeline and Hazardous Materials Safety Administration defines a "hazardous leak" as an unintentional release of gas that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous.

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 25 of 35

Priority Aldyl A Piping

Every pipeline operator strives to install and maintain a safe, reliable and cost-effective system. While the goal is complete system integrity, it is impossible to avoid having any leaks, especially on large systems such as Avista's with over 12,000 miles of mains and several hundred thousand services. Regulators and the industry acknowledge this reality through the adoption of standardized leak-survey methodologies, and recognized pipe remediation practices.

But, while leaks are inherent on a system, there are circumstances where the expected reliability of a particular pipe begins to rise compared with that of other piping and industry norms. We have demonstrated that such is the case for portions of the Aldyl A pipe in Avista's system, and accordingly, we have determined these classes to be at-risk of quickly approaching a level of reliability that is unacceptable and in need of proactive remediation. It's for this reason that Avista refers to these pipe classes as "Priority Aldyl A piping."

Formulation of a Management Program for Priority Aldyl A Pipe

The timely application of Avista's Distribution Integrity Management approach to its recent and ongoing leak analysis and its reliability modeling results, including Dr. Palermo's review, and the experience gained in three priority pipe-replacement projects in 2011, has prompted Avista to formulate a protocol for systematically managing its Aldyl A pipe. The following categories are useful classifications for Avista's definition of "priority Aldyl A pipe"[4]:

1. Aldyl A gas services tapped to steel main pipe
2. Pre-1973 Aldyl A main pipe
3. Pre-1984 Aldyl A main pipe

Avista has determined these classes of pipe are at risk of approaching unacceptable levels of reliability without prompt attention. Accordingly, Avista believes the decision to formulate a management program for its priority Aldyl A pipe is both timely and prudent, and is consistent with results of our leak investigations, Integrity Management principles and the recent Call to Action of Secretary LaHood. The decision is also consistent with the prior federal bulletins on this subject and with the decisions of other similarly-situated utilities that have implemented similar pipe-replacement programs. Finally, given the significant amounts of priority Aldyl A pipe on Avista's system, commencing a protocol now provides us greater opportunity to manage this facility in a prudent and cost-effective manner.

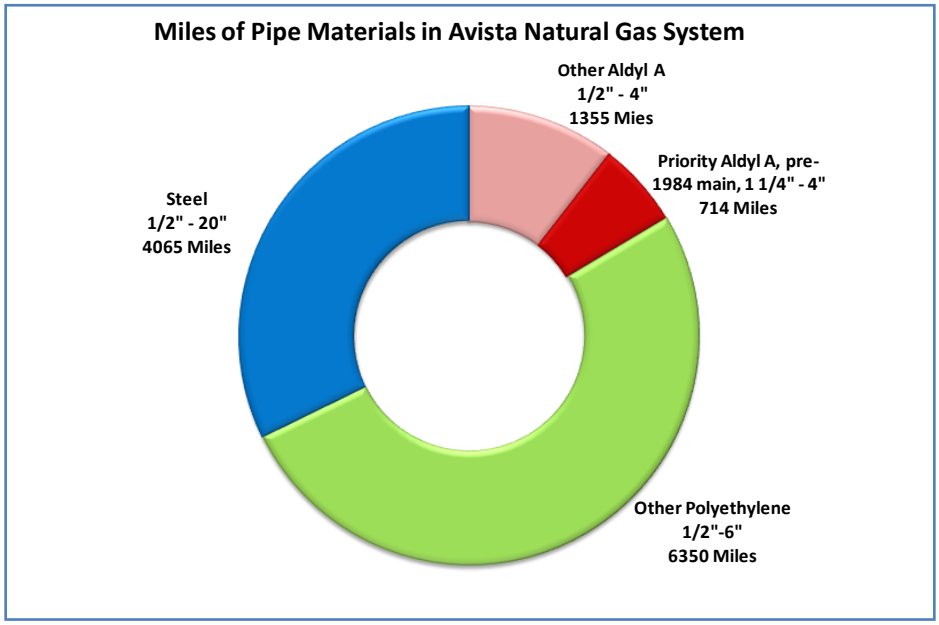
[4] Each class noted above is subject to material failures due to concentrated stresses such as rock impingement, bending stresses, squeeze off, and failures of service towers and caps.

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 26 of 35

Priority Aldyl A Piping in Avista's System

Main Pipe - Avista has approximately 12,500 miles of natural gas main pipe in its service territories in the States of Washington, Oregon and Idaho. Approximately seventeen percent of this total, or 2,000 miles, is Aldyl A pipe of all classes and sizes. Proportions of various classes of piping in Avista's system, including priority Aldyl A pipe (pre-1973 and pre-1984 mains) is shown below in Figure 6.

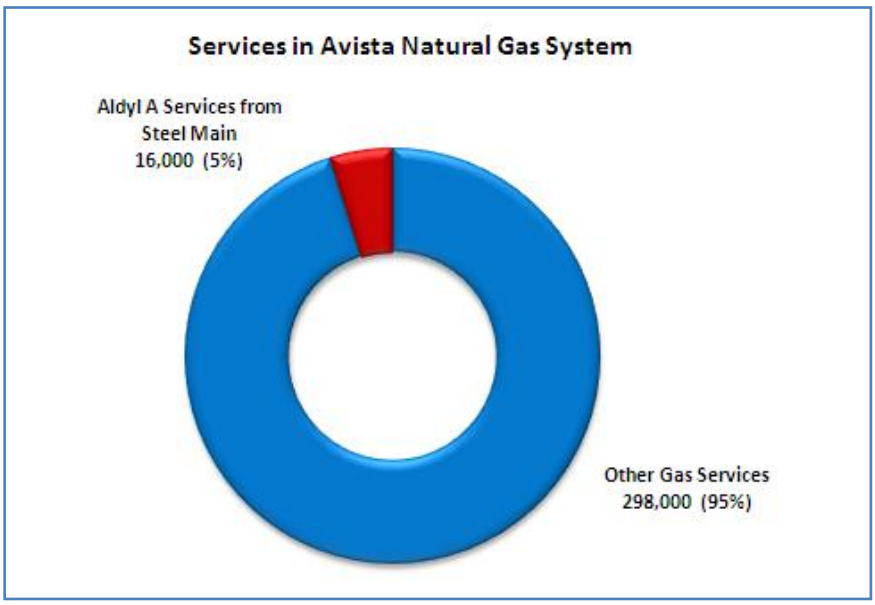
Figure 6. Avista's priority Aldyl A pipe, shown as a proportion of the different pipe classes in Avista's natural gas system (items 2 and 3 from the list above).



Gas Services - Avista has approximately 314,000 natural gas services, of which approximately 16,000, or five percent, are Aldyl service pipe tapped to steel main pipe, shown below in Figure 7 as priority Aldyl A services.

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 27 of 35

Figure 7. Avista's priority Aldyl A gas services (tapped from steel mains), shown as a proportion of Avista's total gas services.



Other Aldyl A Pipe Replacement Programs

Aldyl A Pipe in the Pacific Northwest

Through general conversation with our colleagues in western gas utilities, Avista believes it has a substantially greater proportion of Aldyl A pipe in its system than do our neighboring Pacific Northwest gas utilities. The proportions of Aldyl A in Avista's system (or of any other brand of early polyethylene pipe), however, is not a reflection of the unique purchasing practices of Avista, since plastic pipe quickly became the standard of the industry and the predominant pipe installed by utilities across the county. But, the proportions of early plastic pipe in a system do tend to track with the amount of system growth that gas utilities experienced during the 1970s and early 1980s. For Avista, this was a time of particularly rapid expansion of its natural gas system (from the Spokane metro area to outlying communities in its Washington and Idaho service territories), and consequently, the proportion of early Aldyl A pipe in our system reflects this period of expansion.

Established and Emerging Programs for Aldyl A Pipe Replacement

Two western utilities, Southwest Gas and Pacific Gas & Electric, have significant Aldyl A pipe management programs either well underway or anticipated, which are very briefly summarized below.

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 28 of 35

Southwest Gas – Responding to a fatality incident in the early 1990s, Southwest Gas entered into a settlement agreement with the Corporation Commission of Arizona to conduct additional leak monitoring and pipeline remediation. By the late 1990s, Southwest Gas had replaced 74 miles of Aldyl HD (high density) main pipe covered by the agreement, and had replaced another 648 miles of Aldyl A pipe based on its leak survey monitoring results. In 2005, Southwest Gas had another injury and property incident on their system involving Aldyl A pipe, and implemented an additional pipe replacement program in the vicinity of the incident. Southwest Gas has also worked closely with staff of the Public Utilities Commission of Nevada in the monitoring and replacement of what the Commission refers to as "aging" and "high risk" natural gas pipe, including Aldyl A pipe.

Pacific Gas & Electric - After some very high-profile natural gas incidents in 2011 that involved Aldyl A piping, Pacific Gas & Electric has announced plans to replace all the Pre-1973 Aldyl A pipe in its system. The utility reportedly has 7,907 miles of Aldyl A pipe of all classes in its system, which is about 19 percent of its gas system inventory. By comparison, Avista's Aldyl A pipe stock is about 16 percent of its system. Pacific Gas & Electric's planned replacement of its Pre-1973 Aldyl A pipe represents a massive effort because the utility plans to remove and replace the 1,231 miles of pipe in a proposed timeframe reported as in the range of three years, and at a cost said to exceed $1 billion, but that has not yet been formalized. There is some question regarding the selection of only pre-1973 Aldyl A for replacement in PG&E's system, since at least one recent high-profile incident was reported on newer vintage (still pre-1984) Aldyl A.

Developments of Interest

US Congresswoman Jackie Speier of California has been raising the awareness of Congress and Transportation Secretary, LaHood, in two separate actions. First, in May 2011, Speier sponsored House Resolution 22 entitled the "Pipeline Safety and Community Empowerment Act of 2011." The legislation provided for citizens being able to easily access pipeline maps and safety-related information from pipeline owners, prescribed certain changes in pipeline monitoring requirements, and called for the addition of physical safety devices to existing pipelines. The bill is currently under consideration by the House Committees on Transportation and Infrastructure, and Energy and Commerce.

In October 2011, Speier wrote to Secretary LaHood calling on him to direct the Pipeline and Hazardous Materials Safety Administration to "take immediate action to address the long-known safety risks associated with pre-1973 Aldyl-A plastic pipe manufactured by DuPont." She went on to advocate for the removal of this pipe from use in the U.S., and to commend Pacific Gas & Electric for its planned removal of all of its pre-1973 Aldyl A pipe. Citing the DuPont letters to customers, federal safety bulletins, and the Waterloo incident, she chided Congress for not taking action, and urged the Secretary to immediately do so.

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 29 of 35

Designing Avista's Replacement Protocol for its Priority Aldyl A Pipe

Avista modeled two different approaches to the replacement program, one that was systematic, based on an established timeframe and one that was responsive to problem areas as they were identified.

Systematic Replacement Program

Time Horizon

Determining the appropriate length of time over which to replace the Priority Aldyl A pipe involves the optimization of several factors, including: 1) the overall urgency from a reliability and safety perspective, both present and forecast; 2) potential consequences; 3) the impact of more intensive leak survey methods to better identify priority facilities in need of replacement and in helping reduce the potential for harmful incidents; 4) the ability to effectively prioritize specific projects to better ensure facilities in greatest need are addressed earliest; 5) the availability of equipment and labor resources needed to conduct the work, and the ability to coordinate the work with Avista's ongoing construction programs; 6) program efficiency, and 7) the degree of rate pressure placed on customers, both in absolute terms and in relation to other reliability and safety investments required across the natural gas and electric business. Ultimately, Avista must ensure that management and removal of its Aldyl A pipe is conducted in a way that shields our customers from imprudent risk, while at the same protecting them from the burden of unnecessary costs.

Prudent Management of Potential Risk

Avista believes it is important to establish for our customers and other stakeholders that while there can never be 'zero risk' associated with the program, the potential risk can be prudently managed. On one hand, a replacement program carried out over a very short timeframe cannot prevent the occurrence of all leaks forecast to occur over the course of the program. But at the other extreme, it's clear that setting a replacement timeline that's too lengthy would likely result in safety, reliability and financial consequences for our customers and our business that could be regarded as imprudent. Avista believes the timeline for the replacement program should optimize the factors mentioned above in a way that reduces the risk associated with Aldyl A pipe to the range of 'prudent risks' associated with the myriad other electric and gas facilities and practices that are used to serve the energy needs of utility customers. Said differently, there is no possible way to eliminate the risks associated with energy infrastructure, but there is a range of limited risk that's deemed prudent in the conduct of our business. Avista's treatment of its Aldyl A pipe will be managed to comport with these sound business practices.

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 30 of 35

Prioritizing the Work

As important as the replacement timeline in prudently managing the reliability of Avista's Aldyl A piping, is the ability of the Asset Management and Distribution Integrity Management staff to partner in effectively prioritizing the pipe-replacement activities in a way that minimizes the potential for hazardous leaks. Results of the Availability Workbench modeling provide some support in prioritization but do not take into account factors such as soil conditions or the proximity to buildings or people. Obviously, a leak occurring in a vacant field will have little, if any, consequence and will likely be detected and repaired during the next leak survey. By contrast, the potential hazard of a leak increases with its proximity to people and structures, so replacing pipe that has a high probability of leaking and is located in populated areas is first priority.

Avista's Integrity Management approach provides the analytical tools that integrate key knowledge and information needed to effectively prioritize replacement activities based on the potential hazard. In the prioritization process, each segment of Aldyl A pipe in Avista's system is assigned a relative risk ranking, based on its age, material, soil conditions, construction methods, and its maintenance and leak history. This information is then loaded into Avista's GIS database containing the gas system maps. These maps contain a "layer" of grid squares (50 feet per side) that correspond with sections of the Aldyl A pipe. Each square is known as a "raster" and each raster contains all of the risk-related information that was loaded into the GIS system, as associated with the Aldyl A pipe, at that precise geographic location.

Next, the software integrates the historic leak information for Aldyl A pipe on Avista's system with the risk data associated with each of the Aldyl A pipe segments, and predicts the geographic areas (via the risk rasters) where Aldyl A pipe failures are expected to be greatest. In the last step, the software integrates the results for expected failures with information for each risk raster that identifies the potential consequence of a leak on that segment (i.e. the proximity of that raster to buildings and people, and the population density/sensitivity of those structures). The end result is a color-coding of the rasters that provides a visual picture of where on the gas system that both the potential likelihood of a leak, and the potential consequence of a leak, are greatest. This approach provides Avista with a comprehensive and objective means of identifying Aldyl A pipe that has the highest priority for replacement.

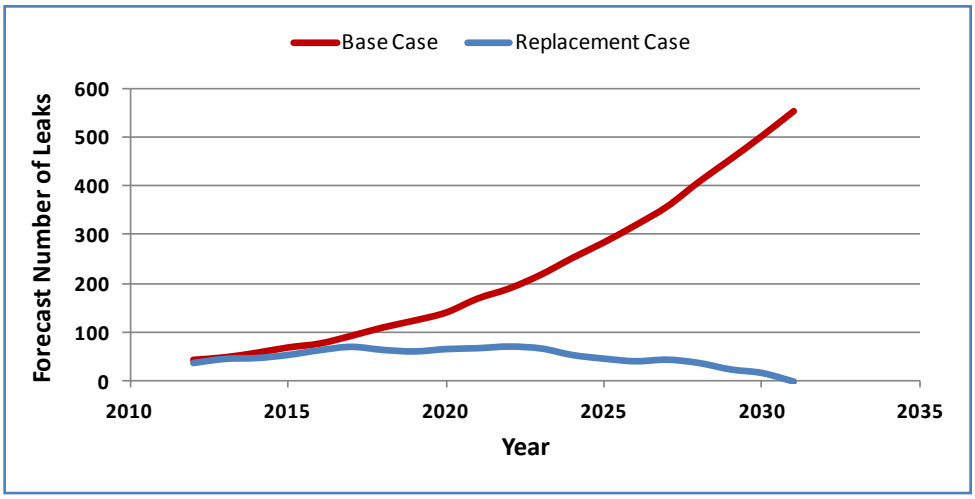
Twenty-Year Proposal

Avista modeled various time horizons for the replacement program, up to a timeline of 30 years, and determined a replacement horizon in the range of twenty years to represent an optimum timeframe for removing and replacing its priority Aldyl A pipe. Shortening the timeline was found to have increasing cost impacts to customers but with little improvement in the numbers of expected facility failures. Lengthening the timeline past twenty years, however, was found to result in a substantial increase in the number of material failures expected. A replacement timeline of 25 years, for example, resulted in more than a doubling of the number of leaks expected when compared with the twenty year horizon. Under the twenty year replacement program, the number of material

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 31 of 35

failures each year is expected to increase slightly until 2017, at which time the cumulative effect of priority piping replaced since 2012 begins to check the failure count and then drive it toward zero over the remaining course of the program (Figure 8).

Figure 8. Expected numbers of material failures in Avista's priority Aldyl A piping in two cases: Replacement Case - piping replaced over a twenty year horizon in the manner proposed by Avista in this report, and Base Case – assumed that priority piping was not remediated under any program.



Importantly, Avista is not saying that experiencing an increase in leaks on our system is "acceptable" per se, in particular, after having had two harmful incidents in the past few years. What we are saying, however, is that by using the Integrity Management model to prioritize work activities in the manner described above, Avista believes it can manage the forecast Aldyl A leaks in a way that significantly reduces their potential occurrence in areas that could result in harm. Under this approach, Avista believes it can prudently manage the replacement of priority Aldyl A pipe with the goal to avoid harmful incidents altogether, and at a reasonable rate impact for our customers.

Initial Optimization

Importantly, Avista's proposal for a 20-year replacement program represents an optimization based on the information we have available today. Any number of factors could change as the work proceeds over the first few years that could result in a 'new' optimum time horizon. Avista will be collecting new leak survey and other information each year, and will continue to use its Asset Management models to further refine expected trends and potential consequences, making program adjustments as appropriate.

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 32 of 35

Responsive Replacement Program

Avista also modeled a very-different pipe replacement strategy to provide a further measure of the efficacy of the systematic replacement program. This scenario, referred to as the Responsive Case, was essentially a reactive approach where pipe remediation and replacement activities would be driven by leak survey results and the magnitude of leak consequences. Under this case, it's expected that pipe replacement activity would commence at a lower level than in the systematic case, but would also vary significantly from year to year, depending on patterns of detected leaks and their consequences. Ultimately, however, the expected activity and spending levels would far exceed both the annual and cumulative costs of the systematic approach. This is because pipe segments are not replaced ahead of actual material failure (as happens in the structured case) and so the resulting work activity more-generally follows the geometrically-increasing numbers of material failures expected over time. This scenario was easily judged as failing to provide an appropriate measure of prudence, including system safety, reliability, cost-efficiency, or business risk. Without a prioritized replacement protocol in place Avista would be resigned to replacing pipe in response to serious leaks and potential incidents, after-the-fact, rather than with foresight. Such was the case with the Aldyl A replacements Avista completed in 2011.

From a practical standpoint, Avista believes that by managing the replacement of its priority Aldyl A pipe in a systematic way it can prudently manage potential risks and impacts to its customers and other stakeholders, plan for and use construction resources most efficiently, and plan more effectively for the capital and expense requirements necessary for the effort. This is clearly the case when compared with a responsive approach.

Dr. Palermo's Assessment of the Proposed Protocol for Managing Avista's Priority Aldyl A Piping

Following Avista's Integrity Management evaluations of failure trends in its Aldyl A piping, and the development of its proposed protocol, we invited Dr. Palermo to review the completed protocol and to judge, from his expert perspective, the overall effectiveness and adequacy of the program. Dr. Palermo completed his review in February 2012, and judged Avista's protocol to be highly responsive and appropriate to the management needs of the priority Aldyl A pipe in Avista's system. In particular, he noted his support for Avista's priority focus on pre-1973 Aldyl A pipe, and on the plan to remove and replace its pre-1984 Aldyl A mains. He further noted his agreement with Avista's priority for remediating Aldyl A services tapped to steel main pipe, and to the protocol of "managing in place" existing Aldyl A service piping between the mains and meters. Finally, Dr. Palermo agreed with the proposed twenty-year replacement time horizon for Avista's priority Aldyl A pipe, noting the reliability modeling results, and the effectiveness of Avista's increased leak survey and application of Integrity Management information, tools and analysis in prioritizing pipe replacement activities. Dr. Palermo reviewed and approved this affirmation prior to the finalization of this report.

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 33 of 35

Application of Avista's Washington State Study Results to Aldyl A Pipe in the States of Oregon and Idaho

Forty-six percent of Avista's Aldyl A main pipe is currently in service in the State of Washington, and coincidentally, so are 46% of Avista's Aldyl A services tapped to steel mains. Since Avista's leak survey study and subsequent modeling results are based on Washington State data, then it follows that the expected results are most applicable to this jurisdiction. The degree to which the reliability modeling results are applicable to Avista's Aldyl A pipe in the States of Oregon and Idaho depend on factors such as the age of the at-risk pipe and on the known similarity of conditions under which the pipe was installed, including method (trenching or plowing), backfill material, compaction and squeeze-off practices, soil conditions and ambient soil temperature, etc. Avista is aware of at least some general differences among state jurisdictions, including more favorable soil conditions in Oregon, newer pipe materials, and construction techniques potentially more favorable to low-ductility pipe. A contributing complication, too, is the relatively large amount of pipe of unknown age and material in services in Oregon. This territory was acquired by Avista from a utility that did not have a consistent practice of mapping services, and some existing maps were lost before the purchase. As a result, Avista is conservatively managing this 'unknown' pipe as if it was priority Aldyl A pipe, until the time that these segments are verified by records review and possible field verification.

Most important to this discussion, however, is the fact that Avista is using its Integrity Management model to integrate leak survey and other data to develop the priority pipe replacement activities for each year of the program. Since comparable leak survey data from priority Aldyl A pipe in Idaho and Oregon will be included in the prioritization analysis, then regardless of any differences that do affect the expected reliability of the Aldyl A pipe, that inherent reliability will be automatically integrated into the modeling, ensuring that Avista is systematically replacing the pipe at greatest risk, regardless of the jurisdiction. Finally, since the Medford and Grants Pass, Oregon, service territory offers a 12-month construction season, Avista will be able to continuously mitigate priority Aldyl A piping within that area when northern territories are effectively unable to continue working.

Resource Requirements and Expected Cost

Staffing

Avista's proposed Aldyl A pipe replacement project represents a major undertaking, even when spread over a twenty-year horizon. In addition to the scope of the effort, there's added complexity in efficiently managing the project, since Avista's territory extends from Bonners Ferry, Idaho to Ashland, Oregon, a distance of over 650 miles. Each year, the deployment of equipment and inspection and construction personnel will have to be adjusted across this service area in response to the sites identified for highest-priority pipe replacement in any given year. Avista is planning to coordinate with contractors to manage much of this construction, and since this project represents a long-term

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 34 of 35

construction commitment, it is expected that the pool of contractors bidding for this work will be substantial, resulting in advantageous pricing and flexibility of field labor.

Though much of the physical construction will be accomplished through the use of contractors, there will still be a need to increase Avista's internal staffing to manage the flow of information, quality assurance, mapping, and related project documentation. Quality assurance is a critical project element that Avista will rigorously control. Effective remediation of Avista's priority Aldyl A pipe is a critically-important corporate objective, and we must continually ensure that sound inspection, training and auditing delivers the results we expect. Finally, the pipe replacement activities themselves will often have disruptive effects on our customers and others. Avista will carefully coordinate customer and community communications and notifications in an effort to minimize the effects of any disruptions.

Capital Costs

Avista's analysis and planning effort is projecting capital costs just over $10 million annually from the year 2013 – 2032. Actual costs will vary somewhat depending on the prioritization of piping to be replaced each year, among other factors, and the calculated amounts will also be subject to an estimated 2.3% annual inflation. Avista is planning to spend approximately $5 million in capital on this program in 2012, allowing for effective planning with contractors, hiring Avista staff, and developing a solid project management foundation for years 2013 and beyond.

Exhibit No. 10
Case No. AVU-E-25-01 & AVU-G-25-01
J. DiLuciano, Avista
Schedule 1, Page 35 of 35

Avista Utilities

Study of Aldyl-A Pipe Leaks 2022 Update

Asset Management

9/15/2022

Executive Summary

Avista began a program to replace all its Aldyl-A pipe in 2011 in Washington, Oregon, and Idaho. A regulatory mandate to replace the pipe in 20 years is in place for Washington State (2031 deadline). While not mandated to do so, Avista enabled similar replacement timelines for Idaho and Oregon. The purpose of this report is to provide a regulatory update on progress made. Avista provided similar updates in 2013 and 2018. While not limited to the following, the update's primary intent is to show the amount of pipe removed (to date), the pipe removal costs, and the impact to safety from the remaining Aldyl-A pipe in the ground.

Washington and Idaho, despite rising costs, are on track to have all Aldyl-A pipe replaced by 2031. It is likely the Oregon replacement will not be complete until 2037. Several slowdowns have occurred in Oregon due to COVID-19 impacts, contractor strikes, 3rd party contractor staffing issues, wildfires, and municipal permitting turnaround times. Part of this study/update will target specifically the risk impact of extending the Oregon program out additional years. While all risk cannot be eliminated, the question to be answered is whether the Oregon extension adds substantial risk to Avista's customers living within these service territories.[1]

Scope

The scope is limited to Asset Management providing a review and update on Avista's Aldyl-A pipe replacement program. A key factor in this update is testing whether the remaining ("in use") pipe carries an unacceptable level of catastrophic failure risk that justifies amending the program's existing timeline[2]. Based on risk levels, can the program be extended, in Oregon, to 2037, given the delays noted above? The update will also provide detail on the amount of pipe that has been replaced, the amount of pipe still in active use, and the costs associated with pipe replacement. Benefit/Cost for the program will be discussed and it is noted the primary driver for removing the pipe is the catastrophic risk associated with the Aldyl-A pipe and not whether the program cost justifies itself. Consideration is being given to two failure type modes: service tees and slow crack growth. It is recognized that other failure modes exist, but these two failure modes are unique to the Aldyl-A pipe.[3]

[1] Similar safety criticality test and results will be discussed for WA, ID and OR. However, OR will be looked at separate due to the likely extended timeline (completion by 2037).
[2] Refer to Key Assumptions/Constraints. Availability Work Bench ('AWB') software was utilized to run Safety Criticality tests for the remaining pipe still in use.
[3] Remaining failure modes, considered for the Aldyl-A pipe, would not be all that dissimilar to the replacement pipe being installed.

Regulatory Requirements

As of August 2011, the US Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) mandates gas distribution pipeline operators to implement Integrity Management Plans, or in Avista's case, a Distribution Integrity Management Plan (DIMP) in which pipeline operators are required to identify and mitigate the highest risks within their system. For Avista, aside from third party excavation damage, the highest risks within our natural gas distribution system is Aldyl-A Main Pipe (Manuf. 1964-1984), and the bending stress that occurs on Aldyl-A service pipe where it is connected to steel main pipe.

More specifically, and as related to the risks identified above, in February 2012 Avista's Asset Management Group released findings in the "*Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System*" report. 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 Idaho, Oregon, and Washington.

Subsequently, the Gas Facility Replacement Program's (GFRP) was formed as the operational entity committed to structuring and implementing a systematic approach to mitigating the Aldyl-A pipe risks as identified in aforementioned report.

On December 31, 2012, the **Washington Utilities and Transportation Commission** (WUTC) issued its policy statement on Accelerated Replacement of Pipeline Facilities with Elevated Risks which requires gas utility companies to file a plan every two years for replacing pipe that represents an elevated risk of failure. The requirement to file a Pipe Replacement Plan (PRP) commenced on June 1, 2013. In response to this order, Avista's first 2-year PRP for 2014-2015 was submitted and approved in 2013 per Docket PG-131837, Order 01. Avista's second two-year PRP for 2016-2017 was submitted in 2015 and approved in 2016 per WUTC Docket PG-160292, Order 01. Avista submitted a PRP in June 2017, and 2019. In Avista's filings, the *"Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System"* report serves as the pipe replacement "Master Plan", and two-year pipe replacement goals which includes specific project locations, and the anticipated pipe replacement quantities.

On March 6, 2017, the **Public Utility Commission of Oregon** ("OPUC") issued Order 17-084 (*Docket UM 1722, Investigation into Recovery of Safety Costs by Natural Gas Utilities)*, which in part required each of the natural gas distribution companies serving customers in Oregon to file with the OPUC by September 30th each year an annual "Safety Project Plan" (or Plan). The purpose of the Plan is to increase transparency into the investments made by each utility that are based predominantly on the need to achieve important safety objectives. More specifically, the Plan is intended to achieve the following objectives:

- Explain capital and expenses needed to mitigate safety issues identified by risk analysis or new federal and state rules.
- Demonstrate the utility's safety commitment and priority to its customers.
- Provide a non-technical explanation of primary safety reports each utility is required to file with the OPUC's pipeline safety staff; and
- Identify major regulatory changes that impact the utility's safety investments.

The **Idaho Public Utilities Commission** (IPUC) has not required gas utility companies to submit an action plan, Avista has submitted the "Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System" report for review and communicates annual pipe replacement goals which includes specific project locations, and the anticipated pipe replacement quantities.

Key Objectives/Assumptions/Constraints

Key Objective:

Utilizing a Safety Criticality test, demonstrate whether an unacceptable risk of catastrophic failure exists on the remaining Aldyl-A pipe. Assuming a test failure, alternative approaches would be considered, including moving up, rather than extending timelines. Through this same test, confirm whether a timeline extension in Oregon is appropriate given the risk parameters set around this program. In addition, provide an update on progress made (to date) and discuss the costs involved with this program.

Key Assumptions/Constraints:

Weibull Curve

- Utilizing data from prior updates, existing leak data, and input from Subject Matter Experts, the Weibull curve parameters were established. Existing pipe data was incomplete for building out the model due to the fact it has yet to complete a full life cycle. Therefore, the existing data set required certain assumptions to be made to build out the model.
    - ETA, 80 years.[4]
    - Beta, 4.[5]
- Unit quantity based on size of Phase replacement. Oregon = 1,025 feet (Phase). Washington/Idaho = 2,000 feet (Phase).[6]

[4] Assumes 63.2% of all pipe sections will have experienced a failure within 80 years of installation.
[5] Beta < 1, Infant Mortality, Beta = 1, Random Failure, Beta > 1, Long Term Failure. In line with 2018 study that used a 3.95 Beta for Rocky Soil and 4.02 for Sand.
[6] A 10,000-foot stretch of pipe would equate to 5 units for WA/ID and 10 units (rounded) for OR.

Failure Mode(s)/Consequences

- Failure modes utilized in this update:
    - Slow crack growth
    - Service Tees.
- Leak data is from 2011 (program start date) to 2021 and was provided by Avista's Manager, Natural Gas Pipeline Integrity.
- Effects (consequence of failure), for modeling purposes, were limited to catastrophic failure. Failures, both catastrophic and non-catastrophic, would require immediate replacement. However, the costs to repair a non-catastrophic failure are immaterial to the overall results, do not impact the Safety Criticality test, and do not provide cost justification for the overall program.
    - Catastrophic Failure cost, $20,000,000.
    - Catastrophic Event occurrence, 1 every 40 years.
        - Redundancy Factor, 0.00125, based on an assumed 20 leaks/year.[7]
- Inspections are successful in detecting leaks but not necessarily preventing future leaks. Therefore, the Potential Failure/Functional Failure (P-F) Interval on leak detection = 0.[8]

Safety Criticality Test

- Safety Criticality Test models the likelihood of a catastrophic failure over a certain time period.
- Test parameter, 1 failure in 40 years.[9]
- Lifetime model simulation, 10 years. Assumes all or most of the remaining pipe will be replaced in the next 10 years; Oregon is likely to be complete in 15 years.
- Test simulation run for each year of the 10-year period. When the next year is modeled, the pipe is aged 8,760 hours (1 year) and the amount of expected pipe to be removed (prior year) is subtracted from the total.
- Oregon replacement assumed to be 15 years. Therefore, residual safety risk exists, for Oregon, after the 10-year run period. Approximately 56 miles of pipe, to be replaced, will remain in Oregon after 10 years.
- Safety Criticality results ≥ 1 = failure.
- Safety Criticality test run separately for Idaho & Washington and Oregon, given the expected different timeline to completion for Oregon.

[7] 28 leaks were detected in 2020 (WA/ID/OR) while 18 were detected in 2021. 20 leak assumption is conservative based on pipe replacement program which reduces mileage annually. Less pipe in the ground assumes fewer leaks.
[8] Assumes a pipe section passes a leak test but could fail as soon as the next day. Inspection does not create safe period for risk avoidance. Test is limited to determining whether an existing leak exists.
[9] For clarification, 1 or greater failures over a 40-year period would indicate a test failure.

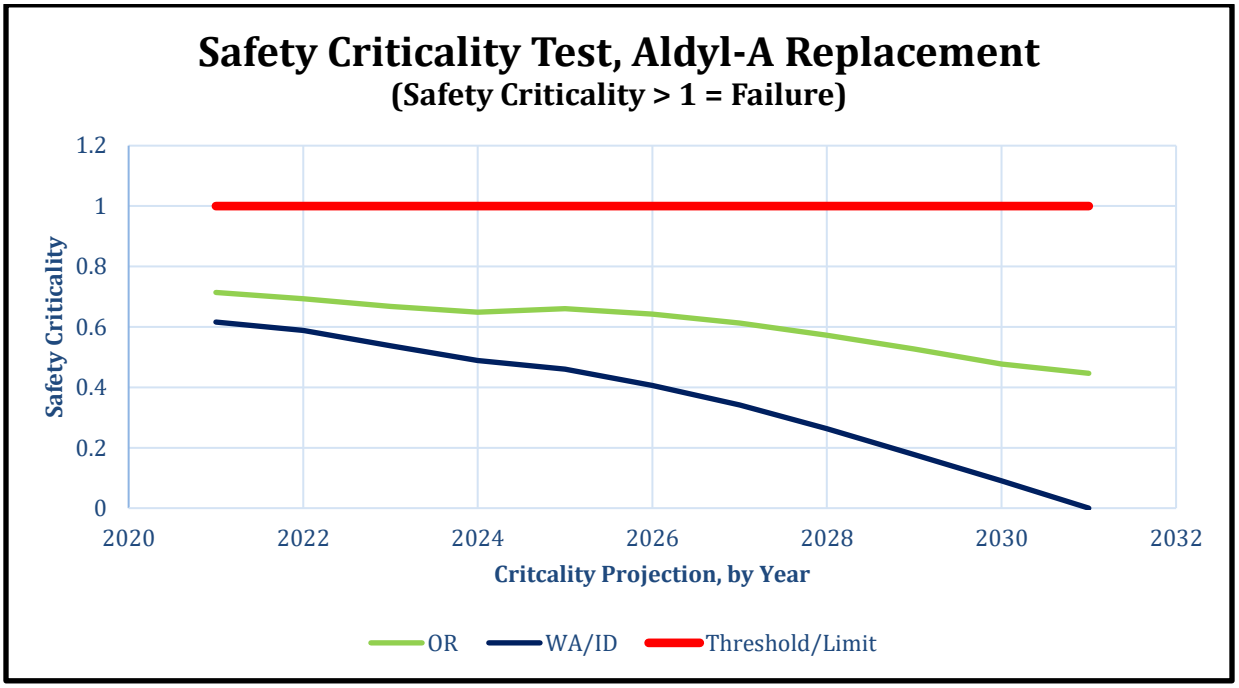
Linear Regression Assumptions

- Linear Regression analysis based on the leak data from 2011-2021.
- All slow crack growth and service tee leaks are included. Additional leaks, not specific to Aldyl-A, are removed from consideration as those leak types would occur with non Aldyl-A pipe.[10]
- Leaks per mile are determined by comparing total leaks to in use pipe remaining (end of year).

Results/Findings

Safety Criticality threshold not exceeded: (<u>Test Passed</u>)

Safety Criticality Test was built in Availability Workbench (refer to Key Assumptions, above). As already noted, the Safety Criticality Test was built around the probability of a catastrophic event occurring in the next 10 years. Based on the replacement schedule, the test is passed in all instances for Idaho/Washington and Oregon. Therefore, a critical failure is highly unlikely throughout the remainder of this program (refer to chart below).



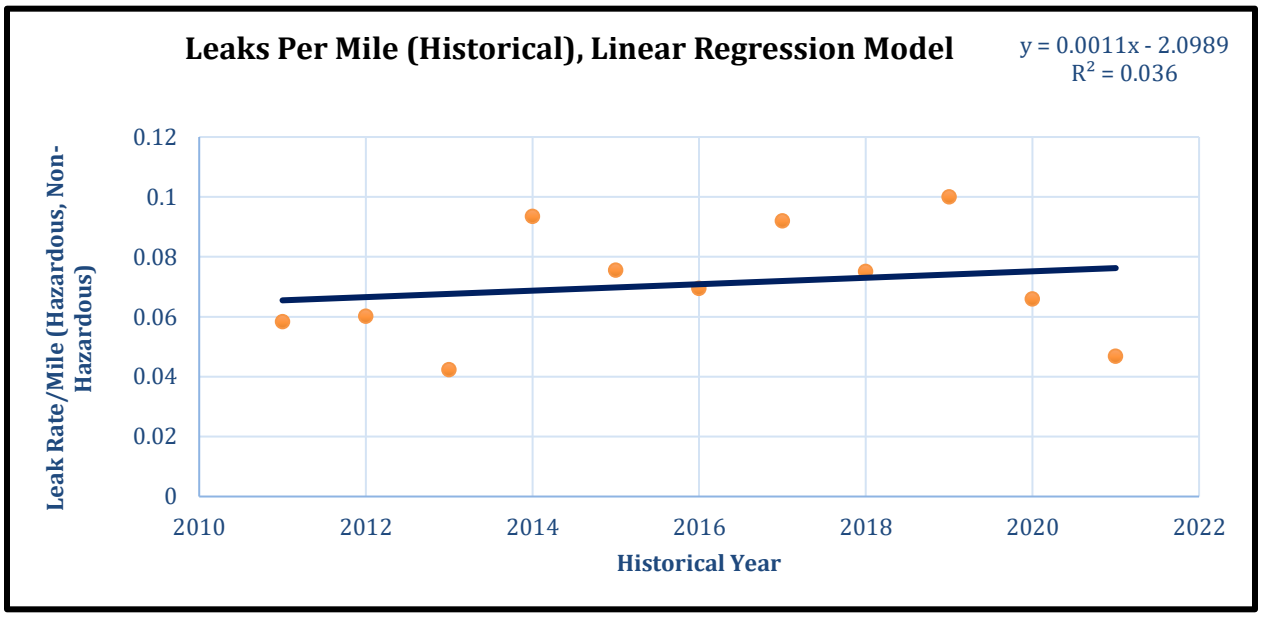
- Safety criticality test success does not eliminate all risk. Rather, the likelihood of a catastrophic failure is unlikely.[11]

[10] Purpose of the study is to isolate those leaks (failures) specific to Aldyl-A.
[11] Safety Criticality Test factors in number of prior leaks, age of pipe and the planned replacement schedule.

- Declining trend supported by pipe replacement. The pipe that is replaced is removed from future test consideration. Example: 300 miles of in use pipe remains. 40 miles is removed in year 1. Year 2 calculation would be based on 260 miles of in use pipe (300-40=260 miles).
- Residual risk remains for OR after 2031 because the OR portion is not expected to be completed until 2037. WA/ID assumes all pipe is removed by 2031.

Linear Regression Analysis shows stable trend and overall risk reduction:

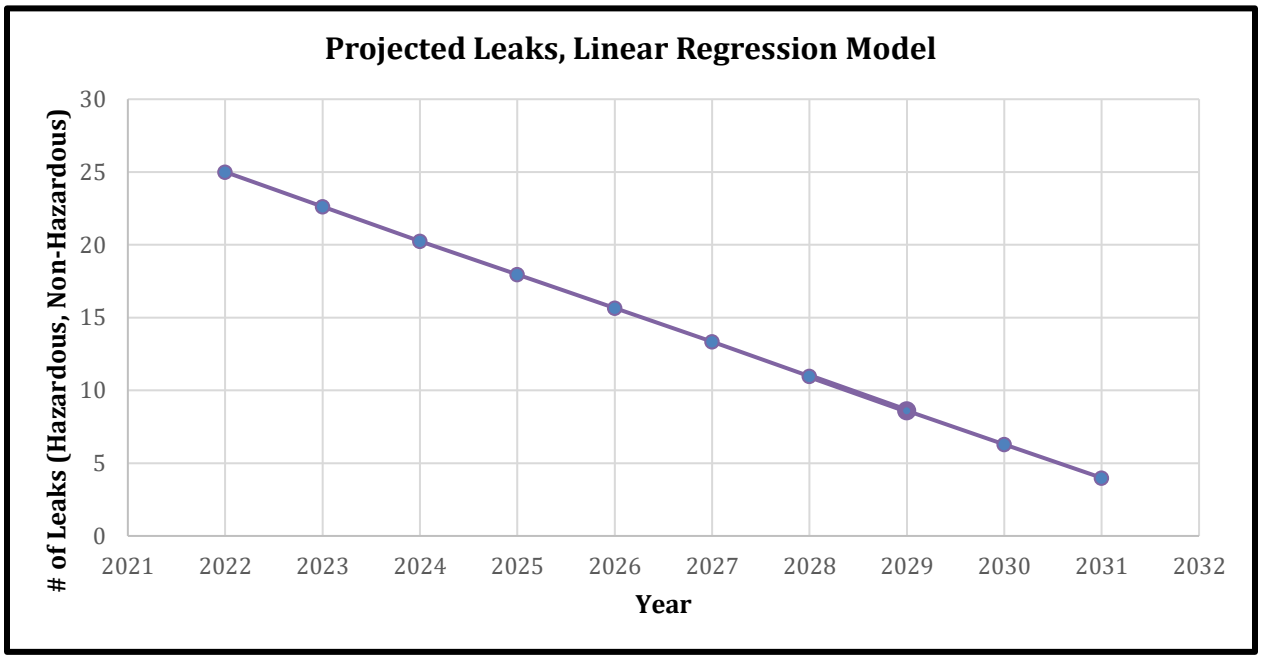
The Linear Regression Model (below) measures the number of hazardous and non-hazardous leaks since 2011.[12] The leak rate per mile can be determined through linear regression. As shown, there has been a slight uptick in the number of leaks per mile but the overall the trend is relatively flat and stable.



- Low R^2 suggests randomness in the data set but is consistent with the age of the pipe (yet to experience long-term wear out, therefore subject primarily to random failures and infant mortality).
- Trend line is relatively flat and while ticking up, it does not suggest a near-term material concern that supports changing the project's timeline.

[12] Linear Regression includes slow crack growth leaks and service tee problems experienced since 2011 for OR, ID and WA (combined). Hazardous and Non-hazardous leaks relate to the immediacy for a response. A hazardous leak does not mean a catastrophic failure has occurred.

Utilizing the linear regression equation (chart, above, top-right), the expected number of leaks can be plotted against anticipated remaining pipeline in the ground at end of year.



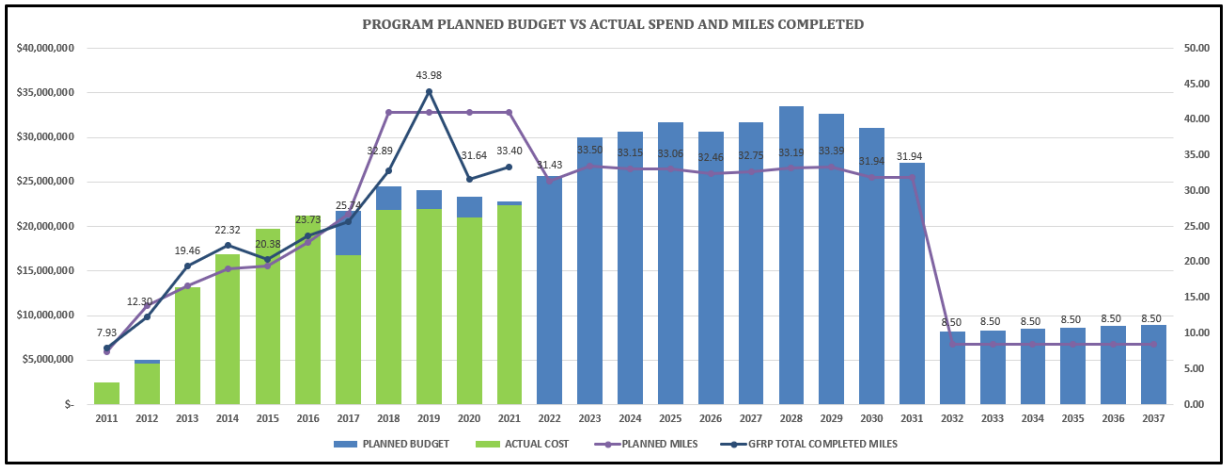
The Projected Leaks, Linear Regression Model (above) demonstrates continued risk reduction through pipe replacement and covers the combined service territory (WA, ID, and OR). The modeling does not indicate a need for any material adverse changes in the program's timeline and supports extending Oregon an additional five years (due to already mentioned delays in Oregon). Risk for a catastrophic failure remains but the chances of such an event occurring are remote. In addition, the leak survey program serves as an additional mitigant as many of the past leaks have been detected, through the program, and remedied.

Program is on schedule to be completed in time in WA and ID. Additional time is needed in OR (2037):

Completion in WA and ID is expected by 2031; the project remains on schedule for both states. Oregon is expected to be completed by 2037. As noted in the Executive Summary, delays have occurred in Oregon due to COVID-19 impacts, municipal permitting delays, wildfire, and 3rd party contractor strikes, to name a few.

The chart below measures mileage completed (to date) and mileage planned against budget costs. [13]

[13] Source: GFRP Historic Program Analysis Asset Management V.2



The table below shows progress in aggregate terms by listing out the amount of pipe in the ground at the end of 2011 versus 2021. It highlights the slower progress being made in Oregon but overall demonstrates the program is on track for completion. It should be noted, however, budgets are tentative and subject to revision, based on[14]:

- Schedules and miles completed (prior year)
- Distribution Integrity Management Plan (DIMP) Analysis
- Budget Constraints

Any material changes in dollar amounts made available to the program could limit its progress going forward.

State	Pipe Remaining (EOY 2011, Miles)	Pipe Remaining (EOY 2021, Miles)	Percent Complete[15]
Washington	353	208	41%
Oregon	253	178	30%
Idaho	131	77	41%
Total	737	463	37%
Opportunity Work		*385*	*48%*

- *Note. As of January 2022, an additional 78 miles of pipe replacement has been completed, outside of the program, through opportunity work done by local*

[14] Budget and actual costs incorporate all planned work within the program: major main work, minor opportunity work, STTR work, priority services, and Aldyl-A replacement (cross bore).
[15] Includes 'Good' miles. 'Good' pipe is pipe that was manufactured and installed in 1985 and 1986 and does not need to be replaced. It is found during the year through potholing and map editing. This amount is combined with the construction completed amount to arrive at the annual total.

districts, pipe verification and map editing. Therefore, the overall project is closer to being 50% complete.

The program is getting more expensive as the cost per foot (CPF) has increased:

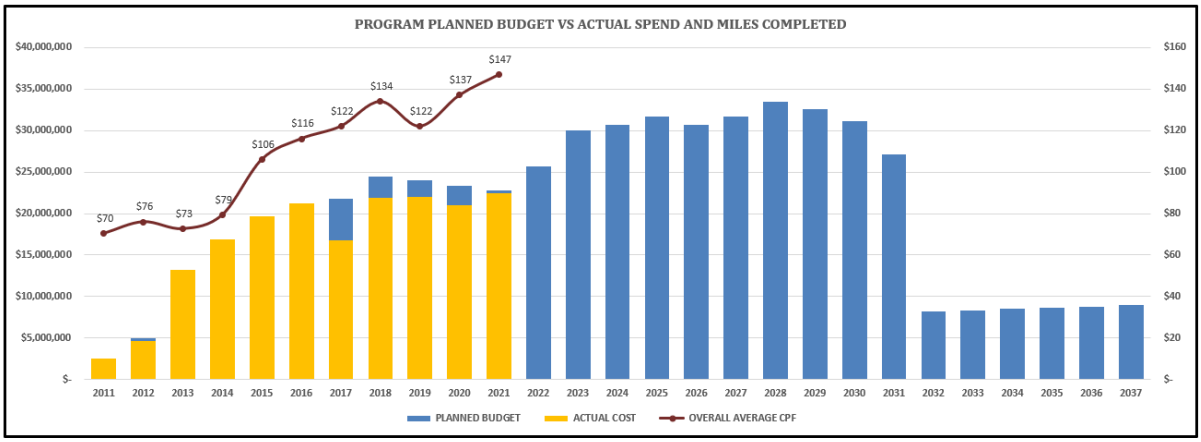
Replacing natural gas facilities decades after the initial installation, and after the subsequent development of the service areas is challenging. Replacement pipe must be installed in fully developed and occupied areas that consist of numerous below ground facilities, paved streets, sidewalks, arterials, landscaped residential neighborhoods, and hard-surfaced commercial developments teeming with daily traffic and other activity. New main pipe is most often installed by either "horizontal drilling" or open trenching. While horizontal drilling is far less invasive, both methods require cutting into existing pavement or other hard surfaces. Care must be taken to plan and locate the existing underground facilities to avoid damaging them, new service lines must be ditched into landscaped yards, etc., and all these features must be restored to unblemished service once the installation is complete.

During the first two years of the program Avista reported average per foot replacement costs ranging from $69 to $83 per foot. These costs included pipe replacement in hard-surfaced areas as well as areas of exposed soil, such as the shoulder of semi-rural roadways with limited adjacent facilities and road restoration. More recently, Aldyl-A pipe replacement project locations have been primarily located in suburban developments in which the right-of-way is fully built-out with paved roads and sidewalks and has required increased permitting stipulations. As a result of these conditions, pipe replacement costs have increased. In 2021, the average cost of main pipe replacement was $122/LF (per linear foot), with a low of $ $90/LF in Klamath Falls and a high of $155/LF in the City of Medford.

Avista continued to report its experience with replacement construction costs, in particular, as we experienced a trend on the part of municipalities toward more restrictive and expensive roadway restoration and traffic control requirements. Over the past several years these traffic control, pavement cutting, and remediation policies of local jurisdictions have had a significant impact on the scheduling, logistics, operational methods, extent of the area to be repaved, and the ultimate cost of pipe replacement. In Avista's experience, this continuing trend to enforce more restrictive moratoria on cutting in newer arterials and streets, to require more stringent requirements for backfill and compaction, for patching or repaving of streets cut for pipe replacement, and traffic control requirements have had a substantial impact on installation costs.

The chart below shows the average cost per foot from 2011-2021 for all three states. The actual pipe replacement costs are higher in Oregon. The major element of the total cost disparity is related to road restoration requirements in Oregon jurisdictions. These higher construction costs are a direct result of municipally driven traffic control permit requirements (e.g. plate locks), material handling requirements that include 100% export and import of trench backfill materials (e.g. slurry backfill), significant soil

compaction the width of pavement restoration, which averages 4 feet and can range from 2 feet up to 8 feet for segments of a project all which are beyond Avista's direct control.



- CPF has increased steadily since the program's inception.
- The program does not cost justify itself in that the actual and planned spends far exceed the dollar costs associated with a catastrophic failure.[16]

Summary of program changes for Oregon

While taking into consideration the extension of Oregon's Aldyl-A pipe replacement to 2037, there has been extensive analysis and research completed to ensure risk does not increase. As previously stated, various slowdowns have occurred which have impacted program timelines relating to work in Oregon. Impacts such as COVID-19, contractor strikes, contractor staffing issues, wildfires, municipal restrictions and municipal permitting delays have all created significant effects on operations and made replacement efforts much more challenging. Extending Avista's Aldyl-A replacement work in Oregon to 2037 will allow us the opportunity to balance affordability and overall impact to our customers. The data in this report supports that risk is continuing to be mitigated and that extending work in Oregon will not increase the risk of catastrophic failure.

[16] Cost associated with a catastrophic failure is $20,000,000 and is based on the following risk formula to determine its annual value: ***Pf * Pc * c, where Pf = Annual probability of failure, Pc = Annual probability of consequence, and c = consequence cost ($20 million).*** This annual amount can then be measured against the annual spend.

Exhibit No. 10, Schedule 3
Capital Investment Business Case Justification Narratives Index

Business Case Name	Page Number
Electric Distribution Capital Projects	
Distribution Grid Modernization	3
Distribution Minor Rebuild	15
Distribution System Enhancements	25
East CDA Lake Reinforcement Program	40
Elec Relocation and Replacement Program	56
Electric Storm	65
Joint Use	73
Meter Minor Blanket	84
Metro 115kV Substation	92
New Revenue - Growth	114
Substation - Asset Condition	121
Substation - Performance and Capacity	134
Substation Failed Plant	150
Wood Pole Management	157
Electric Transmission Capital Projects	
Ambient-Adjusted Transmission Line Ratings	171
Colstrip Transmission	180
Electric Storm	187
SCADA - SOO and BuCC	195
Substation - West Plains System Reinforcement Project	208
Transmission - Minor Rebuild	221
Transmission Construction - Compliance	228
Transmission Critical Crossing Reinforcement	237
Transmission Major Rebuild - Asset Condition	249
Transmission NERC Low-Risk Priority Lines Mitigation	260
Westside 230/115kV Station Brownfield Rebuild Project	266
Natural Gas Distribution Capital Projects	
Gas Above Grade Pipe Remediation Program	273
Gas Cathodic Protection Program	284
Gas Facility Replacement Program (GFRP) Aldyl A Pipe Replacement	293
Gas Isolated Steel Replacement Program	307
Gas Non-Revenue Program	322
Gas PMC Program	336
Gas Regulator Station Replacement Program	346
Gas Reinforcement Program	359
Gas Replacement Street and Highway Program	371

Gas Telemetry Program	379
Gas Transient Voltage Mitigation Program	390
Jackson Prairie Natural Gas Storage Facility	401
New Revenue - Growth	409
General Plant & Fleet Investments Capital Projects	
Capital Equipment Program	416
Central 24 HR Operations Facility	428
Fleet Services Capital Plan	447
Palouse Service Center	462
Right-of-Way Use Permits	479
Sandpoint Service Center	486
Structures and Improvements/Furniture	504
Telematics 2025	523

DocuSign Envelope ID: CEF1520C-4F79-4B1A-A653-51D5D4E2CEF0

Distribution Grid Modernization

EXECUTIVE SUMMARY

Avista's distribution system has numerous facilities at, or near, the end of their useful life. Over decades, many of these were built to different construction standards using a wide variety of materials. These factors contribute to energy losses due to inefficiencies due to age and vintage of materials and technology, and increased outages that take longer to restore and fall short of modern expectations that utilities face.

The Grid Modernization Program (GMP) is a capital program that was established in 2013 to holistically evaluate and address the improvement of Avista's approximately 11,300 circuit miles of overhead and underground primary electric distribution infrastructure. The goals of the program address service reliability and cost avoidance.

Service Reliability

Increase system and service reliability through targeted replacement of aging and failed infrastructure, removal of low reliability equipment and construction practices, relocation or reconfiguration of high-risk outage locations, and the addition of devices and equipment that improve service continuity.

Avoided Costs

Increase energy efficiency efforts through the replacement of equipment and materials that have increased energy losses, improvement of line losses through voltage and VAR optimization, load balancing, and the addition of devices and equipment that improve circuit efficiency.

The program was updated and re-approved in 2020 with a recommended solution based on an updated average cost per mile requiring a $28.88M annual investment to achieve a 60-year cycle. $77M in funding was requested over a 5-year duration as a ramp up to recommended funding levels. Since approval, priority and resources have been re-allocated to mitigate wildfire risk which includes approval and execution of Grid Hardening projects under the Wildfire Resiliency Program. The Grid Modernization program schedule was updated in 2022 to account for reduced budget allocation by extending project design and construction duration.

Upon the completion of GMP projects which are defined per distribution feeder, Washington and Idaho customers benefit from improved system reliability, safety, and performance. These can be measured by a reduction in outage frequencies and durations in addition to power quality metrics. Delaying the business case increases the likelihood and severity of various risks including equipment failure, wildfire, and energy losses. A delay would also impact the cycle time of Avista's Wood Pole Management Program (WPM). Not approving the business case places the responsibility of rebuilding the system on the individual offices throughout the company which are responsible for daily maintenance and operations as well as new revenue projects. Additionally, it jeopardizes the ability to holistically address system wide performance.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Robb Raymond*	*BCJN Final Draft*	*5/3/2024*
BCRT	*BCRT Member - Katie Snyder*	*Has been reviewed by BCRT and meets necessary requirements*	*05/08/2024*

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 3 of 535

DocuSign Envelope ID: CEF1520C-4F79-4B1A-A653-51D5D4E2CEF0

Distribution Grid Modernization

GENERAL INFORMATION

	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	$1,022,000	$1,096,660
2026	$803,400	$805,096
2027	$852,600	$776,244
2028	$957,000	$957,000
2029	$0	$0

Project Life Span	***1 year, 5 years, 10 years, etc.***
Requesting Organization/Department	Asset Maintenance
Business Case Owner | Sponsor	Robb Raymond | Paul Good
Sponsor Organization/Department	Asset Maintenance
Phase	Execution
Category	Program
Driver	Customer Service Quality & Reliability

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

The Grid Modernization Business Case (GMP) was developed to address the aging and failing infrastructure found throughout the electric distribution system. Other issues that are addressed include sub-optimal system performance and inaccessible facilities that drive increased routine maintenance costs. Outage durations and frequencies and power quality problems are also targeted for improvement through the installation of automated devices. Safety is also a key benefit of the Program as Grid Modernization projects bring facilities up to current NES and Avista construction standards, fulfill the efforts of Wildfire Resiliency, and address structures located within the control zone of roadways subject to Washington State's Department of Transportation Target Zero requirements.

1.2 Discuss the major drivers of the business case.

The GMP business case is driven by asset condition, performance and capacity. Customers benefit from improvements in electric distribution infrastructure in the following ways:

Grid Reliability

Proactively replacing aging and failed infrastructure that has high likelihood of creating customer outages reduces higher cost unplanned callouts which are ultimately passed on to the customer. Without programs like Grid Modernization and Wood Pole Management, there would be an average of 40 pole failure events per year affecting an average of 80 customers for 4.8 hours per event. The total customer impact value of

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 4 of 535

DocuSign Envelope ID: CEF1520C-4F79-4B1A-A653-51D5D4E2CEF0

these events is approximately $24,000 per event totaling $960,000 per year. *(2017 Wood Pole Management Program Review and Recommendations, Rodney Pickett).*

Energy Efficiency

Replacing equipment such as old or undersized conductors and transformers that have high energy losses with new equipment that is more energy efficient and with better performance.

Operational Ability

Replacement of conductor and equipment that hinders outage detection and install automation devices that enable isolation of outages.

a. This leads to shorter duration of outages for customers because areas that have failed can be more quickly identified and there is a potential to reroute power automatically.
b. Installation of automated line devices on a feeder of 1,600 customers reduces an average outage duration from 3 hours to 5 minutes for 1,200 of those customers.
c. Potential reduction in hotline holds.

Safety

Focus on public and employee safety through smart design and work practices.

a. Replacing aging and failed infrastructure puts employees and customers at risk.
b. Infrastructure is brought up to current National Electric Safety Code
c. Eliminating PCB risk to the public and environment by eliminating transformers with known PCBs.
d. Lowers risk of high severity safety (S4) events, defined below as follows:
    - Having potential for multiple serious injuries or loss of an individual life, major damage to property or business, and a public health infrastructure impact up to 72 hours.
    - Base case (do nothing) has the risk of 10 S4 events every 50 years with a total cost of $52.3 million. Grid modernization brings this risk down to 2 events in 50 years with a total cost of $10.4 million (2017 Wood Pole Management Program Review and Recommendations, Rodney Pickett.)
e. Address Washington State's Department of Transportation (WSDOT) Target Zero requirements, which states that utilities move all non-breakaway structures such as power poles and pad mount transformers out of highway clear zones as defined in the 10/2005 AASHTO "A guide for Accommodating Utilities Within Highway Right-of-Way". Washington law requires that this task is completed by 2030. Additional control zone justifications are included in following Washington Administrative Codes (WAC) and Revised Codes of Washington (RCW):
    - WAC 468-34-350- Control Zone Guidelines
    - WAC 468-34-300- Overhead Lines Location
    - RCW 47.32.130 Dangerous Objects and Structures as Nuisances
    - RCW 47.44.010 Wire and Pipeline and Tram and Railway Franchises- Application- Rules on Hearing and Notice
    - RCW 47.44.020 Grant of Franchise- Condition- Hearing

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1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Delaying the work performed by the GMP would result in an increased risk of equipment failure, continued energy losses over time, expanded system maintenance costs, and unplanned outages. There would also be a lost opportunity to apply holistic and sustainable solutions following an in-depth engineering analysis to locations that experience recurring unplanned outages.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link.*

Avista Strategic Goals

Improvements to Avista's electric distribution system through the Grid Modernization program are an example of proactive efforts that focus on the customer's best interests serving them now by improving reliability as well as preparing for the future addressing capacity. Avista also must be responsible for mitigating risks that increase over time as infrastructure ages which impact customer and employee safety.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

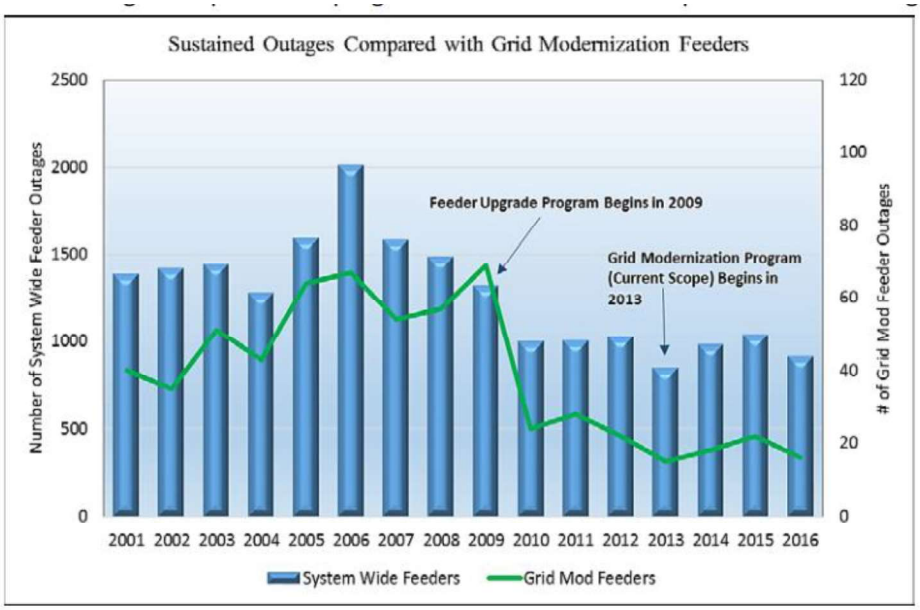
In an increasingly digitized world, power quality now plays a major role; even small transients or fluctuations can be more disruptive than full power loss. The value of lost service is growing each year as people depend more and more on what they consider essential services. Thus, Avista will continue to explore how resiliency fits into our overall reliability strategy. In addition, given the very long life of our electric transmission and distribution assets as well as the size of the investments and timeframe required to significantly change their overall performance, frequently revisiting our reliability and resiliency objectives will help us make targeted and timely adjustments to our strategy in ways that meet customer expectations and deliver the greatest optimized value.

Indicators of GMPs impact on feeder reliability are discussed below. The following graph as reported on page 69 of Avista's Electric Distribution Infrastructure Plan illustrates the positive correlation of the number of system wide outages relative to the number of outages on feeders treated by the Feeder Upgrade and Grid Modernization programs.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 6 of 535

DocuSign Envelope ID: CEF1520C-4F79-4B1A-A653-51D5D4E2CEF0



Secondly, A study was conducted by Asset Maintenance to measure the effectiveness and efficiency of holistically executing the planning and construction of multiple asset maintenance programs at once on a single feeder. The programs that were included in this model were Grid Modernization, Wood Pole Management and Transformer Change Out. Customer Internal Rate of Return (CIRR) was utilized to compare different program refresh models and integrating the three provided the highest value to the customer. Avista provided results of such a financial analysis in response to PC-DR-221, Attachment A, which is the Company's 2017 Wood Pole Management Program Review and Recommendations (see Exh. JD/LL-2, pages 2-94).

The lifecycle cost analyses reported were based on the output of 172 different Availability Workbench models integrated together to provide optimized solutions for individual assets and programs including the transformer changeout work as part of the Wood Pole Management and Grid Modernization programs, which is identical to its application in Distribution Minor Rebuild. Including transformer changeouts with the program reduced the total lifecycle cost to customers by $18.3 million in direct costs and by $46.9 million in risk costs, for a combined reduction in lifecycle costs to customers of $65.2 million, compared with the "Run-to-Fail" alternative of allowing the transformers and attached equipment, including the cutout to fail in service and returning to the feeder later to replace them one at a time. *(See Exh. JD/LL-2, pages 52-54).*

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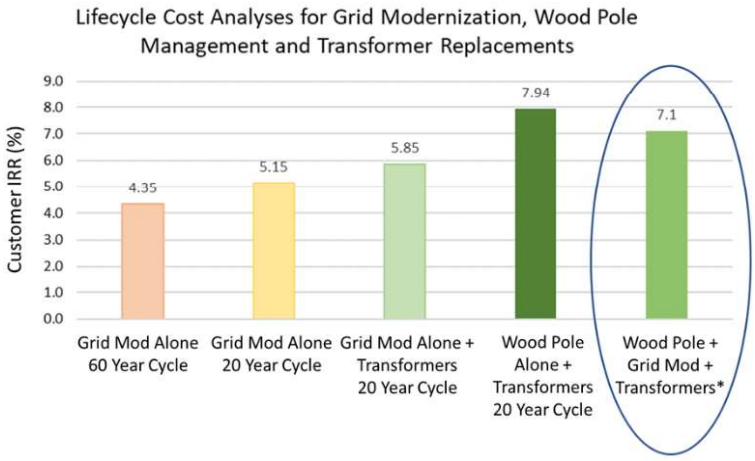
Illustration No. 8 – Lifecycle Cost Analysis of Avista's Grid Modernization Program as Optimized with Wood Pole Management and Transformer Replacements[91]



2. PROPOSAL AND RECOMMENDED SOLUTION - DESCRIBE THE PROPOSED SOLUTION TO THE BUSINESS PROBLEM IDENTIFIED ABOVE AND WHY THIS IS THE BEST AND/OR LEAST COST ALTERNATIVE (E.G., COST BENEFIT ANALYSIS).

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Follow the approach as stated in Avista's Electric Distribution Infrastructure Plan where the holistic scope of this program addresses reliability efficiency and effectively as part of the larger objective, Grid Resiliency. CPG funding has been re-directed through 2029 to mitigate wildfire risk, continue Grid Modernization efforts in parallel at reduced pace.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

Reliability improvements have been quantified that are a direct benefit to the customers in feeders that GMP has addressed. The analysis was performed by comparing reliability metrics in years before and after the GMP for all feeders completed through 2018. Figures 1-4 show these reliability metrics, and the raw data and analysis is located in the workpaper *"Grid Mod Reliability Data Analysis Before and After.xlxs"*

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

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CEMI3 is the percentage of customers experiencing 3 or more interruptions per year. The data shows that customers on feeders that have been addressed by the Grid Modernization Program experience a 61% reduction when major event day (MED) are not included and a 54% reduction when MED are included.

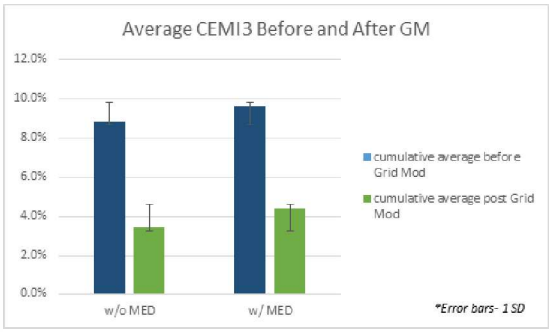

Figure 1.2A: Average CEMI3 on feeders that have been fully addressed by GMP. This includes all the feeders completed through the end of 2018.

SAIFI is the **S**ustained **A**verage **I**nterruption **F**requency **I**ndex. The data shows that customers on feeders addressed by the GMP experience a 51% reduction (with MED) and a 64% reduction in the duration of power interruptions.

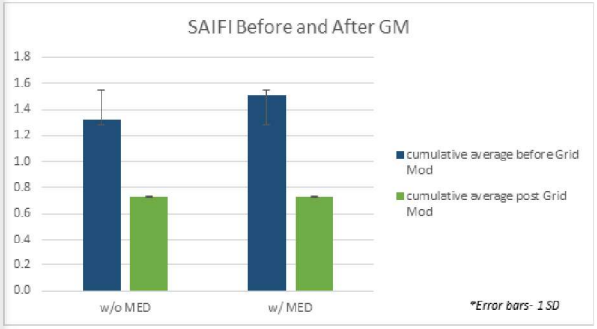

Figure 1.2B: SAIFI before and after Grid Modernization on feeders completed through the end of 2018.

SAIDI is the total duration of interruptions experienced by customers (in this case, the customers on one feeder). Customers on feeders addressed by the GMP experience a 64% reduction (without MED) and a 73% reduction with MED included. This means that the outages customers experience are shorter in duration.

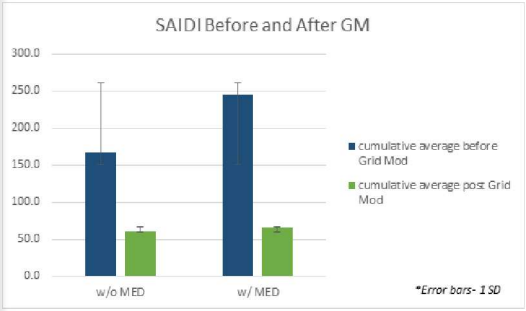

Figure 1.2C: SAIDI before and after GMP for feeders completely addressed by the end of 2018

CAIDI is the **C**ustomer **A**verage **D**uration **I**ndex, which indicates the amount of time it takes to restore service. Customers experience an 11% reduction (without MED) and an 18% reduction with MED after GMP.

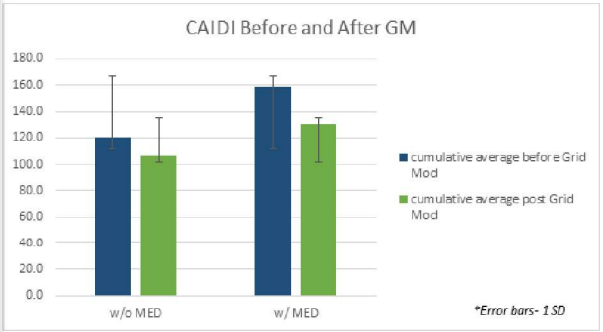

Figure 1.2D: CAIDI before and after being addressed by the Grid Modernization Program.

Looking forward, the Company will be evaluating options for establishing what we refer to as "actionable" goals and targets for reliability that will complement lagging outage frequency and duration metrics.

- That are within the control of the Company.
- That have a demonstrable impact on the reliability of our system.
- That are needed to support our overall reliability objectives.

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- That are cost-effective and make sense for our customers.

The objective of the program is realizing the most value gained by addressing service reliability, cost avoidance, and operational efficiencies by holistically treating a feeder with a comprehensive scope derived from the following asset maintenance programs [i].

- Wood Pole Management Program
- PCB Transformer Change Out Program
- Vegetation Management
- Segment Reconductor and Feeder Tie programs
- Distribution Device Management program

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Feeder health addresses how asset condition affects reliability where there are direct O&M savings due to a reduction in the average number of equipment outage events incurred per year based on asset condition.

Capital offset figures are estimated by feeder based on feeder analysis information provided to the Commission in PC-DR-110 (referenced in WUTC Rebuttal 200900-901-AVA-Exh-JD-LL 1-T_05_26_2021) Docket No. UE-200900, UG-200901, UE-200894).

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	n/a	n/a	n/a	n/a	n/a	n/a
O&M	Reduction in Service Calls	$101,839	$161,456	$198,726	$208,412	$208,412

Basis of estimation[4]:

- The capital offset figure was captured from the respective feeder status report.
- Figures were calculated by Asset Maintenance via the EVENTS Access Database
- Looks at only number of O&M equipment outage events per year.
- The following O&M Outage sub-reason events were used to model direct cost savings:

1. Conductor – Primary	6. Lightning	10. Undetermined
2. Conductor – Secondary	7. Pole Fire	11. Weather
3. Connector – Primary	8. Regulator	12. Wildlife Guard
4. Connector – Secondary	9. Snow/Ice	13. Wind
5. Elbow		

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] *Capital offsets were calculated in the workpaper "Grid Mod Cost and Schedule Management Baseline.xlsx"*

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2.4 Summarize in the table, and describe below the INDIRECT offsets[5] (Capital and O&M) that result by undertaking this investment.

The capital offsets below represent the deferred amount of work that the Grid Modernization completed that satisfies Wood Pole Management program scope. The values are based on the average cost ($47,900) to complete one mile of work under WPM scope. This value was calculated using YE 2022 data by our WPM Program Manager.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	Wood Pole Management Deferral	$244,815	$192,594	$204,571	$124,563	$0
O&M	None identified	$0	$0	$0	$0	$0

A second indirect capital offset attributable to Grid Modernization is the replacement of equipment such as old conductor and transformers that have high energy losses with new equipment that is more energy efficient and improve the overall feeder energy performance. This creates the need for less power generation or acquisition and equates to lower rates for customers.

The table below shows the estimated kWh energy savings[6,7,8] expected after completion of each project. These calculations are conservative in that not every energy efficiency improvement made during design and construction can be anticipated in the initial assessment. These estimates are derived from the initial assessments noted in the feeder baseline reports found in PC-DR-110 Attachment A-O. The primary reconductor savings are for trunk reconductor work only.

Feeder	State	Estimated Annual Pri. Reconductor MWh Savings	Estimated Annual Transformer Loss MWh Savings	Total Estimated Annual MWh Savings	% of Feeder to be Constructed	Avoided cost (per MWh) for energy conservation investments	Annual Capital Offset Estimate
ORO1282 Grid Mod	ID	0.0	103.0	103.0	100%	$105	$10,815
ROS12F4 Grid Mod	WA	2.6	64.1	66.7	100%	$105	$7,004
SIP12F4 Grid Mod PH2	WA	10.5	272.8	283.3	34%	$105	$5,652

[5] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

[6] *Additional MWh savings estimated through Distribution Automation enabled improvements are not included in these figures.*

[7] *Additional MWh savings estimated through the removal of Open Wire Secondary districts are not included in these figures*

[8] *Additional MWh savings estimated through power factor correction initiatives with capacitors, IVVC, or CVR are not included in these figures.*

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2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

[Recommended Solution]

Follow feeder modernization scope and timeline as stated in this Business Case Justification Narrative (BCJN) which is constrained by Capital Planning Group (CPG) annual budget allocation. Priority and resources have been re-allocated to mitigate wildfire risk which includes approval and execution of Grid Hardening projects under the Wildfire Resiliency Program.

Revise funding request down to $5M over 5 years to reflect change in capital prioritization.

Feeder	Miles to Modernize
ORO1282 Grid Mod	7.3
ROS12F4 Grid Mod	6.1
SIP12F4 Grid ModPH2	1.5
Total	14.9

Alternative 1:

Follow scope as stated in the Business case and follow the budget and timeline request stated in the 2020 BCJN as the recommended solution. The 2020 BCJN recommended solution was based on an average cost per mile requiring a $28.88M annual investment to achieve a 60-year cycle.

Alternative 2:

Address issues through the different specific company initiatives, such as WPM, TCOP, URD, Segment Reconductor, etc.

This means that a crew would potentially go out to the same area multiple times. This costs more for set up, travel time, flagging, etc. which means higher rates for customers. It also means the customer could have multiple planned outages and be impacted by multiple street closures for crews to address needed work at separate times. The risk reduction is also cut in half compared to the comprehensive work completed by GMP.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Measuring these goals is defined through the following key attributes organized into three categories.

- Performance: Thermal utilization, efficiency, voltage regulation, reliability performance (CAIDI, power factor, FDR imbalance.
- Health: Age, OH/UG ratio, pole rejection rate, reliability health (CEMI3, SAIFI).

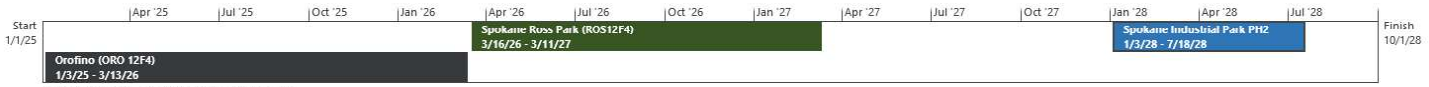
Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 12 of 535

DocuSign Envelope ID: CEF1520C-4F79-4B1A-A653-51D5D4E2CEF0

It should be noted that reliability indices are a lagging indicator against established baselines to measure performance and should be considered a barometer due to the complexity and variability of the metrics that make up these indexes such as seasonal conditions affecting average and peak loadings and extreme weather events.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

The 2025 through 2029 plan addresses ~14.9 circuit miles on the following feeders that have been designed. Transfer to Plant will occur on a monthly basis as each feeder initiates the construction phase of the project. At this time, there are no projects scheduled for 2029.



Grid Modernization Summary Timeline

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The steering committee is comprised of the Asset Maintenance Manager, Director of Operations, Operations Engineering, and the Program Manager. This group meets as needed, usually quarterly, for an update on the program or when key program decisions or changes in scope need to be discussed. The members of this group are called out in the Grid Modernization Communication Management Plan. The annual spend is also reviewed every three weeks by the Operation Round Table (ORT) that is comprised of the Director of Operations, various operations managers, and business case owners.

DocuSign Envelope ID: CEF1520C-4F79-4B1A-A653-51D5D4E2CEF0

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *<Project Name>* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Heather Webster A4EC470DF0D24E5...	Date:	May-15-2024 | 1:25 PM PDT
Print Name:	Heather Webster		
Title:	Manager, Asset Maintenance		
Role:	Business Case Owner		
Signature:	DocuSigned by: Robb Raymond 6EF8DBDFC86140E...	Date:	May-15-2024 | 11:26 AM PDT
Print Name:	Robb Raymond		
Title:	Program Manager		
Role:	Business Case Owner		
Signature:	DocuSigned by: Paul Good 8ADE2AA1AB5C4A9...	Date:	May-15-2024 | 4:12 PM PDT
Print Name:	Paul Good		
Title:	Director of Electric Operations		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

[i] Refer to page 64 of Avista Utilities Electric Distribution Infrastructure Plan

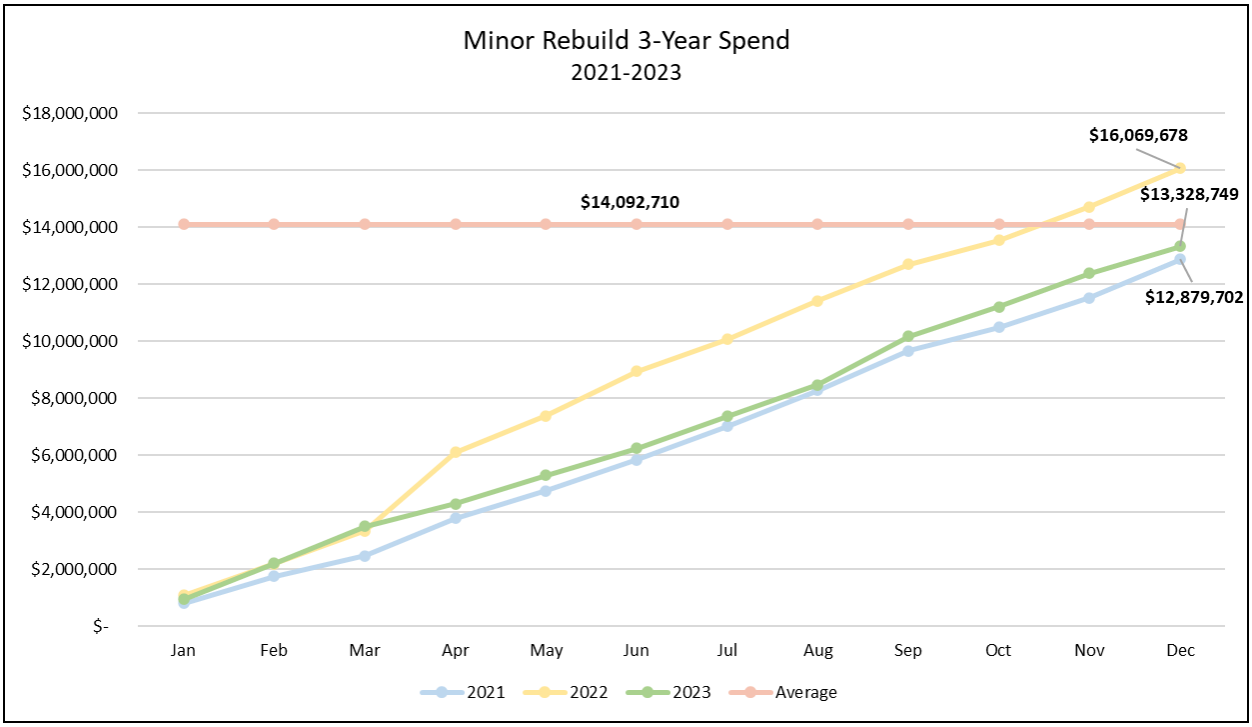
Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 14 of 535

Distribution Minor Rebuild

EXECUTIVE SUMMARY

Distribution Minor Rebuild is an ongoing program that focuses on keeping the distribution system in a reliable and safe condition for customers and employees. It ensures responsiveness to unplanned damages on distribution assets not related to weather events, as well as small customer driven rebuilds. Throughout the entire distribution system minor rebuilds or replacements of asset units are needed to maintain system reliability and safety. This work impacts customers in both Washington and Idaho. If not funded, the it will impact various types of work that will need to be absorbed into other funding due to the necessity of the work (i.e., the replacement of a car-hit pole in the alley, a broken cross-arm, a burned-up transformer, and a myriad of other safety related projects.) Also, if not funded, the business will affect the ability to respond to customers' needs for modifications to their electrical service.

The historical 3-year average spend for minor rebuild work is $14M per year. Based on recent analysis we anticipate the work demand to continue for the next 5 years. Minor Rebuild spends approximately $1.1M per month; as of March 2024 the spend on Minor Rebuild related work is $3M and we project the spend for this year to exceed $14M.



We have one upcoming change to this business case starting 2025. Beginning next year we will also be completing the LED Change outs under the Minor Rebuild business case. Currently, LED is it's own program, but since the program has primariliy ended and we are only changing the lights on a burnout basis, we will be absorbing that work under the minor rebuild business case. We have added what was approved for the LED Change Out program, which was $200,000, to our requested budget through 2029.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Katie Snyder*	*Annual Business Case Narrative Update*	*4/16/2024*

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 15 of 535

BCRT	*BCRT Team Member – Steve Corrozzo*	*Has been reviewed by BCRT and meets necessary requirements*	*4/18/2024*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$14,000,000**	**$14,000,000**
2025	**$14,620,000**	**$14,620,000**
2026	**$15,050,000**	**$15,050,000**
2027	**$15,500,000**	**$15,500,000**
2028	**$16,000,000**	**$16,000,000**
2029	**$16,474,000**	**$16,474,000**

Project Life Span	***Ongoing***
Requesting Organization/Department	Electric Operations
Business Case Owner | Sponsor	Katie Snyder | Paul Good
Sponsor Organization/Department	Operations
Phase	Execution
Category	Program
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

Distribution Minor Rebuild is an ongoing program that focuses on keeping the distribution system in a safe and reliable condition for customers, ensuring responsiveness to unplanned damages on distribution assets such as car hit pole, broken crossarm, burned up transformer, etc. that are not related to weather events, as well as small customer driven rebuilds. Throughout the entire distribution system, minor rebuilds or replacement of asset units are required to be completed to maintain system reliability and safety.

The work includes failed asset replacements, small mandatory or compliance driven work, smaller performance and capacity improvements, or unplanned customer requests. Occasionally, larger projects with an identified need and short timeframe for implementation are constructed under the Distribution Minor Rebuild business case. Even though the work is unplanned, Minor Rebuild work occurs regularly due to the nature of the utility business and numerous assets in the field spread

over a wide geographical area. An adverse accumulation of unrepaired assets would greatly put line workers and the public at risk as minor asset failures begin to deteriorate pockets of the distribution system as well as decreasing the reliability of the distribution system

1.2 Discuss the major drivers of the business case.

The primary drivers for the work are Asset Condition, safety, and reliability. This work focuses on keeping the distribution system in a safe and reliable condition for customers, ensures responsiveness to unplanned damages on distribution assets not related to weather events, as well as small customer driven rebuilds. Throughout the entire distribution system, minor rebuilds or replacements of asset units need to be completed to maintain system reliability and safety, which are a benefit to customers.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Distribution Minor Rebuild is an ongoing program that focuses on keeping the distribution system in a safe and reliable condition for customers, ensuring responsiveness to unplanned damages on distribution assets not related to weather events, as well as small customer driven rebuilds. Throughout the entire distribution system, minor rebuilds or replacement of asset units need to be completed real time to maintain system reliability and safety.

If it does not continue to be funded so we can do the work as it comes it could impact the overall reliability of the distribution system as well as responsiveness to customer requested service demands and system safety. The minor rebuild business case provides the funding for work such as replacement of a car-hit pole in the alley, a broken cross-arm, a burned-up transformer, and a myriad of other safety related projects. If unfunded, this will impact our ability to respond to customers' needs for modifications to their electrical service.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

Our oganization's main focus areas are our customers, our people, performance, and invention. Distribution Minor Rebuild aligns with the strategic vision, goals, objectives, and mission statement of the organization because it's focus is to maintain and improve the safety and reliability of our distribution system for our customers and to improve performance by expanding our distribution system through small customer requests to meet more customer's needs. We are putting the customer at the center of all the work we complete.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 17 of 535

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

Distribution Minor Rebuild is an ongoing program that focuses on maintaining safety and reliability for our customers and workers. When unplanned repairs, customer requests, or compliance related modifications present themselves they must be addressed in order to preserve the safety and reliability of our distribution system. Funding this business case allows us to make repairs or upgrades that allow us to maintain a safe and reliable distribution system.

In order to identify the problem(s) this business case will solve we look at historical data that shows the instances where minor rebuild repairs needed to be made and use it to establish a minimum funding level baseline, identify trends, forecast if the problem will continue and what resources we will need to remedy those situations as they come.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Distribution Minor Rebuild is an ongoing program that focuses on keeping the distribution system in a safe and reliable condition for customers ensuring responsiveness to **unplanned damages** on distribution assets not related to weather events, as well as small customer driven rebuilds. It also enables Avista to better be able to respond to unanticipated weather events. Throughout the entire distribution system, minor rebuilds or replacement of asset units need to be completed to maintain system reliability and safety. Our proposed solution is to continue funding this business case at the level which provides us with the resources needed to make repairs and maintain our standard for safe and reliable service.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 18 of 535

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

Historical spend was used to determine the requested amount. A steady increase in costs for unplanned minor rebuild work has occurred for several reasons. Many assets on the distribution system are past their end-of-life cycle and contributing to this increase. The 3-year average actual spend for minor rebuild work is $14M. This level of work demand is expected to continue for the next 5 years due to age of plant and anticipated inflation.

In 2023, 2,300 work orders were created with the average cost equaling $4,035, which demonstrates the work is made up of thousands of small dollar critical non-discretionary jobs. Occasionally larger rebuild projects, such as a small reconductor project, are undertaken as Distribution Minor Blanket projects if prioritized by the Area Ops Engineers. Only 61 (3%) of the 2,300 work orders created in 2023 were over $25,000. Those 61 work orders averaged $56,291.

This analysis shows that under this business case we are effectively addressing a large number of minor rebuild situations that occur each year. Without it, all these little occurrences would compound into a less safe and less reliable distribution system to deliver service to our customer with.

Figure 3 displays a breakdown of the different types of charges that occur in the Minor Rebuild. The majority of charges are from specific work orders created to design the minor rebuild work needed on our distribution system. Distribution Minor Rebuild work also consists of isolated replacement of failed asset(s) that do not lend themselves to a specific project (i.e. trouble related work), which are charges falling under craft and non-craft expenditures.

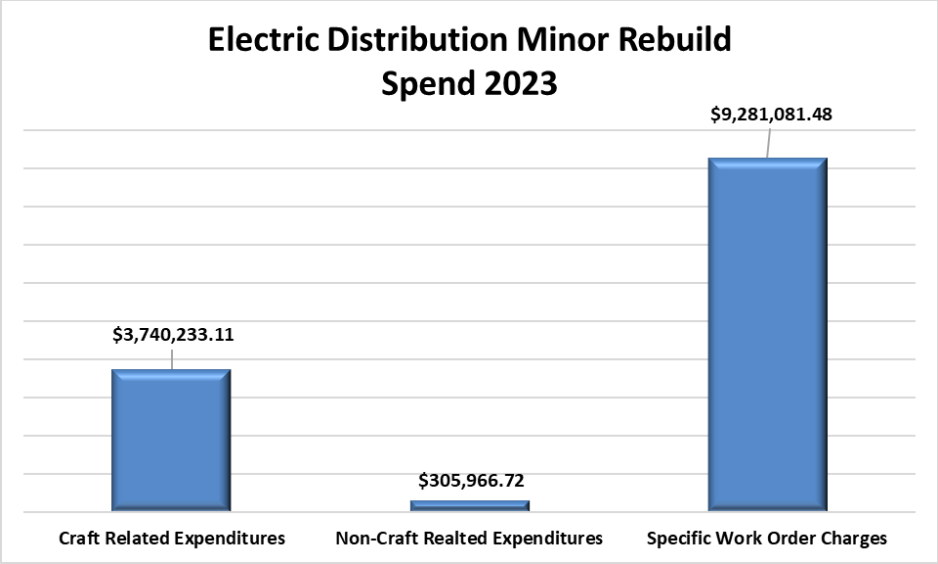


***Figure 3**: Types of Charges to Minor Rebuild*

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no direct offsets related to this business case.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

The Distribution Minor Rebuild Business Case is for unplanned repairs, replacement of failing equipment and/or small required upgrades on our system. These are jobs that are required to occur for safety, reliability, and compliance. One indirect offset for this business case would be avoidance of outages. By replacing failing equipment, we could potentially be avoiding an outage. As calculated by the ICE (Interruption Cost Estimate), our current outage cost per customer per hour is $116.15.

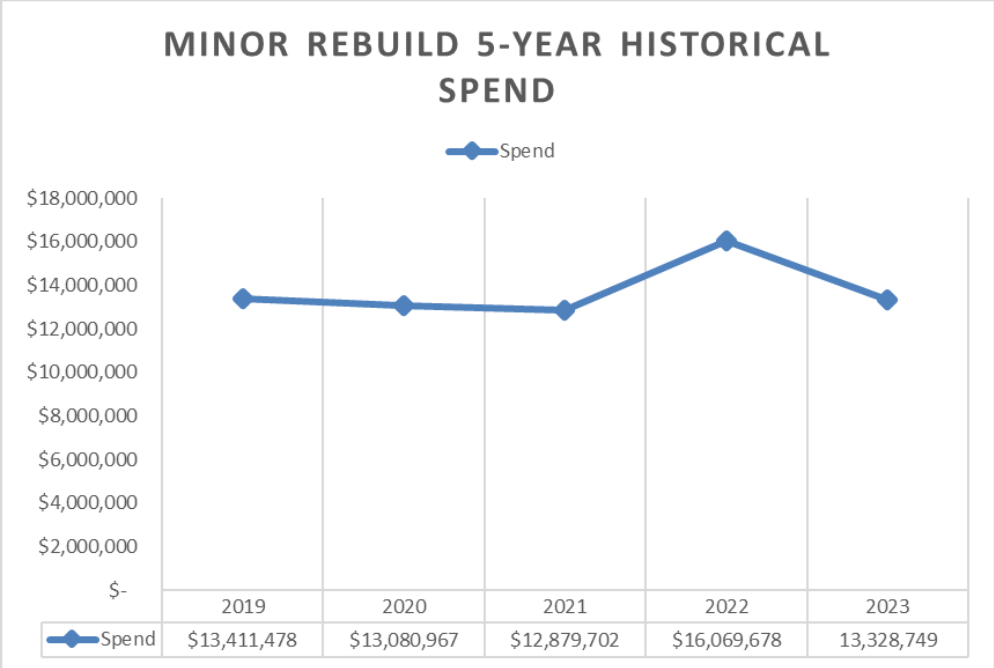
[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 20 of 535

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1: The work could be rolled up into another business case such as Storm or New Revenue/Growth. However, if we were to do that the expected spend for the work included in Minor Rebuild would be the same and would exceed the current budgets for those programs by almost double, requiring budget increases for those programs.



Alternative 2: Another alternative would be to not fund the program. If the program was not funded the ability to focus on keeping the distribution system in reliable condition for customers, maintain safe conditions for the workers, provide responsiveness to unplanned damages to distribution assets not related to weather events, as well as small customer driven rebuilds would be severally diminished. This would add unnecessary risk to our customers, employees, and the general public.

Alternative 3: There are no other known alternatives.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

In 2023 the Minor Rebuild spend was $13.3M. This spend allowed us to deliver/maintain a more reliable, compliant, and safe distribution system. We were able to focus on main categories below.

- **Customer Requested Rebuilds** – Work is initiated by an existing customer or property owner. The costs associated with the work are typically reimbursed by the requesting party. Examples include, but are not limited to: Customer requested reroute, overhead to underground line conversion, or customer load increase.
- **Trouble Related Rebuilds** – Emergency work required to repair damaged facilities caused by non-storm and non-fire related outages. Activities include a car hit pole, car-hit Padmount enclosure, copper theft, or unforeseen failed equipment that needs immediate response.
- **NESC / Operating Standard Violations** – Activities include, but are not limited to, NESC violations (not related to Joint Use clearances), secondary/service-related voltage mitigation, fusing protection mitigation, aerial trespass, and undersized equipment (transformers, regulators, etc.).
- **Asset Condition**– Activities include, but are not limited to, deteriorated wood poles, leaking transformers, condition related replacement (not outage related) of line devices and equipment.
- **Facility Upgrades/Efficiency Improvements** – Activities include, but are not limited to, small scale reconductors, small scale feeder ties, installation of new switches or sectionalizing devices, feeder balancing, installation of new regulators, reclosers, or capacitor banks, and removal of open wire secondary.
- **Facility Route / Location Modifications** – Activities include, but are not limited to, overhead to underground conversions, facility re-route, or relocation of midline devices to facilitate future maintenance and optimize sectionalization.

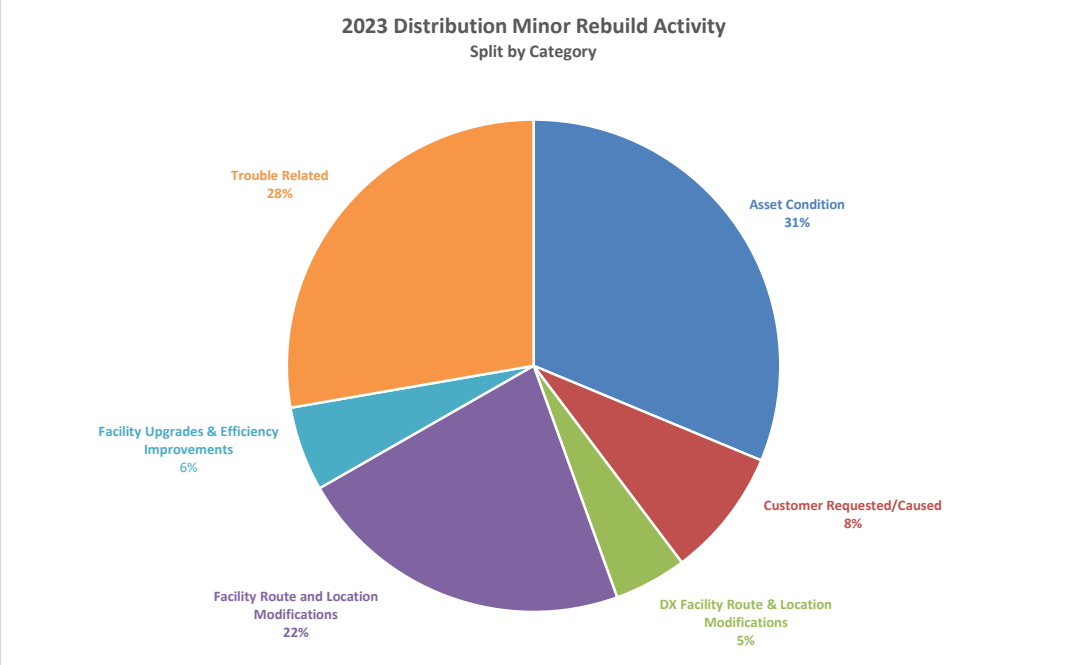


Figure 1 shows the allocation of the spend from 2023 for the six general categories above.

We continue to monitor the spend and allocation of the funds for Distribution Minor Rebuild to track our progress and ensure our customers are benefitting from this business case.

We use these metrics to understand the drivers of the business case and ensure we request sufficient resources to continue maintaining and improving our distribution system to provide safe and reliable service to our customers.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Distribution Minor Rebuild is an ongoing program and has no anticipated end date. Any upgrades or repairs made under this program are used and useful right away and transfers to plant on a monthly basis.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

This business case is written by the business case owner, reviewed by the business case sponsor, and then reviewed by the business case review team. It's then submitted to the Financial Planning and Analysis (FP&A) team for final approvals. This business case and it's spend are continuously monitored by the Operations Round Table which is comprised of Business Case owners, department managers and the department Sponsor, who meet once a month, and then finally the FP&A who also meet monthly.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Electric Distribution Minor Rebuild* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Katie Snyder	Date:	5/10/2024
Print Name:	Katie Snyder		
Title:	Business Analyst III		
Role:	Business Case Owner		

Signature:	PAul Good	Date:	5/15/2024
Print Name:	Paul Good		
Title:	Director Electric Operations		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 23 of 535
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Role:	Business Case Sponsor
Signature:	
Date:	
Print Name:	
Title:	
Role:	Steering/Advisory Committee Review

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 24 of 535

DocuSign Envelope ID: 94B3E083-EF10-4288-8074-73EEF96FAEC8

EXECUTIVE SUMMARY

Avista's electric distribution system is the largest part of the company's infrastructure. It consists of poles, wires, underground cable, transformers, and a variety of other equipment. In addition, Avista's electric distribution system has the largest footprint of any other infrastructure within the company's service territory. This creates a unique challenge for the company. The distribution system is the largest contributor to a customer's reliability and the overall safety of the public, mostly from the sheer volume of exposure it establishes. Most of our customer outages result from incidents that occur on our electric distribution system and this business case is one of several such as, Minor Rebuilds, Wood Pole Management, Grid Hardening, etc., that creates a direct customer benefit by completing projects that improve the electric distribution system's safety, performance, and reliability. Avista is required by the Washington Utilities and Transportation Commission (WUTC) to provide an annual reliability report that includes several industry standard reliability metrics. This business case along with others mentioned above are needed to keep our electric system's reliability and subsequent metrics within acceptable parameters. Not funding this business case or failing to fund it at an adequate level will limit our ability to proactively work on system issues resulting in a decline in our electric system's reliability. Such a decline in our electric system's reliability would undoubtably trigger substantial questioning from the WUTC. The current funds request for this business case is for $14 million on an ongoing basis. The projects for this business case are identified by Avista's Operations Engineers for their regional areas within Washington, Idaho, and Montana and they are prioritized against other regional projects with input from the Distribution Planning Engineers.

Most of the funds provided by this business case are used to complete projects that solve performance and capacity issues driven by system wide electric load growth. Other projects address power quality mitigation, reliability improvements, operational flexibility, system protection improvements, and safety reinforcements. As mentioned above, the risk in not funding this business case is the inevitable decline in the overall health and operation of Avista's electric distribution system, e.g., overloading conductor to the point of failure. This business case was used to address many electric distribution capacity constraints experienced during the heat event of June 2021. Additionally, we have completed projects and continue to complete work with this business case that mitigates system issues that are tied to Commission complaints from customers. The most recent have been voltage issues (service voltage below the 114-volt threshold) experienced by our customers after the cold snap in December 2022. The ongoing nature of issues that arise within the electric distribution system coupled with the large amount of work drives the need for this business case to be funded on a yearly basis.

DocuSign Envelope ID: 94B3E083-EF10-4288-8074-73EEF96FAEC8

VERSION HISTORY

Version	Author	Description	Date
1.0	*David James*	*Initial draft of original business case*	*04/07/2017*
1.1	*Cesar Godinez*	*Updated to include voltage/transformer mitigation work.*	*07/03/2019*
2.0	*Cesar Godinez*	*Updated narrative and business case template.*	*07/01/2020*
2.1	*Cesar Godinez*	*Minor updates.*	*01/04/2022*
3.0	*Cesar Godinez*	*Updated narrative.*	*08/31/2022*
4.0	*Cesar Godinez*	*Updated narrative and changed business case name.*	*03/01/2023*
5.0	*Cesar Godinez*	*Updated 5-Year Budget Request*	*04/11/2024*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	*4/26/2024 Steve Carrozzo*

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 26 of 535

DocuSign Envelope ID: 94B3E083-EF10-4288-8074-73EEF96FAEC8

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	*9,946,000*	*9,946,000*
2025	*14,000,000*	*14,000,000*
2026	*14,000,000*	*14,000,000*
2027	*14,000,000*	*14,000,000*
2028	*14,000,000*	*14,000,000*
2029	*14,000,000*	*14,000,000*

Project Life Span	*Continuous Program*
Requesting Organization/Department	*C51 / Electric Distribution Design*
Business Case Owner | Sponsor	*Cesar Godinez | Vern Malensky*
Sponsor Organization/Department	*T08 / Electrical Engineering*
Phase	Monitor/Control
Category	Program
Driver	Performance & Capacity

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

Avista's electric distribution system consists of three hundred and seventy (370) discrete primary electric circuits (feeders) encompassing over 19,300 circuit miles of overhead conductors and underground cables, along with all the other equipment needed to operate an electric distribution system. Our electric distribution system is the largest asset the company owns, and it has a book cost of about $2.1 billion. It represents the largest dollar value of any aggregated company owned system, including the sum of all our generation facilities. Load Demands on the grid are dynamic with load patterns changing because of many factors including weather, temperature, economic conditions, conservation efforts, and seasonal variations. The distribution grid is managed by division or 'Operations Engineers' and centralized Distribution Planning. The performance and capacity needs of this system are constantly changing, and this business case is the main tool available to our Operations Engineers so that they can keep up with these system demands. Most of the work completed with this business case addresses capacity constraints driven by load growth throughout the system. In addition to capacity constraint work this business case also addresses other electric distribution system performance work that is identified by engineering analysis and observed system performance issues. In 2021, 2022, and 2023 we experienced major weather events that exposed some system performance issues, some of these system performance issues resulted in Commission

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 27 of 535

DocuSign Envelope ID: 94B3E083-EF10-4288-8074-73EEF96FAEC8

complaints from customers who experienced low service voltage, below 114 volts. This business case was used in both cases of Commission complaints to fund mitigation work to fix the low voltage issues our customers were experiencing. In addition, our load growth has also been increasing when compared to historical growth rates. In our 2020 IRP we forecasted our system wide load growth as 0.3% with a peak load forecast of 0.3% in winter and 0.4% in summer. The current load growth forecast is projecting system wide load growth of 0.9% with peak load forecast of 1.2%. Additionally, the load forecast scenarios that consider electrification are showing system wide load growth of 1.9% with peak load growth of 3.2% in winter and 1.9% in summer. Figures 1 & 2 below help illustrate this trend, graphs provided by System Planning. Our Planning department has also completed some forecasting work that is showing pockets of growth in excess of 5%.

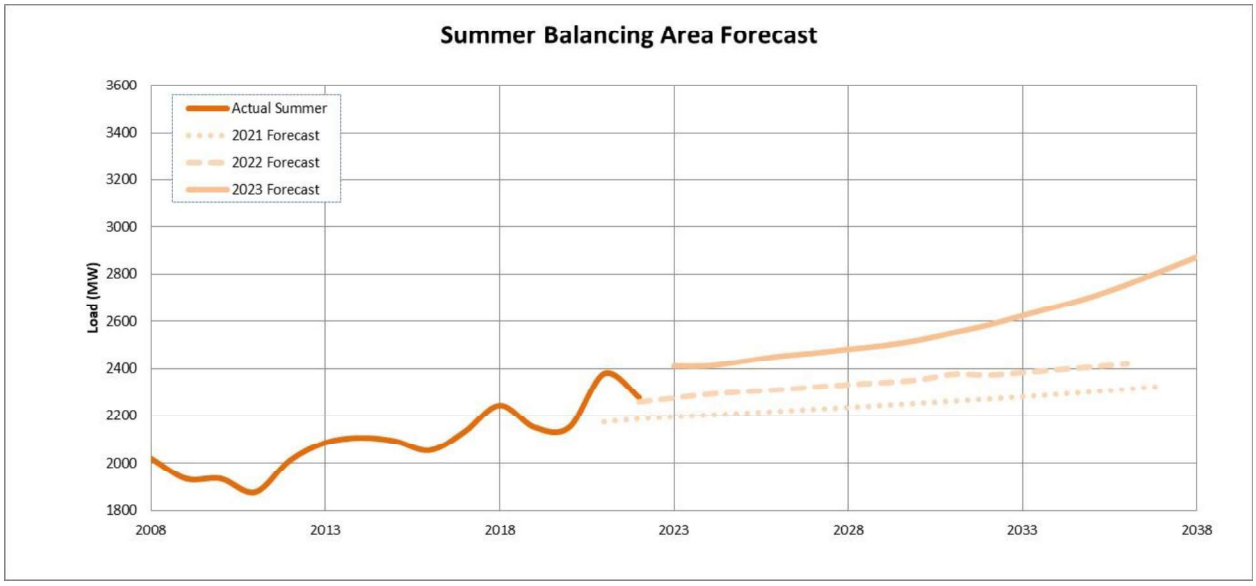

Figure 1: Summer Load Growth Forecast

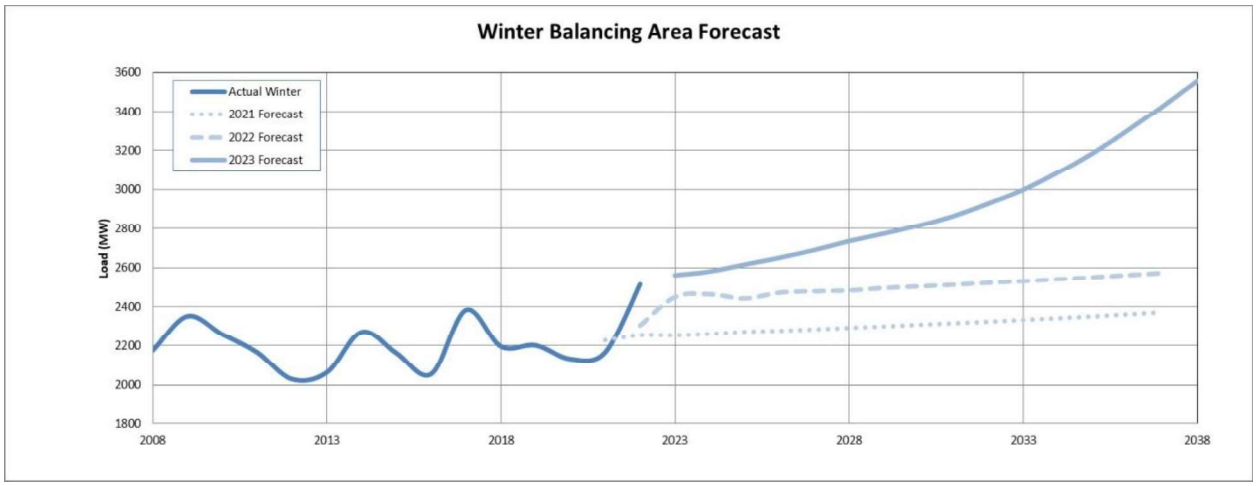

Figure 2: Winter Load Growth Forecast

Avista operates a radial distribution system using a trunk and lateral configuration (industry standard). Though many circuits are monitored at the source substation (SCADA), downstream trunk and lateral

DocuSign Envelope ID: 94B3E083-EF10-4288-8074-73EEF96FAEC8

branch circuits loading are analyzed via computer simulation. At Avista, distribution analysis is performed with the Synergi load flow program. AMI data is also used to analyze service voltages and transformer loading. AMI data has shown system issues in the form of service voltage problems and transformer overloading. Our System Planning group is also starting to export AMI load data into Synergi to use it in the computer simulation.

1.2 Discuss the major drivers of the business case.

The main driver for this business case is load growth on our electric distribution system. Outside of our New Revenue business case, this is the only other business case that is primarily focused on ensuring that our electric distribution system is adequate to accommodate our load growth. One big difference between this business case and the New Revenue business case is that in this business case our engineers are looking at the system as a whole within their areas and identifying needed projects that will keep the system operating within acceptable parameters. The New Revenue business case primarily deals with new line extension and rarely focuses on the existing system that often gets loaded to capacity because of these new line extensions. Other drivers of this business case include power quality investigations and subsequent mitigation projects which are initiated by customer inquiries or engineering analysis work. Work is also driven by reliability and safety concerns that are identified by our engineers and/or operation personnel. Power quality, reliability and safety driven projects completed through this business case are meant to mitigate code violations and observed system issues that will help maintain adequate levels of service in these areas for our customers. Operational flexibility can also drive the need to upgrade electric circuits, install switching equipment, and other infrastructure as needed.

In a manner like substation rebuilds, expansions, and additions that are planned for and scheduled years in advance, the distribution system also requires rebuilds, expansions, and additions. The Distribution System Reinforcements business case allows for a methodical and planned out approach to needed feeder reinforcements. Secured funding for future years allows for planning large projects in a multi-year approach, with completion of a portion of the overall project happening over a series of years.

Avista's electric distribution system analysis and mitigation strategies are informed by several internal documents and data repositories. These are listed below for reference:

1. Distribution Planning Standard "DP-SPP-02 Distribution System Performance" – internal document that defines the performance criteria and limits for our distribution system. This document is maintained by System Planning (John Gross).
2. FDR Status Report – Distribution Engineering publishes an annual report indicating peak circuit demand by season, reliability outage statistics, circuit health check, and other logistic information.
3. Distribution Standards – Distribution Engineering maintains construction standards for both overhead and underground primary circuits. It also maintains standards for all electrical material and apparatus.

DocuSign Envelope ID: 94B3E083-EF10-4288-8074-73EEF96FAEC8

4. PI Database – operating data retrieved by either the SCADA or DMS system is stored in the PI historian. This allows direct access by engineers and planners to help inform both operating and design strategies. (Distribution Operations)
5. Feeder Automation Strategy – a design guide to assist the CPC/Engineer when making decisions involving automated devices (Distribution Engineering).
6. Synergi Computer Program – the load flow program derives topology information from Avista's GIS system. Updates to the Synergi database are performed by Distribution Planning.
7. SCADA Variable Limit (SVL) – Avista uses temperature compensated program to monitor conductors, cables, and series connected major equipment (e.g. transformers, breakers, switches, regulators, and etc.). This system is deployed on Avista's EMS/SCADA system. The program is SME supported by Substation Engineering and Distribution Engineering.
8. AMI Data – AMI service voltage data is used to identify services that are out of compliance with the ANSI C84.1 standard of +/- 5% of 120 volts. AMI service load data is used to identify transformers that are overloaded according to the standards set by Distribution Engineering.

A typical distribution circuit is illustrated on the next page. Like municipal water systems, grid capacity decreases with distance away from the source substation. This leads to system 'constraints' as loads are added to the system through direct customer action or load shifting between circuits (Avista).

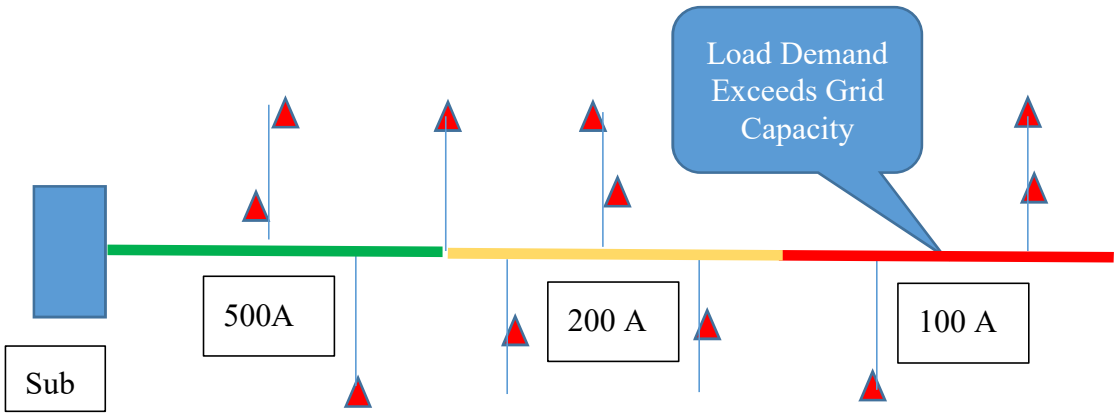

Illustration of Distribution Grid Capacity Constraint

Avista's Distribution System contains over 75 different wires and cables

DocuSign Envelope ID: 94B3E083-EF10-4288-8074-73EEF96FAEC8

2020 Avista Standard OH Primary Conductors
556 All-Aluminum (AAC) – 601 Amps (main trunk, urban)
336 All-Aluminum (AAC) – 442 Amps (main trunk, rural)
2/0 Aluminum Conductor, Steel Reinforced (ACSR) – 238 Amps (gen purposes, rural)
#4 Aluminum Conductor, Steel Reinforced (ACSR) – 119 Amps (lateral circuit)

Legacy Conductors
2/0-3/0 Copper – 319-369 Amps (main trunk)
#2 Copper – 197 Amps (main trunk)
#6 Copper - 110 Amps (lateral circuit)

Avista's distribution grid contains over 1,000 miles of conductor equivalent or smaller than #6 Copper.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The main benefit to our customers in continuing with this business case, as stated in the Executive Summary, comes from this business case's overall contribution to maintaining a healthy and operational electric distribution system. In absence of this business case, critical issues would be resolved in a reactionary and haphazard fashion, funded through the Minor Blanket, and completed outside the confines of a "big picture" plan and approach to feeder management. This reactionary and haphazard approach would increase the public's and the company's overall risk significantly. Without this business case our Operations Engineers would not have a funding mechanism to complete projects they have on their five-year plan. These projects target both current system issues and forecasted system constraints and they help ensure that our equipment does not fail under the ever-changing service load demands. Completing this work in a reactionary manner would mean that most of the time our efforts to correct a system issue will be after the fact once something has failed. The risk of allowing our equipment to fail can be immensely impactful to our customers and communities. In addition, overloading our equipment has the potential of creating several code violations as conductor starts to sag below allowable clearance parameters.

Another risk that this business case helps mitigate are the unforeseen weather events that have been occurring more regularly. As mentioned previously, in 2021, 2022, and 2023 our electric distribution system experienced extreme weather events that stressed the system so much so that we struggled to keep the power on for some of our customers. Not funding this business case now will perpetuate our system's inability to withstand these unforeseen weather events. The best way to ensure that our electric distribution system can withstand unforeseen weather events is take a big picture planned approach to system reinforcements, completing projects that help keep everything running within our system performance criteria. As previously stated, without this business case we're left completing

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work in a reactive manner never really getting in front of system issues and always fixing problems after the fact.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

This business case and the proposed investment lies at the heart of way we're a company and it is in full alignment with our vision, goals, objectives, and mission. Our electric distribution system is the threshold between Avista and most of our customers and to accomplish all the items listed above we must be able to maintain a healthy and operational system. There is no other business case that gives Avista such a proactive approach in creating and maintaining a healthy and operational electric distribution system.

In June of 2021 we experienced a heat event that stressed our system so much that we had to proactively shut power off to some customers to avoid larger more catastrophic failures. In December of 2022 and in the Winter of 2023, we experienced cold snap events that stressed our system such that we struggled to keep the lights on for some customers and others experienced service voltages below acceptable limits. Our vision as a company is "better energy for life" but it's impossible to deliver better energy for life when you can't keep the lights on.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

The projects completed via this business case are typically first proposed with a Project Requirements Diagram (PRD). These PRDs outline the high-level scope of a project, and they are complimented by documented analyses that shows why the need for the project exists. The Distribution Planning group also develops distribution system assessments that provide additional documented analyses in support of projects completed through this business case.

Section 1.2 lists eight internal documents and data repositories that are used in the evaluation and analysis of our electric distribution system to develop our planned projects. These documents and sources of data are the main tools available to our engineers and they're used on a yearly basis to keep ahead of potential system issues.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

DocuSign Envelope ID: 94B3E083-EF10-4288-8074-73EEF96FAEC8

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

There are three main elements to the proposed solution: Load Shifting, Capacity Increases, and System Reinforcements. Load Shifting requires that new feeder ties be created. This action is represented in the Distribution System Reinforcements program. By extending lines to adjacent circuits, load can be shifted to underutilized circuits and mitigate overloads. This action requires capital investment. Capacity Increases require power line reconductoring. Reconductor overloaded 'segments' to increase line capacity, mitigate identified low voltage issues, and correct system protection issues. Install voltage regulators to mitigate feeder level low voltage issues. Replace Transformers (or install additional transformers) to mitigate overloaded transformers and service voltage issues. All electric components are thermally limited. Reconductoring is the most direct approach to mitigating overloaded circuits and low voltage issues. Lastly, System Reinforcements help solve all the other problems identified. It's used to mitigate power quality issues, as well as reliability and safety issues. It helps us add operational flexibility to the electric distribution system and expand distribution automation by adding targeted "smart" devices. Accomplishing this type of work ensures that our electric distribution system is operated efficiently, reliably, and safe.

This proposed solution helps solve the business problem identified above by giving our Operations Engineers a funding mechanism to complete the work they've identified as needed. It also allows them to address system performance issues that come up unexpectedly.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

One of the planning objectives is to levelize the resource demands and avoid significant upswings or downturns in crew resource forecasting. Distribution Engineering works closely with the Operating Divisions and Asset Maintenance to develop a resource balanced work plan and maximize the effectiveness of Avista craft resources. In addition, reductions in funding of this business case typically result in increase spend in our Minor Blanket business case. There are also significant capital investment offsets created by the work this business case accomplishes.

Distribution assets are fixed resources and therefore, project alternatives are generally dominated by supply side solutions. Operating limitations are codified in Avista internal standards (as listed) but derived through industry and regulatory policies including: Washington Administrative Code (WAC),

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

DocuSign Envelope ID: 94B3E083-EF10-4288-8074-73EEF96FAEC8

National Electric Safety Code (NESC), National Electric Code (NEC), and IEEE/ANSI standards & manufacturer recommendations specific to equipment ratings and operating limits. This creates a challenge to provide a typical cost to benefit analysis. When a piece of equipment has reached its capacity threshold and is at risk of overloading there are few options available to address this risk. We are starting to look into non-wired alternatives but so far, the preliminary evidence is showing that these options are not cost effective or timely when compared to our traditional solutions (replacing wire/equipment). The best evidence of the benefit these projects create for customers is when nothing happens on the electric distribution system. Unfortunately, this can be difficult for others to accept as its abstract and not as tangible as IRR analyses. However, it's worth pointing out that during the 2021 heat event we proactively shut the power off to some customers to avoid catastrophic overloads of our equipment. This is exactly the type of risk we are mitigating with this business case and the benefit this business case provides our customers comes from giving us a tool to avoid these situations in the future.

2.3 Summarize in the table and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

The direct capital offset shown in the table below was calculated using the 2020 cost value for our Wood Pole Management (WPM) program to complete 1 mile worth of work ($39,570/mile). This cost value was calculated in 2021 by our WPM program manager. Next, our average miles of reconductor performed through this business case (12.76 miles) were calculated. This value was calculated using actual miles of reconductor completed through this business case every year from 2018 to 2022. These two values multiplied together produced an average WPM offset value, $504,913. The other direct saving comes from our avoided cost in outage labor/work. The calculated number for avoided cost for outage work ($1,108/mile) comes from our Asset Management Business Analyst and was calculated in 2021. Using this avoided cost number produces an average outage cost offset value of $14,143. To produce the new offset values for future years the average yearly actual spend ($5,957,897) was calculated for the same timeframe (2018 to 2022). This allowed us to calculate a percent increase/decrease from the average spend and apply that percentage to the average offset values for future expected spends. The details of how the offset values were originally calculated can be found in our 2021 document "Capital Investment Offsets Form – Distribution System Enhancements" and the calculation for future years being used here can be found in our excel spreadsheet "Average Offset Calculation." A $14,000,000 budget represents a 135% increase from the average yearly spend. This percent increase applied to the average offset values resulted in a WPM direct offset of $1,186,456 and an outage cost direct offset of $33,233.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	*WPM & outage cost Offset*	*$1,219,689*	*$1,219,689*	*$1,219,689*	*$1,219,689*	*$1,219,689*
O&M		$	$	$	$	$

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

DocuSign Envelope ID: 94B3E083-EF10-4288-8074-73EEF96FAEC8

2.4 Summarize in the table and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

The indirect offset shown in the table below was calculated by our Asset Management group in 2021. This calculated value assumes that every year we have at least one reconductor/feeder tie job that differs the need for substation capacity.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	*Substation Deferment*	*$28,683*	*$28,683*	*$28,683*	*$28,683*	*$28,683*
O&M		$	$	$	$	$

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1: Estimated cost unknown as work done as needed.

Reactionary Approach

Reacting only when an issue occurs to mitigate thermal overloads, power quality issues, reliability, and safety issues.

Conductor will 'sag' down beyond design limits and contact joint-use telecom circuits or violate NESC prescribed limits. In extreme situations, conductor failure will occur. Service quality will degrade below acceptable levels and customer outages will increase. System reinforcements (if they occur at all) will be done in a "scattered" approach and not guided by engineered plans and solutions.

Reactionary Approach is unacceptable. Violates NESC/WAC regulations and industry standards. It also represents an unacceptable level of risk to public safety and infrastructure. Knowingly avoiding upgrades until there is an actual observed violation might open the company up to more liability in the form of negligence. This can be financially devastating for the company, and it is difficult to estimate how much this added liability might cost.

This approach removes this business case entirely and all reactionary work would be completed via the Minor Rebuilds business case. Initially we would see cost savings ($14 million requested budget) because this business case would no longer be funded. However, there would be an inevitable cost increase in the Minor Rebuilds business case. Additionally, the increased cost associated with the added liability would more than offset any cost savings.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

DocuSign Envelope ID: 94B3E083-EF10-4288-8074-73EEF96FAEC8

Alternative 2: Estimated cost $5 million.

Load Shifting and Capacity Increases Only

Focus our efforts on Capacity Increases and Load Shifting projects only while not funding any work for System Reinforcements.

Attempting to only focus on either Load Shifting or Capacity Increases alone would miss many other projects that target reliability, service quality, operational flexibility, and distribution automation. Additionally, this approach would not allow for projects to be completed under this business case to address safety issues increasing the public's and the company's overall risk exposure. These projects would have to be addressed through other funding mechanisms and would likely be more reactionary efforts. This alternative would likely still require at least a $5 million investment on a yearly basis.

Alternative 3: Estimated cost $14 million each year for the next 5 years then back down to original request of $7.5 million.

Accelerate Funding in Distribution System Reinforcements

Increase the funding amount to nearly double of the previously requested amount, i.e., increase the funding to $14 million per year for the next 5 years.

Increasing the funding to $14 million would allow us to work through the stockpile of projects that we have in our 5-year plan. All the projects in our 5-year plan are needed but because of our limited budget we're prioritizing them accordingly. However, as we've experienced recently in the last few years unforeseen weather events can accelerate the need immediately leaving our system ill-equipped to handle the service load. Predicting which areas will have these issues has proven challenging at best and most of the time we've exhausted the quick fixes leaving us with only the longer term more complex and costly fix as a viable solution. Many of these longer-term fixes require multiyear projects but accelerating our funding would allow us to complete this work quicker to get ahead of the next weather event that might stress our system beyond what it's currently capable of handling.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

The main metric to use to measure this business case's success is our electric distribution system performance. This business case provides a mechanism for our Operations Engineers to address the most critical system issues which in turn improves system performance. Our ability to mitigate system performance issues and how many we address every year is the best metric to measure success. In general, our intent is to keep our feeders and other equipment below 80% of their capacity ratings. This 80% threshold comes from our System Planning group and their system planning standard "DP-SPP-02 Distribution System Performance." Keeping our infrastructure below the 80% threshold helps our system handle unforeseen weather events that often are accompanied by extra ordinary service loads. As previously stated, most of the work in this business case addresses system capacity constraints but all the work is tied to a system issue or forecasted issue being corrected. We keep

DocuSign Envelope ID: 94B3E083-EF10-4288-8074-73EEF96FAEC8

track of what issue each project is mitigating so that it can be easily reported out in the following format (example only): 10 capacity constraint jobs, 3 reliability jobs, 5 voltage issue mitigation (power quality) jobs, and 2 safety mitigation jobs. We also keep track of miles of reconduct and/or overhead to underground conversions.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

This business case is an ongoing effort that must be funded on a yearly basis. As such, next year's projects are identified in Q3 of the current year and work is started as soon as possible. Additionally, there are numerous projects every year in this business case that span Avista's entire 19,300+ circuit miles of electric distribution. The work is typically done consistently throughout the year monthly and is coordinated with each Operations Office. This work gets incorporated into every Operations Office's workplan schedule and is subject to changes depending on how each workplan fluctuates. The peak months typically follow our services territories construction season, Spring to Fall, as often we have limited access to areas during the Winter months. Most of the time when a project is complete it will be transferred to plant immediately.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Steering Committee or Advisory Group Information

Distribution Area/Operations Engineers and Distribution System Planning:

Tim Figart & Caitlin Greeney – Spokane and Deer Park

Marshall Law & Marc Lippincott – East Region (CDA, Kellogg, St. Maries, Sandpoint)

Dan Knutson – Othello & Davenport (Big Bend)

Tyler Dornquast – Colville

Chris Dux & Knute Rognaldson – South Region (Pullman, Clarkston, Grangeville)

John Gross, Amber Blackstock, Erick Lee, Kyle Hausam, & Damon Fisher – Distribution System Planning

Cesar Godinez – Distribution Engineering Manager

The Operations Engineers meet monthly to review projects and construction processes and discuss near term operating conditions. The entire team also meets annually to focus attention and resources on the system planning needs for grid capacity, service revisions, and substation capacity.

Decision Making Process

The decision model is represented by individual 'proposals' coupled with joint review and acceptance by distribution engineering and distribution system planning. The project 'proposals' typically consist of a Project Requirement Diagram (PRD) that outlines the scope of the project and includes supporting

DocuSign Envelope ID: 94B3E083-EF10-4288-8074-73EEF96FAEC8

calculations and documentation. The program's business case is modified annually to reflect the 5-year work plan. The Capital Planning Group then reviews all the submitted business cases and prioritizes and allocates resources across the organization. Distribution infrastructure is not part of the "Engineering Roundtable" except for distribution substations and other larger distribution projects on occasion.

The Distribution System Reinforcements business case decision model is illustrated below.

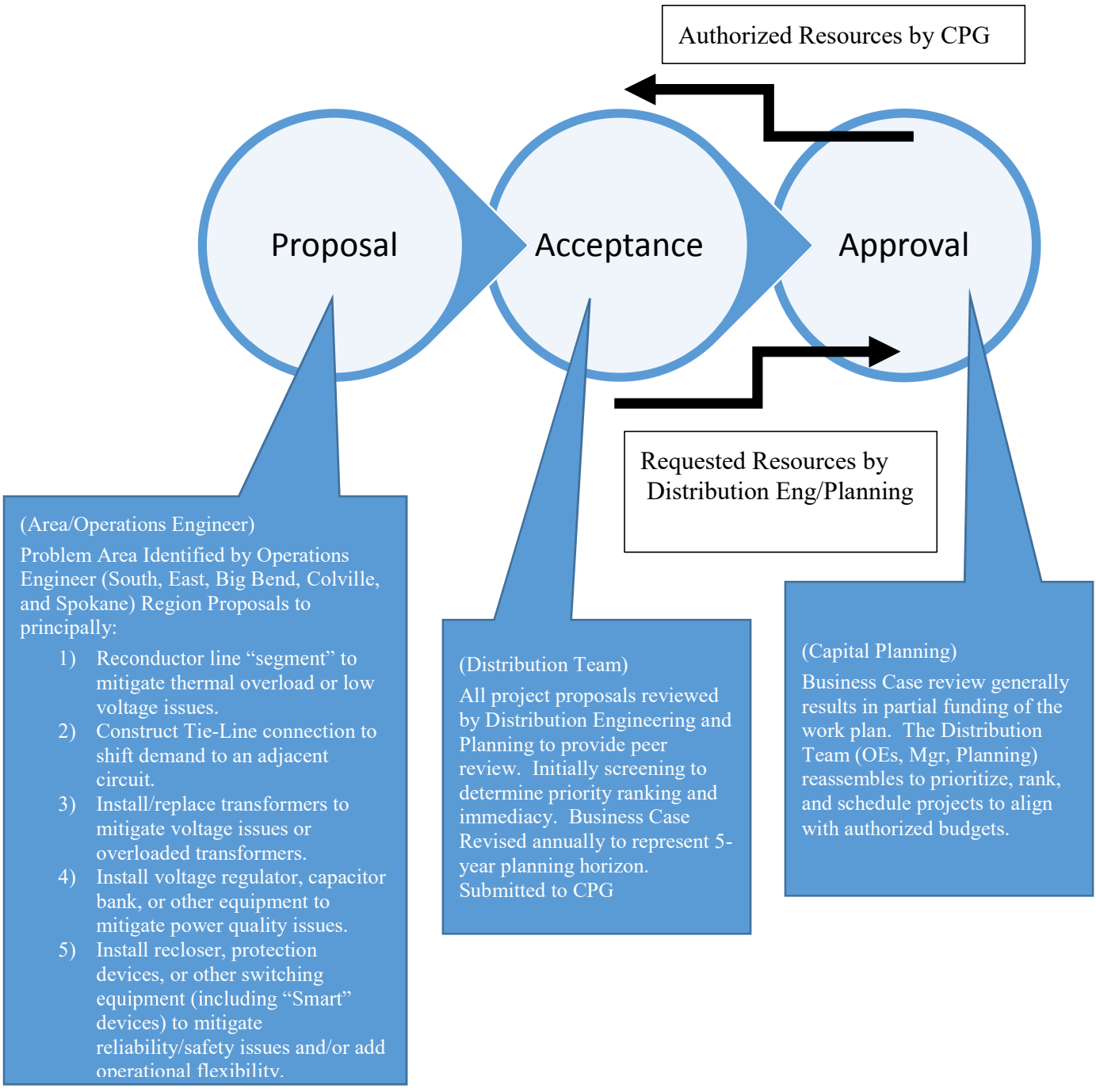

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 38 of 535

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3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Distribution System Reinforcements* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Cesar Godinez 0BC6F80AA30B422...	Date:	May-02-2024 | 2:48 PM PDT
Print Name:	*Cesar Godinez*		
Title:	*Distribution Engineering Manager*		
Role:	Business Case Owner		

Signature:	DocuSigned by: Vern Malensky 06C4FF5AB09E40B...	Date:	May-02-2024 | 2:52 PM PDT
Print Name:	*Vern Malensky*		
Title:	*Director of Electrical Engineering*		
Role:	Business Case Sponsor		

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EXECUTIVE SUMMARY

Growth on the east side of Lake Coeur D'Alene is impacting the ability of the existing distribution system to reliably serve customer load. During winter peak loading conditions, the feeder cable that crosses Lake CDA is reaching the cable's rating limits. Exceeding equipment ratings will require either pre-emptive load shed to reduce loading or risk permanently damaging the equipment due to the overload which would result in a longer duration outage. Operations are also experiencing protection concerns which will only be exacerbated in the near term. The protection concern is the ability to properly size fault detection devices, fuses and reclosers, to adequately detect faults while not tripping the circuit due to heavy load. Long rural feeders such as BLU321 have very low fault current which makes it difficult to distinguish fault current from load current. The consequence of the protection concerns is primarily fuses melting due to load causing customer outages and the ability to restore service to the customers is constrained by the additional loading from cold load pickup therefore requiring staged restorations. Low voltage issues are also evident on several portions of BLU321. The consequence of low voltage is potentially damaging customer's end use equipment and not meeting required performance criteria enforced by the state commission. The need for a plan to mitigate these concerns has been evident for years, and property was purchased in 2011 on Elk Road near Carlin Bay to be utilized for a future substation. The project was formally brought to the Engineering Round Table (ERT) in January 2017 for review and prioritization. Upon its approval and subsequent scoring, it was budgeted under the Substation Asset Business Case (O'Gara), Substation Performance & Capacity Business Case (Carlin Bay), and Transmission Performance & Capacity Business Case (115kV Transmission Line) respectively. Due to the complexity, dependencies, and cost of these system reinforcement projects it was deemed prudent to move it to its own business case. The identified operational challenges have become more severe with load growth around 5% per year, leading to the need for the Carlin Bay Substation project. The complete scope will be executed in a phased approach so equipment loading and protection coordination issues are mitigated and operational while the remainder of the scope can be completed. The complete scope includes the following:

- Phase 1 includes construction of the Carlin Bay Substation and construction of a 115kV transmission line tap from the Benewah – Pine Creek 115kV line near O'Gara to the new Carlin Bay Substation. The initial phase will relieve adjacent Blue Creek and O'Gara distribution feeders in the near term.
    - 115kV Transmission Line Cost: $14,500,000
    - Carlin Bay Substation Cost: $13,100,000
- Phase 2 includes a rebuild of the O'Gara Substation. The rebuild will address aging infrastructure, capacity needs, and increase reliability for area customers and Kootenai Electric who has a feeder out of the existing substation.
    - O'Gara Substation Cost: $17,100,000

It is important to note the dependencies amongst the three projects. Due to the lack of transmission in this area the transmission line will need to be constructed first in order to energize the new Carlin Bay substation upon its completion. From there Phase 2 will commence with the construction of the rebuild of the existing O'Gara Substation. Property for the new O'Gara substation was purchased in 2023. The transmission line project commenced with the line siting process in 2023. This portion involved hiring a consultant to identify the best route possible while limiting environmental, property, and cost impacts.

Technical analysis completed by System Planning has been performed to confirm the project as proposed provides acceptable system performance and mitigates the critical issues which exist on the distribution feeders, impacting customers on the east side of Lake Coeur D'Alene.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Katie Prugh / Karen Kusel / John Gross*	*Initial draft of original business case*	*May 2024*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	DS SC

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GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$525,000	
2025	$3,995,000	
2026	$8,850,000	
2027	$19,400,000	$27,600,000 (TRANSMISSION LINE, CARLIN BAY SUBSTATION)
2028	$10,530,000	$17,100,000 (OGARA SUBSTATION)
2029	$610,000	

Project Life Span	10 Years
Requesting Organization/Department	Substation Project Delivery
Business Case Owner | Sponsor	Brian Vandenburg | Vern Malensky
Sponsor Organization/Department	P03
Phase	Initiation
Category	Project
Driver	Performance & Capacity

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

The population and load demand growth on the east side of Lake Coeur D'Alene has resulted in rising concerns for Avista to reliably support new customers at the far-reaching end of two distribution feeders. Currently, two distribution feeders serve the east shore of Lake Coeur D'Alene, one originating from the Blue Creek Substation and the other originates from the existing O'Gara Substation. The associated feeders cannot support additional growth in the area and have reached their capacity. A 13.2kV distribution system is constrained in serving long distances due to protection coordination issues distinguishing fault current from load current. The consequence of protection coordination issues is customers will experience outages due to fault detection devices, fuses and reclosers, tripping under heavy load conditions. Equipment capacity issues have emerged, including overloaded feeder cable, voltage drop, voltage imbalance, reduced fault current, overloaded fusing and feeder protection, and cold load pickup, all of which, contribute to system protection challenges. To prevent overloading equipment, Avista will disrupt service to customers to reduce loading or risk the equipment becoming damaged which would result in a longer outage duration to customers.

Forecasted load in the area will further stress the existing infrastructure. Much of the new and forecasted load is concentrated at the far reaches for each distribution feeder. Additionally, several

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large developments, similar to the Gozzer Ranch development have either been proposed or are under development. The following table is a list of known developments under various stages of construction or planned for the near future. Some customer projects are waiting for Avista to mitigate the above listed performance issues prior to them starting construction.

Project	Description	Year	Feeder
Powderhorn Ranch	[25% conf] up to 1300 residences	2023	OGA611
Patriot Homes	[100% conf] ~40 units	2023	BLU321
Fish Inn Campground	[100% conf] Campground w/cabins & RV spots	2023	BLU321
Burma Rd	[100% conf] old mill needs cleanup	2024	BLU321
Gotham Bay	[100% conf] ~50 premium lots	2024	BLU321
Stonegate Development	[100% conf] 3000 sq ft houses - Harrison has building moratorium b/c of sewer issues - 3ph PM for water	2024	BLU321
Carlin Bay Lodge Replacement	[75% conf]	2024	OGA611

Table 1 provides the expected feeder and transformer loading over the next 10 years. Avista has established performance criteria in the planning horizon to mitigate equipment loaded about 80% of its applicable facility rating. When equipment approaches 100% of its facility ratings in real time operations, customers power will be turned off to prevent damaging equipment. In the East Lake Coeur d'Alene area, customer outages can have long restoration times due to cold load pickup causing fuses and/or reclosers to trip.

Feeder / Sub	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
BLU Xfmr 1	55	58	61	64	67	71	75	79	83	88	93
BLU321	75	80	84	90	95	100	107	113	120	127	135
BLU322	24	24	24	25	25	25	26	26	26	27	27
OGA Xfmr 1	90	90	94	96	98	100	102	104	106	106	106
OGA611	94	94	102	105	109	113	116	120	124	124	124
OGA612_KEC[1]	121	121	121	121	121	121	121	121	121	121	121

Table 1: Blue Creek and O'Gara Forecasted Peak Loading (%)

Several enhancements have been implemented to the distribution system to delay the need for a new substation and all feasible alternatives have been exhausted.

- Reconductor four miles of the BLU321 feeder
- Adjust locations of protective devices and their settings as well as fuse sizes to best accommodate load.
- Balance feeders and laterals

Despite system enhancements, the near-term planning horizon reveals existing infrastructure will be unable to reliably accommodate anticipated customer service requests and load growth in the area.

1.2 Discuss the major drivers of the business case.

Gozzer Ranch and other housing developments on the east side of Lake CDA continue to drive up loading levels on BLU321 and OGA611 and has pushed our existing system to its capacity. A substation near Carlin Bay will be needed to serve the load as it continues to increase. The

[1] Loading constraints on the OGA612 feeder are being addressed outside of the scope of this business case.

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transmission tap to feed Carlin Bay will come from O'Gara, which will need 115kV breakers installed when the new tap is added, becoming a switching station. Additionally, BLU321 is experiencing loading and protection coordination challenges and Avista is running out of switching options for this area. To accommodate the new Carlin Bay Tap, and to improve reliability to O'Gara and St. Maries, a switching station at O'Gara needs to be installed with four transmission line breaker positions and a new distribution transformer with two 13kV feeders. Today BLU321 supports 1,847 customers and that number is expected to continue to grow. Once Carlin Bay is in service, approximately 500 of our existing Blue Creek customers will be transferred to one of the new Carlin Bay feeders.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The impact of not performing this work is Avista would not be able to reliably serve an area that is experiencing significant growth. Customers will experience outages during peak winter conditions when building electric heating demand is high. The outages may occur due to overloaded equipment tripping or failing, or Avista intentionally reducing load to prevent equipment damage. The outages could impact several hundred customers for multiple hours and may occur daily until peak winter loading weather conditions pass. Further customer growth in the area will increase the number of impacted customers.

Phase 2 of the project is the rebuild of O'Gara Station to provide circuit breaker protected transmission line positions for the existing Benewah – Pine Creek 115kV Transmission Line, radial transmission line tap to Saint Maries Station, and new radial transmission line tap to Carlin Bay Station. Deferral of Phase 2 will result in the customers served by the Carlin Bay, O'Gara, and Saint Maries stations to be exposed to 15 miles of additional transmission line. The rebuild of O'Gara Station will result in only the customers served by Carlin Bay Station to be exposed to the additional 15 miles of transmission line. Fifteen miles of transmission line exposure through forested areas may expect to have 1-2 unplanned outages per year. Restoration to the 5000+ Avista customer and KEC customers served by O'Gara and Saint Maries stations will take approximately 2-4 hours.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

The East Lake Coeur d'Alene System Reinforcement project provides additional capacity to the system which is "critical to serving our customers and unlocking pathways to growth" as stated in our Perform Focus Area. The Perform Focus Area of Avista's focus goals is the primary alignment with the requested project but there are elements to the project which are aligned with the theme of our Vision, Mission, and Focus Areas.

Our Customers:
Existing and future customers on the East side of Lake Coeur d'Alene expect to have reliable electrical service. Avista needs to deliver a system which can serve the customer demands and continue to meet the company's defined reliability objectives.

Our People:
The portion of our company who will support the implementation of the project represents a core electric utility collection of our employees. These employees will take pride in the efforts of such a transformative project which will impact the community in a positive way.

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Perform:
With completion of the project, Avista will be unlocking growth potential in this area by providing an electric system with capacity to meet the energy demands of new customers.

Invent:
Constructing transmission lines and substations are traditional project alternatives but Avista has the opportunity to improve the construction and delivery process as part of such a large-scale project.

Vision; *Better energy for life:*
Investment in the transmission system represents a long term invest of infrastructure which will be in place to serve our customers for several generations.

Mission: *We improve our customers' lives through innovative energy solutions:*
The Carlin Bay Substation and associated projects have been identified as the most prudent energy solution to deliver the high-level capacity needed to serve the area. The additional capacity is needed to meet our customer's need for power.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[2]

System Planning has completed a thorough system study for this project. Many of the details have been added to this business case document, a detailed engineering analysis is included in the System Planning Study Report. Additionally, the electric system is analyzed bi-annually through the System Assessment process performed by the System Planning team. The most recent System Assessment is the 2023-2024 System Assessment Version 0 (2023-2024 Avista System Assessment-V0.pdf). An example of study results are shown in the table provided in section 1.2.

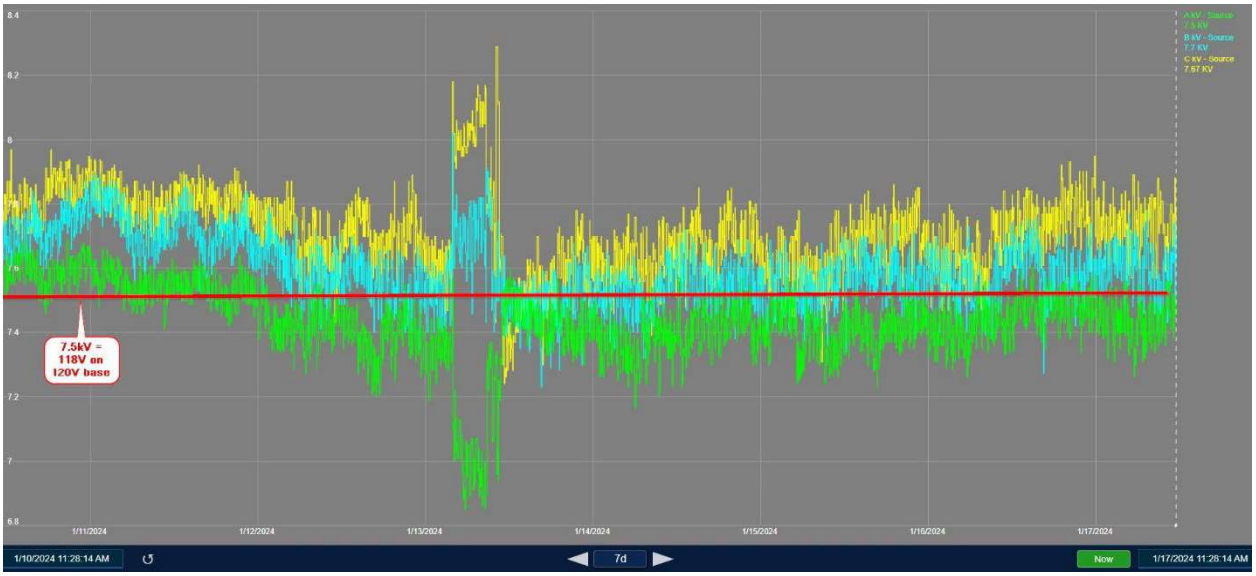
During the January 13th, 2024 peak winter conditions, operational issues as previously described impacted customers. The picture provided below is an example of an 80T fuse which melted due too much load.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 44 of 535

DocuSign Envelope ID: 84EBA5D1-6965-4B89-B843-63629E39BC76

Low voltage issues were also experienced during the same peak winter conditions. The first diagram below represents the voltage measured by the ZC952V midline regulator on BLU321. Low voltage on the feeder results in voltage at customer service points not meeting state requirements and can result in damage to customer end use equipment. Low voltage issues were also present on the OGA611 feeder which is represent by the second diagram below for the ZC620V midline regulator.



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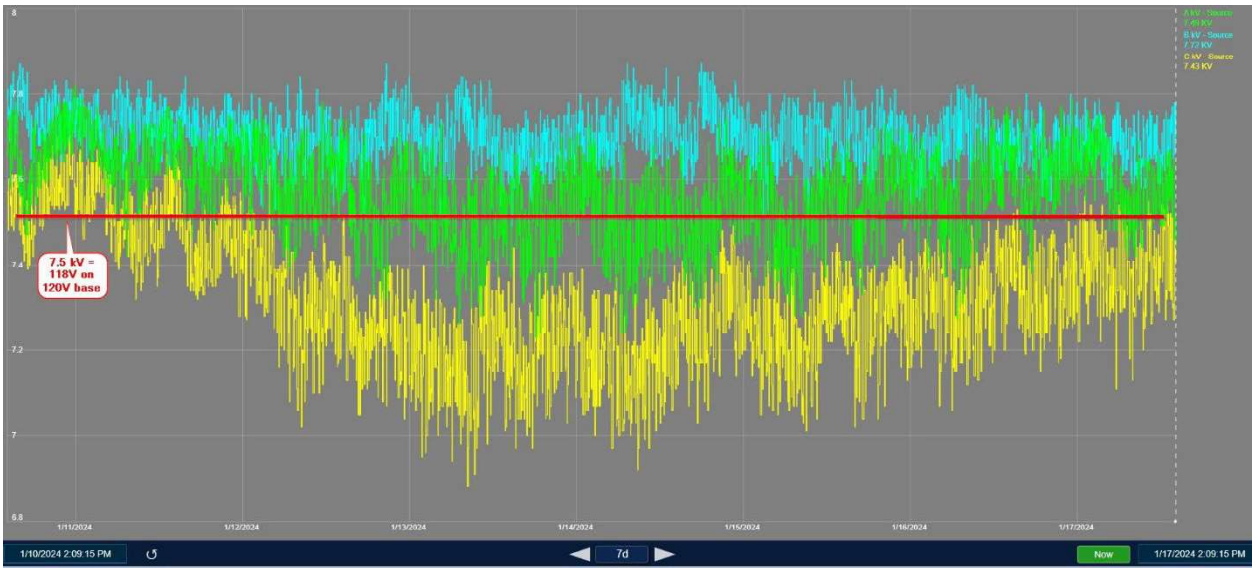

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The complete scope of the Carlin Bay Project will be executed in a phased approach so immediate concerns are mitigated and operational while the remainder of the scope can be completed. The complete scope includes the following:

- Phase 1 includes construction of the Carlin Bay Station and a 115kV transmission line tap from the Benewah – Pine Creek 115kV Transmission Line near O'Gara to the Carlin Bay Station. The expected in-service date is 2028.
    - 115kV Transmission Line Cost: $14,500,000
    - Carlin Bay Substation Cost: $13,100,000

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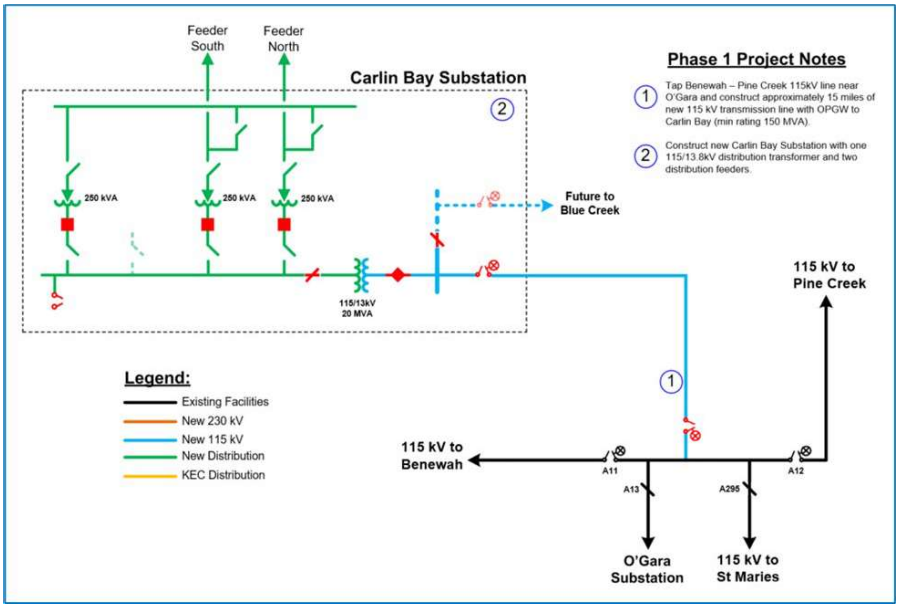

Figure 1: Phase 1 Implementation Project Diagram

- Phase 2 includes a rebuild of the O'Gara Station to a breaker and a half configuration with space for a future line position and future capacitor bank. The expected in-service date for this work is 2028.
    - O'Gara Substation Cost: $17,100,000

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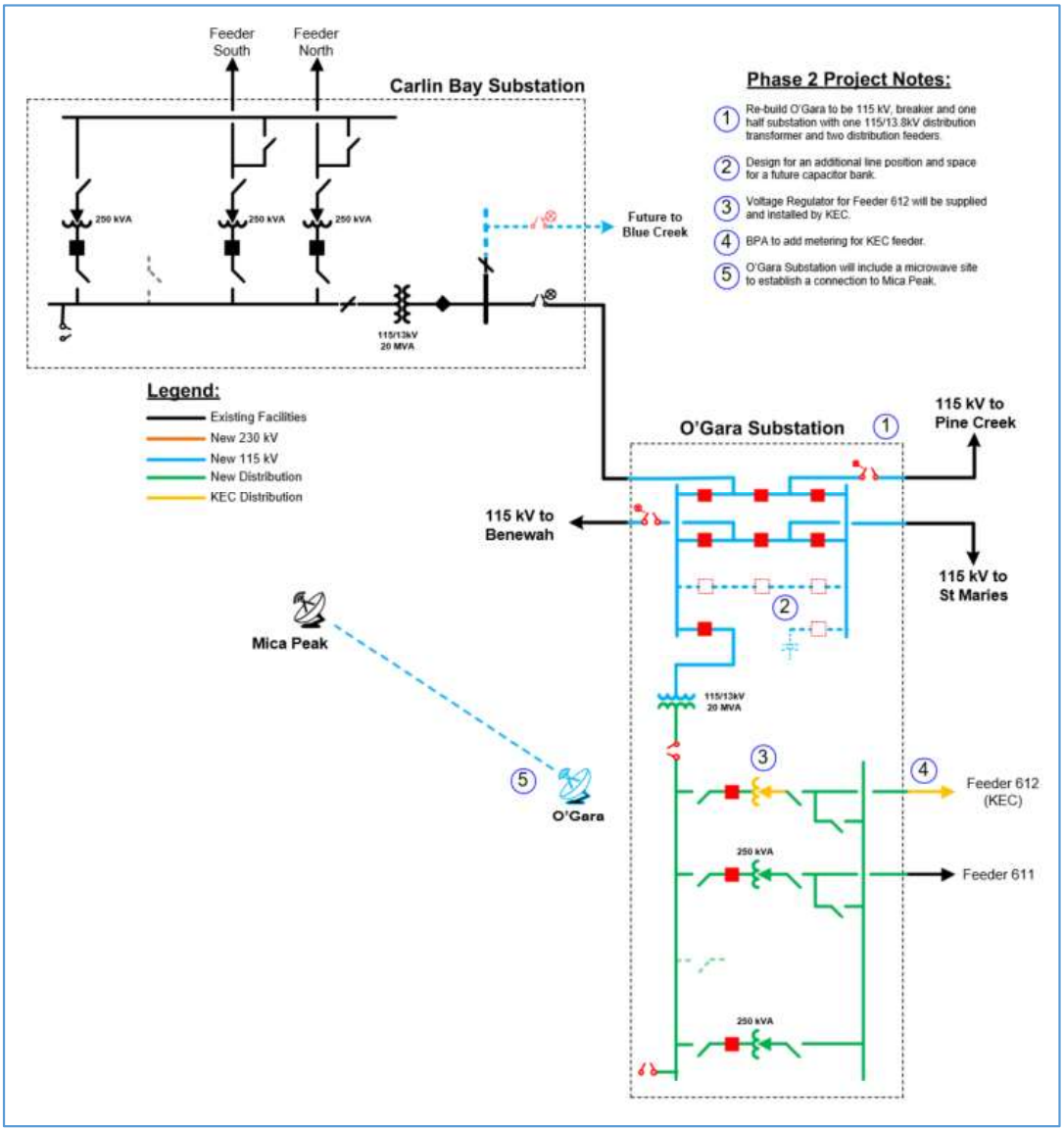

Figure 2: Phase 2 Implementation Project Diagram

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[3]

Study reports prepared by System Planning can be referenced for the East CDA Lake System Reinforcement. An example of work includes:

[3] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

DocuSign Envelope ID: 84EBA5D1-6965-4B89-B843-63629E39BC76

- 2023 Avista System Plan – Version 0, 2024
- BLU321-OGA611 – 2023-24 Winter Peak Loading Summary
- Carlin Bay Station – Version A

Risk analysis performed by System Planning shows the project results in an 80% risk reduction. The scope of the project reduces likelihood of occurrence of the issues described in other sections. The impact scores are based on implications of dropping load during contingency situations. The table below provides analysis results.

Issue	Description	Risk Category	Option 1		Option 2		Option 3		Option 4	
			Do Nothing	Risk	convert to 25kV	Risk	No O'Gara	Risk	Proposed Scope	Risk
1.1	BLU321 Feeder Loading	Likelihood	4	152	1	38	1	38	1	38
		Financial Impact	2		2		2		2	
		Stakeholder Impact	3		3		3		3	
		Outages	3		3		3		3	
		Safety	4		4		4		4	
		Environmental	0		0		0		0	
1.2	BLU321 Low Voltage	Likelihood	5	190	1	38	1	38	1	38
		Financial Impact	2		2		2		2	
		Stakeholder Impact	3		3		3		3	
		Outages	3		3		3		3	
		Safety	4		4		4		4	
		Environmental	0		0		0		0	
1.3	BLU321 Lake Crossing Cable	Likelihood	5	190	1	38	1	38	1	38
		Financial Impact	2		2		2		2	
		Stakeholder Impact	3		3		3		3	
		Outages	3		3		3		3	
		Safety	4		4		4		4	
		Environmental	0		0		0		0	
1.4	BLU321 Protection Coordination	Likelihood	5	190	1	38	1	38	1	38
		Financial Impact	2		2		2		2	
		Stakeholder Impact	3		3		3		3	
		Outages	3		3		3		3	
		Safety	4		4		4		4	
		Environmental	0		0		0		0	
1.5	BLU321 Open Delta Voltage	Likelihood	5	20	0	0	0	0	0	0
		Financial Impact	1		1		1		1	
		Stakeholder Impact	1		1		1		1	
		Outages	1		1		1		1	
		Safety	1		1		1		1	
		Environmental	0		0		0		0	
2.1	OGA Feeder Loading	Likelihood	5	165	1	33	1	33	1	33
		Financial Impact	2		2		2		2	
		Stakeholder Impact	3		3		3		3	
		Outages	2		2		2		2	
		Safety	4		4		4		4	
		Environmental	0		0		0		0	
2.2	OGA Low Voltage	Likelihood	5	165	1	33	1	33	1	33
		Financial Impact	2		2		2		2	
		Stakeholder Impact	3		3		3		3	
		Outages	2		2		2		2	
		Safety	4		4		4		4	
		Environmental	0		0		0		0	
2.3	OGA Transformer Loading	Likelihood	5	165	1	33	1	33	1	33
		Financial Impact	2		2		2		2	
		Stakeholder Impact	3		3		3		3	
		Outages	2		2		2		2	
		Safety	4		4		4		4	

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 49 of 535

DocuSign Envelope ID: 84EBA5D1-6965-4B89-B843-63629E39BC76

Issue	Description	Risk Category	Option 1		Option 2		Option 3		Option 4	
			Do Nothing	Risk	convert to 25kV	Risk	No O'Gara	Risk	Proposed Scope	Risk
		Environmental	0		0		0		0	
2.4	OGA Protection Coordination	Likelihood	4	132	1	33	1	33	1	33
		Financial Impact	2		2		2		2	
		Stakeholder Impact	3		3		3		3	
		Outages	2		2		2		2	
		Safety	4		4		4		4	
		Environmental	0		0		0		0	
2.5	OGA Open Delta Voltage	Likelihood	5	20	0	0	0	0	0	0
		Financial Impact	1		1		1		1	
		Stakeholder Impact	1		1		1		1	
		Outages	1		1		1		1	
		Safety	1		1		1		1	
		Environmental	0		0		0		0	
3.1	Transmission Outages	Likelihood	0	0	0	0	4	124	0	0
		Financial Impact	2		2		2		2	
		Stakeholder Impact	3		3		3		3	
		Outages	3		3		3		3	
		Safety	3		3		3		3	
		Environmental	0		0		0		0	
Overall Option Risk			1389		284		408		284	
Reduction in Risk (Option 1 to Option X)			0%		80%		71%		80%	

2.3 Summarize in the table and describe below the DIRECT offsets[4] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

New transmission infrastructure projects are required to safely and reliably serve customers. O&M costs include monthly inspection of the substations, periodic inspection of the transmission line, substation yard maintenance (i.e., weed prevention, fire extinguisher replacement), and substation equipment maintenance. Annual O&M costs for a transmission substation is approximately $50,000.

2.4 Summarize in the table and describe below the INDIRECT offsets (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

No indirect capital or O&M offsets are expected to result from this investment. Qualitatively the project reduces exposure to potential customer outages as described in the problem statement and avoidance of possible fines for non-compliance with NERC standards. Both examples of savings cannot be clearly defined with assumed values.

[4] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

DocuSign Envelope ID: 84EBA5D1-6965-4B89-B843-63629E39BC76

The table below details the Avista System reliability results for 2023.

Reliability Measure	2023 Results	2022 Results	Prior 5-Year Average (2018-2022)
SAIFI	0.79	0.92	0.95
SAIDI	113 minutes (1.89 hours)	146 minutes (2.43 hours)	140 minutes (2.34 hours)
CAIDI	142 minutes (2.37 hours)	158 minutes (2.64 hours)	148 minutes (2.47 hours)
$CEMI_3$	3.61%	6.02%	5.73%
CAIFI	1.77	2.05	2.06

Table 2: Reliability Results for Key Measures in 2023[10]

The table below details the reliability results for the OGA611 Feeder:

Reliability Measure	2023 Results
SAIFI	1.93
CAIDI	3.36
CEMI3	31.53%

The table below details the reliability results for the BLU321 Feeder:

Reliability Measure	2023 Results
SAIFI	3.92
CAIDI	3.19
CEMI3	69.8%

As shown in the tables above, both feeders are substantially above the average system reliability results. The implementation will help improve the reliability in this area. Additionally, it will add operational flexibility for the area when work needs to be performed.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1 – Do Nothing/Status Quo: $0

The expected system performance if no mitigation alternatives are executed were previously discussed in the Business Problem. BLU321 is at capacity to accommodate existing loading levels as it relates to maintaining adequate feeder protection. Both BLU321 and OGA611 each have 3 stages of voltage regulation (including substation regulators). Providing sufficient voltage regulation is already a challenge and will become more difficult as load continues to increase. Represented

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below are previous recorded winter peak loading values compared to the last cold load pickup event recorded.

The following data was recorded for the BLU321 feeder.

- The highest cold load pickup was 397A recorded on 3/25/2021 which was ~2.5x the pre-outage load of 145A.
- The winter peak load on 1/13/2024 was 533A.
- Using 387A as a potential pre-outage load, the cold load pickup is expected to be 2.5 x 387A = 967A. The cold load pickup exceeds the phase pickup setting of 525A for the ZC150R.

The following data was recorded for the OGA611 feeder.

- The winter peak load on 1/13/2024 was 215A.
- Using 184A as a potential pre-outage load, the cold load pickup is expected to be 2.5 x 184A = 460A. The potential cold load pickup is more than the phase pickup of 310A for ZC613R.

The "do nothing" alternative is not valid for the Carlin Bay Substation project as protection challenges will continue to increase as load in the area increases.

Alternative 2: $75M

Distribution voltage for BLU321 and OGA611 could be increased from 13.2kV, as it operates today, to 25kV. Today BLU321 supports 1,840 customers and that number is expected to continue to grow. This choice would improve distribution reliability for customers on the east side of Lake Coeur D'Alene and eliminate the existing voltage drop, reduced fault current, and cold load pickup concerns. The conversion would be very involved and complicated. The option would include reconductoring the feeder from 15kV cable to 25kV and constructing/reconstructing substations to provide 25kV transformation. This alternative would address the protection challenges however the significant cost of this option has deemed the option invalid. Additionally, it would result in normal operation feeder loading levels in excess of 10 MVA as load growth continues into the future, which is inconsistent with traditional loading guidelines (i.e., the "500A feeder plan").

Alternative 3: $27.6M

A new Carlin Bay Substation could be fed from a tap of the Benewah – Pine Creek 115kV Transmission Line near O'Gara. This option would reduce modifications needed at O'Gara thus reducing the overall cost of the project by almost $17.1M million. Alternatively, this option does not address equipment condition concerns at O'Gara and increases customer exposure to outages on the Benewah – Pine Creek 115kV line thus reducing customer reliability in the area. Approximately 5000+ customers will be exposed to an additional 15 miles of transmission line exposure which may cause 1-2 outages per year with a duration of 2-4 hours.

Alternative 4: $44.7M

In addition to development of the Carlin Bay Station, this option includes re-building the O'Gara station to be a switching station. This option increases the overall cost of the project however provides significant benefits for the reliability of the system. Existing customer exposure to outages, due to the O'Gara – St. Maries 115kV line section and O'Gara – Pine Creek 115kV line section, will be eliminated with implementation of a switching station at O'Gara. Customers fed from transmission between the Benewah and Pine Creek stations will have redundant sources thus increased reliability. Equipment condition concerns at O'Gara are also alleviated with implementation of this option.

Based on benefits described above, a rebuild of the O'Gara Substation is included in the scope of the project.

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2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Successful mitigation of the problem statement will be monitored as part of the bi-annual System Assessment conducted by System Planning. The project will be successful if performance criteria in short-term planning horizon studies can be met, and performance issues are not observed in the operations time horizon. Assumptions made in System Assessments are not static therefore projects are developed based on the best information available. For example, future load forecasts may show additional load growth not expected when a project is requested. If the project takes ten years to construct, it is possible the base line assumptions have changed, and additional projects will need to be justified.

The performance criteria metrics which are monitored as part of the System Assessment process are provided in DP-SPP-02 – Distribution System Performance. Expected performance following completion of the project is all impacted distribution equipment will be loaded less than 80% of applicable facility ratings during forecasted peak load conditions.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Schedule for the new Carlin Bay 115kV Substation, 115kV Transmission Line, and O'Gara 115kV Substation:

115kV Transmission Line:
2023: Line Siting
2024: Design and Easement Acquisition
2025: Final Design
2026: Construction
2027: Finish Construction

Carlin Bay Substation:
2024: Early Permitting
2025: Distribution Design
2026: Scoping, Design, Site prep and Fencing
2027: M/S and Electrical Construction
2028: Relay & Protection Construction and Energize Substation

O'Gara Substation:
2025: Scoping and Start of Design
2026: Complete Design, Site prep and Fencing
2027: M/S Construction and Start Electrical Construction
2028: Complete Electrical Construction, Relay & Protection Construction and Energize Substation

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2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

For the Carlin Bay Substation and associated projects, there will be a Project Manager, Construction Inspectors and Design Engineers (Transmission, Substation and Distribution) that will form the oversight group. The Engineering Roundtable will provide technical review of potential scope changes with the support of the System Planning and Operations department. Scope changes which require additional fund requests to the Capital Planning Group will be vetted at the Engineering Roundtable.

- Expected spend monthly meetings with Electrical Engineering managers.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 54 of 535

DocuSign Envelope ID: 84EBA5D1-6965-4B89-B843-63629E39BC76

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the East Coeur d'Alene Lake System Reinforcement and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Brian Vandenburg 0304BB8B2E5E6A0...	Date:	May-14-2024 | 9:55 AM PDT
Print Name:	Brian Vandenburg		
Title:	Manager of Engineering Projects		
Role:	Business Case Owner		

Signature:	DocuSigned by: Vern Malensky 06C4FE5A899E4AB...	Date:	May-14-2024 | 9:57 AM PDT
Print Name:	Vern Malensky		
Title:	Director of Electrical Engineering		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:	N/A		
Title:			
Role:	Steering/Advisory Committee Review		

EXECUTIVE SUMMARY

The Electric Replacement and Relocation (Road Moves) program is driven by compliance that is mandated by the “Franchise Agreement” contracts with local city and state entities, and “permits” issued by Railroad owners. Within each agreement are provisions for relocation of utilities at the request of the right-of-way (ROW) owner. Under a Franchise Agreement or Permit, Avista is allowed to occupy space within a ROW owned by the respective jurisdiction in order to serve its customers, but must relocate utilities at the request of the ROW owner. Electric relocations occur every year, mainly during construction season, but are primarily unplanned, so historical trends are used to estimate the annual cost to fully fund all the relocation projects. The annual cost of electric relocations varies slightly year to year. Current funding needs have increased due to additional road projects driven by additional government funding sources. Fully funding the business case will likely ensure all electric relocations under franchise agreements or permits will be completed. This is mandatory work to maintain compliance with existing franchise and operating permits with state highway districts and railroads. This impacts both Washington and Idaho customers.

The Electric Relocations business case is unplanned, demand driven work that is contractually obligated and adds high risk to the company if not completed. Funding allocation is based on historical spending trends. The average historical spend for Electric Relocations has consistently increased over the past five years, with the exception of last year where we came in under budget at $5.9M, leaving the 3 year average spend at $7.7M. Since Electric Relocations are directly correlated with the number of highway and street projects, the reason for the continued increase and some variance in spend is due to an increase in transportation project spending by local and federal entities.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 56 of 535

VERSION HISTORY

Version	Author	Description	Date
1.0	*Katie Snyder*	*Initial draft of original business case*	*04/15/2024*
BCRT	*BCRT Team Member - Steve Carrozzo*	*Has been reviewed by BCRT and meets necessary requirements*	*4/18/2024*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**7,000,000**	**7,000,000**
2025	**9,000,000**	**9,000,000**
2026	**9,000,000**	**9,000,000**
2027	**9,000,000**	**9,000,000**
2028	**9,000,000**	**9,000,000**
2029	**9,000,000**	**9,000,000**

Project Life Span	***Ongoing***
Requesting Organization/Department	Electric Operations
Business Case Owner | Sponsor	Katie Snyder | Paul Good
Sponsor Organization/Department	Operations
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

The Electric Distribution and Transmission Replacement and Relocations (Road Moves) program is driven by compliance mandated by the "Franchise Agreement" contracts with local city and state entities and "permits" issued by Railroad owners. A "Franchise Agreement" generally refers to a non-exclusive right and authority to construct, maintain, and operate a utility's facility using the public streets, dedications, public utility easements, or other public ways in the Franchise Area pursuant to a contractual agreement executed by the City and the Franchisee. Although each Franchise Agreement or permit is a little different, they all serve a similar purpose in providing utility access along city, county, state, and railroad right-of-way

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 57 of 535

(ROW). The agreement(s) make provisions for Avista to install electric equipment along these ROWs in order to provide service to Avista customers.

Within each agreement are provisions for relocation of utilities at the request of the ROW owner. These requests are usually driven by road and or sidewalk re-design projects.

> For reference, **franchise 95-0990** recorded with Spokane County paragraph VI states ***"If at any time, the County shall cause or require the improvement of any County road, highway or right-of-way wherein Grantee maintains facilities subject to this franchise by grading or regarding, planking or paving the same, changing the grade, altering, changing, repairing or relocating the same or by constructing drainage or sanitary sewer facilities, the grantee upon written notice from the county engineer shall, with all convenient speed, change the location or readjust the elevation of its system or other facilities so that the same shall not interfere with such County work and so that such lines and facilities shall conform to such new grades or routes as may be established."***

For example, a State Department of Transportation (DOT) is widening an intersection or highway, which requires Avista to relocate their overhead or underground electric facility to accommodate the new DOT design. A smaller example for instance is a local municipality is installing new ADA ramps on the corners of local street intersections, which sometimes requires Avista to relocate a utility pole to accommodate the new ramp design.

The asset conditions replaced through Electric Relocations can vary since the relocations are unplanned and therefore not coordinated with Avista's Asset Maintenance programs. Most assets in an Electric Relocation project are replaced because they are unsalvageable or close to the end of their useful life. In the case of relocating newer assets, efforts are made to re-use as much material as possible.

Under a Franchise Agreement or Permit, Avista is allowed to occupy space within a ROW owned by the respective jurisdiction in order to serve its customers. Electric relocations occur every year primarily during the construction season, but are unplanned, so historical trends are used to estimate the annual cost to fully fund all the relocation projects. The annual cost of electric relocations varies slightly year to year. Current funding needs have increased due to additional road projects driven by both additional government funding sources, therefore fully funding the business case will likely ensure all electric relocations under Franchise Agreements or Permits can be completed

1.2 Discuss the major drivers of the business case.

The major driver of this business case is Mandatory & Compliance. Franchise agreements, state highway and Railroad permits, and the Washington and Idaho Department of Transportation prescribe that the utility will relocate, at their expense, when in conflict with entity activities. We need to complete this Mandatory work to maintain compliance with existing franchise and operating permits with all parties.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

This work is needed, because not doing the mandatory work to fulfill our agreements with state and local entities would result in us being out of compliance. If we are no longer in compliance with our Franchise agreements and permits, we could potentially lose the right to install electric equipment along these ROWs in order to provide service to Avista customers.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 58 of 535

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

This work is needed, because not doing the mandatory work to fulfill our agreements with state and local entities would result in us being out of compliance. If we are no longer in compliance with our Franchise agreements and permits, we could potentially lose the right to install electric equipment along these ROWs in order to provide service to Avista customers.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

N/A

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

This solution is to perform the required mandatory work as set forth by state and local entities under the Franchise Agreements and Permits Avista has entered. This is in order to stay in compliance and continue to be allowed to install electric equipment along ROW's that will enable us to provide service to Avista's customers.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

In order to prepare this business case we review historical spend to help predict what to expect for the current and future years. For instance, our five-year average spend is $5.6M and our

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.
[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 59 of 535

spend has been increasing by an average of 17% per year. This would reason that if our spend was $5.9M in 2023, we could require as much as $7M for Road Moves in 2024. We did see a decrease in spending in 2023, but we believe this was an anomaly due to local entities moving out work that had been scheduled for last year. Due to this, we anticipate 2024 having a higher spend.

Figure 1 Shows the historical 5-year trend in spend and the annual percentage increase rate. As you can see the spend has consistently trended upward since 2019, with the exception of 2023.

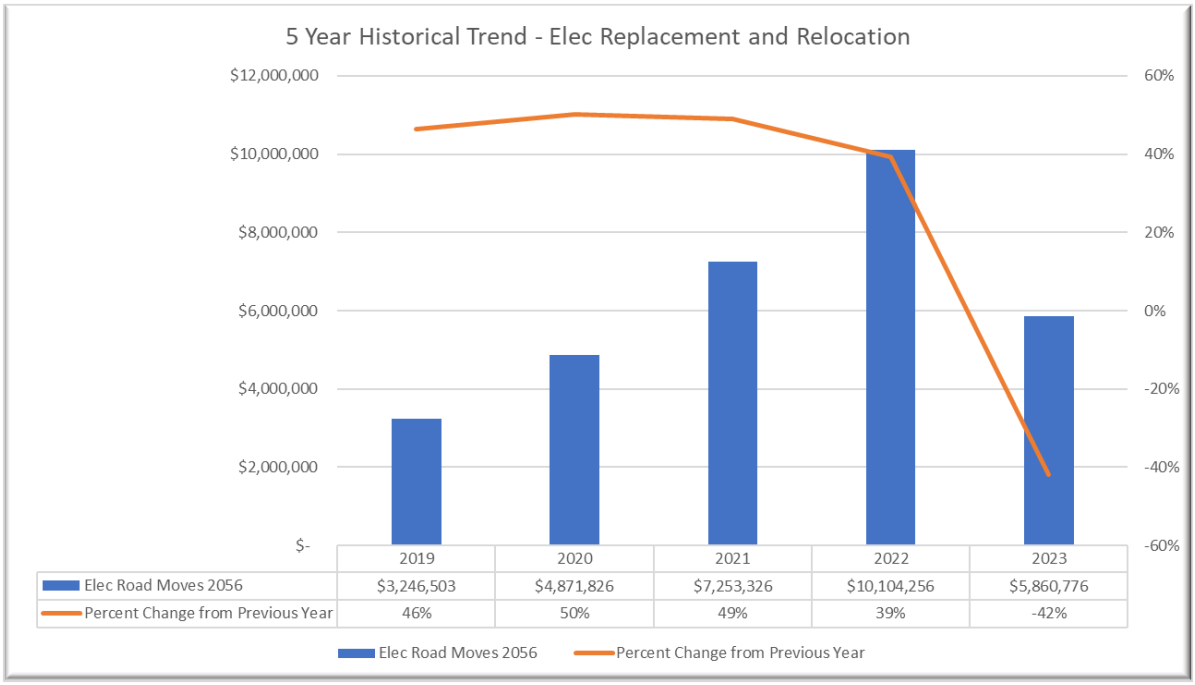

***Figure 1**: 5-Year Historical Trend – Elec Replacement and Relocation*

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no direct offsets related to this Business Case.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

The Electric Replacement and Relocation program is required due to franchise agreements with the state, country, and city jurisdictions within our service territories. If any state, county, or city jurisdiction is conducting road work in our service territory, we are required to move/relocate our facilities to accommodate the work. Any breach in these agreements could have an impact on Avista's ability to operate in the public right-of-way. Indirect offsets include the ability to upgrade aging equipment associated with the facility relocation which will extend the life of the asset. Examples: An older/aging utility vault needs to be relocated for a road project. Avista will relocate and upgrade the facility to current standards which will improve longevity, reliability, and safety.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

This is mandatory work in order for us to remain in compliance and be allowed to continue operating in the public right-of-way. Due to the nature of the work there are no alternatives. If unfunded Avista would not be able to perform necessary work and would be out of compliance with established franchise agreements and/or permits.

Alternative 1:

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 61 of 535

Alternative 2:

Alternative 3:

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Measures to determine successful delivery on business case objectives include:

- Year-To-Date Spend (Tracked monthly)
- Compliance with Franchise agreements and/or Railroad permits.

Figure 2 shows the Year-to-Date spend for the current year and a historical for the previous two years. Based on the previous years we are currently below where we were this time in 2021, but below this time in 2022. This chart is updated and reviewed monthly in order to project what we anticipate the year end spend being based on previous years.

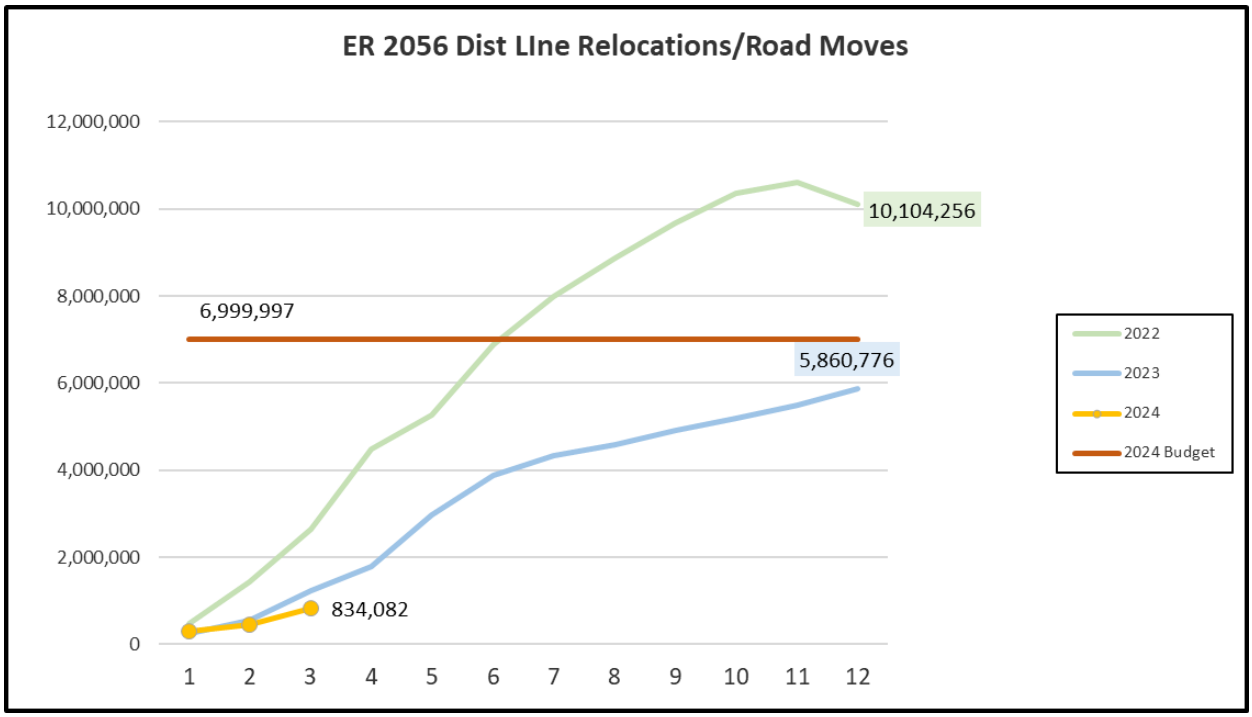

Figure 2: *ER 2056 (Electric Relocations and Road Moves) Year-to-Date Spend*

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

As long as we are operating in the public right-of-way, we must continue to complete mandatory work to remain in compliance. Therefore, this is an ongoing program with no foreseen end date. However, as we complete each road move under this program it is immediately becomes “used and useful” so this business case transfers to plant monthly.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

This business case is written by the business case owner, reviewed by the business case sponsor, and then reviewed by the business case review team. It’s then submitted to the Financial Planning and Analysis (FP&A) team for final approvals. It’s spend is continuously monitored by the Operations Round Table which is comprised of Business Case owners and the department Sponsor, who meet once a month, and then finally the FP&A who also meet monthly.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 63 of 535

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Electric Replacement and Relocation* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Katie Snyder	Date:	5/10/2024
Print Name:	Katie Snyder		
Title:	Business Analyst III		
Role:	Business Case Owner		

Signature:	PAul Good	Date:	5/15/2024
Print Name:	Paul Good		
Title:	Director Electric Operations		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 64 of 535

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Electric Storm

EXECUTIVE SUMMARY

The Electric Storm Business Case is focused on restoring Avista's transmission, substation, communications, and distribution systems (damaged plant) into serviceable condition during a weather storm event or other natural disaster where assets are damaged. These storm events are random and often occur with short notice. This business case is to fund a rapid response to unexpected damages and outages, so customer outages are minimized. The business case provides funds for replacing poles, cross arms, conductor, transformers, and all other defined retirement units damaged during weather storm events. The damage can be due to high winds, heavy ice and snow loads, lightning strikes, flooding, or wildfires as an example. The importance of quickly replacing damaged facilities is vital to providing reliable service to our customers. This impacts customers in WA and ID.

The annual budget amount is determined based on the historical average rate of capital restoration work including restoration activity related to major event days (MEDs) of relativity minor restoration impact. Request excludes costs related to very large MEDs. If not funded, the work will still occur as needed for outages caused by weather storm events or other natural disasters and would be absorbed through other business cases.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Joe Wright*	*Initial draft of original business case*	*12/12/23*

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 65 of 535

DocuSign Envelope ID: B852F7EA-84B2-437C-8164-70D90409E5D4

BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements*	

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$5,000,000**	**$5,000,000**
2025	**$5,000,000**	**$5,000,000**
2026	**$5,000,000**	**$5,000,000**
2027	**$5,000,000**	**$5,000,000**
2028	**$5,000,000**	**$5,000,000**

Project Life Span	*Annual Program*
Requesting Organization/Department	Operations
Business Case Owner | Sponsor	Paul Good | Josh DiLuciano
Sponsor Organization/Department	Operations
Phase	Execution
Category	Program
Driver	Failed Plant & Operations

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 66 of 535

DocuSign Envelope ID: B852F7EA-84B2-437C-8164-70D90409E5D4

1. **BUSINESS PROBLEM -** *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

The Electric Storm Business Case (BC) is focused on restoring Avista's transmission, substation, communications, and distribution systems (damaged plant) into serviceable condition during a weather storm event or other natural disasters where assets are damaged. These events are random and often occur with short notice. This business case funds a rapid response to unexpected damages, so customer outages are minimized. The business case provides funds for replacing poles, cross arms, conductor, transformers, and other defined retirement units damaged during storm events. The damage can be due to high winds, heavy ice and snow loads, lightning strikes, flooding, or wildfires. The importance of quickly replacing damaged facilities is vital to providing reliable service to our customers.

1.2 Discuss the major drivers of the business case.

The primary driver for the Electric Storm BC is Failed Plant and Operations. The work is a key component to minimizing customer outage times and contributes to Avista's reliability indices like System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI). The secondary driver for this business case is Customer Service Quality and Reliability

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The importance of quickly replacing damaged facilities is vital to providing reliable service to our customers. The Electric Storm BC is to fund a rapid response to unexpected damages and outages, so customer outages are minimized. If this business case is not funded the costs to restoring power to our customers will be absorbed by another business case. The needed work will continue to occur.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

The Electric Storm business case aligns with the company's strategic goal of Safe and Reliable Infrastructure. The work is a key component to minimizing customer outage times and thus contributes to Avista's reliability indices like SAIFI and CAIDI.

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1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

N/A

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The Electric Storm Business Case (BC) is focused on restoring Avista's transmission, substation, communications, and distribution systems (damaged plant) into serviceable condition during a weather storm event or other natural disasters where assets are damaged. These events are random and often occur with short notice. This business case funds a rapid response to unexpected damages, so customer outages are minimized. The business case provides funds for replacing poles, cross arms, conductor, transformers, and other defined retirement units damaged during storm events.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

The annual budget amount is determined based on the historical average rate of capital restoration work.

Figure 1 shows the historical costs (2017-2022) for the distribution/transmission storm business case and YTD 2023 expenses through October. From 2017-2022, the average annual cost for capital storm response was $8.6 million dollars, with a range of $3.6MM (2018) to $14.6MM (2021). There were 7 MEDs in 2020 and 4 in 2021. The majority of the MED costs in 2021, however, occurred

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in January, one $7.2MM storm. Consequently, 2020 results were excluded and 2021 results were adjusted downward to exclude the particularly large January storm for determining the proposed funding level. The average spend for 2017-2019/2021-2022 was $5.4MM. This includes some MED activity of comparatively minor restoration impact during these years. Proposed funding for 2024-2028 is $5M per year. Further funding for significant MEDs will be requested as needed.

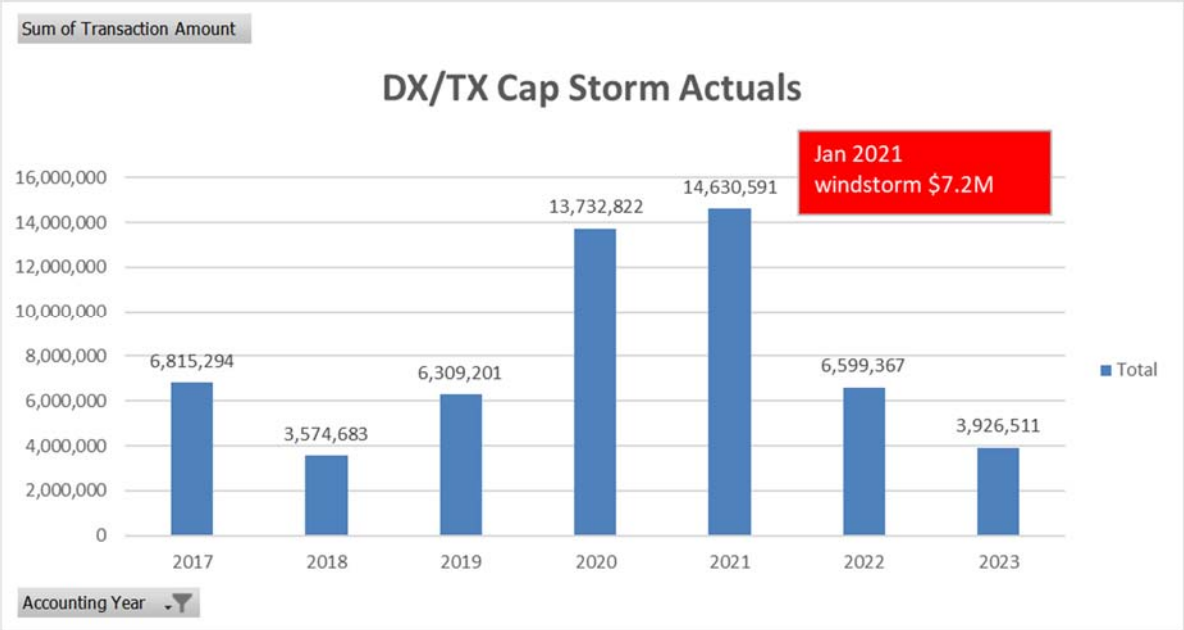

Figure 1: Storm Historical Costs

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no offsets to O&M. There is no identified direct savings related to this business case. This business case is completed to replace failed equipment due to extreme weather events.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

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2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no offsets to O&M.

Current RCW standards obligate us to perform repair work following storm damage. Therefore, an amount of capital is earmarked for a normal year of weather events.

Although there are no financial offsets, an ICE (Interruption Cost Estimate) may be calculated for determining an avoided indirect cost for having this program.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

The alternative to this business case request is not funding. The costs associated with repairing damages as a result of a weather storm event or a natural disaster would be covered through a different business case. Damages from these events must be repaired, regardless of funding.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

The primary measure that will be used to determine success is outage duration including other reliability measures such as Avista's reliability indices like SAIFI and CAIDI. These measures will demonstrate the impact of the work charged to this business case.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

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2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Weather storm events or natural disasters are a continuous risk. Work will occur as needed as a result of damaged facilities related to these events. Many times, multiple events may occur within one year in different office areas. Past data shows there has not been a year where a storm has not happened. Since this is often emergency work, assets become used and useful and transferred to plant immediately.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The Electric Storm work is overseen by the local area operations engineers and area construction managers. The work is unplanned and non-specific in nature but occurs regularly. In the event of larger scale storms or natural disasters, like the historical storm event in November 2015, a formal Incident Command System (ICS) is created to manage the resources needed to respond. Other large events are managed through an emergency operating plan (EOP) with the Director of Operations.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 71 of 535

DocuSign Envelope ID: B852F7EA-84B2-437C-8164-70D90409E5D4

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Electric Storm and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Paul Good 8ADE2AA1AB5C4A9...	Date:	Dec-15-2023 | 12:28 PM PST
Print Name:	Paul Good		
Title:	Director of Electric Operations		
Role:	Business Case Owner		

Signature:	DocuSigned by: Josh DiLuciano A3C71874F6564DB...	Date:	Dec-15-2023 | 8:35 AM PST
Print Name:	Joshua DiLuciano		
Title:	VP Energy Delivery		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 72 of 535

Joint Use Projects

EXECUTIVE SUMMARY

Joint Use is the regulated use of utility poles and other structures by 3rd party telecommunications companies in order for them to provide their services to the customers we have in common. Avista licenses 78 unique enitities that are attached to over 175,000 poles across our service territory. Avista is required by federal, state, and local law to allow non-discrimantory access to each of these licensees. Even though this relationship is mandated by law, and is compliance driven, Avista agrees that this practice provides a direct benefit to our customers who desire those services.

Part of this requirement includes the obligation of Avista to replace infrastructure to taller stronger structures in order to accommodate or “make ready” those facilities for new attachments. This “make-ready” work falls under capital expense and Avista is allowed to recover the actual costs from the requesting attacher. Avista is also permitted to recoup a portion of the costs associated with replacing & maintaining it’s shared infratructure through a regulated yearly pole rental fee.

Avista could face potential regulatory and or civil legal action if timelines and obligations are not met due to a lack of funding. We also risk having an overloaded infrastructure, jeopardizing the safety and reliability of our system. The outcome of these actions could result in significant financial loss and penalties.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Jesse Butler*	*Initial draft of original business case*	*4/2/2024*
BCRT	*BCRT Team Member – Katie Snyder*	*Has been reviewed by BCRT and meets necessary requirements*	*05/08/2024*

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 73 of 535

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$4M**	**$4M**
2025	**$5M**	**$5M**
2026	**$4M**	**$4M**
2027	**$3.5M**	**$3.5M**
2028	**$3.5M**	**$3.5M**
2029	**$3.5M**	**$3.5M**

Project Life Span	Perpetual
Requesting Organization/Department	Operations/Joint Use
Business Case Owner | Sponsor	Jesse Butler | Vern Malensky
Sponsor Organization/Department	Operations/Joint Use
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 74 of 535

1. **BUSINESS PROBLEM -** *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed? Access to safe and reliable utility infrastructure by third parties is not only a crucial element of the connected world in which we live but it is also mandated by regulators at the federal and state levels. Avista therefore has a duty to repair, replace or add infrastructure to accommodate those requests.

1.2 Discuss the major drivers of the business case. The major drivers of this business case are the joint use and licensee's who request new pole attachments or who must upgrade their existing systems to meet the burgeoning and ever-increasing demand for reliable and cost efficient communication needs. This has a direct benefit to not only Avista customers but Avista itself as we are also consumers of those same telecommunications products. As mentioned previously, fair, and non-discriminatory access to investor-owned utility infrastructure is codified in Federal and State laws dating back to the Federal Telecommunications Act of 1934 which laid the groundwork for the current system of asset sharing.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

This work is needed currently and will be needed on an ongoing basis not only for existing wired telecommunication providers but for wireless providers who are more often than not reliant upon existing vertical utility assets to locate their equipment. These technologies are commonly referred to as 4G, 5G and LTE. The risk of not executing to meet these demands could result in regulatory action, resultant fines, and possible civil litigation that could far outweigh any short-term savings. Damage to Avista's reputation and loss of customer trust could also result, and those monetary costs are incalculable.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

The investment that is made in Avista's physical plant, to accommodate joint use telecommunications, benefits the shared customer base of Avista and the joint use providers. It places our customers at the center of our focus and decreases rate pressure through the annual rent that is paid by our joint use providers.

Also, it allows Avista to provide safe, reliable, and cost-effective services, by providing an NESC compliant work environment for all workers who require access to the electric distribution system, which is required by law.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

Below is the link to the Federal Communications Commission website and a link for the Washington state Legislature. This is where the federal and state guidelines/laws we have to adhere to can be found.

Federal Communications Commission

Washington State Legislature

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Our solution is to use the funding from this business case to ensure we follow state and federal guidelines that require us to provide fair and non-descriminate access to our infrustructure for the purpose of telecommunications attachments.

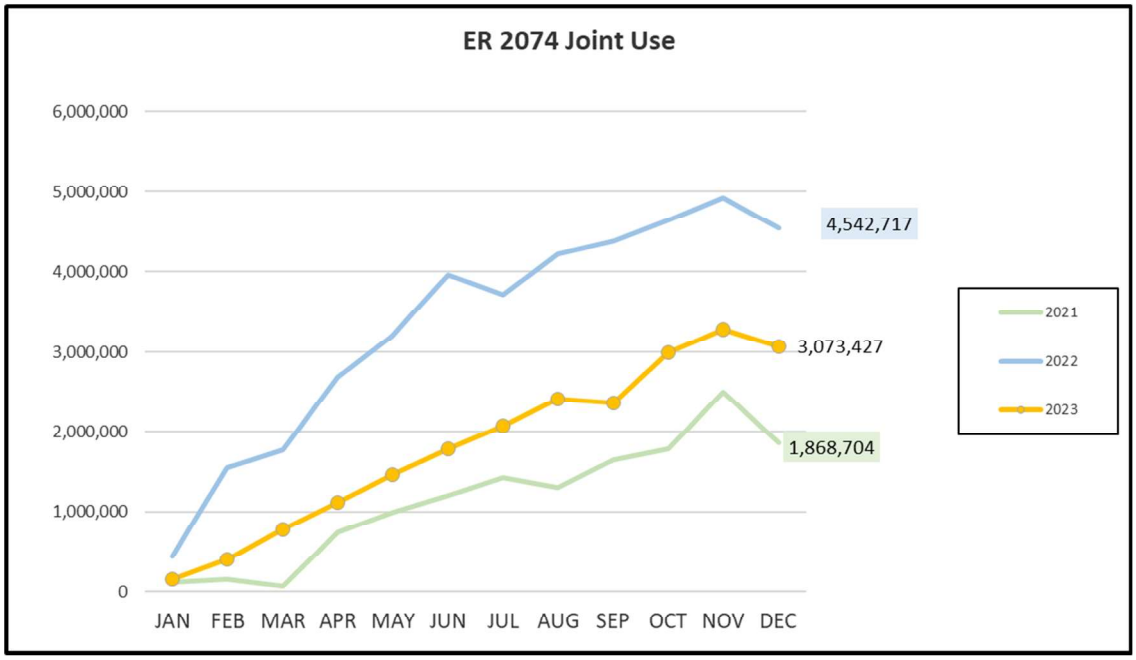
[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 76 of 535

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits, or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

Current joint use capital business case amounts were derived from historic spend data coupled with projected activity based on trends seen in the joint use tracking sheet. This worksheet is where all new pole attachment requests from joint use licensees are recorded. The data includes the number of poles each joint user would like to attach to, the date a job is started and completed, and the estimated and actual costs of the capital make-ready work related to a specific job. Trend, cost, and performance metrics from this tracking sheet are compiled and shared with the Joint Use Steering Committee on a quarterly basis.

Below is a chart showing the gross spend for Joint Use over the last three years. The increases with sudden decreases show where we recovered some of the cost through invoicing. This is a demonstration of the return on our investment; we pay upfront cost to meet mandatory compliance and upgrade our assets that contribute to safer and more reliable service for our customers, and we recoup part of those costs from the Joint Users.



[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

N/A

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

The Joint Use program is required by law and is clearly defined and regulated by the FCC and the Public Utility Commissions in both Washington and Idaho. Part of this requirement includes an obligation by Avista to replace infrastructure to taller/stronger structures to accommodate or "make ready" those facilities for new attachments by our joint use licensees. However, these same rules also allow Avista to recover a portion of the costs associated with these improvements.

The indirect offset is the installation of new infrastructure and the replacement of aging infrastructure, at a significantly reduced cost to Avista. In general, joint use licensees pay for up to half of the cost of pole replacements and infrastructure upgrades. Example: An older/aging utility pole needs to be replaced so that a joint use licensee can safely attach to that pole, that joint use licensee will then pay for all, or a portion of the costs, associated with replacing that pole.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

An additional indirect offset is that the replacement of this aging infrastructure and/or addition of new infrastructure acts to enhance and further harden Avista's network against adverse weather and other damage that would directly impact our ratepayers.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1:

No realistic alternatives exist. The only alternative would be to cease performing this work which would result in regulatory/legal action and customer dissatisfaction. In addition, we would be defaulting on 73 Joint Use Master License agreements.

Alternative 2:

Alternative 3:

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

We track and measure our ability to meet WUTC guidelines bi-monthly. This Information is presented to the Joint Use Steering Committee for their review.

Application Approvals & New Contracts

Average Application Approval Time/ Joint Use Company

Company	Average of Net Approval Time
AVISTA	18
CHARTER	20
CMC	24
COM	13
CTL	37
ELI	12
FTBM	30
INTERMAX	17
MCI	32
NOANET	28
POC	34
POL	18
POW	9
SPARKLIGHT	27
SUDDENLINK	20
TDSM	8
VZW	0
XO	23
ZAYO	26
ZIPLY	24

Joint Use Mutual Licensing Agreement Information

Total number of contracts in place	New Contracts 2021	New Contracts 2022	New Contracts 2023	Pending New Contracts 2024
78	0	3	8	0

Work Demand - Attachment Requests 2023

COMPANY	BACKLOG	WAITING	APPROVED	CANCELLED	GRAND TOTAL
CMC	4	59	352	16	431
ZIPLY	16	106	90	2	214
FTBM		6	130	4	140
CTL	10	23	105		138
TDS		46	34	4	84
CHARTER		13	48	5	66
TDSM			28	1	29
DECLARATION NTWK		26	2		28
INTERMAX		4	23		27
SPARKLIGHT		2	17		19
LINCOLN COUNTY		10	8		18
VYVE-NORTHLAND			18		18
MCI			16	1	17
ADAMS CO	10		6		16
POC		2	9		11
ZAYO		2	8		10
CONCEPT COMM		4	6		10
COLVILLE TRIBE	4	6			10
ELI	2		6		8
POW			6		6
FATBEAM			4		4
WHOLESAIL			4		4
AVISTA			4		4
POL			3		3
WOW		2			2
ARDENT WIRELESS		2			2
KNIGHTCOM			2		2
XO COMMUNINCATIONS			2		2
TOWN OF WASHTUCNA			2		2
DAVIS COMMUNICATIONS			2		2
MOBILITIE			2		2
ST. JOHN			2		2
WIFIBER		2			2
VZW			2		2
COM			2		2
NOANET			2		2
GRAND TOTAL	**46**	**242**	**945**	**33**	**1,339**

Data as of 12/31/23

Backlog (The clock starts) – Application, design, and fee received. Not yet fielded or reviewed.

Waiting (clock on hold) – Redlines returned to customer, waiting for response and updated design from customer.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 81 of 535

COMPANY	NEW TOTAL INSPECTION POINTS	NEW ATTACHMENTS	OVERLASH
AVISTA	22	17	
CHARTER	377	146	192
CMC	2,224	777	1,378
COM	7	4	
CTL	1,528	420	876
ELI	33	8	24
FTBM	2,054	1,944	44
INTERMAX	490	367	50
MCI	163	124	14
NOANET	3	2	
POC	371	303	9
POL	5	-	4
POW	52	47	2
SPARKLIGHT	129	14	108
TDS	1,286	968	2
TDSM	34	12	4
VZW	1	1	
ZAYO	61	1	57
ZIPLY	5,849	3,648	1,493
WHOLESAIL	77	63	14
VYVE-NORTHLAND	173	36	133
LINCOLN COUNTY	1,747	1,644	50
MOBILITIE	(30)	(30)	
WIFIBER	75	61	
KNIGHTCOM	20	18	
XO COMMUNICATIONS	-	-	
DAVIS COMMUNICATIONS	2	1	
DECLARATION NTWK	1,297	1,108	
ADAMS CO	761	681	3
ARDENT WIRELESS	14	8	
TOWN OF WASHTUCNA	42	31	
WOW	30	-	28
CONCEPT COMM	401	-	401
ST. JOHN	126	-	120
COLVILLE TRIBE	469	374	
FATBEAM	9	-	7
GRAND TOTAL	**19,902**	**12,798**	**5,013**

2.7 Please provide the timeline of when this work is scheduled to commence and complete, if known.

This capital work related to this business case are on-going and immediate. Transfers to plant occur on a monthly basis and the assets become used and useful immediately following physical construction.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The advisory group for this business case is the Operations Round Table. This team is a Director/Manager level review team that monitors the year to date spend for various capital projects including Joint Use. Meetings are held monthly. In-year Change requests would be reviewed by this team prior to going to the Capital Planning Group for approval.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Joint Use Business Case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Jesse Butler Digitally signed by Jesse Butler Date: 2024.05.13 09:04:48 -07'00'	Date:	5/13/2024
Print Name:	Jesse Butler		
Title:	Joint Use Business Manager		
Role:	Business Case Owner		

Signature:	Vern Malensky Digitally signed by Vern Malensky Date: 2024.05.13 09:30:05 -07'00'	Date:	05.13.2024
Print Name:	Vern Malensky		
Title:	Director of Electrical Engineering		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 83 of 535

Meter Minor Blanket

EXECUTIVE SUMMARY

The meter minor blanket is used to charge the labor associated with new electric meter installations in Washington and Idaho due to the replacement of failed plant (meters) that can no longer gather or communicate accurate consumption data.

The Meter Minor Blanket Business Case is driven by tariff requirements that mandate Avista's obligation to serve existing customer load within our franchised area. Annual spending is approximately $250k per year.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Dan Austin*	*Initial draft of original business case*	*5/10/2024*
BCRT	*BCRT Team Member* – Katie Snyder	*Has been reviewed by BCRT and meets necessary requirements*	*5/10/2024*

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 84 of 535

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$250,000	$250,000
2025	$250,000	$250,000
2026	$250,000	$250,000
2027	$250,000	$250,000
2028	$250,000	$250,000
2029	$250,000	$250,000

Project Life Span	***Ongoing***
Requesting Organization/Department	Electric Meter Shop
Business Case Owner | Sponsor	Dan Austin | Paul Good
Sponsor Organization/Department	Electric Operations
Phase	Execution
Category	Program
Driver	Failed Plant & Operations

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

The meter minor blanket is used to charge the labor associated with new electric meter installations in Washington and Idaho when a replacement is needed to due failed plant (meters) that can no longer gather or communicate accurate consumption data. Failed plant could be the result of various scenarios including, but not limited to, age, weather or environmental damage, hardware failure, or radio communication failures. A meter must be installed as soon as possible to accurately capture customer energy consumption data. For this reason, Avista must sustain a continuous stock of each electric meter type and budget the required labor to install these meters. The meter Minor Blanket Business Case is driven by tariff requirement that mandate Avista's obligation to serve existing customer load within our franchised area.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 85 of 535

1.2 Discuss the major drivers of the business case.

The current or potential problem is the failure and needed replacement of meters. If the meter has failed and isn't promptly replaced we will not be able to accurately record customer usage and the customer will not be able to see their usage data online. This data is what enables us to charge customers accurately for their actual usage, helps customers make wise decisions on their daily usage, and may even encourage conservation.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The work is required now because we need to be ready to respond to failed meter right away. If we don't have the funding to provide the right resources to replace meters as they fail we will not be able to properly measure customer's usage. If we mitigated this request it could cause a build up of failed meters and an increase in estimated bills. This is not a benefit to the customer or Avista.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link.*

Avista Strategic Goals

Having working meters in the field and being able to to accurately measure a customer usage is in the customer and the company's best interest. This is in line with our vision by keeping our customer's at the center of everything we do.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

There we no specific studies that were done to initiate the creation of the business case. Installing and replacing failed meters with new meters allows us to bill the customer accurately per the requirement of the tarrif.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 86 of 535

As depicted in the graph below we are staying fairly consistent with the number of meters/dollars required each month to ensure all failed meters are getting replaced in a timely manner. The three year average spend for this business case is $281K.

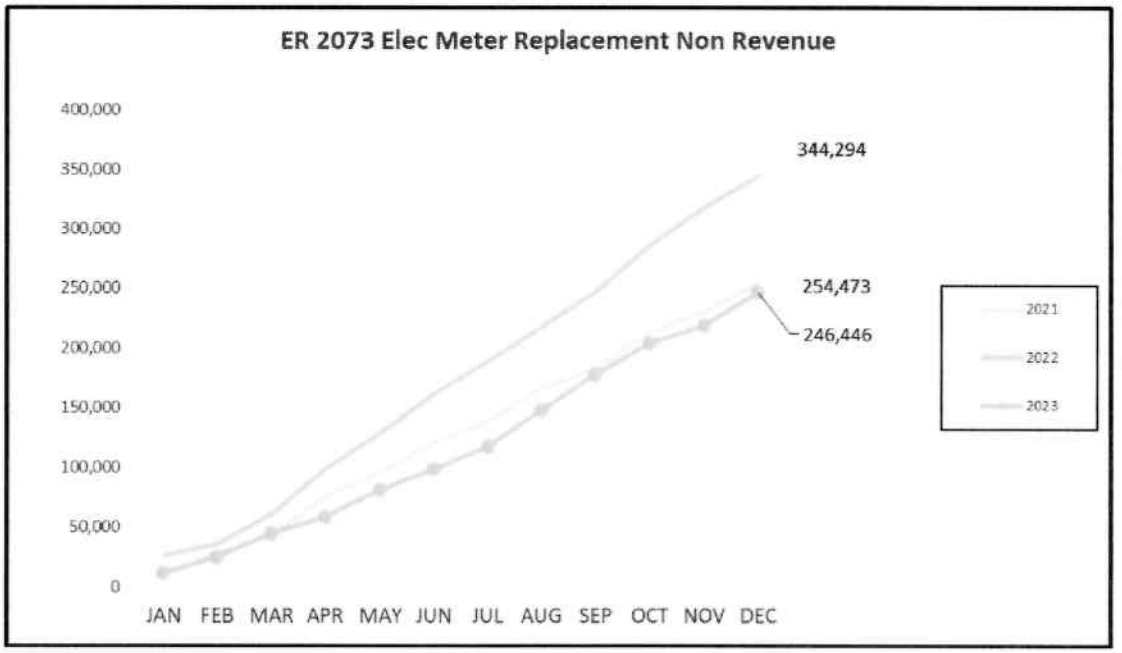


Table 1: 3-Year average spend for Meter Minor Business case (2021-2023)

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The recommended solution is to fund this business case to enable Avista to have the right inventory and resources to replace meters as they fail. If we do not fund this business case and we cannot replace meters as they fail we will not meet the requirement set forth in the tariff.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 87 of 535

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

N/A – This is a requirement of our tariff and no studies or metrics are available. However, the benefit to our customesr is that we are getting accurate readings from their meters for their usage and therefore billing them correctly. Additionally, they can view their actual usage on our website to make informed decisions about their electric use.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

N/A – This is a requirement of our tariff and there are no direct offsets.

2.4 Summarize in the table, and describe below the INDIRECT offsets4 (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 88 of 535

The indirect offset we see by funding this business case is the savings of not having to send a meter reader to each location to read the meters. If we weren't able to replace the failed meters in a timely manner we would have to roll a truck each month to get the reads in order to bill customers for the correct usage. On average, rolling a truck to read a meter costs about $47. Depending on how many failed meters we needed to read each month this could end up being a significant cost. This business case allows us to avoid those unnecessary costs.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

No reasonable alternatives exist. This is a requirement of our tariff and must be completed.

Alternative 1:

Alternative 2:

Alternative 3:

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

The only metric that's currenlty being used to ensure and demonstrate that the investment is being delivered upon is the tracking of our spending each month. This shows that we have the stock and resources needed to complete this work throughout the year.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 89 of 535

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

There is no end date for this business case. The work completed under this business case is used and useful right away and transfers to plant monthly.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The business case is reviewed and approved by our Capital Planning Group (CPG) and the annual spend is also reviewed every three weeks by the Operation Round Table (ORT) that is comprised of the Director of Electric Operations, various operations managers, and business case owners.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 90 of 535

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *<Business Case Name>* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Dan Austin	Date:	May 16, 2024
Print Name:	Dan Austin		
Title:	Manager Electric Meter Shop		
Role:	Business Case Owner		

Signature:	PAUL Good	Date:	5/16/2024
Print Name:	Paul Good		
Title:	Director Electric Operations		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 91 of 535

DocuSign Envelope ID: 74121ACF-5716-41D2-A58F-04C0959B3B62

Metro 115kV Substation

1.0 BUSINESS CASE REQUEST – 5 YEAR PLANNING 2024

Year	Requested Amount	CPG Approved Amount *(Admin use only)*
2025	$11,000,000	
2026	$11,000,000	
2027	$8,500,000	
2028	$2,500,000	
2029	$0	

1.1 DISCUSS HOW THE ABOVE REQUESTED AMOUNT WAS CALCULATED INCLUDING ANY CONSIDERATION OF HISTORICAL SPENDING, ESTIMATES, CONFIDENCE LEVELS AND ESCALATION RATES.

This request includes dollars for the design, equipment, and construction of the Metro 115kV Station Rebuild. This project is currently under construction in downtown Spokane.

Major Project Milestones

- 2025 – Power Transformers (Three) Received.
- 2026 – Substation Complex Complete
- 2027 – Communication and Security Construction Complete.
- 2028 – Final Project Closeout.

2.0 INITIAL BUSINESS CASE APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds request and agree with the approach presented, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Brian Chain	BC Owner	DocuSigned by: Brian Chain	May-02-2024 | 3:49 PM PDT
Vern Malensky	BC Sponsor	DocuSigned by: C4012FF13CFC491... Vern Malensky	May-03-2024 | 1:41 PM PDT
	FP&A	06C4FF5AB09E40B...	

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 92 of 535

DocuSign Envelope ID: 74121ACF-5716-41D2-A58F-04C0959B3B62

EXECUTIVE SUMMARY

The Metro 115kV Substation serves the urban core of downtown Spokane and has done so reliably for almost 50 years. Customer outages in this area are counted in terms of “minutes per decade”, which has enabled our customers to implement and sustain a dense population of both commercial and residential interests, in a zero-lot line environment. The high reliability of the Spokane urban core comes about through the Metro Substation being partnered with the Post Street Substation to provide full redundancy to the downtown core. This strategy is typical for most large cities. The Metro Substation typically powers half of downtown Spokane, including the Historic Davenport Hotel, Washington Trust, Century Link, and Wells Fargo buildings among many others.

Our customers’ trust in our reliable service that depends on this station, with components that are approaching the end of life, equipment that no longer meets present safety standards, and a unique existing site that imposes severe operational constraints. The existing transformers are 40+ years old, are unique and do not have spares, and use of the mobile transformer is not an option at Metro. These constraints threaten to create significant and extended customer outages if major equipment failure for a significant portion of the downtown area. This project will address both the equipment and site issues in the most efficient and affordable way possible, based on the alternatives and risk analysis performed for this substation and detailed further in this document.

The result of this project will be a flexible and reliable station that fulfills needs in multiple operating divisions. The new substation will provide safer equipment, necessary redundancy, increased capacity, and a design that enables a longer station lifespan where individual pieces of equipment can be safely serviced. Additionally, the new substation would include two additional distribution feeders that will provide needed capacity and a redundant path for the hospital district and lower South Hill. A rebuilt Metro Substation will provide the reliability that our customers expect.

The total project cost is estimated at $73 Million. The selected option for the Metro 115kV Substation rebuild includes four 115kV lines, ring bus configuration with 6 breakers, two 30 MVA power transformers, 9 network feeders and 2 distribution feeders, 8 air core reactors with enclosures, and switchgear in its own enclosure. Also included in the substation cost is an architectural wall enclosure to provide security around the site, an underground cable vault for the large amount of network cables, a control and battery enclosure to house the control panels, and multiple underground duct banks that provide pathways in/out of the site for distribution, network, and transmission. The location of the new Metro substation in the City’s downtown core requires the surrounding wall enclosure to adhere to a design review and permitting process that also includes architectural, landscaping, and other requirements to meet the downtown aesthetic. The smaller footprint of this site requires unique layouts and designs to accommodate all of the structures and equipment that are needed. Substantial cost increases in equipment and materials in the past few years have affected the overall project budget and long-lead time equipment has had a negative impact on the timeline resulting in a longer construction period as well.

The risks associated with the existing Metro substation are significant and could include extended outages for half of the downtown area that is fed via Metro and Post St. The mobile substation is not an option at this location to back up the site and keep the downtown area energized due to space constraints and technical incompatibilities. Beyond a temporary tie-line solution in the event of a transformer outage, there is no other option to maintain critical service to our downtown customers. Safety risks include significant fire risks to adjacent structures that are within 50 feet of the oil-filled equipment. Additionally, the switchgear which is not arc-flash rated puts personnel at risk as they must be inside the front of the cubicle to manually switch it. Due to the long lead times of major equipment (3 years for transformers) and the length of time to construct such a large and unique substation, the cost of the project is substantial. The longer the project takes to start and complete construction and energize, the higher the overall project cost due to compounding construction costs, all while there is an ongoing increase in the potential risk of equipment failure at the existing station.

The Metro rebuild project was scoped in 2020 and a Project Charter was started and approved in 2021. This effort included analysis and assessments of operational risks and challenges, mitigation options and

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costs for multiple rebuild, brownfield, and greenfield scenarios, and project estimation and milestones. These documents were developed by engineering teams, reviewed and approved by engineering managers and the Director. Continued monitoring and controlling, and reporting of the project scope, schedule and budget occur on a monthly basis with the department managers and Director. Any proposed changes to the project are managed and tracked through the change management process.

Major Project Milestones

- 2025 – Power Transformers (Three) Received.
- 2026 – Substation Complex Complete
- 2027 – Communication and Security Construction Complete.
- 2028 – Final Project Closeout.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Karen Kusel / Crystal Holmes*	*Final Draft of Business Case*	*3/1/2023*
2.0	*Karen Kusel / Brian Chain*	*Annual Update of Business Case*	*5/2024*
BCRT	*Steve Carrozzo*	*Has been reviewed by BCRT and meets necessary requirements*	DS SC

DocuSign Envelope ID: 74121ACF-5716-41D2-A58F-04C0959B3B62

GENERAL INFORMATION

YEAR	SPEND AMOUNT ($) ACTUALS AND EXPECTED	TRANSFER TO PLANT ($) ACTUALS AND EXPECTED
2018	**$2,850,000**	**$2,850,000**
2019	**$3,300**	
2020	**$200,000**	
2021	**$1,600,000**	
2022	**$3,610,000**	
2023	**$12,700,000**	
2024	**$18,800,000**	
2025	**$11,000,000**	**$3,200,000**
2026	**$11,000,000**	**$55,800,000**
2027	**$8,500,000**	**$6,000,000**
2028	**$2,500,000**	**$3,500,000**
2029	**$0**	**$0**

Project Life Span	***11 years (2018 – 2028)***
Requesting Organization/Department	M08 / Substation Engineering
Business Case Owner | Sponsor	Brian Chain | Vern Malensky
Sponsor Organization/Department	Energy Delivery
Phase	Execution
Category	Project
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

Transmission Related Issues

- Metro-Post St MTR-PST and Third & Hatch-Post St 3HT-PST Transmission Line Cables in Shared Duct Line/Manholes (3HT: Third & Hatch, PST: Post Street)

  Issue: Between Post Street and Metro substations the latter being where the Third & Hatch-Post St 3HT-PST line transitions to underground cable) the two 115 kV lines share the same duct bank and ~10 manholes/splice vaults. The cables are exposed in this area to a double circuit failure due to single circuit problems (e.g., splice failure, cable fault, manhole fire).

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 95 of 535

DocuSign Envelope ID: 74121ACF-5716-41D2-A58F-04C0959B3B62

Risk: The shared duct bank path is susceptible to a single cause of failure (e.g., dig-in) that affects both lines, similar to a double circuit 115 kV overhead design. Outage work affects both lines in the same way.

- Tunnel Design Causes Transmission Outages for Unrelated Work

  Issue: Immediately south of the existing Metro Substation, in the Steam Plant alley, is an approximately100' long "tunnel" that contains many types of cable including the 115 kV 3HT-PST Third & Hatch-Post St line racked on the tunnel walls. Other cables are various Avista and joint use communications cables, secondary cabling that is part of the Downtown Network and 13 kV Metro-Post St MTR-PST tie line cabling – 6 1500 kCM copper EPR cables, critical to backup operation of Downtown in the event of an equipment failure at either Metro or Post Street. Safe work practices from the industry are in use at Avista; these dictate that crews and engineers are not able to enter the tunnel (or any 115 kV underground facility) with the 115 kV energized. This requirement has led to the need to take the 115 kV transmission out of service, making the Bulk Electrical System (BES) less reliable for unrelated work.

  Risk: The many shared uses of the Metro tunnel drive outages on the 115 kV 3HT-PST line that pose operational challenges and lessen the overall reliability of the Bulk Electric System.

- 115 kV Line Outages Required for Other Various Unrelated Work

  Issue: Metro-Sunset 115 kV MTR-SUN transmission line exits the station and goes over specialized structures on top of the Steam Plant building.

  With the recent Steam Plant restaurant modifications/upgrades, kitchen vent fan(s) have been installed underneath this line and it is assumed we will need some sort of on-going future maintenance, which will require an outage to this circuit.

  Given that Steam Plant workers and maintenance crews are not familiar with the procedures required by WECC and NERC with regard to the BES, often outages to this line are requested with only 1-2 weeks of planned Steam Plant work. Avista's standard requires at least 21 days of notice for non-emergency outages.

  Due to the limited conductor clearance to the Steam Plant roof, there is a fence installed prohibiting access underneath this line. Controlling who has access is ongoing; non- qualified personnel have had access.

  Due to clearances, maintenance work to the exterior of adjacent buildings requires a safety watch and/or line outage. This is namely the building south of the OH section of PST-3HT at Metro.

  Double 115 kV line outages are required for almost all vault inspection/maintenance work of underground sections of both PST-3HT and MTR-PST. There are around ten transmission vaults that are shared between these two lines, mostly on Lincoln, between Post St and Metro. One way we have been operating around these conditions is by taking line outages at night for O&M work to be performed on overtime. Double line outages during the night are 2 to 2.5 times the cost of single line outages that can be performed during the day. This is due to the doubled labor cost per hour plus the need to have multiple crews and additional switchmen for the duration of the outage for multiple switching operations throughout the night.

DocuSign Envelope ID: 74121ACF-5716-41D2-A58F-04C0959B3B62

Risk: Unrelated non-utility work causes outages on the 115 kV 3HT-PST line that pose operational challenges and lessen the overall reliability of the BES. Non-qualified workers have possible access to transmission line areas that do not have compliant NESC clearances.

- Nearby Overhead Transmission Lines – General Risk Assessment

  Issues: The Metro-Sunset transmission MTR-SUN line was built in 1976 (47 years old) and north of I-90 there are four original structures (excluding the lattice steel structures on the Steam Plant roof – a building that Avista no longer owns).

  The structures are along Lincoln St., which is one of the busiest north-south thoroughfares in Spokane. Several of these structures are on the corners of streets and alleys, putting them in prime locations for vehicle impacts.

  The two tangent structures are class #3 wood poles, and do not meet NESC code with regards to strength requirements.

  The pole on the corner of Steam Plant Alley is guyed in two locations. One guy is across Lincoln St. and is secured into the side of a brick building, and the other is guyed to the north, approximately 175’ over the entrance to the Steam Plant, into a BNSF railroad trestle.

  Current structures in the vicinity, including steel lattice structures, would not be suitable for a conductor upgrade to 795 ACSS, a higher capacity and current Avista standard conductor than existing, due to the existing structures not meeting NESC strength requirements.

  Avista no longer owns this building so any access for inspections or maintenance by Avista must be coordinated with the current owners.

  Due to the Lattice Steel Structure on the roof of the Steam Plant, there have been many necessary outages at the request of the owners to complete work and maintenance on the building. These include roof repair and maintenance, restaurant cooking vents install and servicing, air conditioning repairs and maintenance, and other structural maintenance.

  The overhead section of the Post St-Third and Hatch PST-3HT transmission line was built in 1987 (36 years old) and consists of three self-supporting steel structures and one wood structure, north of I-90.

  The current configuration for transitioning from OH to UG at Metro does not lend itself well to a mobile sub installation if one was required for an extended time to make repairs at the current location.

  Clearance to the building south of Metro does not allow for exterior maintenance without an outage.

  A large steel pole in the middle of the sidewalk along Post St, approximately 6 inches from the curb.

  Risk: Various out of date and non-standard transmission structures provide an increased potential for failure (car-hit poles, structural failure, corrosion, guy anchor failures or breaks). This could result in line faults, reduced reliability to the BES, and

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public safety hazards. Approximately 1-2 poles per year are hit/damaged in the downtown area.

- 115 kV Source Reliability (Recent Transmission Trip)

  Issue: Transmission service to this station is redundant, but compared to other two-line stations and has had issues in the past with one side being underground and the other being overhead. For example, in 2018, a line tripped in the area, when a contractor dug up a guy wire which caused the wire to snap, resulting in the 115 kV Metro-Sunset 115 kV transmission MTR-SUN line and College & Walnut Feeder 12F4 (an overhead radial feeder in the area) to fault together.

  Both the 115 kV line and the College & Walnut feeder tripped out. The other source to Metro, the 115 kV Metro-Post St line, also tripped. Due to the lack of event recording equipment (old microprocessor relays) at Metro, the line could not be closed back to service and resulted in an extended outage. The lack of necessary information to determine what had occurred eliminated any confidence to re-energize.

  With both 115kV source lines tripped, Metro was momentarily without a source for half of Downtown. The relaying for the underground cable line between Metro and Post St does not allow reclosing, so this line stayed out of service. Metro at this point was a radial feed.

  Fortunately, the line held once energized. Had the line needed to be repaired, or replaced, there would have been a substantial delay as Avista does not stock the parts, nor do we have the expertise in-house to do the work. While Metro was solely sourced by one 115kV line for about a week and a half, it could have been months, if repairs had been necessary. Note that the replacement of the oil-filled cabling with newer cross-linked polyethylene (XLPE) cabling does not change the fact that our most experienced in-house distribution cablemen do not have the training, experience, or equipment necessary to install transmission splices, even on XLPE. We would have to bring in external contractor resources and also find replacement cables that are significant long lead time materials.

  Risk: Single transmission line trips can, and have cascaded, causing a full Metro Substation outage. Cable transmission line trips cannot be repaired in-house and leave Metro susceptible to an extended sustained outage for an N-1 trip during the subsequent repair time, could extend to months. Having two transmission lines (sources) creates redundancy which reduces this risk significantly.

Distribution Related Issues

- Racking Breakers for Feeder Outages

  Issue: The switchgear at Metro Substation is some of the most heavily utilized on the system, from a feeder outage standpoint. This is because, due to the secondary network, it is inconsequential to customers for a feeder to be out of service. All primary conductors are underground cabling, which cannot be worked on while energized. Therefore, in the Downtown Network, Hot Line Holds are not used at all. Instead, if any work is necessary on the feeder, the feeder is completely taken out of service. This results in more planned switchgear breaker operations as well as more instances of breakers being racked in and out, as compared to any other distribution station on the system, except for Post Street, the other Downtown Network substation.

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Remote racking is available at Post Street, but not at Metro. Instead, the older switchgear is either jacked into place using a portable jacking motor, or in some cases, ratcheted horizontally into the energized 13 kV bus, manually. In order to do either requires a cableman to be physically inside the front of the switchgear cubicle.

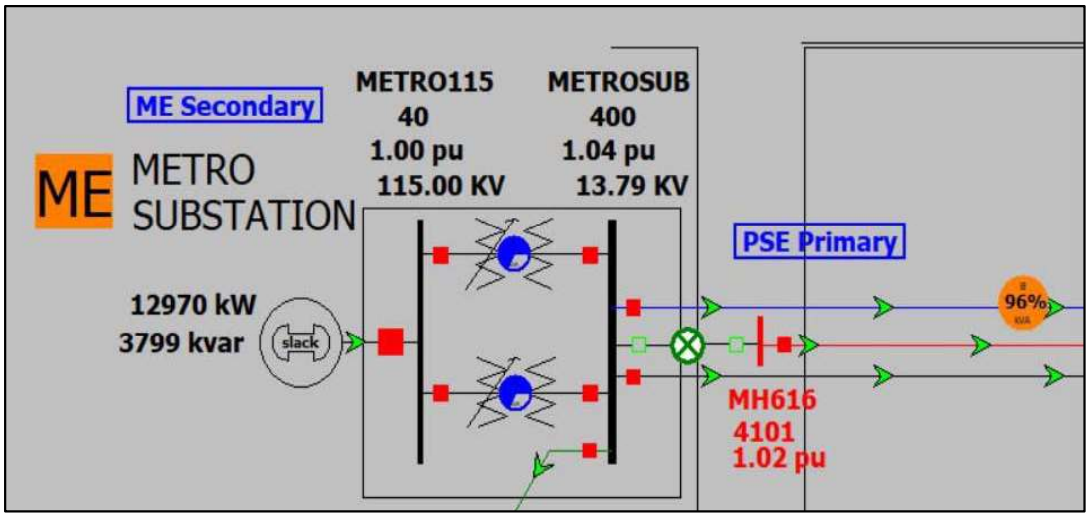
While this operation is safe assuming everything goes correctly, it is not necessarily a design that is a good idea to "run to failure" as many failure scenarios involve severe employee injury or death due to arc flash. When Metro's switchgear was procured, arc flash was not an industry-recognized concern.

Risk: Arc flash during racking operations will have severe consequences to cablemen who, by design, are directly in the line of fire.

- Three Metro East Feeder Exits Need Upgraded for Thermal Reasons

  Issue: The present Metro East feeder exit cables all show at or over their capacity limits in Powerworld, a power flow system modeling software, under a contingency feeder trip analysis for both summer and winter loading.

  The Powerworld modeling provides data in the figure below. The worst cable capacity limits is Feeder #13636, which peaks at around 96%. Feeder #13637 is around 93%. Feeder #13638 lags and is "only" hitting about 87% but should be upgraded at the same time. Typically, over 80% is the threshold for starting to look at options to mitigate thermal issues and this site is obviously overdue.



Risk: Failure of a feeder exit cable due to being run over capacity would result in an outage to a quarter of downtown. Cable overloads occur under contingency (when one of the other feeders to that quadrant are already out of service) so the second feeder trip triggers the Automatic Feeder Reduction (AFR) scheme which dumps the remaining feeder in the network in order to prevent further cascading failure in both the primary and secondary.

Cable replacement and commissioning would take days to weeks depending on duct bank damage and whether the old cable was able to be removed. During that time, the

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outage would continue as no options to backfeed primary exist within the Downtown Network.

- Lower South Hill Radial Feeder Reliability

  Issue: The existing feeders that serve the lower south hill and the hospital district have experienced several extended outages. These feeders have exposure due to both length (College & Walnut 12F4 for example) and other special circumstances (transmission underbuilds, river crossings). Between 2018-2020, there were at least 2 to 3 outages on the College & Walnut 12F4 feeder that directly impacted the MultiCare Deaconess Hospital requiring them to go on backup generators. When on backup generators, they cannot perform any new surgeries.

  Risk: Multiple recent outages in this area have caused many customer issues including cancellation of surgeries at Deaconess. This is a significant public risk, and the hospitals are critical customers. Work arounds in the past have included reconfiguring the feeders to take on the hospital load but this raises the load on the entire system and depending upon the season (hot or cold conditions/loads) it may be difficult or not possible to resolve.

Substation Related Issues

- Transformer/Low Side Fault Clearing

  Issue: The existing Metro substation is presently only one of three stations on Avista's entire system that requires a 115 kV bus trip in order to clear a transformer or transformer low-side fault. Due to the lack of circuit switchers and the lack of space to add them. Which in turn is due to the station being built on a site that is entirely too small for the intended purposes. The existing scheme will dump the 115 kV bus using the transmission breakers to both Sunset and Post St transmission lines. With the bus and the southern half of Downtown de-energized, an air switch must be opened, which is supposed to be done automatically. However, it should be noted that these transformers disconnect switches have rarely been maintained due to their electrical location; operational success under real conditions is not guaranteed and has proven to be an issue with other 115 kV transformer disconnect switches.

  Risk: If the air switches operate properly and automatically, then the load in the station is restored after only a momentary outage to half of Downtown. If they do not operate, then the outage has the potential to grow longer while a crew is called to the site in order to force the switch open.

- Fire Threat to Nearby Buildings

  Issue: Part of the switchgear at Metro is inside an alcove/garage underneath a section of the Steam Plant building to the west of the station. Avista no longer owns the Steam Plant. The Steam Plant is constructed of brick and steel with no added fireproofing. Required distancing between oil-filled equipment and a "possibly-manned" panel house in any of our stations is 50 feet, per IEEE 979. This is based on industry standards. When oil-filled equipment must be closer to panel houses than 50 feet, a firewall is required to be placed in the gap. There is no firewall, nor space to install one.

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Risk: While the panel house at Metro was constructed within 50 feet of an oil filled 115 kV circuit breaker, the larger concern is that both transformers and both 115 kV circuit breakers (oil-filled) are within 40 feet of the Steam Plant building itself. Again, there is no fireproofing. The Washington Trust Data Building to the south is also only ~30 feet away. In the event of a failure to trip of any protective functionality inside the station, there is a significant risk of a catastrophic commercial building fire potentially putting property and lives in danger.

- Batteries at the Existing Station are Undersized

  Issue: Batteries at the existing Metro are undersized given both the importance of the station (transmission breakers, six feeders of urban load) and the amount of equipment in the station. The station's batteries are presently sized at 100 amp-hours (Ah). Stations), 48V DC and would only last a few hours. A 125V DC system is now the standard for transmission substations, providing 8-12 hours of backup per IEEE 485. Only 4 Avista substations have smaller batteries than Metro.

  Risk: Batteries that are too small do not become an issue until a very critical moment (such as an extended station service outage or battery charger failure). Avista has been lucky to avoid a severe consequence in these scenarios, as can be experienced if a battery runs down in such a situation. Loss of battery backup results in a station service failure, loss of battery charger, breakers cannot trip or close on their own, and the station loses operability. System Operations is well aware of the criticality of station batteries.

  The worst-case scenario at Metro could be a failed charger with a missed alarm in System Operations as there is no battery voltage indication to SCADA at Metro, due primarily to the lack of microprocessor relaying and modern SCADA at Metro. Without this indication to start an immediate crew callout, the undersized battery would run down very quickly (within hours, not days) and limit the amount of time for the missed alarm to be caught.

  Note also, if a feeder or transmission breaker trip had been required during this time, the battery is unlikely to support the trip, which would result in the breaker failing to operate. In turn this could create the same kind of catastrophic effect that Grant County Public Utility District (GCPUD) saw in their Ephrata Substation fire, after the battery was unavailable to support a DC-powered breaker trip. The difference at Metro is that the smaller site, and lack of built-in fire protection for surrounding buildings and railroad, would threaten much larger consequences than just a "simple" substation fire.

- Size of Existing Site is Insufficient

  Issue: The chart below shows a comparison of stations by a metric of "square feet per circuit". Circuit in this case means either a transmission line terminating on a breaker, a distribution line, or built-in space for a future distribution line. Substation Engineering recommended several of the known "small" stations to compare Metro against. These included other similar stations with 115 kV breakers and/or switchgear, as well as a "tiny" station (O'Gara).

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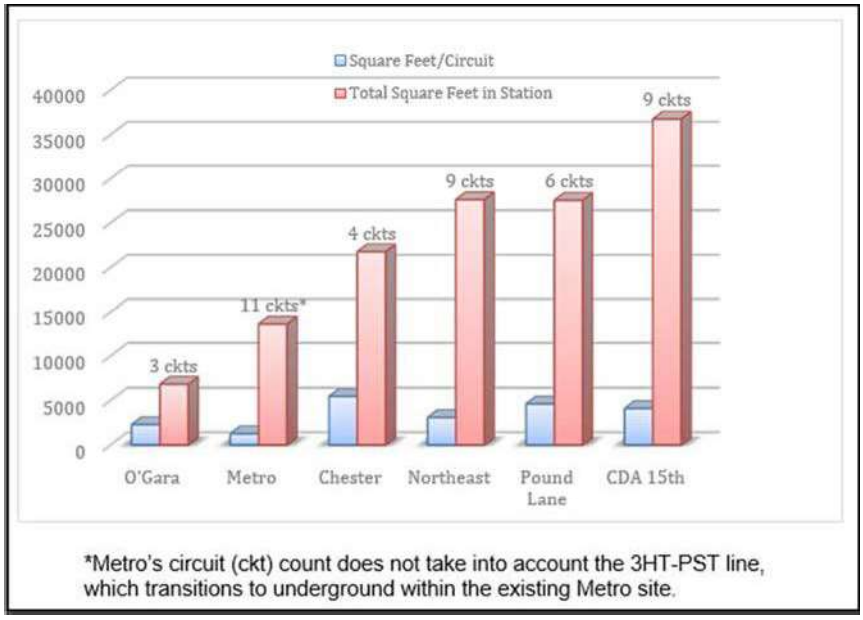

Risk: This metric does not necessarily speak to the specific challenges faced at the existing site, but it does provide context generally as to why Metro is unique, and why it seems to present so many of these specific challenges.

Note that "size per circuit" was not chosen as a metric simply because of the results it produced. If you compare, for example, the simple overall square footage of the existing Metro site to every other transmission station on Avista's system, it is the second smallest at ~12,000 square feet despite serving significantly more load.

It could also be noted that many of the stations that face significant space challenges inside the fence have mitigating factors that allow emergency operations to take place. For example, there typically options to install the mobile substation, replace 115 kV breakers, or crane in a transformer, but with the challenges at Metro due to both the surrounding environment and the equipment inside, these mitigations are not possible.

- AFR Relaying Not Controllable by Feeder

  Issue: The unique secondary network that is fed from the Downtown Network feeders out of the existing Metro Substation has associated unique relaying – an Automatic Feeder Reduction or AFR scheme. AFR is intended to protect both the primary and secondary cabling in the Downtown Network from overloads in the event of more than one feeder being out of service.

  Feeders can be "out of service" in one of two ways: the primary breaker can be opened in the substation, or all network protectors downstream can be opened. As part of a normal primary clearance switching order, both situations must occur.

  The AFR scheme is set up such that, if the primary breaker is open, then the relaying is automatically aware of the inability of that particular feeder to serve load (leaving the remaining feeders in that network as the sole providers of energy). However, unlike at Post Street, the AFR cannot be manually indicated to, in the event that network protectors downstream are open and not serving load.

DocuSign Envelope ID: 74121ACF-5716-41D2-A58F-04C0959B3B62

Risk: Metro's AFR configuration means that, at least once during every switching order, there are moments to sometimes hours (depending on needs of the order and crew availability) when tens of thousands of feet of cabling is exposed to a cascading overload event, if a second feeder is tripped for a fault. There are around 20 of these orders performed out of Metro every year.

- The "Pigeon Problem"

  Issue: The Metro Substation is in a location that lends to having a lot of pigeons around. The pigeons defecate all over the substation.

  Risk: This is not only a health hazard for our personnel but an electrical hazard as well. The droppings can cause unplanned outages due to insulator flashovers. To clean the station there has to be an entire 115 kV bus outage, which is extremely difficult to schedule.

- 115 kV PT Issues

  Issue: On 4/2/2020, it was identified that the B phase 115 kV Bus PT was leaking. The serviceman tried to use the oil level gauge to determine the oil level, which would have helped with determining the urgency behind the replacement. Unfortunately, the gauge was not legible. That is not uncommon for old equipment. The PTs were manufactured in 1976.

  Risk: The failure mode for PT's is quite destructive and has led to flying glass and oil fires. To replace the PT's, there has to be a whole 115 kV Bus outage, which is extremely difficult to schedule. The outage interrupts the continuity of the 115 kV path from Third & Hatch to Sunset. It also requires two simultaneous transformer outages at Metro. At any other site this would be a mandatory mobile transformer installation due to the reduction in distribution reliability in the area but is not possible at Metro.

- Recent LTC Issues Found

  Issue: In May of 2018, Avista crews conducted routine transformer testing on both Transformer #1 and Transformer #2. The crew found an issue with Transformer #2 Load Tap Changer (LTC). They found that when the LTC is tapped in the lower direction, the tap changer may not complete a full operation.

  Risk: Failure of an LTC would require the connected transformer to be taken out of service until fixed or replaced. This would result in an increasing load on remaining feeders and increased potential for negative cascading effect on the system.

- Avista Does Not Carry Spare LTC or Throat-connected Transformers

  Issue: The repair on Transformer #2 LTC brought up the concern about not having a spare transformer with an LTC.

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Risk: Installing a transformer without an LTC would cause the distribution to be unregulated, which is not acceptable. There is no proven option available to install voltage regulators at this station. Space to physically place them, available points in which to connect them in series, and electronic controllers that need to work in an abnormal paralleled fashion are all issues that would have to be solved. There is no way to quickly repair or mitigate this given the current facility.

Without the availability of a spare unit, one must be ordered. Lead times for transformers have varied but are currently around 3 years. In the meantime, while the order was being manufactured, delivered and installed, the N-1 case (e.g., another transformer or LTC or tie line failure) would leave half of downtown without power and no way to mitigate.

- Relaying Archaic: Last 115 kV Blocking Schemes on Avista's System

  Issue: Transmission line relaying at Metro is electromechanical based (primarily KD relays). The fleet is on average over 40 years old, is past its usefulness as it is archaic equipment and provides no operational visibility or records for event analysis after a system disturbance. Additionally, the Metro-Sunset line is the last transmission line in Avista's system to use a carrier blocking scheme. Newer schemes communicate with the system as to faults or status of other equipment or faults on the system. While dependable, blocking schemes are less secure in nature.

  Risk: Relay failures may not be able to be responded to in a timely manner. Spares are limited to those which have been retired from other stations. Expertise around setting KD relays has left the company. The last carrier blocking scheme is a threat to mis-operate, resulting in unnecessary transmission outages, decreased reliability, and FERC PRC-004 reporting.

1.2 Discuss the major drivers of the business case.

The Metro 115kV Station Rebuild project fits firmly within the Asset Condition and Customer Service Quality and Reliability drivers. Put simply, this project replaces old equipment with new equipment, which resets the curve with regard to asset life cycles, while also decreasing the likelihood of catastrophic equipment failures and resultant customer outages over the next 50 years.

However, elements of other investment drivers also apply. The end product of this project will allow construction and operations to occur without violating OSHA-driven circuit grounding requirements (one example of several Compliance drivers). It will also have upgraded feeder exits in the Metro East quadrant, which are presently at overload limits and need to be upgraded regardless. The transmission configuration allows more operational flexibility for 115 kV lines on both the South Hill and West Plains (Performance & Capacity). Finally, the completion of this project avoids a very costly and slow response to major equipment failures (any transformers, LTC's, switchgear, 115 kV breakers) which would likely end up translating into customer outages, unplanned Failed Plant expenses and a negative public image for Avista.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The risks associated with the existing Metro substation are significant and could include extended outages for half of the downtown area that is fed via Metro and Post St. The mobile

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substation is not an option at this location to stand up the site and keep the downtown area energized due to space constraints and technical incompatibilities. Beyond a temporary tie-line solution in the event of a transformer outage, there is no other option to maintain critical service to our downtown customers. Safety risks include significant fire risks to adjacent structures and occupants that are within 50 feet of the oil-filled equipment. Additionally, the switchgear which is not arc-flash rated puts personnel at risk as they must be inside the front of the cubicle to manually switch it. The risks of not moving forward with the new site and substation include the latter but also the negative public impact of not being able to provide power to the heart of the City for an undetermined amount of time. Due to the long lead times of major equipment (3 years for transformers) and the length of time to construct such a large and unique substation, the cost of the project is substantial. The longer the project takes to start and complete construction and energize, the higher the overall project cost, and there is an increase in the potential risk of older equipment failure.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

The Metro Substation project is the epitome of our Vision: “Better Energy for Life”. We already serve the downtown core with the current Metro substation, but we want to do it better by supplying electricity more safely, more reliably, and more responsibly. We aim to accomplish this by addressing safety and reliability issues that the current Metro Substation has and do it in a responsible way by engaging stakeholders well.

The new Metro Substation will use some of the latest technology in substation construction. As such, it aligns with our mission. Metro is an innovative energy solution that will improve our customers’ lives safely, responsibly and affordably. As stated before, the new Metro Substation will address a number of safety and reliability issues that the old Metro Substation has. We intend to do this responsibly and affordably. Nothing is planned for the project that isn’t a request from a stakeholder (City of Spokane, for example) or isn’t necessary from an operational or safety requirement.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

Please refer to the Project Initiation Charter document that includes the following memos in addition to the sections above:

- Metro – Operational Risks & Challenges of Existing Configuration: Categorizes and summarizes the risks and challenges posed by the existing configuration of our electrical system in and around Metro Substation.

- Metro – Mitigation Options & Costs: Categorizes and summarizes mitigation options and their associated costs for operational issues identified at Metro Substation.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

DocuSign Envelope ID: 74121ACF-5716-41D2-A58F-04C0959B3B62

- 115kV Metro Substation – Rebuild Options: History of the Metro Substation and its relation to the Spokane Central Steam Heat Plant, summarizes issues with each Equipment Type in the Metro Substation (as of 2009).

- Metro Station System Impact Study by System Planning: Technical analysis of the Metro Substation rebuilds impact to the transmission system in the region.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

In the table below, the project options and mitigations were identified and evaluated for cost, feasibility, and risk early in the Initiation phase and documented in the Project Charter. These options were re- evaluated and updated in Fall 2022. As detailed in the table below, the Rebuild on New Site was selected as the best, most cost-effective and feasible option to proceed with. Further detailed documentation of the options is included in the Project Charter and supporting documents. Based on the Project Initiation Charter, it is recommended that the station be rebuilt on new property approximately two blocks to the south. The rebuilt station will utilize an open-air transmission bus design with metal-clad switchgear on the distribution side. Both transmission and distribution busses will be arranged in a ring configuration.

The rebuild of Metro on a new site mitigates nearly all concerns and risks associated with the existing installation. Reference the table below and in Section 2.5 for alternative costs, risks and risk reduction. The rebuild also provides a better operating configuration that will result in much lower impacts as failures are (inevitably) observed over the life of the installation. For example, a 115 kV breaker failure at the new Metro will not result in a full station outage. In fact, depending on the exact nature of the failure, it may not result in any outage at all. At the old station, half of Downtown could be out of power.

O&M costs associated with the new station would be the lowest observed relative to all options.

Options	Capital Cost	Estimate Class	Reduced Risk
SELECTED: Rebuild on New Site	**$73M**	Class 3	93%
1) Status Quo	$0	-	0%
2) Selective Mitigation at Existing Site	$12M (Years 1-6)	Class 4 High Risk	44%
3) Rebuild on New Site (GIS)	$97M	Class 5	93%
4) New Transmission Site, Rebuilt Distribution Site	$85M	Class 5 Not Feasible	91%
5) Downtown West & Downtown East	$103M	Class 5 Not Feasible	82%

Class 5: -20% to +100% Strategic Planning & Concept Level

Class 4: -15% to +50% Order-of-Magnitude, Feasibility Study

DocuSign Envelope ID: 74121ACF-5716-41D2-A58F-04C0959B3B62

Class 3: -10% to +30% Budgetary, Semi-Detailed

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

In 2019 and 2020 multiple assessments and analysis were performed as part of the evaluation of the existing substation, scoping for the new substation and preparations for the new Metro Substation Project Charter that was approved in 2021. Refer to section 1.5 for a list of the reference documents. During these assessments, several options and alternate locations were evaluated for cost, risk and risk reduction, reliability, redundancy, capacity, and how they improve or mitigate current issues and risks for the Downtown core and our customers (Reference sections 2.1, 2.5, and 2.6). The summary of the information, assessments, analysis, and documentation provided in and referenced within this document were all considered when preparing this capital request.

	IRR	Annual Revenue Requirement
Base Case Rebuild on New Site	7.90%	$5,613,603
Alt 1 - Status Quo	6.38%	$5,894,718
Alt 2 - Selective Mitigation at Existing Site	4.82%	$7,251,968
Alt 3 - Rebuild on New Site (GIS)	4.03%	$8,132,620
Alt 4 - New Transmission Site, Rebuilt Distribution Site	4.96%	$7,118,115
Alt 5 - Downtown West and Downtown East	3.64%	$8,639,873

2.3 Summarize in the table and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

There are no direct O&M savings if the Metro Substation is rebuilt. Any savings are offset by increased costs to inspect, test, and maintain a much larger station. Annual O&M costs for a distribution substation is approximately $30,000.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$0	$0	$0	$0	$0

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 107 of 535

DocuSign Envelope ID: 74121ACF-5716-41D2-A58F-04C0959B3B62

O&M		$0	$0	$0	$0	$0

2.4 Summarize in the table and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Asset condition issues are present in several types of equipment at the current Metro substation (see Section 1.1 Substation Related Issues for details). Reliability and safety concerns are also present. These three types of issues cause the greatest number of Servicemen callouts. If the substation rebuild is completed, Servicemen will spend less time maintaining and 'limping along' equipment. They will complete the work more efficiently since the safety issues (i.e., switchgear arc flash) are not present and do not have to planned for (i.e., Arc Flash suits are not required). The savings could be as much as $180,000 per year in additional Serviceman labor (salary plus overhead costs) system wide.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	Asset Condition based equipment changeouts	$10,000 (Average)	$10,000 (Average)	$10,000 (Average)	$10,000 (Average)	$10,000 (Average)
O&M	Loaded Cost of One Additional Serviceman to help cover higher call out rates.	$180,000	$180,000	$180,000	$180,000	$180,000

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1:

Status Quo/no Change. Capital Costs No capital costs in years 1 to 9, complete rebuild starting in year 10.

Risk: Small site, feeders are beyond thermal capacity, significant fire risk to adjacent buildings, breakers are arc flash risk during racking, no spare transformer or mobile option. failures may result in outages for half of downtown for unknown duration. There is no reduction in risk.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 108 of 535

DocuSign Envelope ID: 74121ACF-5716-41D2-A58F-04C0959B3B62

Alternative 2:

Selective Mitigation at Existing Site – Upgrade overloaded feeder exits, install arc flash prevention relaying, install larger battery bank, install newer AFR relays, and purchase spare transformer. Capital Costs - $12M in years 1 and 6 with a complete rebuild assumed in year 10.

Risk: Small site, significant fire risk to adjacent buildings, failures may result in outages for half of downtown for unknown duration.

Alternative 3:

Rebuild on New Site (GIS) – Installing Gas Insulated Switchgear would mean the need for contract labor to install the equipment and this equipment requires a high cost to install. Capital Cost - $97M.

Risk: Mitigates almost all risks but comes with a higher cost for specialty equipment and installation.

Alternative 4:

New Transmission Site, Rebuilt Distribution Site – Brownfield rebuild of Distribution and a need for a link between the old and new site makes this option complicated and expensive. Capital Cost - $85M.

Risk: Mitigates some issues but is costly because the existing site would still have to be rebuilt and upgraded with newer distribution equipment and still is a fire hazard to the adjacent building.

Alternative 5:

Downtown West & Downtown East – (Additional options considered in Fall 2022): Downtown West is needed to off-load College and Walnut substation. Downtown East does not have property. Capital Cost - $103M.

Risk: Mitigates some risks but doesn’t offload the existing Metro loads nor fully support downtown. Both sites would have to be developed in order to support the downtown area. These sites are identified as additional needs for other upcoming customer loads and future expansions. Both locations would require significant relocation of underground distribution and transmission lines throughout the downtown streets.

DocuSign Envelope ID: 74121ACF-5716-41D2-A58F-04C0959B3B62

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Over the life of this station, Spokane and the downtown loads have grown. OSHA-driven work practices for electrical workers have evolved, as have the IEEE standards for arc flash and distances between equipment and structures. Avista's tolerance for risk has changed. The existing station falls short of serving today's load in a safe and reliable manner and will only get worse over time. Reliability for our most critical downtown customers, including the hospitals, is essential. There are also unique possibilities for catastrophic failure at this site, with little or no good options for operational mitigations including the inability to use a mobile transformer. Potential equipment failures could result in outages to half of the downtown core for an undetermined amount of time, as well as fire risks to adjacent buildings and occupants. The rebuild of the Metro substation would provide the reliability and redundancy necessary to mitigate outage concerns. The new equipment would meet the IEEE standards for arc flash and the distances between structures and equipment would be resolved on this larger site. Monthly monitoring and controlling of the project budgets, schedules, and scope will be performed by the team with further discussions or analysis as needed throughout the project duration.

<u>Transmission-Related Issues</u>

- 2028-2033 No outages affecting both MTR-PST and 3HT-PST lines because of the shared duct bank.
- 2028-2033 No outages on the 3HT-PST line from shared use of the Metro tunnel
- 2028-2033 No outages on the 3HT-PST line from non-utility workers having access in an area without NESC clearances.
- 2028-2033 No outages on the MTR-SUN line's four original structures north of I- 90
- 2028-2033 No outages on the PST-3HT line's three self-supporting steel and one wood structure north of I-90
- 2028-2033 No single transmission line trips cause a full Metro Substation outage.

<u>Distribution-Related Issues</u>

- 2028-2033 No deaths from arc flash racking by cablemen
- 2028-2033 No failures of feeder exit cable due to it being run over capacity.
- 2028-2033 No canceling of surgeries at Deaconess due to College & Walnut feeder outages

<u>Substation-Related Issues</u>

- 2028-2033 No non-momentary outages at the Metro Substation because the air switches did not operate properly.
- 2028-2033 No fire started at adjacent buildings to Metro Substation

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 110 of 535

DocuSign Envelope ID: 74121ACF-5716-41D2-A58F-04C0959B3B62

- 2028-2033 No battery voltage issues not reported through SCADA.
- 2028-2033 No cascading cabling overload events during switching orders.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

This project is planned for construction over multiple years. The bulk of the project is planned to transfer to plant once construction of the substation is complete.

YEAR	TYPE OF WORK
2018	Property Parcels
2019	
2020	Engineering Design Begins
2021	Engineering Design, Building Demolition
2022	Engineering Design, Property Grading, Major Equipment Payments
2023	Engineering Design, Major Equipment Payments, Wall Construction
2024	Wall and Substation Construction
2025	Auto Transformer Received, Construction Continues
2026	Substation Construction Complete
2027	Communication and Security Construction Complete
2028	Final Equipment Testing and Commissioning Complete, As-Built Drawings Updated

This project started in 2020 with the completion of studies and analysis and the signing of the Project Charter in early 2021. Design began and will continue through 2023. Construction of the enclosure wall, cable vault, control and battery enclosure, and duct banks is to occur in 2023 and 2024. Avista crews will perform build out of the substation into 2026 with anticipated completion in late 2026 and into 2027 for cutovers and final energizations.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Brian Chain – Business Case Owner/Manager, Substation Engineering

Brian Vandenburg – Manager, Engineering Projects

Mike Bosshardt – Senior Engineer, Downtown Network

DocuSign Envelope ID: 74121ACF-5716-41D2-A58F-04C0959B3B62

Brian Parsons – Senior Engineer, Substation Civil/Structural Engineer

Patrick Henderson – Senior Engineer, Substation Electrical Engineer

Bryan Hyde – Senior Engineer, Transmission Engineer

Tim Figart – Principal Engineer, Distribution Engineer

Crystal Holmes – Project Manager, Substation Project Delivery

Mike Lang – Project Manager, ET/Comm/Network/Security Project Delivery

Power Engineers – Substation Design Consulting Engineers

The Substation project progress, schedules, and budget are tracked and communicated monthly with the Business Case owner and department Director. Any necessary quarterly updates for SOX are made, as well as yearly project budget requests are coordinated through the Business Case owner and the CPG, as necessary. Larger project issues involving scope, schedule, and/or budget are brought forth to the project team noted above and any communications and/or recommendations including any change requests would be brought forth to the Sponsor/Director-level stakeholders, as applicable.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 112 of 535

DocuSign Envelope ID: 74121ACF-5716-41D2-A58F-04C0959B3B62

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Metro 115 kV Substation and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Brian Chain C4012[illegible]	Date:	May-02-2024 | 3:49 PM PDT
Print Name:	Brian Chain		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:	DocuSigned by: Vern Malensky 06C4F[illegible]	Date:	May-03-2024 | 1:41 PM PDT
Print Name:	Vern Malensky		
Title:	Director, Electrical Engineering		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:	Brian Vandenburg		
Title:	Manager, Engineering Projects		
Role:	Steering/Advisory Committee Review		

Docusign Envelope ID: 825E3A90-F88A-407A-8DD3-5B461B3ADA81

EXECUTIVE SUMMARY

Avista defines these investments as “customer requests for new service connections, line extensions, transmission interconnections, or system reinforcements to serve a single large customer.” We have often in the past referred to new service connects as “growth,” as in growth in the number of customers, however, these investments are beyond the control of the Company, and as such they do not reflect a plan or strategy on the part of Avista. Responding quickly to these customer requests is a requirement of providing utility service. Typical projects include installing electric facilities in a new housing or commercial development, installing or replacing electric meters, or adding street or area lights per a request from an individual customer, a city, or county agency. As would be expected, fluctuation in the number of new customer connections is largely dependent on local economic conditions both in the housing and business sectors. New customers are served for electric in WA and ID and gas in WA, ID, and OR.

Both connects forecast and 12-month rolling Cost Per Service information are used to calculate costs directly related to providing service to customers. Electric and Gas devices are also included in this business case - Meters, Transformers, Gas Regulators, and ERTs (Encoder Receiver Transmitter). Many of these Meters, Transformers, and ERTs are used as replacements for Wood Pole Management, and Periodic Meter Changes, for example.

Growth Business Case Funds request:

ELEC & GAS	2025	2026	2027	2028	2029
Connects Forecast: Res & Comm	9,434	9,138	9,106	9,121	9,121
Extensions, Services	50,001,574	48,511,564	49,384,495	49,258,202	49,258,202
Lighting	2,471,078	2,471,078	2,471,078	2,471,078	2,471,078
Meters & Devices	12,678,791	13,291,389	13,641,025	14,306,324	15,046,589
Transformers & Network Protectors	20,750,000	21,750,000	23,850,000	26,160,000	28,701,000
Business Case Total	**85,901,442**	**86,024,030**	**89,346,598**	**92,195,604**	**95,476,869**

The 5 yr average annual spend for this business case has been around $89M. Requests for service are variable in number and in cost, sometimes requiring significant investment for system reinforcements such as gas regulator stations and electric distribution infrastructure. This funds request is based on ordinary expectation as supported by forecast and input from electric and gas operations engineers.

For 2025, there are updated impacts to Growth costs, see 2.2 for more detail.

VERSION HISTORY

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 114 of 535

Docusign Envelope ID: 825E3A90-F88A-407A-8DD3-5B461B3ADA81

Version	Author	Description	Date
1.0	*Joe Wright*	*Initial draft of original business case*	*5/02/24*
BCRT	*BCRT Team Memember – Joe Wright*	*Has been reviewed by BCRT and meets necessary requirements*	*5/02/24*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	**$85,901,442**	**$85,901,442**
2026	**$86,024,030**	**$87,087,040**
2027	**$89,346,598**	**$89,089,306**
2028	**$92,195,604**	**$92,321,897**
2029	**$95,476,869**	**$95,476,869**

Project Life Span	***5 years***
Requesting Organization/Department	Energy Delivery
Business Case Owner | Sponsor	Paul Good | Josh DiLuciano
Sponsor Organization/Department	Energy Delivery
Phase	Execution
Category	Mandatory
Driver	Customer Requested

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. **BUSINESS PROBLEM -** *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

The New Revenue – Growth Business Case is driven by tariff requirements that mandate obligation to serve new customer load when requested within our franchised area.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 115 of 535

Docusign Envelope ID: 825E3A90-F88A-407A-8DD3-5B461B3ADA81

1.2 Discuss the major drivers of the business case.

Customer Requested: The New Revenue – Growth Business Case serves as support of several focus areas in Avista. We seek to serve the interests of our customers, in a safe and responsible manner, while strengthening the financial performance of the utility. Our growth contributes to strong communities, ongoing value to our customers, and the device portion of the business case keeps our system safe and reliable.

All new customers on Avista's system are benefitted by this business case. In addition, all customers who have their metering or regulation changed, or who have transformers replaced, benefit from this business case.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Avista is required to serve appropriate new load, complying with our Certificate of Convenience and Necessity, and as part of our Obligation to Serve.

The New Revenue – Growth Business Case will provide funds for connecting new Electric and Gas customers in accordance with our filed tariffs in each state.

Our obligation to serve, mandates that we must extend service to new customers in our franchised service areas. We do not currently have an alternative to serving new customers. All projects are subject to our Line Extension Tariffs, filed with each State Utility Commission.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

This business case is about connecting customers to Avista's facilities. The work directly reflects our focus area for customers as well as our mission statement."We must hold our customer's interests at the forefront of all our decisions" and "We improve our customer's lives through innovative energy solutions."

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 116 of 535

Docusign Envelope ID: 825E3A90-F88A-407A-8DD3-5B461B3ADA81

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

N/A

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Providing service to customers upon request is mandated. As needed customer project coordinators (CPCs) and engineers review requests to determine solutions that best meet the needs of the customer and Avista. These extraordinary requests lend themselves to more visibility and oversight.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

Avista uses a rolling 12-month Cost Per New Service spreadsheet to measure ER1000, Electric New Revenue, and ER1001, Gas New Revenue spending. Device blankets are subject to demand for both new revenue and non-revenue installation and replacement.

Enclosed is a spreadsheet showing projected spend through 2029 with a breakout by Expenditure Request for the New Revenue – Growth Business Case. Connects forecast and 12 -month rolling Cost Per Service information are used. Electric and Gas devices are also included, such as Meters, Transformers, Gas Regulators, and ERTs (Encoder Receiver Transmitter). Many of the Meters, Transformers, and ERTs are used as replacements for

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.
[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Docusign Envelope ID: 825E3A90-F88A-407A-8DD3-5B461B3ADA81

Transformer Change Out Program, Wood Pole Management, and Periodic Meter Changes.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no identified direct savings associated with this business case. This business case supports the installation of equipment to support new customers.

There are no direct or indirect savings represented in the Growth business case. The Growth Business Case is driven by tariff requirements that mandate obligation to serve new customer load when requested within our franchised area. The business case also includes initial purchase of transformers, as well as electric and gas meters and devices which are on hand for immediate response for reliability and customer response reasons. The work utilizing this equipment is represented in various business cases.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no identified indirect savings associated with this business case. This business case supports the installation of equipment to support new customers.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Docusign Envelope ID: 825E3A90-F88A-407A-8DD3-5B461B3ADA81

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1:

In some instances, there may be alternative ways to serve a customer. Customer project coordinators and engineers determine the solution that best serves the customer while considering subsequent customers and Avista's infrastructure.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

We periodically review and update the line extension tariffs to ensure we are not creating excessive rate pressure in connecting new customers.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Work timeline is primarily driven by the request of the customer. The transfer to plant occurs monthly.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The Energy Delivery Director Team assumes the role of advisory group for the New Revenue – Growth Business Case, with quarterly reporting to the Board of Directors through the Financial Planning & Analysis department. The appropriate extension and service tariffs are designed and updated by the Avista Regulatory Affairs Department, in cooperation with Construction Services, and the Financial Planning & Analysis department. All Customer Project Coordinators are trained regularly, by Regulatory Affairs and Finance, on tariff application.

For the Electric and Gas New Revenue Expenditure Requests (ERs): Operations managers and directors receive monthly Cost of Service reports providing 12-month rolling average costs for the construction areas. This allows for review of trending of costs for decision-making regarding processes and resources.

For the Metering and Devices ERs: Monthly Capital ER and project results reports are distributed. These provide updated variance information facilitating oversight by the Electric Meter Shop and Gas Engineering department.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 119 of 535

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3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the New Revenue – Growth and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Signed by: Paul Good 8ADE2AA1AB5C4A9...	Date:	Aug-31-2024 | 3:40 PM PDT
Print Name:	Paul Good		
Title:	Director of Electric Operations		
Role:	Business Case Owner		
Signature:	Signed by: Josh DiLuciano A3C71874F6564DB...	Date:	Aug-30-2024 | 12:02 PM PDT
Print Name:	Josh DiLuciano		
Title:	VP Energy Delivery		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 120 of 535

DocuSign Envelope ID: C26DCAF1-CAD2-4348-A8D1-A453F0303C8B

Substation – Asset Condition

1.0 BUSINESS CASE REQUEST – 5 YEAR PLANNING 2024

Year	Requested Amount	CPG Approved Amount *(Admin use only)*
2025	$21,025,000	
2026	$5,200,000	
2027	$3,100,000	
2028	$3,600,000	
2029	$4,700,000	

1.1 DISCUSS HOW THE ABOVE REQUESTED AMOUNT WAS CALCULATED INCLUDING ANY CONSIDERATION OF HISTORICAL SPENDING, ESTIMATES, CONFIDENCE LEVELS AND ESCALATION RATES.

This business case provides the asset management equipment replacements due to asset condition, Substation property purchases and equipment purchases for system spares.

Major Equipment payments:

Year	Power Transformers	Auto Transformers	High Voltage Breakers
2025	$2,250,000	$3,400,000	$600,000
2026	$1,300,000	$0	
	Total of 9 Transformers	Total of 1 Auto	Total of 4 HV Breakers

Other Major Projects:

- Garfield Transformer Replacement – planned for 2025.
- Poleline Substation Construction Completion (2025).
- Substation Property Purchases.
    - $5M in 2025, $2M each year after.

2.0 INITIAL BUSINESS CASE APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds request and agree with the approach presented, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Brian Chain	BC Owner	DocuSigned by: Brian Chain	May-02-2024 | 4:06 PM PDT
Vern Malensky	BC Sponsor	DocuSigned by: Vern Malensky 06C4FF5AB09E40B...	May-03-2024 | 2:03 PM PDT
	FP&A		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 121 of 535

DocuSign Envelope ID: C26DCAF1-CAD2-4348-A8D1-A453F0303C8B

Substation – Asset Condition

EXECUTIVE SUMMARY

The Substation - Asset Condition business case is one of the largest business cases for Avista because there is a vast amount of expensive equipment, such as power transformers, high voltage circuit breakers, etc, necessary to serve customers reliably throughout our electric system.

Substations transform electrical energy from high voltage transmission lines to lower voltage distribution lines that feed customers service points. Substations also allow switching, which reroutes electricity to enable reliability to customers and employee safety. Substations can be meter points as well as locations that provide protection for the expensive assets that can be vulnerable to faults. Substations are one of the main locations where voltage can be controlled.

The Substation Asset Condition Business Case is comprised of three ERs. ER 2000 includes major equipment spares (power transformers, high voltage breakers etc) that are held in stock until they are transferred to a location. ER 2204 includes major substation projects that contain multiple equipment asset condition issues, compliance updates and capacity upgrades. A substation rebuild is planned when several equipment types are at end of life. These projects also include significant Distribution system, Transmission system and Communication system work. This ER also includes property purchases for future substations. ER 2215 includes small substation projects (single transformer replacements, regulator upgrades, etc) that have been deemed needed due to asset condition. Equipment failures are now funded through the Substation – Failed Plant business case.

Substation equipment needs to be replaced when it fails to fulfill its intended function. Substation equipment may also need to be replaced when it has become obsolete. Obsolescence is due to parts or software not being available to maintain a piece of equipment.

Good, reliable electric service to the distribution system is dependant on the Substation Asset Condition Business Case being able to address issues when necessary at Avista's 165 substations. If not funded, customers would have poor electric service, numerous outages and be dissatisfied.

Major Equipment payments:

Year	Power Transformers	Auto Transformers	High Voltage Breakers
2025	$2,250,000	$3,400,000	$600,000
2026	$1,300,000	$0	
	Total of 9 Transformers	Total of 1 Auto	Total of 4 HV Breakers

Other Major Projects:

- Garfield Transformer Replacement – planned for 2025.
- Poleline Substation Construction Completion (2025).
- Substation Property Purchases.
    - $5M in 2025, $2M each year after.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Madden/Kusel*	*Initial draft of original business case*	*5/12/2023*
2.0	*Chain/Kusel*	*Annual revision of business case*	*3/2024*
BCRT	*Steve Carrozzo*	*Has been reviewed by BCRT and meets necessary requirements*	DS SC

DocuSign Envelope ID: C26DCAF1-CAD2-4348-A8D1-A453F0303C8B

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	$21,025,000	$20,000,000
2026	$5,200,000	$3,750,000
2027	$3,100,000	$2,500,000
2028	$3,600,000	$1,000,000
2029	$4,700,000	$2,000,000

Project Life Span	Ongoing
Requesting Organization/Department	Substation Engineering
Business Case Owner | Sponsor	Brian Chain | Vern Malensky
Sponsor Organization/Department	Electrical Engineering
Phase	Execution
Category	Program
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - THIS SECTION MUST PROVIDE THE OVERALL BUSINESS CASE INFORMATION CONVEYING THE BENEFIT TO THE CUSTOMER, WHAT THE PROJECT WILL DO AND CURRENT PROBLEM STATEMENT.

1.1 What is the current or potential problem that is being addressed?

Avista substations have numerous age related issues that lead to failures and need to be addressed on a regular basis. At a point where an overwhelming number of issues in a substation yard exist, rebuilding the entire substation is necessary.

The Substation Asset Condition Business Case includes three types of projects: Capital Spares, Asset Management Capital Maintenance and Substation Rebuilds.

ER 2000 includes major equipment spares (power transformers and high voltage breakers) that are held in stock until they are transferred to a substation location. This ER and associated project numbers are separated from the other two ERs in this business case because they don't have specific substation projects that they are associated with at the time of purchase of the assets. Most of these units are spares for future work and are deemed used and useful after they are installed at a substation.

ER 2215 includes small substation projects (single transformer replacements, regulator upgrades, high-voltage circuit breakers, lower voltage circuit breakers and reclosers, circuit switchers, capacitor banks, etc.) that have been deemed needed due to asset condition leading to imminent equipment failure. This ER is for individual equipment replacements and is

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 123 of 535

DocuSign Envelope ID: C26DCAF1-CAD2-4348-A8D1-A453F0303C8B

separated from the other two ERs in this business case because it is focused on specific stations but is not a total rebuild of a substation.

ER 2204 includes major substation projects, i.e. a rebuild, that include multiple equipment asset condition issues, compliance updates or capacity upgrades. A substation rebuild is planned when several equipment types are at end of life or have other reasons triggering the need for replacement. These projects also include significant Distribution system, Transmission system and Communication system work.

It is preferred to perform substation rebuilds on a non-energized substation parcel (or portion of the current property) which is called a ‘greenfield’ rebuild. This allows for quicker construction and safer conditions for the crews building the new station. A substation can also be built on the current site, a ‘brownfield’ rebuild. Brownfield rebuilds are much more complicated due to construction occurring within an energized substation.

Replacing substation apparatus and equipment as it approaches end of life or becomes obsolete is necessary to maintain safe and reliable operation of Avista's transmission and distribution systems. Avista’s purpose is to improve life’s quality with energy, safely, reliably and affordably. Functioning substations are key to fulfilling this purpose.

Substation equipment that no longer fulfills its intended purpose has failed. Often, the failure is a complete inability to function. Beginning in 2024, these equipment failures will be completed under the Substation – Failed Plant business case.

Rebuilding significant portions of substation or the entire subsation may be triggered after an equipment failure due to some of the other equipment in the substation being obsolete. Obsolete equipment is equipment that there are no or limited replacement parts or software is not supported.

While asset condition is the primary driver triggering the need to replace major apparatus and equipment, additional factors that may contribute to the need to broaden the scope of a station rebuild project include operational and maintenance requirements, updated design and construction standards, SCADA communications, future customer load-service needs, and other programs (e.g. Grid Modernization). This would provide some costs efficiencies for Avista to do all this work at once.

Because much of the equipment in a substation was installed at the same time, it often reaches the end of life at a similar period in time. Therefore, Asset Management evaluations of a substation can be performed to determine if just a few pieces of equipment need to be replaced or if it is cost-effective to rebuild the entire substation.

Another reason a substation rebuild project may expand in scope after a piece of equipment fails is that updated equipment spacing requirements may need to be accommodated. Appropriate spacing of equipment in a substation is necessary because of the need to limit the situation of a fire traveling from one piece of equipment to another piece of equipment. Additionally, arc flash safety distances as well as proper physical access to equipment may be reasons why additional spacing between equipment is warranted and thus, among other factors a substation rebuild may be needed.

Aging apparatus and equipment plus changes in customer needs and compliance requirements contribute to the heavy need for substation rebuilds on the Avista system. Using up of extra capacity on the Avista distribution system has Avista’s Electric Distribution Substations in a state of vulnerability. Substation failures can result in customer outages because of a lack of capacity for Operations Engineers to be able to switch around outages with the use of other capacity on the system

As with any electric supply system, there are many types of equipment at varying ages and conditions. See the table below a list of major substation equipment and the total number currently operating in the Avista system. Currently, Avista owns and maintains 165 substations.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 124 of 535

DocuSign Envelope ID: C26DCAF1-CAD2-4348-A8D1-A453F0303C8B

Equipment Type	System Count
Air Switch (>100kV)	1,051
Battery Banks	135
Circuit Breakers (<100kV)	480
Circuit Breakers (>100kV)	380
Circuit Switchers	123
Power Transformers	228
Voltage Regulators	1,094

Below is the list of oldest equipment operating in Avista substations. South Lewiston, Garfield and Kooskia 115kV substations are on the 5-year plan for rebuilds or equipment replacements.

Substation Desc	Equipment Type	Asset Description	Manuf Year
South Lewiston 115kV	Circuit Breakers (<100kV)	1348 OCR	1924
South Lewiston 115kV	Circuit Breakers (<100kV)	1358 OCR	1924
Leon Jct. 115kV	Air Switch (>100kV)	A-145 Air Switch	1930
Four Lakes 115kV	Air Switch (>100kV)	A-16 (B-1731) LINE DISC	1946
Four Lakes 115kV	Air Switch (>100kV)	D-2138/7085 GRD SWT	1946
Garfield 115kV	Power Transformers	Transformer #1	1946
Four Lakes 115kV	Air Switch (>100kV)	A-14 (B-1729) LINE DISC	1947
Four Lakes 115kV	Air Switch (>100kV)	A-16 (B-1730) LINE DISC	1947
Four Lakes 115kV	Air Switch (>100kV)	D-244/7083 GRD SWT	1947
Four Lakes 115kV	Air Switch (>100kV)	D-841/7084 GRD SWT	1947
Kooskia 115kV	Power Transformers	Transformer #1	1947

1.2 Discuss the major drivers of the business case.

The work included in this business case is asset condition based.

Asset Management Replacement projects include equipment replacements based on the following strategies:

Equipment Type	Asset Management Strategy
Air Switches (>115kV)	Inspection-based replacement
Battery Banks	Calendar-based replacement
Circuit Breakers (>115kV)	Monitor-based and Inspection-based replacement
Circuit Breakers (<115kV)	Inspection-based replacement
Circuit Switchers	Inspection-based replacement
Power Transformers	Monitor-based and Inspection-based replacement
Voltage Regulators	Inspection-based replacements

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 125 of 535

DocuSign Envelope ID: C26DCAF1-CAD2-4348-A8D1-A453F0303C8B

Substation rebuilds are typically asset condition based but other drivers like Performance & Capacity and Customer Service Quality and Reliability can play a role in triggering a total substation rebuild.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The Substation Asset Condition Business Case is a programmatic business case because of the need for continued rebuilding substations, replacing substation equipment and support of spare substation parts. With 165 substations, continued addressing of asset condition issues is necessary so that substation infrastructure continues to operate and service customers. If neglected, substations would not be able to support the electric system and outages to large numbers of customers would result. Substations typically serve between 1,000 and 3,000 customers.

Because Avista has 165 substations and substations can last 80 years, Avista needs to rebuild about 2 substations per year to keep from having an overwhelming number of substations that need to be rebuilt.

Equipment expected life varies from equipment piece to equipment piece. Heavy electronic pieces of equipment may only last 10-15 years where mechanical equipment may last as long as 80 years. Continual replacement of equipment throughout the 165 substations helps to limit the number of stations that need to be totally rebuilt. Targeting levelized replacements or at least tracking them being aware of how close replacements are to levelized amount is an Asset Management strategy that helps keep reliability high and limits the potential of a bow wave of replacements that need to be done at the same time.

Spare substation equipment is necessary to have on hand so that when a piece of equipment fails to operate and must be replaced, there are spares available. Typically a small number of the major equipment is necessary to have as spares because the equipment usually lasts quite long. Beginning in 2020, lead times on equipment have increased exponentially on most items, which necessitates having more spare pieces of equipment. Not having enough spare equipment in case of need can lead to a substation failure and thus, customer outages and poor customer experience.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

The Substation Asset Condition Business Case keeps the system functioning which is critical to serving our customers well and unlocking pathways to growth. The Perform Focus Area of Avista's focus goals is the primary alignment with the requested business case but there are elements to the business case which are aligned with the theme of our Vision, Mission, and Focus Areas.

Our Customers:

Existing and future customers in the Avista service area interested in having reliable electrical service. Avista needs to deliver a system which can maintain serving customers reliably.

Our People:

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 126 of 535

DocuSign Envelope ID: C26DCAF1-CAD2-4348-A8D1-A453F0303C8B

The portion of our company who will support the implementation of the project represents a core electric utility collection of our employees. These employees will benefit from this business case by having safe substations to work in.

Perform:

With continued work to address asset condition issues, our system will remain reliable and serve customers well.

Invent:

Rebuilding substations with standard equipment is typical but Avista has the opportunity to improve the equipment, construction and delivery process as part of a large-scale program.

Vision; Better energy for life:

Investment in the substation system represents a long term invest of infrastructure which will be in place to serve our customers for several generations.

Mission; We improve our customers' lives through innovative energy solutions:

The Substation Asset Condition Business Case has been identified as the best method to maintain the reliability of Avista's substation system that are part of the backbone of an electrical system.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

All of Avista's substations except for one are located outside. Sun and weather take a toll on the equipment located outside. Over time, advances in technology make some substation equipment obsolete. The equipment may either not provide the function that is now expected of that equipment or replacement parts may not be available.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The recommended approach is to replace substation apparatus and equipment as needed due to asset condition and rebuild substations when the majority of assets in the impacted substation have been determined to have reached their end of life. This business case aligns with the Company's mission to deliver safe and reliable electric service to customers by preventing the

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 127 of 535

DocuSign Envelope ID: C26DCAF1-CAD2-4348-A8D1-A453F0303C8B

potential failure of substations that would lead to degradation of reliability and mitigating the frequency and duration of outages due to equipment failure.

Increased costs due to inflation as well as aging substations and substation equipment has led to an increase in the budget for the Substation Rebuilds Business Case over the last five years. The inclusion of the large Metro project in the budget for 2022 and 2023 has contributed to the increase of spend.

As of the 2023 budget, the Metro Project was separated into its own business case, so the budget estimates for Metro are not shown in the budget requests for 2025-2029.

Project prioritization is supported by the Engineering Roundtable (ERT) and substation subject matter experts for prioritization of work within this risk category. Project and funding levels are reviewed and approved by the ERT on an annual basis.

Fixing the equipment issues when they fail to function is necessary as is getting a good amount of life out of each piece of equipment until it approaches end of life. The balance is found by evaluating each piece of equipment and the substation as a whole when there are an overwhelming amount of equipment in a substation that is close to end of typical life.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

In a memo document dated December 27, 2017, Substation Performance Requirements were outlined by Rich Hydzik, Transmission Operations Engineer and Garth Brandon, then the Chief System Operator. The document identified issues which were integral to the reliable operation of the Avista electric system. This document is directly related to the Substation Asset Condition Business Case because it aims at addressing the identified issues.

Substation equipment requires regular maintenance to function reliably for good customer service. Well designed substations enable equipment maintenance without service outages to to customers. Short momentary outages (less than 4 hours) to conduct switching may be required to allow maintenance activities to take place but extended outages are not acceptable customer service.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

DocuSign Envelope ID: C26DCAF1-CAD2-4348-A8D1-A453F0303C8B

No direct offsets are anticipated because rebuilding substations requires O&M activities such as monthly inspections and equipment maintenance. Annual O&M costs for a distribution substation is approximately $30,000. Annual O&M costs for a transmission substation is approximately $50,000

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$0	$0	$0	$0	$0
O&M	Substation Rebuilds & Asset Management Offsets	$176,800	$176,800	$176,800	$176,800	$176,800

The indirect offsets assume that each substation has four pieces of equipment that require 'limp along' maintenance (power transformer, low voltage breaker recloser, high voltage breaker, and a voltage regulator). It is assumed that a Generation Production & Substation Support (GPSS) Serviceman spends approximately 10 hours each week driving to a substation, maintaining equipment to 'limp it along' instead of replacing it, and cleaning up.

1,040 hours (two locations * 10 hours of O&M * 52 weeks = 1,040 hours) of additional maintenance would be needed if these station rebuilds did not take place. Avista rebuilds two substations per year on average. If that work is not done, then 1 additional GPSS Serviceman will be needed to address the limp along maintenance needed to keep those stations in service. One additional Serviceman, will cost $176,800 annually (1 Journeyman Electrician * $85 loaded labor/hour *40 hours/week * 52 weeks). This figure does not include tools, materials and vehicle costs (miles and maintenance) used during this equipment maintenance.

Risk of Outages due to not replacing equipment.

There is a risk of customer outages and an associated cost to customers for outages as a result of not replacing equipment when it is needing to be replaced. The cost turns out to not be material. Risk Cost = Prob of Failure * Prob (consequence) * Cost (consequence). Assuming 30 voltage regulator failures that result in customer outages per year. Also assuming ~1,000 customers per feeder. Risk Cost = 4% prob of failure * 1% catastrophic failure (customers out) * (1,000 customers * 4 hour outage * $116.15/hr) = $185.84 per outage * 30 failures per year = $5,575 per year.

If a substation Transformer fails, assume 3,000 customers out (three feeders). Assume 1 transformer failure / year. Risk Cost = 0.4% prob of failure * 1% catastrophic failure * 3,000 customers * 8 hour outage * $116.15/hr = $111.50 per outage * 1 failure per year = $111.50 per year.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

DocuSign Envelope ID: C26DCAF1-CAD2-4348-A8D1-A453F0303C8B

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

The options for asset condition issues on the system are limited to do nothing, maintain current funding level and reduce the current funding level. Each of the options are discussed below:

Option 1: Do nothing - Not recommended because it would not be prudent to let the system deteriorate and not fix things in the substations that have failed. Obsolete and/or high loss equipment, deteriorated wood structures, and non-standard construction or equipment would remain in service until failure. Below are discussions of the consequences of not funding the individual ERs.

Option 2: Maintain current funding level. Project prioritization is supported by the Engineering Roundtable and substation subject matter experts for prioritization of work within this risk category. The project and funding levels are reviewed on an annual basis.

Option 3: Reduce current Asset Condition capital investments. This option is not recommended. This option would lead to a reduction in the level of reliability and or operating flexibility that can be achieved by the transmission and distribution systems.

See the table below for a risk comparison between funding the business case and not funding the business case. Note that the Substation Asset Condition Business Case is projected to reduce the likelihood of an Environmental; Safety and Health to the Public; Legal, Regulatory, External Business Affairs; Safety and Health to Employees; and Customer Service and Reliability from once every 10 years to once every 50 years.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 130 of 535

DocuSign Envelope ID: C26DCAF1-CAD2-4348-A8D1-A453F0303C8B

Unfunded Risk					
Likelihood of Event	**Environmental**	**Safety and Health: Public**	**Legal, Regulatory, External Business Affairs**	**Safety and Health: Employee**	**Customer Service and Reliability (# customers * duration of an outage)**
<Once / 10 years	Large volume transformer oi spill, hazardous waste cleanup, moderate to low volume or level PCBs, minimal impact to waterways, repeated or moderate air emission exceedance.	Potential for minimal or minor injury, Outages and/or equipment damage, Public health infrastructure impact up to 24 hours	Could result in a sustained negative impact to local, online, or industrial relationship and/or national / global media coverage	Potential for minimal or minor injury Lost Time Incident and Severaity Rate increase year or year	>7,500 Customer hours
Revised Risk if funded/completed					
Likelihood of Event	**Environmental**	**Safety and Health: Public**	**Legal, Regulatory, External Business Affairs**	**Safety and Health: Employee**	**Customer Service and Reliability (# customers * duration of an outage)**
<Once / 50 years	Isolated spill with 0 to low level PCBs, no migration, air emission minor exceedance, standard clean-up	Potential for injury, Public health infrastructure impact up to 8 hours	No likely impact on media or regulatory relationship	Potential for injury	<1,500 Customer hours

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Success for the asset condition business case can be measured ultimately by the average age of the listed equipment types operating in substations.

The table below lists common substation equipment, the number of pieces of the equipment has in service and the average number of replacements per year for that equipment type. From the system count and the average replacements per year, an average levelized replacement length in years can be calculated. For comparison purposes, the number of pieces of equipment needed to be on a 20 year replacement cycle where 5% of the system for that equipment type is replaced is show in the table as well.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 131 of 535

DocuSign Envelope ID: C26DCAF1-CAD2-4348-A8D1-A453F0303C8B

Equipment Type	Avista System Count	Avista Average Replacement per Year (2018-2022)	Avista Average Levelized Replacement Length
Air Switches (>100kV)	1,051	26.80	40.0 years
Battery Banks	135	11.00	12.5 years
Circuit Breakers (<100kV)	480	13.20	38.5 years
Circuit Breakers (>100kV)	380	16.60	24.1 years
Circuit Switchers	123	2.75	45.8 years
Power Transformers	228	5.40	44.3 years
Voltage Regulators	1,094	61.60	18.1 years

The table demonstrates that not all equipment lasts the same period of time. Avista does not have an Asset Management strategy where pieces of equipment are replaced based on age. Instead each piece of equipment is evaluated as to whether it is meeting its required function. However, it is good practice to monitor what the average levelized replacement length is for each piece of major equipment to know if a bow wave of replacements are being created because of a low number of replacements are occurring.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Projects within this business case are at all stages of work. There are continually several substation rebuild projects in scoping, design, construction, commissioning and closeout stages. Asset management replacements are being assessed, designed and constructed throughout the year.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Each of the three ERs that are part of the Substation Asset Condition Business Case have different steering committes or governance teams.

ER 2000, the ER for Substation Spare Major Equipment is governed by the Apparatus Engineers and Substation Engineering Manager.

ER 2204, the Substation Rebuilds ER is governed by Engineering Rountable (ERT) Members: Substation Engineering, Transmission Engineering, Distribution Engineering, Communication Engineering, IT/ET Network Engineering, System Planning, and System Operations.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 132 of 535

DocuSign Envelope ID: C26DCAF1-CAD2-4348-A8D1-A453F0303C8B

ER 2215, the Substation Asset Management ER is governed by the Substation Maintenance Engineers, Distribution Area Engineers, Electric Shop Servicemen, Distribution Area Servicemen, and Substation Engineering Manager.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Substation – Asset Condition and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Brian Chain C4012FB413CF40...	Date:	May-02-2024 | 4:06 PM PDT
Print Name:	Brian Chain		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:	DocuSigned by: Vern Malensky 06C4FF5AB09E40B...	Date:	May-03-2024 | 2:03 PM PDT
Print Name:	Vern Malensky		
Title:	Director, Electrical Engineering		
Role:	Business Case Sponsor		

Signature:	DocuSigned by: Brian Vandenburg 0304BE8BAF96490...	Date:	May-03-2024 | 8:49 AM PDT
Print Name:	Brian Vandenburg		
Title:	Manager, Engineering Projects		
Role:	Steering/Advisory Committee Review		

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Substation – Performance and Capacity

1.0 BUSINESS CASE REQUEST – 5 YEAR PLANNING 2024

Year	Requested Amount	CPG Approved Amount *(Admin use only)*
2025	$14,900,000	
2026	$24,000,000	
2027	$24,800,000	
2028	$34,000,000	
2029	$25,000,000	

1.1 DISCUSS HOW THE ABOVE REQUESTED AMOUNT WAS CALCULATED INCLUDING ANY CONSIDERATION OF HISTORICAL SPENDING, ESTIMATES, CONFIDENCE LEVELS AND ESCALATION RATES.

The Substation – Performance and Capacity Business Case is intended to be a programmatic business case allowing the continual flow of performance and capacity projects to be funded under one business case with projects that have the same project driver.

Major Projects Planned (>$10 million):

- Bronx Substation Rebuild (electrical construction 2025-2027). $14M.
- Five Mile Substation Construction (electrical construction 2027-2029). $19M.
- Melville Substation Construction (electrical construction 2027-2028) – Transmission Line easement work has begun. $26M.
- Midway Substation Construction (electrical construction 2028-2029). $16M.
- Pleasant View Substation Capacity Mitigation (electrical construction 2026-2028). $12M.

2.0 INITIAL BUSINESS CASE APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds request and agree with the approach presented, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Brian Chain	BC Owner	DocuSigned by: Brian Chain	May-03-2024 | 8:57 AM PDT
Vern Malensky	BC Sponsor	DocuSigned by: C4012FF13CFC491... Vern Malensky	May-03-2024 | 2:06 PM PDT
	FP&A	06C4FF5AB09E40B...	

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EXECUTIVE SUMMARY

Inadequate electric distribution system capacity to serve new customer growth has been identified through technical studies and real-time operations. The System Planning team performs an evaluation of the distribution system biannually which includes a ten-year forecast of expected distribution substation equipment loading during peak summer and winter conditions. The most recent analysis performed in 2023 and documented in 2023-2024 System Assessment Version 0 concluded several anticipated capacity deficiencies in Avista's distribution substations over the next ten years. Capacity issues arise from increased customer demand. The growth in demand is driven by migration of customers to Avista's service territory and changes in end-use equipment such as transportation electrification and building electrification.

The 2023-2024 System Assessment incorporated improved statistical evaluation of peak loading conditions and improved modeling accuracy utilizing additional distribution planning engineers therefore additional capacity issues have been identified compared to previous assessments. The 2021 summer peak loading, documented in Heat EOP Event Analysis – Version 0, 2021, provided an example of observed operational issues which led to customer outages (not all customer outages were caused by inadequate distribution substation capacity). Technical analysis performed as part of the system assessment process is intended to identify expected capacity issues before they cause real-time operational issues.

The recommended solution to mitigate the observed capacity deficiencies is to programmatically add distribution substation capacity through the construction of new substations and upgrades to existing stations. Estimated costs for 2025-2029 vary between $11 and $35 million based on construction resource capabilities, constrained outage windows, and competing high priority projects. A list of mitigation projects provided in the 2023-2024 System Assessment associated with this business case includes:

- **Bronx Station Rebuild** - Reconstruct existing Bronx Station to include distribution facilities with a 20MVA transformer and two distribution feeders. The 115kV portion of the station will include two 115kV transmission line positions protected with circuit breakers and configuration suitable for future expansion.
- **Poleline (Prairie) Station Rebuild -** Construct new distribution station to replace Avista facilities at existing Prairie Station. New station to include two 30MVA transformers, four feeders, and looped- through transmission line.
- **Valley Capacity Mitigation –** Rebuild existing Valley Station with increased distribution capacity.
- **Pleasant View Capacity Mitigation** - Rebuild existing Pleasant View Station with increased distribution capacity.
- **North Spokane Distribution Reinforcement (Northeast) -** Replace two existing 20MVA transformers with 30MVA transformers and add new NE12F6 feeder. Transformer circuit switchers replacements are included in scope to eliminate existing fault blocking scheme. Distribution integration scope includes new switches and an express feeder truck.
- **Orin Capacity Mitigation - Construct** new distribution station connected to BPA's Colville – Republic 115kV Transmission line. New station will include a single 20MVA transformer and two distribution feeders.
- **Glenrose Capacity Mitigation -** Replace existing transformer with 30MVA and rebalance feeders. Regulator upgrades assumed to be an existing flex crew project.
- **Bunker Hill Customer Capacity -** Install new 20MVA transformer to replace existing transformer and construct new dedicated customer distribution feeder.
- **Melville Station -** New switching station near existing tap to Four Lakes Station off the South Fairchild Tap 115kV transmission line. Construct new transmission line from Airway Heights to Melville including passing through Russel Road and Craig Road distribution stations. Requires new transmission line terminal at existing Airway Heights Station.

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- **North Spokane Transmission Reinforcement (Five Mile 115kV Station)[1] –** Construct new Five Mile Station with new loop through of Nine Mile - Westside 115 requiring 3 miles of new 115 line. New BPA interconnection at Bell Station to create a Bell – Five Mile 115 line using 1.5 mile of new line and portion of Beacon - Francis & Cedar 115 line. New Francis & Cedar – Five Mile line using 1.5 mile of new line.
- **Midway Station –** Construct new distribution station to include 30MVA transformer and two distribution feeders.

Adequate system capacity to serve customers is aligned with Avista's vision: Better Energy for Life. Investment in the electric distribution system capacity provides Avista with the ability to meet the demands of our customers and the communities we live in. Without adequate capacity, Avista will be required to turn customer's power off during peak loading conditions and the company will not be able to accommodate new customer requests for service in certain locations.

The Substation – Performance and Capacity Business Case is intended to be a programmatic business case allowing the continual flow of performance and capacity projects to be funded under one business case with projects that have the same project driver. Each project under the program is evaluated and prioritized by the Engineering Roundtable.

VERSION HISTORY

Version	*Author*	*Description*	*Date*
1.0	*Karen Kusel / John Gross / Glenn Madden*	*Initial draft of original business case*	*05/2023*
2.0	*Karen Kusel / John Gross / Brian Chain*	*Annual update of business case*	*04/2024*
BCRT	*Steve Carrozzo*	*Has been reviewed by BCRT and meets necessary requirements*	DS SC

[1] The North Spokane Transmission Reinforcement project includes a new substation which addresses performance and capacity issues related to the transmission system which differs from the other projects included in the scope of this business case.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 136 of 535

DocuSign Envelope ID: 244DBD63-018D-4BE3-A2BE-8265FA47DB79

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	**$14,900,000**	**$8,200,000**
2026	**$24,000,000**	**$1,300,000**
2027	**$24,800,000**	**$33,000,000**
2028	**$34,000,000**	**$46,000,000**
2029	**$25,000,000**	**$25,800,000**

Project Life Span	Ongoing
Requesting Organization/Department	Substation Engineering
Business Case Owner | Sponsor	Brian Chain | Vern Malensky
Sponsor Organization/Department	Electrical Engineering
Phase	Execution
Category	Program
Driver	Performance & Capacity

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

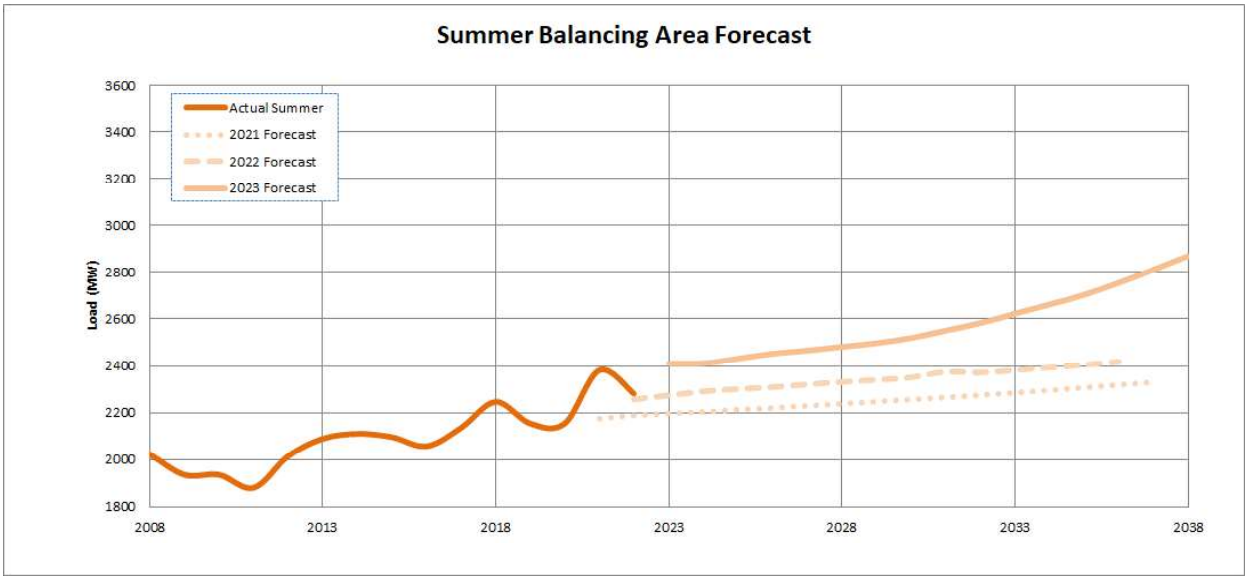
1.1 What is the current or potential problem that is being addressed?

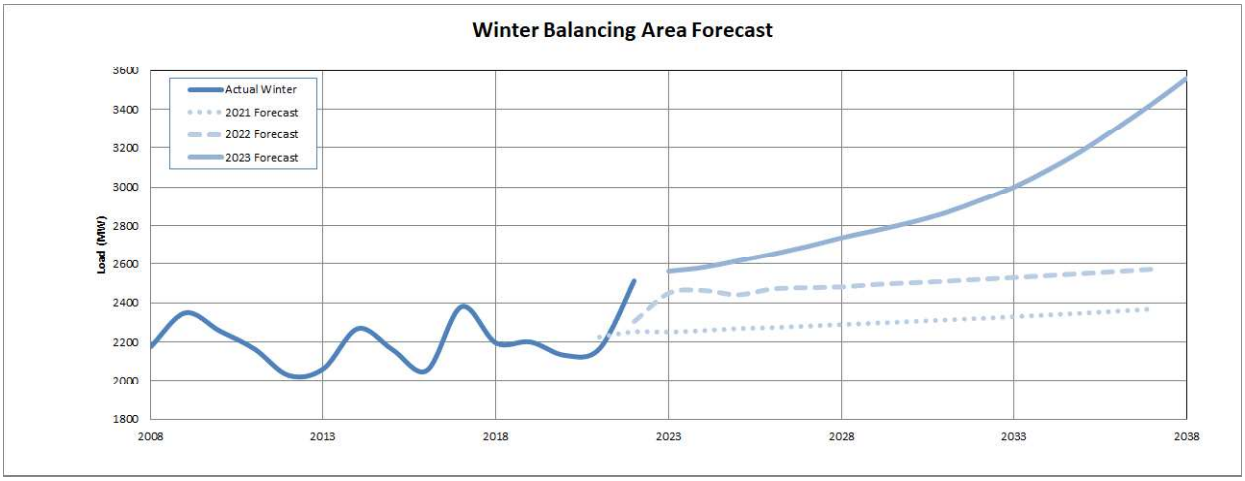
The Substation – Performance and Capacity Business Case supports new or modifications to substations in the system to serve new and growing load, increased system reliability, and operational flexibility. New substations under this program will require planning and operational studies, justification, and approved project diagrams prior to funding. Capacity issues arise from increased customer demand. The growth in demand is driven by migration of customers to Avista's service territory and changes in end-use equipment such as transportation electrification and building electrification.

The below figures illustrate the expected load growth for Avista's Balancing Authority area for peak summer and winter conditions. The summer load forecast is estimating approximately 20-25MW growth per year and the winter load forecast is estimating approximately 35-45MW per year. Winter growth rates are expected to be higher than past decades due to the trending of reduced natural gas usage for building heat.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 137 of 535

DocuSign Envelope ID: 244DBD63-018D-4BE3-A2BE-8265FA47DB79





The added load forecasted in the above figures will be spread across the Avista service territory, but the specific areas of North Spokane, Sandpoint, Colville, West Plains, Post Falls, and Coeur d'Alene are expected to have higher growth rates. The existing distribution system capacity has been shown to be inadequate to accommodate the new load. The below map is a representation of expected feeder equipment utilization in the year 2033 from the 2023-2024 System Assessment. Areas with red highlighted feeder indicate observed performance issues from the distribution system planning studies. Areas with low growth rates may still have capacity issues identified from previous deferral of necessary mitigation projects.

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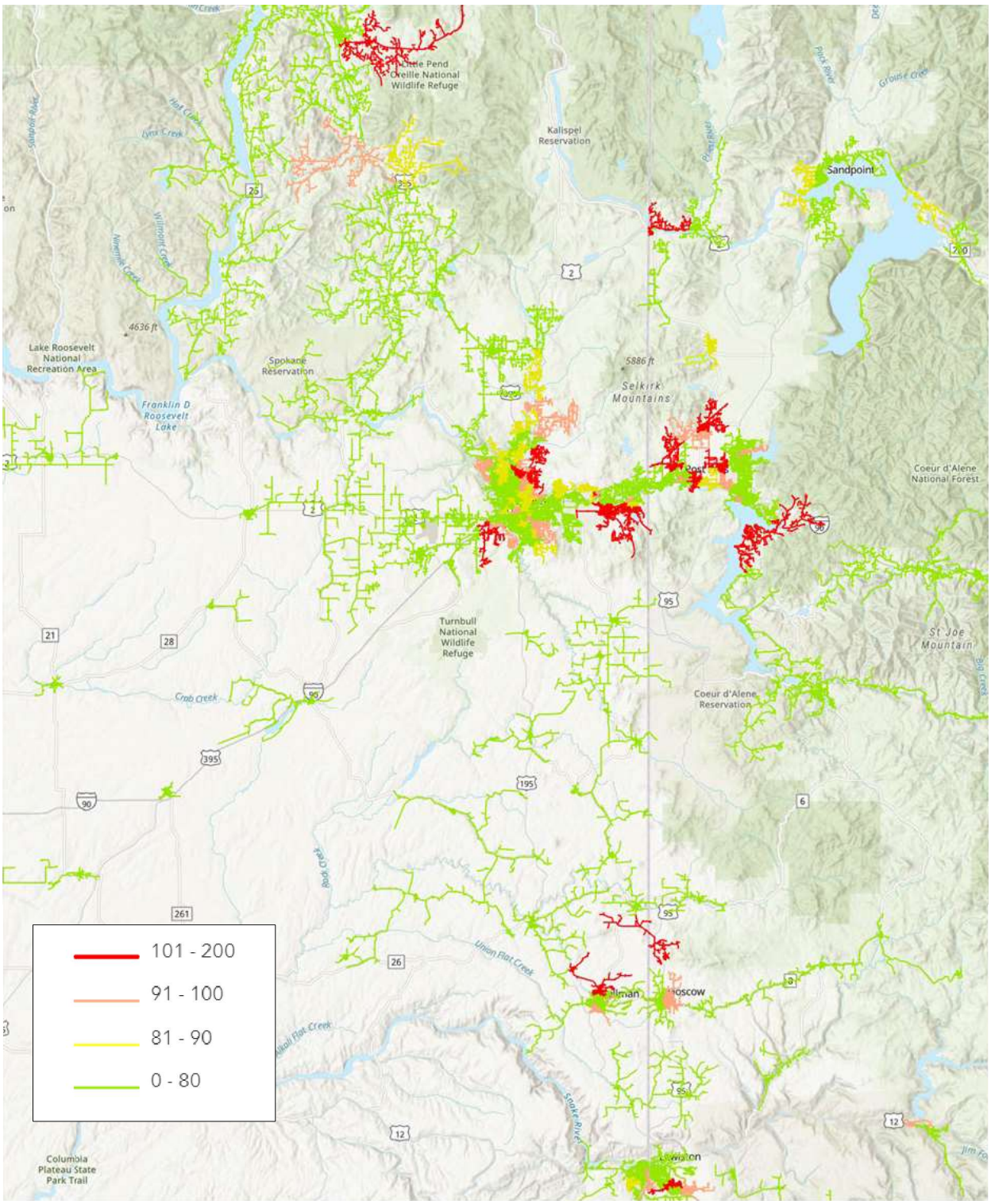
Substation – Performance and Capacity



The following tables from the 2023-2024 System Assessment provide a summary of system wide performance concerns with equipment exceeding 80% of their applicable facility ratings. The first table represents assumed conditions for a peak summer scenario and the second table represents assumed conditions for a peak winter scenario. Each identified performance concern is then further evaluated with more specific data and a project alternative evaluation is

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 139 of 535

DocuSign Envelope ID: 244DBD63-018D-4BE3-A2BE-8265FA47DB79

performed. Once a project is selected and vetted through the Engineering Roundtable, it is added to the applicable Business Case for funding.

Name	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
SUN12F5	55.2	61.3	68.0	75.5	83.9	93.1	103.3	114.7	127.3	141.3	156.9
PRA - XFMR #2	84.0	88.9	94.1	99.7	105.5	111.7	118.3	125.2	132.6	140.3	148.6
LIB12F3	83.3	88.0	92.9	98.1	103.6	109.4	115.5	122.0	128.8	136.1	143.7
PRA221	83.7	88.2	93.0	98.0	103.3	108.8	114.7	120.9	127.4	134.3	141.5
SUN - XFMR #2 (2023)	64.4	69.6	75.3	81.4	88.0	95.1	102.8	111.1	120.1	129.9	140.4
NE - XFMR #1	71.7	76.2	81.0	86.1	91.5	97.2	103.4	109.9	116.8	124.1	131.9
TEN1254	86.6	90.1	93.6	97.3	101.2	105.2	109.4	113.7	118.2	122.9	127.8
GRA - XFMR #1	78.5	82.1	85.8	89.6	93.7	97.9	102.3	106.9	111.7	116.7	121.9
NE12F4	69.1	73.1	77.3	81.8	86.5	91.5	96.8	102.3	108.2	114.5	121.1
RAT233	73.2	76.7	80.3	84.1	88.1	92.3	96.6	101.2	106.0	111.0	116.3
HUE - XFMR #1	84.0	86.5	89.1	91.7	94.5	97.3	100.2	103.2	106.3	109.4	112.7
SPT - XFMR #1	81.8	84.4	87.2	90.0	92.9	95.8	98.9	102.1	105.4	108.8	112.3
LIB - XFMR #2	66.0	69.5	73.2	77.1	81.2	85.6	90.1	94.9	100.0	105.3	111.0
PF - XFMR #1	75.2	78.1	81.2	84.3	87.6	91.0	94.5	98.2	102.0	106.0	110.1
L&S12F4	67.7	71.0	74.5	78.1	81.9	85.9	90.1	94.5	99.1	103.9	109.0
TEN1257	76.0	78.8	81.6	84.6	87.6	90.8	94.1	97.5	101.0	104.7	108.5
COB - XFMR #1	84.8	86.9	89.1	91.3	93.6	95.9	98.3	100.7	103.3	105.8	108.5
SIP - XFMR #1	64.9	68.3	71.9	75.6	79.6	83.7	88.1	92.7	97.6	102.7	108.0
GRA12F1	79.0	81.5	84.1	86.7	89.5	92.3	95.2	98.2	101.3	104.5	107.8
HUE142	71.7	74.7	77.8	81.0	84.3	87.8	91.4	95.2	99.2	103.3	107.5
LOL - XFMR #3	82.8	85.0	87.1	89.4	91.6	94.0	96.4	98.8	101.4	104.0	106.6
IDR253	79.2	81.6	84.0	86.5	89.1	91.7	94.4	97.2	100.1	103.0	106.1
GRA12F3	53.9	57.6	61.6	65.9	70.5	75.5	80.7	86.3	92.4	98.8	105.7
SPT - XFMR #2	76.8	79.3	81.8	84.4	87.2	90.0	92.9	95.8	98.9	102.1	105.4
IDR - XFMR #1	76.3	78.7	81.1	83.6	86.1	88.8	91.5	94.3	97.2	100.1	103.2
PRA222	58.0	61.4	64.9	68.7	72.7	76.9	81.4	86.1	91.1	96.4	102.0
TEN - XFMR #2	83.9	85.5	87.2	88.8	90.5	92.2	94.0	95.8	97.6	99.5	101.4
ROS - XFMR #2	82.9	84.6	86.3	88.0	89.7	91.5	93.3	95.2	97.1	99.0	101.0
LOL1359	83.1	84.6	86.2	87.8	89.4	91.0	92.7	94.4	96.2	98.0	99.8
GLN12F2	86.4	87.7	88.9	90.2	91.4	92.7	94.1	95.4	96.8	98.1	99.5
NE12F1	67.1	69.8	72.5	75.4	78.4	81.5	84.7	88.0	91.5	95.1	98.9
COB12F2	73.0	75.2	77.5	79.8	82.3	84.8	87.4	90.0	92.7	95.6	98.5
NE12F3	49.7	53.2	56.9	60.9	65.2	69.7	74.6	79.8	85.4	91.4	97.8
TVW131	58.6	61.7	64.9	68.3	71.9	75.7	79.6	83.8	88.2	92.8	97.6
SOT - XFMR #1	73.6	75.6	77.6	79.7	81.9	84.1	86.3	88.7	91.1	93.5	96.0
PF211	51.4	54.8	58.3	62.0	66.0	70.3	74.8	79.6	84.7	90.2	96.0
SLW1368	66.4	68.9	71.5	74.2	77.0	79.9	82.8	85.9	89.2	92.5	96.0
KAM1291	70.4	72.6	74.9	77.2	79.7	82.2	84.7	87.4	90.1	92.9	95.9
BEA12F2	77.2	78.9	80.6	82.3	84.1	85.9	87.7	89.6	91.5	93.5	95.5
NE - XFMR #2	69.5	71.7	74.0	76.3	78.8	81.3	83.9	86.6	89.4	92.2	95.2
GLN - XFMR #1	85.5	86.4	87.3	88.3	89.2	90.2	91.1	92.1	93.1	94.1	95.1
M15 - XFMR #1	86.8	87.6	88.4	89.2	90.0	90.8	91.6	92.4	93.3	94.1	94.9
NW12F1	70.3	72.4	74.6	76.9	79.2	81.7	84.1	86.7	89.4	92.1	94.9
DAL131	72.7	74.7	76.7	78.7	80.9	83.1	85.3	87.6	90.0	92.4	94.9
RAT231	69.0	71.2	73.5	75.9	78.3	80.8	83.4	86.1	88.9	91.7	94.7
SPU123	70.2	72.3	74.5	76.7	79.1	81.4	83.9	86.4	89.1	91.7	94.5
3HT12F7	68.5	70.7	73.0	75.4	77.8	80.3	82.9	85.6	88.4	91.3	94.2
L&S12F2	73.2	75.0	76.9	78.8	80.8	82.8	84.8	86.9	89.1	91.3	93.5
CDA124	83.0	84.0	85.0	86.0	87.0	88.0	89.1	90.1	91.2	92.3	93.4
NE12F2	71.5	73.4	75.4	77.4	79.5	81.7	83.9	86.1	88.4	90.8	93.3
SIP12F5	60.4	63.1	65.9	68.8	71.9	75.0	78.4	81.8	85.5	89.2	93.2
INT12F1	78.6	80.0	81.3	82.7	84.1	85.5	86.9	88.4	89.9	91.4	93.0
ODS - XFMR #1	70.8	72.8	74.7	76.8	78.9	81.1	83.3	85.5	87.9	90.3	92.8
GLN12F1	86.5	87.1	87.7	88.3	88.9	89.4	90.1	90.7	91.3	91.9	92.5
L&S - XFMR #1	74.5	76.1	77.7	79.3	81.0	82.8	84.5	86.3	88.2	90.0	92.0
M15512	78.0	79.3	80.6	81.9	83.2	84.6	86.0	87.4	88.8	90.3	91.8
TUR116	68.8	70.8	72.9	75.0	77.1	79.4	81.6	84.0	86.4	88.9	91.5
WAK - XFMR #2	84.5	85.1	85.8	86.4	87.1	87.7	88.4	89.1	89.8	90.4	91.1
SUN - XFMR #1 (2023)	74.8	76.2	77.7	79.2	80.8	82.4	84.0	85.6	87.3	89.0	90.8
GRA12F2	65.3	67.5	69.7	71.9	74.3	76.7	79.2	81.8	84.4	87.2	90.0
F&C - XFMR #2	79.1	80.1	81.1	82.2	83.2	84.3	85.4	86.5	87.6	88.7	89.9
M15514	67.2	69.2	71.2	73.2	75.4	77.5	79.8	82.1	84.5	86.9	89.5
SOT521	67.1	69.0	71.0	73.0	75.1	77.2	79.4	81.7	84.0	86.4	88.9

DocuSign Envelope ID: 244DBD63-018D-4BE3-A2BE-8265FA47DB79

Substation – Performance and Capacity

Name	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
L&S12F3	68.5	70.3	72.2	74.1	76.0	78.0	80.1	82.2	84.3	86.6	88.8
ROS12F5	71.7	73.2	74.8	76.4	78.0	79.6	81.3	83.0	84.8	86.6	88.4
BLU321	52.2	55.0	58.0	61.1	64.4	67.9	71.5	75.4	79.5	83.8	88.3
INT - XFMR #1	73.8	75.1	76.5	77.8	79.2	80.6	82.1	83.5	85.0	86.5	88.1
WAK12F4	75.4	76.5	77.7	78.9	80.2	81.4	82.7	84.0	85.3	86.6	88.0
ROS - XFMR #1	71.8	73.3	74.7	76.2	77.7	79.3	80.9	82.5	84.1	85.8	87.5
SLW - XFMR #1	84.1	84.5	84.8	85.1	85.4	85.7	86.0	86.4	86.7	87.0	87.3
F&C12F4	75.3	76.4	77.5	78.6	79.8	81.0	82.1	83.3	84.6	85.8	87.1
3HT12F5	62.7	64.7	66.8	69.0	71.3	73.6	76.0	78.5	81.0	83.7	86.4
M15 - XFMR #2	71.5	72.8	74.2	75.6	77.0	78.5	80.0	81.5	83.0	84.6	86.2
ROS12F1	67.8	69.4	71.0	72.7	74.4	76.2	78.0	79.9	81.8	83.7	85.7
TEN - XFMR #1	66.5	68.2	70.0	71.7	73.6	75.4	77.4	79.3	81.4	83.4	85.6
WAK - XFMR #1	85.3	85.3	85.3	85.3	85.3	85.3	85.3	85.3	85.3	85.3	85.3
APW112	78.3	79.0	79.6	80.2	80.9	81.5	82.2	82.8	83.5	84.1	84.8
BEA - XFMR #2	71.3	72.5	73.8	75.0	76.3	77.6	79.0	80.3	81.7	83.1	84.5
SIP - XFMR #2	64.6	66.3	68.1	69.9	71.8	73.8	75.7	77.8	79.9	82.0	84.3
SIP12F4	63.8	65.5	67.4	69.3	71.2	73.2	75.2	77.3	79.5	81.7	84.0
MEA12F1	64.9	66.6	68.2	70.0	71.7	73.5	75.4	77.3	79.3	81.3	83.3
F&C12F2	82.9	82.9	82.9	82.9	82.9	82.9	82.9	82.9	82.9	82.9	82.9
BEA12F5	65.5	67.0	68.6	70.2	71.9	73.6	75.3	77.0	78.9	80.7	82.6
MIL12F3	69.3	70.5	71.7	73.0	74.3	75.6	77.0	78.3	79.7	81.1	82.6
HUE141	75.2	75.8	76.5	77.2	77.9	78.6	79.3	80.0	80.8	81.5	82.2
C&W12F6	68.6	69.8	71.1	72.4	73.7	75.0	76.4	77.8	79.2	80.6	82.1
SIP12F2	47.3	50.0	52.8	55.8	58.9	62.2	65.7	69.3	73.2	77.3	81.6
WAK12F3	81.6	81.6	81.6	81.6	81.6	81.6	81.6	81.6	81.6	81.6	81.6
CFD1210	81.6	81.6	81.6	81.6	81.6	81.6	81.6	81.6	81.6	81.6	81.6
MIL12F2	66.8	68.1	69.5	70.9	72.3	73.7	75.2	76.7	78.2	79.8	81.4
MIL - XFMR #1	64.6	66.1	67.6	69.2	70.8	72.5	74.1	75.8	77.6	79.4	81.2
COB12F1	68.6	69.7	70.9	72.1	73.3	74.6	75.8	77.1	78.4	79.7	81.1
APW - XFMR #1	72.3	73.1	73.9	74.8	75.6	76.5	77.3	78.2	79.1	80.0	80.9
BKR - XFMR #1	71.9	72.7	73.6	74.4	75.3	76.2	77.1	78.0	78.9	79.9	80.8
MIL - XFMR #2	69.6	70.6	71.6	72.6	73.7	74.8	75.8	76.9	78.1	79.2	80.3
3HT - XFMR #2	65.2	66.6	67.9	69.4	70.8	72.3	73.8	75.3	76.9	78.5	80.1

Name	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
SUN12F5	67.4	75.5	85	95.7	108.1	122.1	136.3	152.3	168.8	187	207
ORI - XFMR #1	107.9	111	114.7	118.4	122.3	126.5	130.7	134.6	139.6	143.6	149
ORI12F3	107.8	110.7	114.4	118.3	122.2	126.3	130.6	134.2	139.4	143.1	148.6
RAT233	80.5	84.3	88.3	92	96.3	100.4	105.2	110.1	115.3	120.8	126.5
NE - XFMR #1	68.9	69.3	74.4	79.7	85	90.7	96.8	103.3	110.3	117.6	125
GRA12F3	60.7	65.2	70.5	75.7	81.4	87.9	94	100.5	107.8	115.3	123.3
L&S12F4	75.8	79.6	83.5	87.6	91.4	95.9	100.7	105.6	110.8	116.8	122.6
MLN - XFMR #2	87.4	90.3	93.3	96.4	99.6	103	106.5	110.2	114	118	122.2
TUR116	93	95.7	98.4	101.2	104.1	106.5	109	111.6	114.2	116.9	119.7
CLV - XFMR #3	110.3	111.4	112.3	113.3	114.2	115.1	115.9	116.8	117.6	118.4	118.9
LIB12F3	64.3	68.3	72.4	76.9	81.6	87	92.3	98.4	105	111.9	118.8
LIB - XFMR #2	65.8	69.6	73.7	78	82.6	87.6	93	99	105.3	112.1	118.7
SPT - XFMR #1	90	92.3	94.6	97.2	99.7	102	104.8	107.7	110.7	113.7	117.1
SPT - XFMR #2	90	92.3	94.6	97.2	99.7	101.9	104.7	107.6	110.6	113.7	117.1
NE12F4	73.9	77.4	74.9	79.2	83.8	88.6	93.7	99.1	104.7	110.7	117.1
PRA - XFMR #2	68.1	71.7	75.4	79.5	83.6	88.2	93.1	98.2	103.7	109.7	115.9
BLU321	68.2	71.9	75.8	79.8	84.2	88.8	93.6	98.5	103.8	109.7	115.5
KAM1291	83.9	86.4	89.3	91.9	95.1	97.9	100.8	104.4	107.5	111.3	115.4
TUR117	71.7	75.1	78.6	82.7	86.6	90.6	94.8	98.8	102.8	107.1	111.6
OLD - XFMR #1	58.2	62.1	66.3	70.8	75.7	80.5	85.6	91.2	97	103.3	110
GRA - XFMR #1	68.4	71.6	75.4	79.1	82.8	87.1	91.4	95.7	100.2	104.9	109.9
NE12F3	49.9	54	58.8	64	69	74.4	80.2	86.6	93.5	100.6	107.6
PAL312	86.7	89.9	92.8	95.8	99.3	102.5	106.2	106.2	106.2	106.2	106.2
CKF - XFMR #1	85.6	87.4	89.4	91.5	93.5	95.7	97.6	99.7	101.8	103.9	106.1
WIL - XFMR #1	91.1	92.3	93.6	95	96.5	97.9	99.2	100.7	102.2	103.8	105.4
OLD721	55.6	59.4	63.4	67.7	72.3	76.9	81.8	87.1	92.7	98.7	105.1
PRA221	63	66.1	69.5	73	76.4	80.3	84.6	89	93.8	99.3	104.7
SPA - XFMR #1	90.6	91.8	93	94.2	95.5	96.8	98.1	99.4	100.7	102.1	103.6

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Substation – Performance and Capacity

Name	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
GRA12F2	73.5	76.1	79.1	81.9	84.5	87.5	90.5	93.4	96.4	99.6	102.9
PRA222	58.3	61.7	65.3	68.7	72.7	76.9	81.4	86.1	91.1	96.9	102.5
M15 - XFMR #1	92.6	93.4	94.6	95.6	96.4	97.2	98.5	99.5	100.4	101.5	102.4
SIP12F2	61.5	64.3	67.6	71	74.7	78.5	82.5	87.1	91.6	96.2	101.6
PRV - XFMR #1	89.8	90.7	91.9	92.9	93.9	95	96.1	97.3	98.5	99.7	100.9
L&S12F3	76.3	78.2	80.5	82.5	85	87.6	89.7	92.5	94.8	97.6	100.6
APW112	75	75.6	97	97.3	97.6	97.9	98.2	99	99.3	99.7	100
TUR - XFMR #2	70.8	73.4	76.1	79	82	84.8	87.7	90.6	93.6	96.8	99.9
SIP - XFMR #1	62.1	64.9	67.9	71.1	74.6	78.2	81.9	86.2	90.3	94.7	99.8
GRV - XFMR #1	87.2	88.2	89	90.1	91	91.9	93	94	94.9	94.9	97.1
LIB12F4	55.2	58.2	61.5	64.9	68.5	72.3	76.7	81.4	86.4	91.7	96.9
SOT - XFMR #1	74.6	76.6	78.5	80.7	82.7	84.8	87.2	89.5	91.7	94.1	96.6
CHW - XFMR #1	73.5	75.2	76.9	78.6	80.3	82	83.2	84.7	87	88.6	96.2
M15514	74.5	76.3	78.1	80.4	82.3	84.2	86.7	88.7	90.9	93.5	95.7
L&S12F2	72.3	74.4	76.3	78.5	80.9	83.3	85.3	87.8	90.5	92.7	95
CHW12F3	68.5	70.2	71.9	73.8	75.6	77.1	78.9	81.9	81.4	88.3	94.5
IDR253	68.6	71	73.4	75.5	77.7	80	82.4	84.9	87.4	90	92.7
SUN12F2	71.8	73.8	75.5	77.7	79.5	81.3	83.6	85.6	88	90	92.5
SIP - XFMR #3	91.8	91.8	91.8	91.8	91.8	91.8	91.8	91.8	91.8	91.8	91.8
ORO1282	72	74	75.6	77.3	79.4	81.1	83.3	85.2	87.5	89.4	91.8
IDR - XFMR #1	66.9	69	71.2	73.3	75.4	77.6	80	82.5	84.8	87.5	90.1
NE12F1	58.4	61	63.4	66.2	69.1	72.1	75.3	78.6	82.1	85.7	89.5
EWN - XFMR #1	89.4	89.4	89.4	89.4	89.4	89.4	89.4	89.4	89.4	89.4	89.4
GRV1272	75.7	76.9	78	79.6	80.7	82	83.2	84.8	86.1	86.1	89.1
GIF - XFMR #2	59.7	61.9	64.4	67.1	69.6	72.6	75.7	79	81.8	85.3	89.1
SAG - XFMR #1	65.7	67.9	70	72.2	74.4	76.6	78.9	81.3	83.7	86.4	89
ROS12F2	71.1	72.5	74.3	75.8	77.7	79.3	81.2	82.9	84.9	87.1	88.8
3HT12F5	65.2	67.4	69.3	71.5	73.6	76	78.5	80.7	83.4	86.1	88.6
3HT12F7	63.1	65.5	67.6	69.8	72.4	74.8	77.2	80.1	82.7	85.8	88.5
SPL361	88.4	88.4	88.4	88.4	88.4	88.4	88.4	88.4	88.4	88.4	88.4
M15512	74.3	75.5	77.2	78.5	79.8	81.1	82.8	84.2	85.6	87	88.4
ODN - XFMR #1	69.5	71	72.2	73.6	75.2	76.7	78.7	80.7	82.8	85.1	87.8
MLN12F2	40.9	44	47.4	51	54.9	59.1	64	69.3	74.6	80.8	87.5
L&S - XFMR #1	69	70.5	72.2	73.9	75.7	77.5	79.3	81.4	83.1	85.2	87.3
PF211	47.4	50.4	53.7	56.8	60.5	64.4	68.1	72.5	77.1	82.1	87.3
DIA - XFMR #1	85.8	85.8	85.8	85.8	85.8	85.8	85.8	85.8	85.8	85.8	85.8
DAL131	67.2	69	70.5	72.1	73.7	75.7	77.3	79.1	81.2	83	85.2
C&W12F6	69.7	71.4	72.7	74	75.4	77.1	78.5	79.9	81.8	83.3	84.8
TVW131	51.6	54.3	56.8	59.8	62.5	65.8	69.2	72.4	76.2	80.1	84.3
SUN12F1	75	75.8	76.5	77.7	78.5	79.3	80.5	81.3	82.1	83.4	84.2
BEA12F2	67.6	68.9	70.7	72.1	73.5	75.4	76.9	78.5	80.4	82.1	83.7
CKF711	67.3	68.6	70.4	72.1	73.5	75.3	76.8	78.3	79.9	81.5	83.1
3HT12F4	80.6	80.7	80.8	81.3	81.4	82	82.5	82.6	82.7	82.9	83
SIP - XFMR #2	63.9	65.7	67.2	68.9	70.7	72.6	74.3	76.4	78.3	80.6	82.5
3HT - XFMR #2	67.5	68.7	70	71.5	72.8	74.3	76	77.5	79	80.7	82.3
LOO - XFMR #1	77.5	77.9	78.4	78.8	79.3	79.6	80	80.5	80.9	81.5	82.2
SIP12F3	66.6	68.2	69.4	70.7	72.4	73.8	75.2	77.1	78.6	80.6	82.1
SPT4S21	47.5	50.3	53	56.1	59.3	62.2	65.6	69.4	73.4	77.5	81.9
MEA12F1	65	66.6	67.9	69.2	70.9	72.7	74.2	76.1	77.6	79.6	81.3
LIB12F1	80.6	80.6	80.6	80.6	80.7	80.7	81.1	81.1	81.1	81.1	81.2
ROS12F3	54.4	56.7	58.8	61.3	63.8	66.2	68.9	71.8	74.4	77.6	80.8
C&W12F2	73.5	74.5	75.1	75.7	76.4	77	78	78.7	79.3	80	80.6
NE - XFMR #2	56.7	58.7	60.9	63	65.1	67.3	69.7	72.2	74.8	77.7	80.3
SE12F2	80.2	80.2	80.2	80.2	80.2	80.2	80.2	80.2	80.2	80.2	80.2
SLW1368	57.4	59.1	61.2	63	65.3	67.3	69.7	71.9	74.6	77.3	80.2
MIS - XFMR #1	80.1	80.1	80.1	80.1	80.1	80.1	80.1	80.1	80.1	80.1	80.1
CHW12F2	61.1	62.8	64.6	66.3	67.9	69.8	71.8	73.7	75.7	77.7	80.1

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1.2 Discuss the major drivers of the business case.

The Substation – Performance and Capacity business case primary driver is Performance and Capacity. The identified problem being addressed by the proposed solution is inadequate distribution substation capacity to serve expected customer demand. Capacity is generally quantified through system planning engineering analysis showing utilization percentage of applicable facility ratings. Providing an electric system with sufficient capacity to meet customer demands will allow equipment to be operated within designed limits while maintaining service to customers.

A secondary driver of the business case is Asset Condition. Some mitigation alternatives include adding capacity at existing distribution substations which may require the replacement or upgrades to the existing equipment in the substation. Justification to replace the existing equipment may not be prudent based only on the condition of the asset. When replacing the equipment to address capacity issues, the potential asset condition issues will be addressed.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The risk of not approving the business case or deferring the requested capital funds will lead to insufficient distribution system capacity to adequately serve customer demand. The 2021 Heat Wave, see Heat EOP Event Analysis report, is an example of past observed system performance where customer's power was turned off due to, in part, inadequate system capacity. In some instances, deferring proposed capacity projects may not lead to immediate performance issues but it will create an engineering, construction, and capital resource constraint in future years as the necessary projects will still be needed.

This business case is an ongoing program of multi-year substation projects that are at all stages of construction (Initiation, Planning, Execution and Closeout). This business case serves as the umbrella for all projects within Substation Engineering that have a primary driver of Performance and Capacity.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

The Substation – Performance and Capacity business case provides additional capacity to the system which is "critical to serving our customers well and unlocking pathways to growth." The Perform Focus Area of Avista's focus goals is the primary alignment with the requested projects but there are elements to the projects which are aligned with the theme of our Vision, Mission, and Focus Areas.

Our Customers:
Existing and future customers expect to have electrical service. Avista needs to deliver a system which can serve the customer demands and continue to meet the company's defined reliability objectives.

Our People:
The portion of our company who will support the implementation of the projects represents a core electric utility collection of our employees. These employees will take pride in the effort of adding infrastructure to the electric system to meet the needs of our customers.

Perform:
With completion of the projects, Avista will be unlocking growth potential in the areas of each project.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 143 of 535

DocuSign Envelope ID: 244DBD63-018D-4BE3-A2BE-8265FA47DB79

Vision; Better energy for life:
Investment in the electric distribution system represents a long-term investment of infrastructure which will be in place to serve our customers for several generations.

Mission: We improve our customers' lives through innovative energy solutions.
Distribution substation capacity projects are needed to meet the demands of our customers. Customer's livelihoods depend on the electrical services we provide.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[2]

A comprehensive evaluation of the distribution system adequacy is performed bi-annually as part of the System Assessment process. Documentation of the results is provided in the System Assessment. The most recent document is the 2023-2024 System Assessment Version 0 (2023-2024 Avista System Assessment-V0.pdf). The tables provided in Section 1.1 above provides the observed performance issues. The 2023-2024 System Assessment incorporated improved statistical evaluation of peak loading conditions and improved modeling accuracy utilizing additional distribution planning engineers therefore additional capacity issues have been identified compared to previous assessments.

A list of mitigation projects provided in the 2021-2022 System Assessment associated with this business case includes:

- **Bronx Station Rebuild** - Reconstruct existing Bronx Station to include distribution facilities with a 20MVA transformer and two distribution feeders. The 115kV portion of the station will include two 115kV transmission line positions protected with circuit breakers and configuration suitable for future expansion.
- **Poleline (Prairie) Station Rebuild -** Construct new distribution station to replace Avista facilities at existing Prairie Station. New station to include two 30MVA transformers, four feeders, and looped- through transmission line.
- **Valley Capacity Mitigation –** Rebuild existing Valley Station with increased distribution capacity.
- **Pleasant View Capacity Mitigation** - Rebuild existing Pleasant View Station with increased distribution capacity.
- **North Spokane Distribution Reinforcement (Northeast) -** Replace two existing 20MVA transformers with 30MVA transformers and add new NE12F6 feeder. Transformer circuit switchers replacements are included in scope to eliminate existing fault blocking scheme. Distribution integration scope includes new switches and an express feeder truck.
- **Orin Capacity Mitigation -** Construct new distribution station connected to BPA's Colville – Republic 115kV Transmission line. New station will include a single 20MVA transformer and two distribution feeders.
- **Glenrose Capacity Mitigation -** Replace existing transformer with 30MVA and rebalance feeders. Regulator upgrades assumed to be an existing flex crew project.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

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- **Bunker Hill Customer Capacity -** Install new 20MVA transformer to replace existing transformer and construct new dedicated customer distribution feeder.
- **Melville Station -** New switching station near existing tap to Four Lakes Station off the South Fairchild Tap 115kV transmission line. Construct new transmission line from Airway Heights to Melville including passing through Russel Road and Craig Road distribution stations. Requires new transmission line terminal at existing Airway Heights Station.
- **North Spokane Transmission Reinforcement (Five Mile 115kV Station) –** Construct new Five Mile Station with new loop through of Nine Mile - Westside 115 requiring 3 miles of new 115 line. New BPA interconnection at Bell Station to create a Bell – Five Mile 115 line using 1.5 mile of new line and portion of Beacon - Francis & Cedar 115 line. New Francis & Cedar – Five Mile line using 1.5 mile of new line.
- **Midway Station –** Construct new distribution station to include 30MVA transformer and two distribution feeders. Each individual performance issue and associated project is reviewed and prioritized by the Engineering Roundtable.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The business problem identified is inadequate distribution system capacity to serve customers. The proposed solution is to programmatically fund substation projects to add capacity to the system. Specific capacity deficiencies and mitigation projects will be identified by System Planning in coordination with internal and external stakeholders. The Engineering Roundtable will review and prioritize each project. Substation projects which require capacity upgrades or new distribution substations are proposed to be funded through the Substation – Performance and Capacity business case. Historically funding levels in the business case has generally resulted in approximately one substation project per year. When specific projects are better understood in funding years 1-3, actual cost estimates are used for the funding request.

Implementation of the proposed solution will strategically add capacity to the system to mitigate the issues identified in the 2023-2024 System Assessment. Each project under this program will require planning and operational studies, justifications, and project reports prior to funding.

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2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[3]

Study reports prepared by System Planning can be referenced for the Substation – Performance and Capacity business case. An example of work includes:

- 2023-2024 System Assessment – Version 0, 2023
- Heat EOP Event Analysis – Version 0, 2021
- Poleline (Prairie) Substation Rebuild Project – Version 0, 2023
- Northeast Capacity Mitigation – Version A, 2023
- North Spokane Distribution System Analysis – Version 0, 2023
- Orin Capacity Mitigation Project – Version A, 2023
- Glenrose Capacity Mitigation – Version A, 2024
- Bunker Hill Mine Load Addition – Version 0, 2022
- North Spokane Transmission Reinforcement Study – Version 0, 2024

Individual project documentation is under development for project not included in the above listed reports. Each project report will include detailed study results showing how the project will mitigate identified capacity issues.

2.3 Summarize in the table and describe below the DIRECT offsets[4] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

No direct offset or savings are expected as a result from this investment. Having the right amount of backup capacity in each area is critical for the continued appropriate management of the electric system. Any direct savings would be offset by direct costs due to more stations to inspect, test and maintain. Some savings will be seen with SCADA being extended to about 40 substations over the next several years – this will benefit our wildfire prevention efforts, quicker outage remediation and general maintenance needs. [Reference 2022-2023 – TTP Forecast by BC by Director for Offset Exercise-Final]

Annual O&M costs for a distribution substation is approximately $30,000. Annual O&M costs for a transmission substation is approximately $50,000.

[3] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[4] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

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2.4 Summarize in the table and describe below the INDIRECT offsets[5] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

No indirect capital or O&M offsets are expected to result from this investment. Adding SCADA to substations means more data collected about the substation which will require more personnel to analyze and manage the data. Adding new substations to the electric system will require additional GPSS personnel (Batterymen, Servicemen, and general staff) to inspect, test and maintain the new substations plus Substation Engineers to manage the compliance and maintenance requirements for these new substations. [Reference 2022-2023 – TTP Forecast by BC by Director for Offset Exercise-Final]

2.5 Describe in detail the alternatives, including proposed cost for each alternative, which were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Each individual project funded by this business case includes evaluation of project alternatives. Alternatives may include alternate substation expansion projects, expanding existing substation capacity, constructing new substations, potential targeted demand side management, installation of utility scale battery systems, and feeder loading optimization through phase balancing and load transfers to adjacent facilities.

With a programmatic business case, reasonable alternatives to consider are narrowed to variation in funding levels. Under funding the business case from the requested amount will result in the deferral of addressing the identified performance issues. Continual deferral of projects will result in a compression of needed funding in future years.

Alternative 1:

Do not adequately fund new distribution substation capacity projects. $Unknown

Alternative 2:

Fund two performance and capacity substation projects per year on average. $25 million/year

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Successful mitigation of the problem statement will be monitored as part of the bi-annual System Assessment conducted by System Planning. The project(s) will be successful if performance criteria in short-term planning horizon studies can be met, and performance issues are not

[5] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 147 of 535

DocuSign Envelope ID: 244DBD63-018D-4BE3-A2BE-8265FA47DB79

observed in the operations time horizon. Assumptions made in System Assessments are not static therefore projects are developed based on the best information available. For example, future load forecasts may show additional load growth not expected when a project is requested. If the project takes ten years to construct, it is possible the base line assumptions have changed, and additional projects will need to be justified.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

This is an ongoing business case. New projects are being scoped and initiated while complete projects are constructed and in closeout.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The Engineering Roundtable will provide technical review of potential scope changes with the support of the System Planning and Operations department. Scope changes which require additional fund requests to the Capital Planning Group will be vetted at the Engineering Roundtable. Substation Engineering and Engineering Project Delivery will manage the projects with a project team consisting of a Project Manager, Lead Electrical Engineer, a Lead Civil Engineer, and many others that support the project.

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3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Substation – Performance and Capacity and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Brian Chain C4012BE4B3FC4D1...	Date:	May-03-2024 | 8:57 AM PDT
Print Name:	Brian Chain		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:	DocuSigned by: Vern Malensky 06C4FB5AB09EA0B...	Date:	May-03-2024 | 2:06 PM PDT
Print Name:	Vern Malensky		
Title:	Director, Electrical Engineering		
Role:	Business Case Sponsor		

Signature:	DocuSigned by: Brian Vandenburg 0304BB8AF964A9...	Date:	May-03-2024 | 8:52 AM PDT
Print Name:	Brian Vandenburg		
Title:	Manager, Engineering Projects		
Role:	Steering/Advisory Committee Review		

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Substation – Failed Plant

EXECUTIVE SUMMARY

The Substation – Failed Plant Business Case is focused on restoring Avista's substation systems into serviceable condition after equipment fails due to animal 'contact', lightning, or other sudden equipment failure. These equipment failure events are random and cannot be planned. This business case is to fund a rapid response to unexpected damage, so customer outages are minimized. In the past, these replacements were completed under the Substation – Asset Condition Business Case, but better overview and tracking is desired by Electrical Engineering and the decision to create a separate business case to encourage better knowledge of how many substation equipment failures occur and any possible equipment manufacturer/model issues. Future maintenance practices and programs will also be reviewed in light of these equipment failures. The importance of quickly replacing damaged equipment is vital to supplying reliable service to our customer. This affects electrical customers in Washington, Idaho and Montana.

The annual budget amount is determined based on the historical average of capital substation equipment replacements. For the first three years, this rate will include non-failure projects since all replacements are under the Asset Management ER in the Substation – Asset Condition Business Case. Budget requests include all substation equipment types except Auto and Power Transformers. Large transformer failures are rare and when they occur, special budget requests will be made to the Capital Project Group.

These emergency projects were previously funded through the Substation – Asset Condition business case.

VERSION HISTORY

Version	Author	Description	Date
1.0	*K Kusel / B Chain*	*Initial draft of original business case*	*04/2024*
BCRT	*Steve Carrozzo*	*Has been reviewed by BCRT and meets necessary requirements*	DS SC

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 150 of 535

DocuSign Envelope ID: 4F15503D-7BE4-412E-B384-4043D60CC76D

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	**$2,000,000**	**$2,000,000**
2026	**$2,000,000**	**$2,000,000**
2027	**$2,000,000**	**$2,000,000**
2028	**$2,000,000**	**$2,000,000**
2029	**$2,000,000**	**$2,000,000**

Project Life Span	Ongoing
Requesting Organization/Department	Substation Engineering
Business Case Owner | Sponsor	Brian Chain | Vern Malensky
Sponsor Organization/Department	Electrical Engineering
Phase	Execution
Category	Program
Driver	Failed Plant & Operations

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

This Business Case is focused on restoring Avista's substation system into serviceable condition when sudden equipment failures occur. These events are random and cannot be planned. This business case funds a rapid response to unexpected damages so customer outages are minimized. This business case provides funds for replacing air switches, circuit breakers, voltage regulators, transformers, station batteries, bushings, relays and other defined substation retirement units. Equipment failures can be caused by lightning strikes, animal 'interference' and operational failure.

1.2 Discuss the major drivers of the business case.

The primary driver for this business case is Failed Plant and Operations. The work is a key component to minimizing customer outage times and contributes to Avista's reliability.

In the past, failed substation equipment replacements were funded under the Substation – Asset Condition business case (under ER 2215) which included all small substation projects (i.e., voltage regulator upgrades, low voltage breaker upgrades). With the shift of creating business cases that focused on primary drivers, it made sense to break out Failed Plant capital projects to their own business case. This move will provide clarity to see how many emergency/failed plant projects are completed annually and separate this work from other projects. This information could provide information for better equipment maintenance programs.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 151 of 535

DocuSign Envelope ID: 4F15503D-7BE4-412E-B384-4043D60CC76D

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

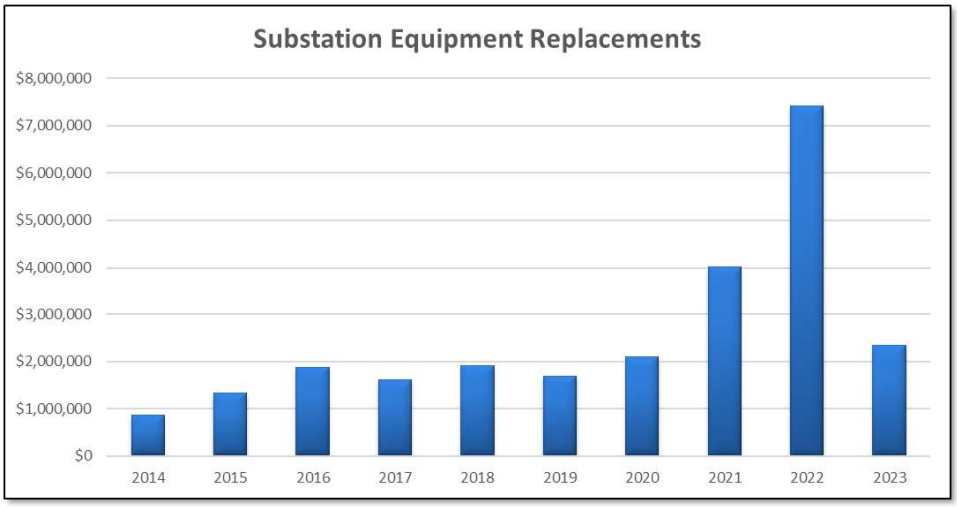
This program business case is needed to provide quick replacement of failed substation equipment. If this work is not approved or deferred, the cost of replacement will be absorbed by another business case. The needed work will continue to occur, it will simply be hidden within other types of substation work.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization.

This business case focuses on 'Our Customers' and 'Perform' focus areas. While we cannot completely avoid customer outages, this business case supplies immediate funding to allow for quicker equipment replacements and shorter customer outages. Being able to study substation equipment failures and finding better ways to design and maintain substations in the future is key to better performance.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

Funding requests are based on average failure costs across all substation equipment types excluding power and auto transformers. Large substation transformer failures are rare and expensive, a capital budget request will be completed if a transformer fails. As it's not possible to completely predict when a substation asset will fail, funding requirements could change and may result in an increase or decrease in annual funding amounts.

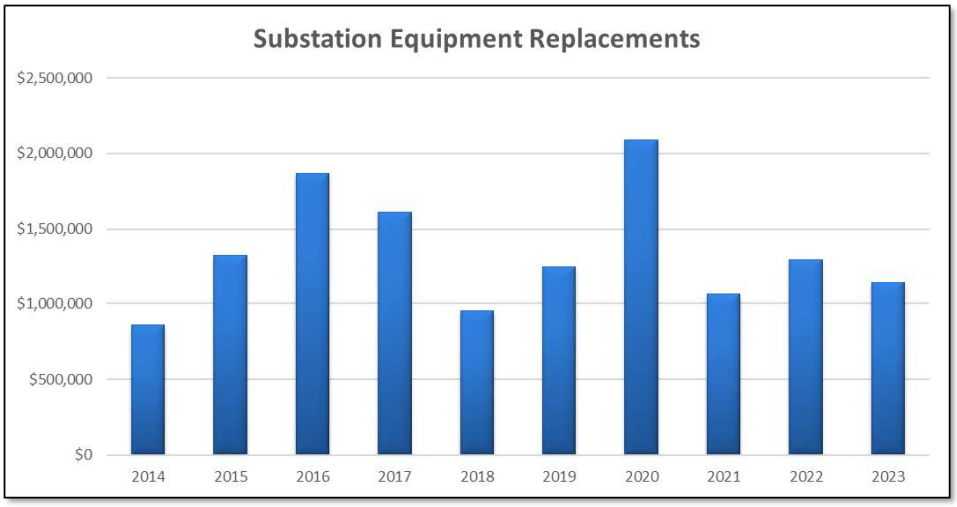


[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 152 of 535

DocuSign Envelope ID: 4F15503D-7BE4-412E-B384-4043D60CC76D

The above figure includes dollars spent annually to replace all types of substation equipmnet. This includes the North Lewiston Auto Replacement project (2021-2022 and theMoscow Auto Replacement project (2022-2023)) both auto transformers failed in service and where replaced.



The above figure shows the total dollars spent per year for all types of substation equipment except auto transformer. This shows a more true year over year cost of substation equipment failure dollars spent.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

This Business Case is focused on restoring Avista's substation system into serviceable condition when sudden equipment failures occur. These events are random and cannot be planned. This business case funds a rapid response to unexpected damages so customer outages are minimized. This business case provides funds for replacing air switches, circuit breakers, voltage regulators, transformers, station batteries, bushings, relays and other defined substation retirement units. Equipment failures can be caused by lightning strikes, animal 'interference' and operational failure.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 153 of 535

DocuSign Envelope ID: 4F15503D-7BE4-412E-B384-4043D60CC76D

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

The annual budget amount is determined based on the historical 5-year average costs of failed substation equipment. If more or less dollars are needed during a fiscal year, a mid-year budget request or giveback will be requested.

For this initial funding, data from 2014 through 2023 was reviewed and $2,000,000 was decided as a good first year budget.

2.3 Summarize in the table and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	N/A	N/A	N/A	N/A	N/A	N/A
O&M	N/A	N/A	N/A	N/A	N/A	N/A

There is no direct offset in this business case. Not funding failed equipment replacement would result in the replacement being funded from a different business case.

2.4 Summarize in the table and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	N/A	$	$	$	$	$
O&M	N/A	$	$	$	$	$

There are no offsets to O&M. All substation failed plant work are like kind replacements and cause no change to O&M costs.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 154 of 535

DocuSign Envelope ID: 4F15503D-7BE4-412E-B384-4043D60CC76D

2.5 Describe in detail the alternatives, including proposed cost for each alternative, which were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

The alternative to this business case request is not funding. The costs associated with replacing failed substation equipment would be covered through a different business case. Failed equipment has to be repaired, regardless of which business case they are funded from.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

This business case is created to align with Avista's style of primary drivers. Knowledge of small substation equipment projects vs other primary drivers (performance & capacity, mandatory & compliance, etc.) will show the need (or lack of) for asset management programs.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

This business case is a program that transfers to plant as each project is completed. This varies from 1 month to several months depending on the equipment type. The Substation Engineering Manager will review the costs monthly to decide if budget adjustments are needed.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Substation Engineering Manager: Owner of Substation – Failed Plant business case. Reviews monthly spend and makes budget decisions.

Electrical Engineering Director: Owner of Expected Spend meeting held monthly. Reviews the monthly spend of all business cases sponsored by the EE department.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 155 of 535

DocuSign Envelope ID: 4F15503D-7BE4-412E-B384-4043D60CC76D

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Substation - Failed Plant business case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Brian Chain C4012F...	Date:	May-02-2024 | 7:15 AM PDT
Print Name:	Brian Chain		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:	DocuSigned by: Vern Malensky 06C4FF...	Date:	May-03-2024 | 1:45 PM PDT
Print Name:	Vern Malensky		
Title:	Director, Electrical Engineering		
Role:	Business Case Sponsor		

EXECUTIVE SUMMARY

Asset Management and Distribution Engineering provided the analysis of Avista's distribution assets and their condition. This analysis is used to direct the Wood Pole Management (WPM) work that includes inspecting and maintaining Avista's poles, hardware, and equipment on a twenty-year cycle. This analysis is documented in the 2017 Wood Pole Management Program Review and Recommendations. It is reiterated in the Avista Utilities Electric Distribution Infrastructure Plan June 2017, and the 2021 Wood Pole Management (Distribution) Inspection Cycle Analysis. The reports are in the (\\c01m570) drive under Wood Pole Management. In 2021 WPM changed the cycle for feeders in high fire risk areas to seventeen- years for the next ten-years to help ensure poles are inspected and failed assets replaced before Grid Hardening Programmatic work occurs. The seventeen-year cycle analysis is discussed in the Wood Pole Management (Distribution) Inspection Cycle Analysis. Asset Maintenance manages and tracks the work, budget, and schedule. The major drivers for the program are system reliability, improved cost performance, and increasing customer reliability. These drivers are achieved by replacing defective poles, associated hardware, and equipment when the condition of the asset requires replacement. The National Electric Safety Code (NESC) is adopted as Washington Law under WAC 296-45-045. Part 013C of this code describes the application, Part 121 defines the inspection interval, and Part 214 details documentation and correction of the pole inspection results. We have also communicated to our insurance carrier Aegis that we are committed to staying on cycle and completing the work in a timely manner.

WPM work encompasses Avista's electric distribution overhead facilities in Washington, Idaho, and Montana. In order to maintain a seventeen-year cycle for the next ten years, approximately 13,000 poles need to be inspected and follow-up work completed annually. The work plan was developed to complete 66% of the poles in the State of Washington and 34% of the poles in the State of Idaho each year. The average cost to replace defective poles, crossarms, equipment, and hardware is $1334/pole on a feeder basis, whether work is required or not. To stay on a seventeen-year cycle requires $17,342,000 per year which also benefits the Grid Hardening efforts by replacing identified defective assets before they complete their work. A portion of the funding is under the WPM-GH Make Ready budget. The combined WPM and WPM-GH Make Ready budget for 2024 is $16,000,000. Our customers benefit from this combined program by reducing unplanned outages, replacing assets under capital funding, and increasing safety for our line workers and the public. The risk of not approving this Business Case means we will run our facilities in a run-to-failure mode as identified rejected assets are not replaced in a timely manner, safety for our line hands and the public would decrease, and our Operating and Maintenance Costs would increase.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 157 of 535

VERSION HISTORY

Version	Author	Description	Date
1.0	*Mark Gabert*	*Final Draft of opigonal business case*	*7/31/2020*
2.0	*Mark Gabert*	*Business Case Refresh*	*8/31/2022*
3.0	*Mark Gabert*	*Business Case Refresh*	*4/14/2023*
4.0	*Mark Gabert*	*Business Case Refresh*	*4/5/2024*
BCRT	*BCRT Team Member – Katie Snyder*	*Has been reviewed by BCRT and meets necessary requirements*	*04/21/2023*
BCRT	*BCRT Team Member – Katie Snyder*	*Has been reviewed by BCRT and meets necessary requirements*	*05/08/2024*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$13,000,000**	**$13,000,000**
2025	**$13,000,000**	**$13,000,000**
2026	**$17,342,000**	**$17,342,000**
2027	**$18,902,780**	**$18,902,780**
2028	**$19,469,863**	**$19,469,863**
2029	**$20,053,958**	**$20,053,958**

Project Life Span	*Ongoing*
Requesting Organization/Department	M51
Business Case Owner | Sponsor	Mark Gabert-Heather Webster- Paul Good
Sponsor Organization/Department	Operations
Phase	Execution
Category	Program
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. **BUSINESS PROBLEM -** *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

   The Wood Pole Management (WPM) program historically inspected and maintained the distribution wood poles on a twenty-year cycle and the transmission poles on a fifteen-year cycle. In 2021 we moved the distribution inspection cycle for feeders in high fire risk areas

to a seventeen-year cycle to support the Grid Hardening work plan. Avista has approximately 227,000 distribution poles, and to meet the seventeen-year cycle, approximately 13,000 poles need to be inspected annually, including associated replacement work. Approximately 26 percent of the poles are older than 60 years of age which will increase over time. The Mean Time to Failure (MTTF) for wood poles is seventy-nine years, but Distribution Engineering recommends replacement at sixty years of age due to the time element of the next cycle and the above-groundline decay characteristics of butt-treated wood poles. Because our poles are not full length treated, they are more susceptible to pole top decay. Currently, we only replace poles that fail the inspection process and do not use age as the criteria for replacing poles under the Wood Pole Management budget. If we used age and pole failure as a guideline it would require a significant increase in budgeted funding.

Along with inspecting poles, WPM visually inspects distribution transformers, cutouts, insulators, wildlife guards, lightning arrestors, cross arms, guying, and pole grounds. The average asset life of this equipment is fifty-five years and requires replacement along with the pole work. The inspections document the asset condition and indicate what assets should be replaced. The asset condition is observed and documented during the pole inspection process as described in S-622 Specification for the Inspection of Poles. This document can be found in the (\\c01m570) drive under Wood Pole Management. Designs and work plans are then created to replace the assets that fail the inspection process. The construction work to replace the assets is also part of this program.

1.1 What is the current or potential problem that is being addressed?

Across Avista's service territory, wood poles are exposed to a variety of environmental conditions which impact their condition. Over time, these poles deteriorate at different rates. In order to maintain safe and reliable operation of the system, these poles need to be periodically tested to determine if they should be replaced or can remain in service. The Wood Pole Management program was developed to mitigate this. The program addresses and reduces issues such as outages, safety risks, and unplanned maintenance by proactively maintaining the wood poles that are at the end of their useful life. This is accomplished by inspecting, documenting, and maintaining our overhead facilities in a useful condition on a twenty-year cycle. This also keeps our poles, equipment, and hardware safe for employees and the general public while maintaining a high level of customer service and reliability. To aid in Grid Hardening efforts, Wood Pole Management changed feeders in high fire risk areas to a seventeen-year reinspection cycle. The decreased inspection cycle enables Grid Hardening to complete its work by replacing poles with the potential for failure ahead of Grid Hardening construction, which is more efficient. However, if Wood Pole Management is underfunded, it will push some feeders past the seventeen-year cycle which may impact the Grid Hardening Program. In addition, if Wood Pole Management is not adequately funded, the company will move toward managing the overhead distribution assets as they fail, which increases both safety and reliability risks.

1.2 Discuss the major drivers of the business case.

From an asset condition perspective, the major drivers for the Wood Pole Management Program include safety, system reliability, improved cost performance, reduced customer outages/increased reliability, and decreased fire risk. This program also has a mandatory

and compliance component to it because the National Electrical Safety Code (NESC) is adopted as Washington Law under WAC 296-45-045. Part 013C of the code describes the application, Part 121 defines the inspection interval, and Part 214A details documentation and correction of the pole inspection results.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The work is required now to keep pace with Avista's aging critical assets and expected failure rates as our infrastructure gets older.

Approximately 26 percent of Avista's poles are older than 60 years of age, which is continually increasing over time. The Mean Time to Failure (MTTF) for wood poles is seventy-nine years, but Distribution Engineering recommends that poles should be considered for replacement at sixty years of age due to the time element of the next cycle as well as the above groundline decay characteristics of butt-treated wood poles. Figure 1 below shows the increased rate at which the poles are reaching the seventy-nine-year end of life. If this work is not maintained, this aging infrastructure will cause an increasing number of failures, leading to increased outages and higher construction costs. It is much more expensive to respond to an asset failure than replacing it under a planned capital program.

In addition to the risks of fires, outages, and failures with the aging equipment, the additional risks associated with this program pertain to the following:

Environmental: Risks include potential large volume transformer oil spills, difficult and expensive hazardous waste cleanup, impact to waterways, and repeated or moderate air emission exceedance. According to the 2017 Wood Pole Management Review and Recommendations, if the program is unfunded the potential occurrence is greater than four spills per year. If funded, the potential occurrence is projected at less than one in fifty years.

Public Safety and Health: Risks include the potential for serious injury for crews or the public, significant damage to equipment, property of businesses, and public health infrastructure impacts of up to forty-eight hours. If the program is unfunded, the potential occurrence is projected at less than one per ten years. If funded, the potential occurrence is projected at less than one in fifty years.

Figure 1.

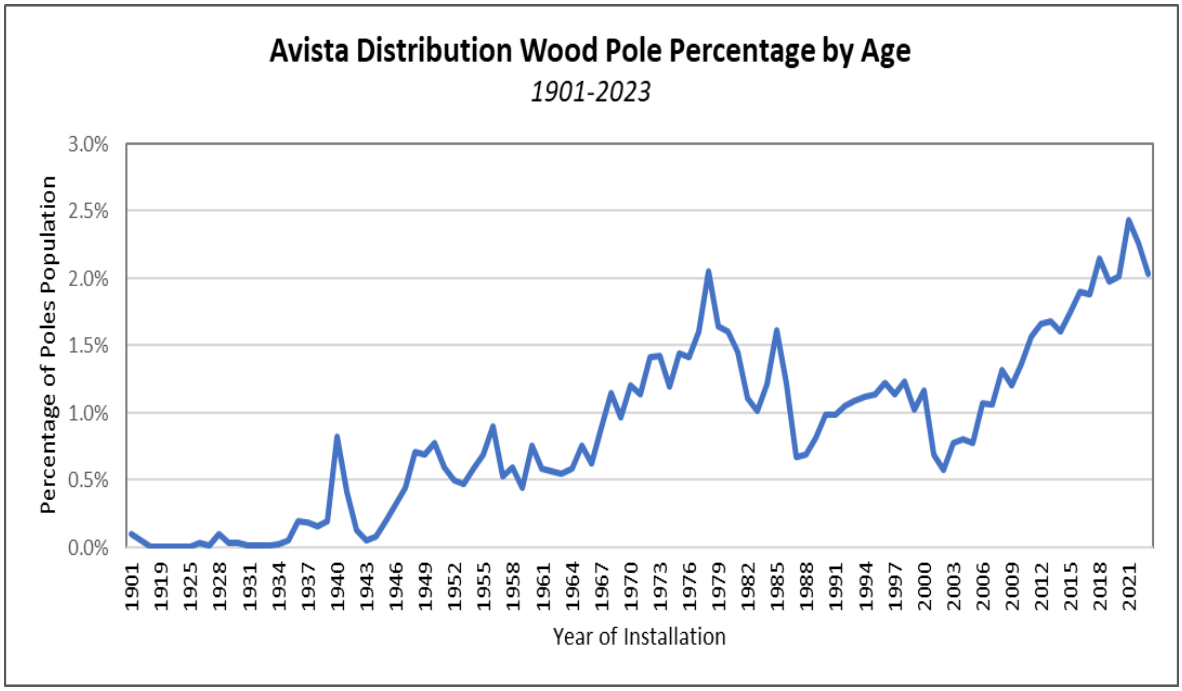


Figure 1: Avista Distribution Wood Pole Percentage by Age

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization.

The link below shows Avista's strategic goals (current at the time of finalizing this version of the business case.

Avista Strategic Goals

This investment replaces end of life assets before they fail, which reduces outages and improves safety and reliability. By delivering safe reliable electric service, we improve the lives of our customers by avoiding unnecessary interruptions in their daily lives. The Wood Pole Management Program most closely aligns with Avista's focus area "Our Customers" as it focuses on improving reliability and keeping rates affordable to our customers.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

The Outage Management Tool (OMT) is used to track asset condition and show trends of failure for specific equipment that should be targeted for replacement. This information is also used to track key program performance as shown in Table 1 below. The number of outage-type events has been reduced by 37% from 2009 to 2023. This reduction in outage events results in significant customer benefit. The reduction also demonstrates increased

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

reliability and safety along with a reduction in outages. The original goal for this program was to stay below the number of events averaged over 2005-2009 for WPM Related OMT events (1460). This goal will be re-evaluated by Asset Management in the future.

	WPM Goal Related Number of OMT Events	Actual WPM Goal Related OMT Events	Projected Poles for Follow-Up Work	Actual Poles Follow-Up Work
2009	1460	1118	11,400	11,548
2010	1460	799	11,400	12,010
2011	1460	804	11,400	10,461
2012	1460	817	11,400	14,530
2013	1460	628	11,400	10,763
2014	1460	727	11,400	10,588
2015	1460	863	11,400	12,018
2016	1460	579	11,400	13,244
2017	1460	714	11,400	12,996
2018	1460	632	11,400	11,532
2019	1460	623	11,400	10,902
2020	1460	577	11,400	8,694
2021	1460	731	13,116	11,404
2022	1460	706	13,116	10,000
2023	1460	701	13,116	11,775

Table 1: Outage event summary from OMT

The type of OMT events are broken down into more detail in Figure 2. Note there are significant improvements to some events, such as squirrels, reducing on average from 672 in 2009 to 325 events in 2023. This improvement has been realized by adding wildlife guards to the top of the transformer bushings to prevent squirrels from touching exposed power connections which can result in outages. Transformer events have been reduced by 50% and cut out/fuse related events are also down about 30% since WPM began due to the replacement of aged equipment. Approximately twelve years ago Avista moved to using fiberglass cross arms which is beginning to reduce the average annual number of pole top fires. This reduction should accelerate as Grid Hardening began replacing wood cross arms with fiberglass cross arms in high-risk WUI areas in the second half of 2019. As an indication of the effectiveness of this action, pole fires are down about 30%.

In 2017 the calculated cost to customers for a pole failure was $24,400 based on an average duration of 4.8 hours for 80 customers. The combined cost impact to customers in 2015 alone for those events was $2,265,600.

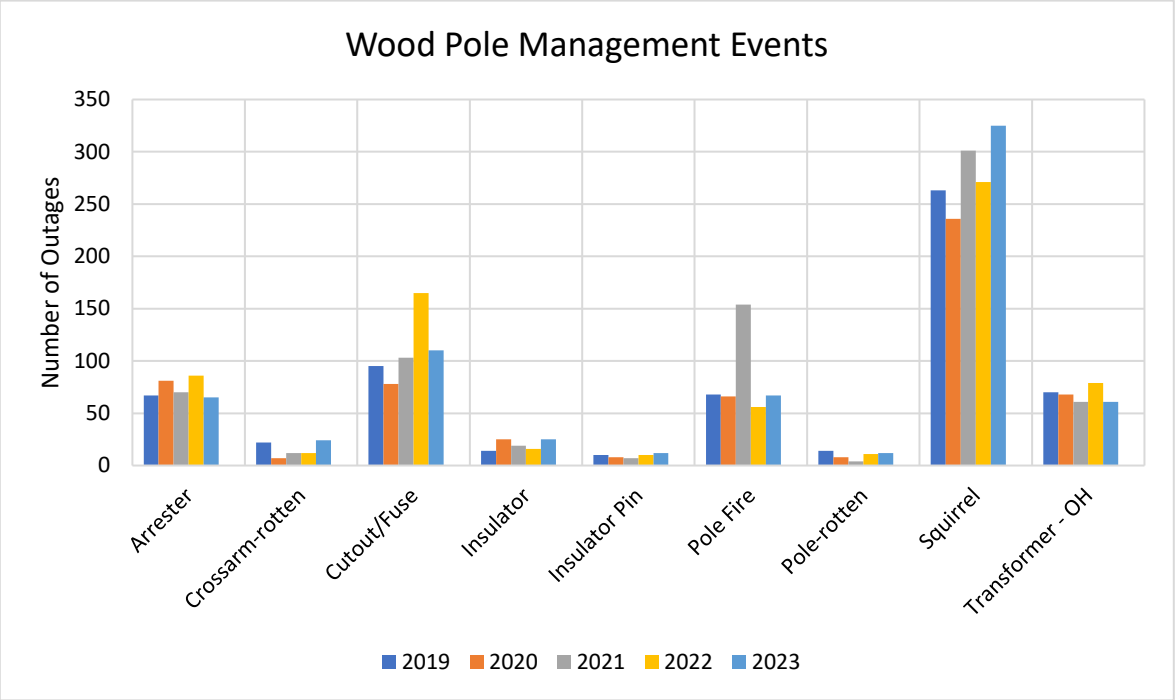


Figure 2: Break down of Wood Pole Management Impacted OMT events

Ultimately the impact of this Program can be associated with our Electric Systems Reliability metrics. The System Average Interruption Frequency Index (SAIFI) represents the average number of sustained interruptions per customer for the year across Avista's entire system. Avista reported a SAIFI score of .79 for the year 2022. The Asset Management group created Figure 3 below to show the impact of this Program to our overall SAIFI score. The predicted contribution is about 0.211, which has a significant impact on the customer, whereas the contribution to SAIFI would be 0.57. This means the customer would experience 0.36 more outages per year without WPM. Without WPM, the contribution to SAIFI would be 1.27 (hours).

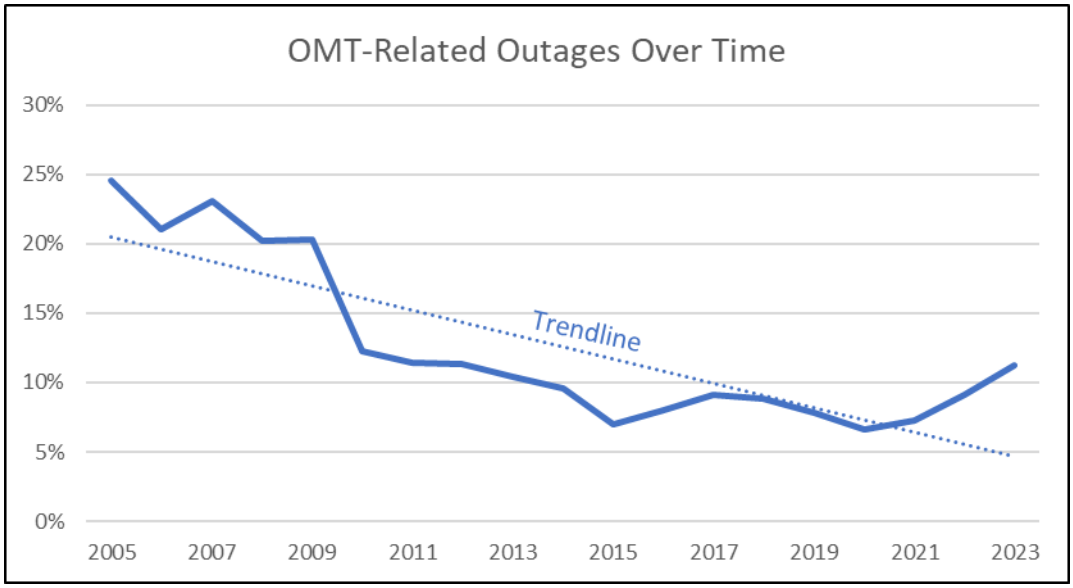


Figure 3:Wood Pole Management impact to SAIFI score

WPM is an ongoing cyclical program that proactively replaces assets identified for replacement during the inspection process. By replacing assets before they fail, outages are reduced, and replacement costs are reduced through planned versus emergency work. Investing in our infrastructure increases life-cycle performance and is cost-effective using unit-based pricing. Figure 4 below shows the significant improvement in "events per mile of feeder" resulting from this program before and after WPM work. The peak of events per mile shown in the graph is from 2011 when there were nearly .3 events per mile. The results after the program show performance as low as .1 events per mile of feeder, a significant improvement.

If funding were to be reduced, expected outages would increase. The team would then need to prioritize which components would be replaced and which would be left as run-to-fail. This would increase the likelihood that crews would need to visit the same pole later if a remaining component were to fail, thereby increasing operating expenses.

The program's documentation and analysis are in several published documents. The documents are the 2017 Wood Pole Management Program and Review, The Electric Distribution Infrastructure Plan June 2017, Structure Specific Distribution Feeder Management Plan, and the Wood Pole Management (Distribution) Inspection Cycle Analysis January 2021, which are located on the (\\c01m570) drive and available upon request.

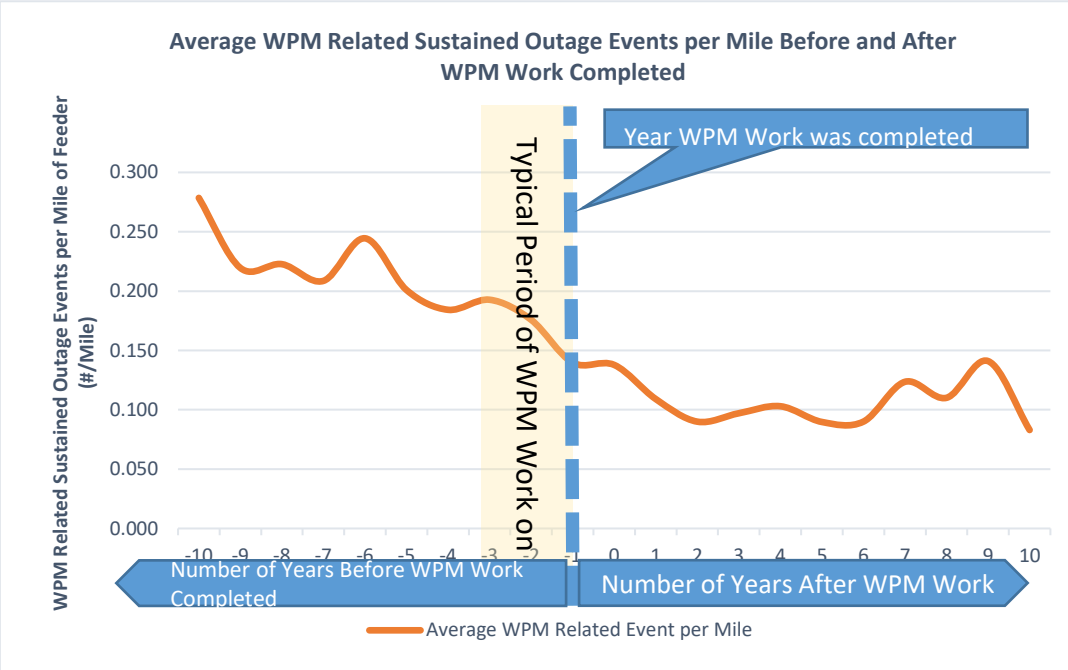


Figure 4: Sustainted outage events per mile before and after Wood Pole Management

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The proposed solution is a Wood Pole Management program with the goal of identifying defective overhead facilities in need of replacement before they fail to maintain our facilities in a safe, responsible, effective, and reliable manner. The proposed solution is to inspect and address poles on a 20-year cycle except for Grid Hardening feeders which are on a seventeen year cycle until approximately 2030.

The current twenty-year cycle delivers the best life cycle value for the funding level. More work on a shorter schedule would increase the cost of this program, less work would lead to increased failures and resulting outages.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits, or risk estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

This information/analysis is documented in the "2017 Wood Pole Management Program Review and Recommendations" located on the (\\c01m570) drive.

In summary, the Asset Management analysis recommended continuing with the twenty -year cycle for the Wood Pole Management Program. They did examine several different alternatives and some do provide a little more value, but they would potentially require very significant capital costs well beyond current budget levels.

The Wood Pole Management program supports our Safe & Reliable Infrastructure strategy. Specifically, Wood Pole Management strives to invest in our infrastructure to achieve optimum life-cycle performance safely, reliably, and at a fair price. The program meets the objective by providing the best customer internal rate of return that will fit within our Capital and Operations and Maintenance budget constraints.

2.3 Summarize in the table and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M	Quantified Direct Savings	$1,284,500	$1,284,500	$1,284,500	$1,284,500	$1,284,500

Between 2005-2009 the average number of OMT events related to Wood Pole Management was 1460 per year. Between 2018 and 2023 the average number of OMT events has been reduced to 734 per year. This is an average reduction of 726 OMT events per year related to WPM work. The average OMT event takes 3.5 hours to restore at a straight time cost of $500 per hour for a total of $1750 per event. Based on this information the annual labor to complete the restoration work is $1,284,500. This does not include the material or any overtime costs. It is anticipated that the 5-year average OMT event will continue to be reduced as feeders are completed and there are no funding or resource delays.

This program has no identifiable direct capital cost savings. This work is required by law or rule. The National Electrical Safety Code (NESC) is adopted as Washington Law under WAC296-45-045. Part 013C of this code describes the application, Part 121

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

defines the inspection interval, and Part 214A details documentation and correction of the pole inspection results.

2.4 Summarize in the table and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M	Indirect Savings	$13.2MM	$13.2MM	$13.2MM	$13.2MM	$13.2MM

Based on the ICE calculator (Interruption Cost Estimate) total hours per incident is 157.5 hours (# of customers impacted (45) * average outage time (3.5). The ICE is $116.15. Therefore, your indirect benefit per incident is $18,294. Wood Pole Management work avoids 726 OMT events per year on average therefore the indirect benefit is $13,281,444.

This program has no identifiable indirect capital cost savings. This work is required by law or rule. The National Electrical Safety Code (NESC) is adopted as Washington Law under WAC296-45-045. Part 013C of this code describes the application, Part 121 defines the inspection interval, and Part 214A details documentation and correction of the pole inspection results.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

For perspective, the industry average for inspecting and maintaining distribution assets is ten years. In 2021 Asset Management's "Wood Pole Management (Distribution) Inspect Cycle Analysis" compared the Avista utility peer group, shown below, which indicates that Avista is a more rural utility and therefore has far fewer customers per pole (approximately 1.5 vs. 10), making it economically feasible for the peer group to inspect poles more frequently as compared to what makes sense for Avista. The ten-year cycle delivers a better rate of return, but any reduction in cycle time requires an increase in expenses to pay for the increased number of poles inspected each year, and a corresponding increase in requirements for capital replacements. Asset Management and Distribution Engineering monitor system reliability to determine if adjustments in the scope of work are needed in the future. They also determine the funding level required to make those adjustments so Asset Maintenance can document those changes as a new alternative in the Business Case for funding approval by the Capital Planning Group. If the Capital Planning Group does not approve a new

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allow current employees to focus on higher priority work.

alternative, it is not incorporated until funding is approved. Therefore the recommended solution in 2.1 is the preferred alternative at this time.

DISTRIBUTION – WOOD POLE

COMPANY	CUSTOMERS/POLE	INSPECTION	INSPECTION CYCLE (IN YEAR)
Avista	1.54	Contractor	20
BC Hydro	2.21	Contractor	10
ENMAX	10.65	Contractor	10
PGE	4.15	Contractor	10
PSE	3.67	Contractor	10
SMUD	4.80	Internal	5
SRP	9.33	Both	10

Alternative 1:

The five-year cycle provided the highest CIRR but this alternative would quadruple the capital and expense costs to execute the plan. In 2024 the cost would be $69,368,000 for capital and $3,400,000 for O&M. The risk of choosing this alternative isn't feasible given the company's many other infrastructure needs in addition to the cost impacts to our customers

Alternative 2:

The ten-year cycle is the industry average for inspection cycle times but this alternative would double the costs to execute. The 2024 capital cost would be $34,684,000 and the O&M cost would be $1,700,000. The risk of choosing this alternative isn't feasible given the company's many other infrastructure needs which would increase risks in other areas of the company. There are also the cost impacts to our customers.

Alternative 3:

There is no feasible third alternative.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Success is measured by staying on cycle and the improvement in the metrics described In section 1.5 of this business case. We track the annual and historic cycle performance on a monthly basis in the Wood Pole Management One Pager.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 168 of 535

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

WPM is an ongoing program. The work is the continuous process of inspecting Avista's poles by feeder.Once a feeder is inspected it will be re-inspected twenty years from completion. Each feeder represents a project within the program. There are several phases to complete each feeder including inspecting, designing, and the capital follow-up work. We currently utilize in-house and contract crews year-round to complete this work. The completed work is transferred to plant on a monthly basis.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Distribution Engineering provides ongoing analysis of distribution asset conditions. This analysis is used to direct the WPM work that includes inspecting a maintaining Avista's poles, hardware, and equipment on a twenty-year cycle. The twenty-year cycle is documented in the 2017 Wood Pole Management Review and Recommendations. The operating guidelines in the recommended solution are documented in the DFMP-Distribution Feeder Management Plan-Design Criteria Manual-Applicable to Wood Pole Management. The governance process is a collaborative process that includes leadership from Distribution Engineering, Director of Operations, Asset Maintenance Manager, and WPM Program Manager. Status updates on progress towards yearly goals are documented and updated on the monthly Wood Pole Management one-pager**.**

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 169 of 535

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Wood Pole Management Business Case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Mark S. Gabert	Date:	5/8/2024
Print Name:	Mark S. Gabert		
Title:	WPM Program Manager		
Role:	Business Case Owner		

Signature:	PAUL Good	Date:	5/15/2024
Print Name:	Paul Good		
Title:	Director Of Operations		
Role:	Business Case Sponsor		

Signature:	Heather Webster	Date:	5/8/2024
Print Name:	Heather Webster		
Title:	Asset Maintenance Manager		
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 170 of 535

Ambient-Adjusted Transmission Line Ratings

EXECUTIVE SUMMARY

The Company is subject to the authority of the Federal Energy Regulatory Commission ("FERC"). FERC issued Order 881 was issued December 16, 2021 giving a three+ year implementation period for transmission providers to implement and use ambient-adjusted ratings for transmission lines used in providing transmission service by July 2025. This business case provides for engineering and deployment of new applications and technology as required to address those requirements. The Company will need to provide upgrades to existing electric control center computing systems to meet the performance requirements of FERC Order 881.

The total project costs under this new business case are estimated to be **$2.6M over three years, 2023, 2024, and 2025**. The FERC Order 881 capital project costs under the SCADA business case expended already in 2023 through Q2 2024 are to be moved out from under SCADA's Business Case to this new FERC ORDER 881 Business Case. The estimated capital project costs for the upcoming five years are **$1.2M** in 2025 only. The 2025 amount requested is based upon a second five-year term GE Dynamic Line Rating Forecasting application license purchase, a calculation engine to determine updated scheduling path ratings, an OATI application license purchase, estimated labor hours for engineering FERC Order 881 required equipment rating methodologies, and labor to apply the updated equipment limits and associated relay settings.

There is compliance risk if this business case is not adequately funded as the effective date for FERC Order 881 is July 12, 2025. The software applications, newly engineered equipment ratings, and new relay settings provide the capabilities required to achieve compliance with FERC Order 881. Mandatory compliance is necessary, as a violation of the Tariff and FERC rules and regulations may subject the Company to incur compliance penalties of up to $1 million per day (Energy Policy Act of 2005). Failure to provide design and construction funding for these projects would be inconsistent with the Ethical Decision Making policy under the Company's Code of Conduct.

The benefits to all electric customers and to the Business for the necessary expenditure of these funds is the ability to operate Avista's electric systems in a more efficient, accurate, safe, reliable, and compliant manner gaining as much capacity as possible out of Avista existing transmission assets. Financial risk is also reduced to the Business and all customers by avoiding any potential financial penalties associated with non-compliance.

VERSION HISTORY

Version	Author	Description	Date
0.5	Craig N Figart David Nichols	First version of 2024 business case – removed from SCADA BC	05.03.2024
1.0	Steve Carrozzo	BCRT Member Review	05.03.2024
1.1	David Nichols	Corrected costs to reflect calculation engine and OATI software	05.06.2024

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 171 of 535

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	**$1.2M**	**$2.6M**
2026	**$0**	**$0**
2027	**$0**	**$0**
2028	**$0**	**$0**
2029	**$0**	**$0**

Project Life Span	***5 years***
Requesting Organization/Department	FERC Policy & Transmission Services
Business Case Owner | Sponsor	Kenny Dillon | Michael Magruder
Sponsor Organization/Department	Energy Delivery
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. **BUSINESS PROBLEM -** *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

This business case provides for engineering and deployment of new applications and technology as required to address FERC Order 881 regulatory and business requirements. FERC Order 881, issued on December 16, 2021, requires transmission providers to implement and use ambient-adjusted ratings (AARs) for transmission lines used in providing transmission service by 2025. These AARs ensure that line ratings align closely with actual operating conditions. The goal is to more efficiently utilize the transmission grid and lower costs for consumers by improving the accuracy and transparency of line ratings. Transmission providers were required to submit compliance filings within 120 days of the effective date of the rule, and all requirements in this rule were to be implemented no more than three years from the compliance filing due date.

Pursuant to the Order, the Company submitted Attachment M to its Open Access Transmission Tariff which identifies Company implementation of the Order by July 12, 2025.

1.2 Discuss the major drivers of the business case.

This business case is crucial in a key aspect of Avista's Perform strategy to, "…affordably operate and maintain safe, clean, reliable generation and energy delivery infrastructure", and is the major driver of the business case. It is essential in providing sufficient control center technology tools, situational awareness, and monitor/control capabilities to achieve reliable energy service. Dynamic Line Rating application software to be deployed per FERC Order 881 will allow Avista to safely and reliably operate its transmission assets to their maximum capacity given additional variable considerations such as time of day, wind speed, temperature, etc.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 172 of 535

The other driver centers around achieving state financial objectives by minimizing financial risks to our Customers and to the Business by adhering to FERC Order regulatory requirements.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Failure by the Company to provide design and construction funding for these projects would be a violation of the Tariff and FERC rules and regulations pursuant to which the Company could incur compliance penalties of up to $1 million per day. Failure to provide design and construction funding for these projects would be inconsistent with the *Ethical Decision Making* policy under the Company's *Code of Conduct*.

New Dynamic Line Ratings and other software and associated engineering is required to provide the capabilities required to achieve compliance with FERC Order 881. The expenditure of these funds is necessary to operate Avista's electric transmission systems in a safe, reliable, and compliant manner.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

Business Case investment upholds the Company's Ethical Decision Making policy under the Code of Conduct The proposed funding of this Business Case also aligns with the following strategic vision, goals, objectives, and mission statement of Avista as follows:

Avista's Focus:

- Our Customers: Avista's electric customers are benefited by the safe and reliable operation of our energy management systems in the control and protection of our electric transmission infrastructure assets serving all of our electric customers, as well as maximizing the operating capacity of our existing assets to minimize or defer future expenses. This effort also allows mechanisms to arrange maximized transmission sales on our system to offset other system costs.
- Our People: Avista's employees benefit from implementing and operating the latest control center technologies for Dynamic Line Ratings applications and increased morale in the opportunity to participate in the installation, maintenance, and ownership of these systems.
- Perform: Control Center technologies supported by this Business Case are required to affordably operate and maintain safe, clean, reliable generation and energy delivery infrastructure. This effort provides for operation of our transmission system at its full capacity based on ambient conditions, often resulting in enhanced capacity overall.

Avista's Values:

- Trustworthy: By funding the secure operation of Avista's electric energy management systems, customer trust is maintained when electric service is extended affordably by deferment of transmission system upgrades assuming better maximization of transmission system capacity utilization.
- Collaborative: Avista's control center staff also collaborate with other utility experts in deploying the latest and company standard technologies to align in strategically meeting FERC Order 881 requirements. For example, we have been in contact with Arizona Public Service regarding new GE application software and line ratings methodologies.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 173 of 535

It is essential in providing sufficient control center technology tools, situational awareness, and monitor/control capabilities to achieve reliable energy service.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

FERC approved a final rule that will more efficiently utilize our nation's transmission grid and help lower costs for consumers by improving both the accuracy and transparency of transmission line ratings.

Transmission line ratings represent the maximum transfer capability of each transmission line and can change based on weather conditions. This final rule requires all transmission providers, both inside and outside of organized markets, to use ambient-adjusted ratings as the basis for evaluating near-term transmission service to increase the accuracy of near-term line ratings. Typically, line ratings are based on conservative assumptions about worst case, long-term air temperature and other weather conditions that can lead to underutilization of our transmission grid.

"If we are going to meet the needs of the grid of the future while keeping customer rates just and reasonable and maintaining grid reliability, we need to squeeze everything out of our existing grid," Chairman Glick said. "Today's final rule is huge step forward in making more efficient use of our transmission system and saving money for customers. But our work isn't done. I look forward to working with my colleagues to explore the adoption of dynamic line ratings to further increase the efficiency of our grid."

While the final rule does not mandate the adoption of dynamic line ratings – ratings that account for other factors like wind speed – the rule does require that organized market operators establish and maintain systems and procedures necessary to allow transmission owners that would like to use dynamic line ratings the ability to do so. The rule acknowledges that dynamic line ratings may deliver incremental benefits and announces that the Commission is opening a proceeding in AD22-5-000 to continue to build the record and explore the potential for further action on dynamic line ratings.

Transmission providers must submit compliance filings within 120 days of the effective date of the rule. All requirements in this rule must be implemented no more than three years from the compliance filing due date.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The proposed Business Case solution addresses FERC Order 881 regulatory and business requirements to provide for ambient-adjusted ratings to Avista transmission lines, as well as for deployment of new applications and technology as required.

Avista's Engineering Departments will provide engineering for the development of new tables of line ratings based on the range of ambient conditions specified in the Order. These expanded rating tables will be fed into the new GE Dynamic Line Rating software in SCADA to be used in calculations

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 174 of 535

for system power flow limits. The GE software will also incorporate ambient temperature conditions to select the appropriate AARs for the next 240 hours as required by the Order. This work will be repeated at least hourly. These AARs will be supplied to the Reliability Coordinator, RC West, for incorporation into the Western Interconnection model and associated power flow studies via an OATI-hosted application to be purchased under this business case as well. This effort is expected to cost $0.5M from 2023 to Q2 2024, plus $0.9M for the remainder of 2024, plus $0.6M in 2025, for a total SCADA-related cost of $2.0M.

System topology, generation dispatch, and area load will be then fed into a calculation engine, such as PowerWorld Cruncher or other in-house developed software, to determine total transfer capability (TTC) for each of our transmission scheduling paths for the next 240 hours. This effort is expected to have a $50k up-front software cost. To implement, three in-house employees working for approximately six months is estimated at 800 labor hours (½ year) x 3 employees x $180 loaded labor rate = $432k in labor for 2025. This amounts to a cost of $0.48M in 2025.

Finally, an application such as OATI's webLinerR, or other in-house developed resource, will post the new TTC values to the Open-Access Same-Time Information System (OASIS) for public access, as required by the Order. This system will also archive the hourly AARs as required by the Order. The up-front software cost for this effort is expected to be $0.12M in 2025.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how [2]are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[3]

As a Mandatory and Compliance driven project, a violation of the Tariff and FERC rules and regulations pursuant to which the Company could incur compliance penalties of up to $1 million per day. Meeting Avista's obligations under the Federal Power Act would be consistent with the Ethical Decision Making policy under the Company's Code of Conduct and remove the risk compliance penalties.

With possible enhanced transmission capacity as a side benefit of complying with the Order, a hypothetical 10 MW increase in transmission sales across our system would result in $32.98/kW-yr * 10,000kW = $329,800 per year in revenue. Transmission service revenue is accounted for in FERC account 456, which flows through the ERM, and ultimately offsets retail customer rate.

[3] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 175 of 535

2.3 Summarize in the table, and describe below the [4][OBJ] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital						
O&M						

There are no known direct offset or savings associated with capital investments in this Business Case.

2.4 Summarize in the table, and describe below the [5]INDIRECT offsets[6] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no indirect offset or savings associated with capital investments in this Business Case. There may be enhanced line capacity due to use of Dynamic Line Ratings or AARs during certain weather conditions, typically cold weather, when our system load is high. This would provide added margin for reliability operations. However, the indirect cost savings of deferring new line construction are not readily quantifiable.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Thus far, there is only one capital project expected to be included under this business case. It includes the following components:

- Purchase of 5yr term licensing for GE's new Dynamic Line Ratings (DLR) application software
- GE Statement of Work to back-port DLR code to Avista's current EMS application version
- Purchase of 5yr term licensing for GE's new DLR Forecasting application software

[4] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[6] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

- Purchase of licensing for use of OATI's new application software to receive, store, and transmit forecasted equipment ratings to the Reliability Coordinator, RC West.
- Engineering labor to develop new line and equipment ratings.
- PCM tech labor to deploy new relay settings required by newly rated equipment
- Implementation of a TTC calculation engine using PowerWorld Cruncher or other in-house application

Alternative 1:

The only portions for alternative considerations in this project are in relation to application software/vendor selections. In this case, Avista's package deal purchase of five-year term licensing for EMS software included GE's new Dynamic Line Ratings as part of the coinciding purchase of GE Advanced Distribution Management term licensing. So there was no opportunity nor real reason to consider other vendors for this solution. Otherwise, as we look to subsequent software purchases, i.e. OATI, we can research other vendor options at that time.

As to labor alternatives, there really are no options.

Alternative 2:

There is certainly a "No Funding" option available for this Business Case. However, failure by the Company to provide design and construction funding for this project would be a violation of the Tariff and FERC rules and regulations pursuant to which the Company could incur compliance penalties of up to $1 million per day. Failure to provide design and construction funding for this project would be inconsistent with the Ethical Decision Making policy under the Company's Code of Conduct.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Success can be measured with implementation of the work described herein and the associated applications by tracking the posted values of AARs and TTCs over time. An internal audit of the new rating methodology on a sample of lines and posted values can demonstrate project success.

Success will be measured upon Avista successfully passing future audits for compliance with FERC Order 881.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

This business case is comprised of a single FERC Order 881 capital project that was opened in late 2023. The project will be transferred to plant upon FERC Order 881's effective date of July 2025, with trailing go-live support costs through the subsequent months in 2025.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 177 of 535

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The steering committee/advisory group for initial and ongoing vetting and department prioritization process includes the members from the entire SCADA team as needed, but more notably the following:

- Director of System Operations and Planning
- Sr Manager of FERC Policy and Transmission Services
- Manager, SCADA/Energy Management Systems
- Transmission Contracts Engineer – acting Project Manager

Individual projects are governed by the Transmission Services member assigned to the project as project lead who is tasked with scheduling and coordinating all the work associated with the project.

Project oversight is provided by the Sr manager of FERC Policy and Transmission Services and also by the SCADA/EMS manager, but also to the assigned project lead.

The steering committee provides governance and oversight of this business case. The Project Manager has periodic check-in meetings scheduled with multiple groups including SCADA, Substation Engineering, Protection Engineering, System Planning, PCM Shop, etc., during which to track progress of this large capital project that comprises the total business case.

Decision-making, prioritization, and change requests at the individual capital project level are taken care of within the Transmission Services and SCADA groups under manager supervision.

Any need for substantial change requests to capital projects that would deviate from the original Capital Project Request (CPR) are documented and submitted to Project Accounting as a revised CPR. Change requests and resulting decisions that lead to significant changes in project scope are documented in the project charter documentation and revisions to the original version and stored in SCADA's SharePoint site and/or the “FERC Order 881 Implementation” Teams site.

Prioritization for each individual project and/or aspect of a project within this business case is performed by the Transmission Services. If the sum total of all aspects of the FERC Order 881 capital project is expected to exceed the approved Business Case funding, then a Business Case Change Request must be approved by the Steering Committee and submitted to Project Accounting.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *FERC ORDER 881* Business Case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Michael A Magruder	Date:	5/6/2024
Print Name:	Michael A. Magruder		
Title:	Director, System Operations & Planning		
Role:	Business Case Sponsor		

Signature:	Kenneth L Dillon	Date:	5/6/2024
Print Name:	Kenny Dillon		
Title:	Sr Mgr FERC Policy & Transmission Services		
Role:	Business Case Owner		

Signature:		Date:	
Print Name:	Craig N. Figart		
Title:	Mgr Energy Mgmt Systems		
Role:	Steering/Advisory Committee Review		

EXECUTIVE SUMMARY

Avista is a joint owner in the 500kV Colstrip Transmission System and party to the Colstrip Project Transmission Agreement ("Agreement"). Avista and the joint owners are obligated to fund their respective shares of the Colstrip Transmission System construction and maintenance budgets, as approved by the Colstrip Transmission Committee, which consists of representatives of each of the parties to the Agreement. The Colstrip Transmission Committee reviews and approves, on an annual basis, the capital and O&M expense program proposed by NorthWestern Energy ("NWE") (the designated Transmission Operator under the Agreement). Pursuant to Section 22 of the Agreement, Avista provides annual input to, and approval for, the Colstrip Transmission System capital and O&M expense program commensurate with its ownership shares in the Colstrip Transmission System.[1] Failure to fund Colstrip Transmission expenditures would be a breach of the Company's obligations under the Agreement.

In conjunction with the Company's ownership interest in Colstrip Project Units 3 and 4, the Colstrip Transmission System has benefited the Company's retail native load customers since the early 1980's. To continue to reliably integrate the Company's Colstrip Project resources to native load and to meet applicable NERC transmission planning and operational reliability standards, the Colstrip Transmission System must be maintained. 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. At such time as the Company may no longer attain output from Colstrip Project Units 3 and 4, the Company's ownership in the Colstrip Transmission System may facilitate access to new resource acquisition opportunities in the state of Montana. In recent years there has been a tremendous increase in the demand for long-term transmission rights, including on the Colstrip Transmission System. Maintaining ownership of Avista's portion of the Colstrip Transmission System will enable Avista to maintain resource adequacy and comply with applicable clean enery mandates, while simultanesouly selling any excess transmission capacity to benefit our retail customers.

Colstrip Transmission program capital expenditures have averaged $350,000 over the ten-year period from 2012-2021. Each year NWE develops a five-year capital plan for necessary capital improvements, renewals and replacements for the Colstrip Transmission System; future program requirements can fluctuate year-over-year and the new five-year average is expected to be roughly double the previous five-year average due to the more costly projects[2] planned during 2025 and 2026. The 5-year average is projected to decrease upon the completion of these capital intensive projects.

[1] Avista owns a 10.2% share in the Colstrip-Broadview segment and a 12.1% share in the Broadview-Townsend segment.

[2] There are two major projects in 2025 and 2026 to complete a series cap bank replacement and purchase a new spare circuit switcher for the CTS. These two projects are forecasted to cost approximately $21 million total, and Avista will only be responsible for it's allocated share according to the Company's ownership percentage of the CTS (approximately $2 million).

VERSION HISTORY

Version	Author	Description	Date
2.0	*Jeff Schlect*	*Initial narrative drafted from pre-existing approved case*	*7/28/2020*
2.1	*Jeff Schlect*	*Business Case refresh*	*5/26/2022*
3.0	*Randy Gnaedinger*	*Business Case refresh to new template*	*10/11/2023*
4.0	*Garrett Brown*	*Business Case refresh*	*4/25/2024*
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements Steve Carrozzo*	*5/1/2024*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	**$1,457,000**	**$1,457,000**
2026	**$854,000**	**$854,000**
2027	**$412,000**	**$412,000**
2028	**$363,000**	**$363,000**
2029	**$450,000**	**$450,000**

Project Life Span	*Ongoing Annual Program*
Requesting Organization/Department	Energy Delivery / Transmission Services
Business Case Owner | Sponsor	Kenneth Dillon | Josh DiLuciano / Mike Magruder
Sponsor Organization/Department	Energy Delivery / Transmission Services
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

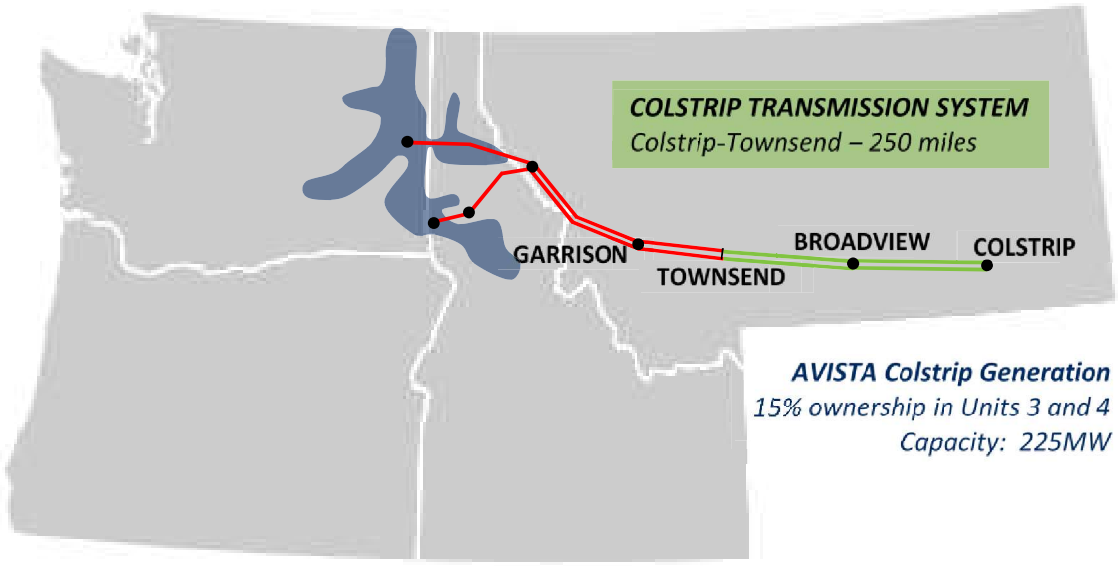
Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 181 of 535

1. BUSINESS PROBLEM

As part of the construction and integration of Colstrip Units 3 and 4 in the early 1980s for the benefit of the Company's native load retail customers, the Colstrip project participants constructed the Colstrip Transmission System, approximately 250 miles of double circuit 500kV transmission facilities extending from the Colstrip Project westward to the Broadview 500kV Substation and the Townsend point of interconnection between the Colstrip Transmission System and the Bonneville Power Administration's Eastern Intertie 500kV facilities.



Avista owns a 15% share of Colstrip Units 3 and 4 (approximately 225MW). Reliable operation of the Colstrip Transmission System is necessary to transfer Colstrip output and prospective renewables to the respective systems of each joint project owner, including Avista (other project owners are: NorthWestern Energy, PacifiCorp, Portland General Electric and Puget Sound Energy). Avista and the other joint project owners are party to the Colstrip Project Transmission Agreement which, among other things, obligates Avista to fund its commensurate share of all construction and maintenance expenses for the ongoing operation, maintenance, renewal and replacement of the jointly owned Colstrip Transmission System facilities.

Examples of recent expenditures in the Colstrip Transmission System are noted in Section 2.2 below.

As NERC transmission planning and operational reliability standards[3] evolve, compliance with both operational and planning standards may require replacement of, or upgrades to, Colstrip Transmission System facilities.

[3] Among its other provisions, the U.S. Energy Policy Act of 2005 provided for the establishment of mandatory reliability standards and authorized the Federal Energy Regulatory Commission (FERC) to assess penalties of up to $1 million per day per violation for non-compliance with these standards and other FERC regulations. FERC has certified the North American Electric Reliability Organization (NERC) to establish and enforce these reliability standards. The Company has a statutory obligation to plan, improve, upgrade, and operate its transmission system, including the Colstrip Transmission System, to maintain compliance with these standards and is required to self-certify its compliance with these standards on an annual basis.

1.1 What is the current or potential problem that is being addressed?

Pursuant to the Agreement, the Company must fund its applicable ownership share of capital improvements to the jointly owned Colstrip Transmission System.

1.2 Discuss the major drivers of the business case.

The Company's capital investment in the Colstrip Transmission System is driven by its contractual obligations under the Agreement (Mandatory & Compliance). Related drivers include Asset Condition and Failed Plant & Operations.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Failure to fund its allocated share of costs under the Agreement will put the Company into default and would eliminate the Company's right to use the Colstrip Transmission System to integrate its resources for service to its bundled retail native load customers.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

Program investment upholds the Company's Code of Conduct and is consistent with its lasting values. Colstrip Transmission System investment maintains the Company's ability to integrate its Colstrip generation assets for service to bundled retail native load customers and provides the Company with a future transmission alternative to integrate prospective renewable resources located in Montana.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[4]

Not applicable

[4] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The Company must fund its allocated share of capital improvements under the Colstrip Transmission Agreement.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[5]

Not applicable

2.3 Summarize in the table, and describe below the DIRECT offsets[6] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

Not applicable

2.4 Summarize in the table, and describe below the INDIRECT offsets[7] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

Not applicable

[5] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[6] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[7] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1:

Not applicable (only alternative is to not fund and default on contract)

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Not applicable (only alternative is to not fund and default on contract)

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Capital amounts are used for improvements, renewals and replacements of Colstrip Transmission System assets. Examples of recent expenditures in the Colstrip Transmission System include:

Past Projects:

- 500kV Broadview Cap Bank Battery
- 500kV Colstrip Ground Switch
- Comm Snowcat

Ongoing and Future Projects:

- Broadview-Colstrip series cap bank replacement (multi-year project)
- Microwave communications equipment upgrade (multi-year project)
- Broadview spare circuit switcher purchase (multi-year project)

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Pursuant to Section 22 of the Agreement, Avista provides annual input to, and approval for, the Colstrip Transmission System capital and O&M expense program commensurate with its ownership shares in the Colstrip Transmission System. The Colstrip Transmission Committee, of which the Company is a member, meets periodically to review, and provide recommendations for, the annual capital program administered by NWE. The Colstrip Transmission Committee provides approval for each year's capital program.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 185 of 535

Also pursuant to Section 22 of the Agreement, the Colstrip Transmission Committee is established to facilitate cooperation, interchange of information and efficient management of the Colstrip Transmission System. The Colstrip Transmission Committee consists of five members, each designated by one of the parties to the Agreement. Each committee member has the right to vote their party's ownership share in the Colstrip Transmission System. Section 22(f) of the Agreement outlines all matters that shall be submitted to the committee by NWE for approval, including Colstrip Transmission System construction and operating budgets.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Colstrip Transmission Business Case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Kenneth L Dillon Digitally signed by Kenneth L Dillon Date: 2024.05.01 15:35:34 -07'00'	Date:	5-1-2024
Print Name:	Kenneth Dillon		
Title:	Senior Manager, FERC Policy and Transmission Services		
Role:	Business Case Owner		

Signature:	Michael A. Magruder Digitally signed by Michael A. Magruder Date: 2024.05.02 08:25:24 -07'00'	Date:	5-2-2024
Print Name:	Mike Magruder		
Title:	Director, Transmission Operations and System Planning		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 186 of 535

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Electric Storm

EXECUTIVE SUMMARY

The Electric Storm Business Case is focused on restoring Avista's transmission, substation, communications, and distribution systems (damaged plant) into serviceable condition during a weather storm event or other natural disaster where assets are damaged. These storm events are random and often occur with short notice. This business case is to fund a rapid response to unexpected damages and outages, so customer outages are minimized. The business case provides funds for replacing poles, cross arms, conductor, transformers, and all other defined retirement units damaged during weather storm events. The damage can be due to high winds, heavy ice and snow loads, lightning strikes, flooding, or wildfires as an example. The importance of quickly replacing damaged facilities is vital to providing reliable service to our customers. This impacts customers in WA and ID.

The annual budget amount is determined based on the historical average rate of capital restoration work including restoration activity related to major event days (MEDs) of relativity minor restoration impact. Request excludes costs related to very large MEDs. If not funded, the work will still occur as needed for outages caused by weather storm events or other natural disasters and would be absorbed through other business cases.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Joe Wright*	*Initial draft of original business case*	*12/12/23*

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 187 of 535

DocuSign Envelope ID: B852F7EA-84B2-437C-8164-70D90409E5D4

BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements*	

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$5,000,000**	**$5,000,000**
2025	**$5,000,000**	**$5,000,000**
2026	**$5,000,000**	**$5,000,000**
2027	**$5,000,000**	**$5,000,000**
2028	**$5,000,000**	**$5,000,000**

Project Life Span	*Annual Program*
Requesting Organization/Department	Operations
Business Case Owner | Sponsor	Paul Good | Josh DiLuciano
Sponsor Organization/Department	Operations
Phase	Execution
Category	Program
Driver	Failed Plant & Operations

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 188 of 535

DocuSign Envelope ID: B852F7EA-84B2-437C-8164-70D90409E5D4

1. **BUSINESS PROBLEM -** *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

The Electric Storm Business Case (BC) is focused on restoring Avista's transmission, substation, communications, and distribution systems (damaged plant) into serviceable condition during a weather storm event or other natural disasters where assets are damaged. These events are random and often occur with short notice. This business case funds a rapid response to unexpected damages, so customer outages are minimized. The business case provides funds for replacing poles, cross arms, conductor, transformers, and other defined retirement units damaged during storm events. The damage can be due to high winds, heavy ice and snow loads, lightning strikes, flooding, or wildfires. The importance of quickly replacing damaged facilities is vital to providing reliable service to our customers.

1.2 Discuss the major drivers of the business case.

The primary driver for the Electric Storm BC is Failed Plant and Operations. The work is a key component to minimizing customer outage times and contributes to Avista's reliability indices like System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI). The secondary driver for this business case is Customer Service Quality and Reliability

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The importance of quickly replacing damaged facilities is vital to providing reliable service to our customers. The Electric Storm BC is to fund a rapid response to unexpected damages and outages, so customer outages are minimized. If this business case is not funded the costs to restoring power to our customers will be absorbed by another business case. The needed work will continue to occur.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

The Electric Storm business case aligns with the company's strategic goal of Safe and Reliable Infrastructure. The work is a key component to minimizing customer outage times and thus contributes to Avista's reliability indices like SAIFI and CAIDI.

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1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

N/A

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The Electric Storm Business Case (BC) is focused on restoring Avista's transmission, substation, communications, and distribution systems (damaged plant) into serviceable condition during a weather storm event or other natural disasters where assets are damaged. These events are random and often occur with short notice. This business case funds a rapid response to unexpected damages, so customer outages are minimized. The business case provides funds for replacing poles, cross arms, conductor, transformers, and other defined retirement units damaged during storm events.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

The annual budget amount is determined based on the historical average rate of capital restoration work.

Figure 1 shows the historical costs (2017-2022) for the distribution/transmission storm business case and YTD 2023 expenses through October. From 2017-2022, the average annual cost for capital storm response was $8.6 million dollars, with a range of $3.6MM (2018) to $14.6MM (2021). There were 7 MEDs in 2020 and 4 in 2021. The majority of the MED costs in 2021, however, occurred

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.
[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

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in January, one $7.2MM storm. Consequently, 2020 results were excluded and 2021 results were adjusted downward to exclude the particularly large January storm for determining the proposed funding level. The average spend for 2017-2019/2021-2022 was $5.4MM. This includes some MED activity of comparatively minor restoration impact during these years. Proposed funding for 2024-2028 is $5M per year. Further funding for significant MEDs will be requested as needed.

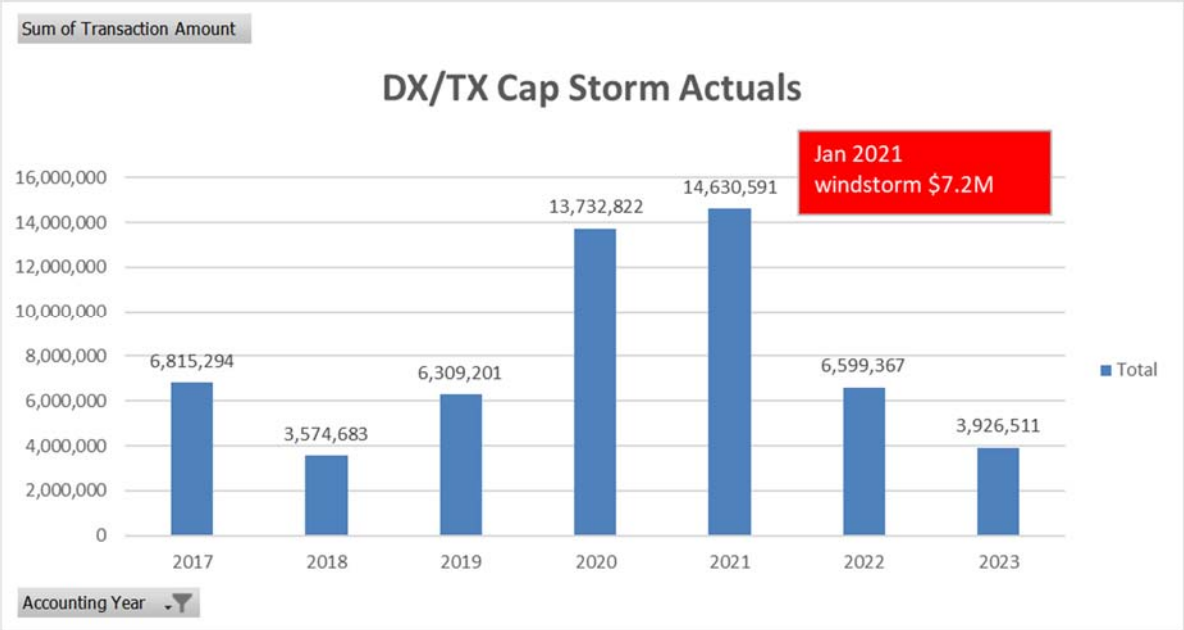

Figure 1: Storm Historical Costs

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no offsets to O&M. There is no identified direct savings related to this business case. This business case is completed to replace failed equipment due to extreme weather events.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

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2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no offsets to O&M.

Current RCW standards obligate us to perform repair work following storm damage. Therefore, an amount of capital is earmarked for a normal year of weather events.

Although there are no financial offsets, an ICE (Interruption Cost Estimate) may be calculated for determining an avoided indirect cost for having this program.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

The alternative to this business case request is not funding. The costs associated with repairing damages as a result of a weather storm event or a natural disaster would be covered through a different business case. Damages from these events must be repaired, regardless of funding.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

The primary measure that will be used to determine success is outage duration including other reliability measures such as Avista's reliability indices like SAIFI and CAIDI. These measures will demonstrate the impact of the work charged to this business case.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

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2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Weather storm events or natural disasters are a continuous risk. Work will occur as needed as a result of damaged facilities related to these events. Many times, multiple events may occur within one year in different office areas. Past data shows there has not been a year where a storm has not happened. Since this is often emergency work, assets become used and useful and transferred to plant immediately.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The Electric Storm work is overseen by the local area operations engineers and area construction managers. The work is unplanned and non-specific in nature but occurs regularly. In the event of larger scale storms or natural disasters, like the historical storm event in November 2015, a formal Incident Command System (ICS) is created to manage the resources needed to respond. Other large events are managed through an emergency operating plan (EOP) with the Director of Operations.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 193 of 535

DocuSign Envelope ID: B852F7EA-84B2-437C-8164-70D90409E5D4

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Electric Storm and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Paul Good 8ADE2AA1AB5C4A9...	Date:	Dec-15-2023 | 12:28 PM PST
Print Name:	Paul Good		
Title:	Director of Electric Operations		
Role:	Business Case Owner		

Signature:	DocuSigned by: Josh DiLuciano A3C71874F6564DB...	Date:	Dec-15-2023 | 8:35 AM PST
Print Name:	Joshua DiLuciano		
Title:	VP Energy Delivery		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 194 of 535

EXECUTIVE SUMMARY

This business case provides for replacement of existing technology, as well as for deployment of new applications and technology as required to address expanding regulatory and business requirements. This program (Supervisory Control and Data Acquisition - System Operations Office and Backup Control Center) replaces and upgrades existing electric and gas control center telecommunications, networks, and computing systems as they reach the end of their useful lives, require increased capacity, or cannot accommodate necessary equipment upgrades due to existing constraints. Some system upgrades may be necessitated by other requirements, including NERC reliability standards, TSA directives, FERC orders, federal gas standards, system growth, and external projects (e.g. Smart Grid). The customers who benefit from the reliable, safe and secure delivery of energy resources are all electric and gas residential, commercial, and industrial customers (CD.AA).

The estimated capital costs for the upcoming five years are $8M. The amount requested is based upon known upcoming major projects and the expected equipment and software upgrade/replacement cycles and multi-year term license renewals, which are new in recent years beginning in 2022. For example, 2026 is expected to be a historical typical average $800k spending year accommodating such notable projects as 1) GPS Clock replacements, 2) CIP Virtual Machine Host replacements, and Digi Terminal Server replacements. The surrounding years, however, include a $400k effort replacing network and firewall hardware including term license software, $400k effort in 2027 upgrading SCADA's Relational Database, a $3.3M effort in 2027-2028 to upgrade our main Energy Management System also including term licensing. Within the program's yearly authorized spend amount, specific budgetary items to be implemented are determined based on asset condition, life-cycle management, technology enhancements, and requests by affected stakeholders including System Operations, Distribution Operations, and Power Supply.

There are multiple risks if this program is not adequately funded. The clearest risk would be to public and personnel safety. The control systems supported by this business case provide real-time visibility, situational awareness, and control of Avista's electric and gas systems. Degradation of these capabilities due to lack of capacity, capability, or aging systems would present increased safety risk. Additionally, there is significant compliance risk. These control systems provide the capabilities required to achieve compliance with numerous reliability standards and requirements. For the electrical system these include the FERC orders, TSA directives, and NERC standards BAL, COM, CIP, EOP, INT, PER, PRC, TOP, and VAR. For the gas system these include the PHMSA "Pipeline Safety: Control Room Management/Human Factors" rule (49 CFR Parts 192 and 195.)

The benefits to all gas and electric customer and to the Business for the necessary expenditure of these funds is the ability to operate Avista's electric and gas systems in a safe, reliable, and compliant manner. Financial risk is also reduced to the Business and all customers by avoiding any potential financial penalties associated with non-compliance.

The incremental Operations and Maintenance labor resource costs for the upcoming five years are estimated to be $3.6M based on SCADA's staffing plan requiring nine additional staff additions in support of this Business Case according to industry staffing benchmarks, new ADMS and security/compliance support requirements. Note, however, that $845k for the 1st two positions in 2025 below are already included as part of the ADMS staffing plan (5 years * $169k/yr = $845k).

Year	SCADA Labor Resource Addition (70/30)	Qty	O&M Cost/ea	Cap Cost/ea	O&M Annual Total	O&M Cum Total
2025	SCADA/ADMS Containerized App Engr *	2	$84,567	$37,994	$169,133	$169,133
2025	SCADA Support/SCADA Sys Tech	2	$84,567	$37,994	$169,133	$338,267
2025	Security Compliance Engr	1	$87,527	$39,324	$87,527	$425,793
2026	SCADA/EMS Engr *	1	$90,590	$40,700	$90,590	$516,383
2027	SCADA/EMS Engr *	1	$93,761	$42,124	$93,761	$610,144
2028	SCADA/EMS Engr *	1	$97,042	$43,599	$97,042	$707,186
2029	SCADA/EMS Engr *	1	$100,439	$45,125	$100,439	$807,625
Total	**2025-2029 BC Cap / O&M Funding Req't**	**9**			**$807,625**	**$3,574,532**
	* NOTE: Classified as SCADA/EMS/ADMS Engineering staff per industry benchmarks					

VERSION HISTORY

Version	Author	Description	Date
0.2	Craig N Figart	Draft version of 2020 business case	07.17.2020
1.0	Craig N Figart	Final version of 2020 business case	09.21.2020
2.0	Jeremiah Webster	formatting to keep the fonts consistent, removed some of the blue help text, and deleted the comments	12.15.2020
3.0	Craig N Figart	Updated per $350k capital funding increase for 2021 due to EMS upgrade	07.05.2021
4.0	Craig N Figart	Updated per $490k capital funding increase for 2021 due to EMS upgrade multi-year budgeting, firewall refresh, file storage expansion	09.10.2021
5.0	Craig N Figart	Updated version for 2022 business case	08.03.2022
6.0	Craig N Figart Mike A Magruder	Updated version for 2023 business case	04.21.2023
7.0	Craig N Figart	Updated with indirect cost saving examples	04.28.2023
8.0	Craig N Figart Steve Carrozzo	Updated version for 2024 business case (2025-2029). Transfer FERC Order 881 capital project and funding to new business case. BCRT Team Member Review	04.30.2024 05.03.2024

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	**$0.8M**	**$0.8M**
2026	**$0.8M**	**$0.8M**
2027	**$2.0M**	**$1.0M**
2028	**$3.2M**	**$4.2M**
2029	**$1.2M**	**$1.2M**

Project Life Span	***5 years***
Requesting Organization/Department	T&D – SCADA/EMS/ADMS – System Operations
Business Case Owner | Sponsor	Craig N Figart | Michael Magruder
Sponsor Organization/Department	Energy Delivery
Phase	Execution
Category	Program
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

In order to effectively operate the Transmission & Distribution (T&D) and Gas Telemetry Systems, sufficient business and computing hardware and software is necessary. This business case provides for replacement of existing technology in alignment with manufacturer product roadmaps for application and technology lifecycles, as well as for deployment of new applications and technology as required to address expanding regulatory and business requirements. Technology continues to change and T&D Systems continue to incorporate improved technology. Here is GE's LifeCycle Roadmap:

Table 1 Grid Software Solutions Product Life Cycle

Transmission AEMS		
Regular 5 years	Extended Additional 2 years	Sustaining 7+ Years

Distribution ADMS		
Regular 3 years	Extended Additional 2 years	Sustaining 5+ Years

Accordingly, for example, the SCADA Front-End (SFE) servers installed in 2018 are scheduled for replacement in 2025, just past the vendor's Extended Additional 2 years support schedule. The SFE Operating System is already under Extended Windows Support as of January 2022, and the SFE application itself will be past the End of Extended Support by July 2024, beyond which GE begins to provide security update validation service on Time and Materials basis. The risk to Avista is increased O&M exposure should Avista require GE to backport security-related updates; additional O&M requirements could exceed over $200k. A recent 2024 quote listed hourly rates of $352/hr to $671/hr for back-porting new GE application code to our current older EMS version totalling over $200k just for GE's labor portion, not including additional labor Avista SCADA resources would be required (i.e. estimate $25k to $50k???).

Another notable project is to upgrade the ICCP servers installed in 2018 as well due for refresh for similar reasons. And the main Energy Management System applications released in 2020 and installed in 2021 are due for refresh on or before May of 2027 after which Extended Support ends. As noted above, the risk to Avista is increased O&M exposure should Avista require GE to backport security-related updates; additional O&M requirements could exceed over $200k.

Additional labor resources, that typically run which typically run **30% capital** and 70% Operations and Maintenance, are also required in order to adequately support SCADA's capital business case efforts and also operate the Transmission & Distribution (T&D) and gas telemetry and control systems. According to SCADA's staffing plan, according to SCADA staffing industry benchmarks for required staffing levels based on system point counts and other relative sizing, Avista should have 25 SCADA/EMS/ADMS engineering staff. Avista SCADA staff currently consists of only less than 10 EMS/ADMS support staff.

The total additional Operations and Maintenance costs to add the next nine of these additional staff totals $3.6M over the next five years per the table below. Note, however, two of the positions are to be funded in 2025 as part of the ADMS project staffing plan ($169k/year * 5 = $845k):

Year	SCADA Labor Resource Addition (70/30)	Qty	O&M Cost/ea	Cap Cost/ea	O&M Annual Total	O&M Cum Total
2025	SCADA/ADMS Containerized App Engr *	2	$84,567	$37,994	$169,133	$169,133
2025	SCADA Support/SCADA Sys Tech	2	$84,567	$37,994	$169,133	$338,267
2025	Security Compliance Engr	1	$87,527	$39,324	$87,527	$425,793
2026	SCADA/EMS Engr *	1	$90,590	$40,700	$90,590	$516,383
2027	SCADA/EMS Engr *	1	$93,761	$42,124	$93,761	$610,144
2028	SCADA/EMS Engr *	1	$97,042	$43,599	$97,042	$707,186
2029	SCADA/EMS Engr *	1	$100,439	$45,125	$100,439	$807,625
Total	2025-2029 BC Cap / O&M Funding Req't	9			$807,625	$3,574,532
	* NOTE: Classified as SCADA/EMS/ADMS Engineering staff per industry benchmarks					

Only six of the nine staff to be added over the next five years classify as EMS/ADMS support staff per industry staffing benchmarks, which would bring the total EMS/ADMS support staff count up to 16, much closer to the required 25. The remaining three additional staff of the nine to be added are for:

- One Security Operations/Compliance Support position to complement SCADA's sole security engineering resource and also provide assistance meeting compliance requirements and documentation responsibilities.
- Two positions (i.e. SCADA Systems Tech & Control Systems Specialist or two SCADA Systems Techs) to provide operations support for the overdoubled infrastructure added in SCADA as part of the ADMS project and also to meet Article 16 obligations.

1.2 Discuss the major drivers of the business case.

This business case is crucial in a key aspect of Avista's Perform strategy to, "…affordably operate and maintain safe, clean, reliable generation and energy delivery infrastructure", and is the major driver of the business case. It is essential in providing sufficient control center technology tools, situational awareness, and monitor/control capabilities to achieve reliable energy service. The other driver centers around achieving state financial objectives by minimizing financial risks to our Customers and to the Business by adhering to NERC security compliance requirements associated with operating energy management systems that are vendor supported and secured to meet security and operational requirements.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

There are multiple risks if this program is not adequately funded. The clearest risk would be to public and personnel safety, for example, if the integrity of Avista's protection systems are not adequately monitored remotely for their ability to protect Avista electric and gas infrastructure and any potential public contact with Avista gas and electric infrastructure. The control systems supported by this business case provide real-time visibility, situational awareness, and control of Avista's electric and gas systems. Degradation of these capabilities due to lack of capacity, capability, or aging systems would present increased safety risk. Additionally there is significant compliance risk and legal negligence liability risk from potential public lawsuits. For example, historic penalties for multiple violations of a handful of requirements are around $300,000, however it varies, and can exceed upwards of $2M for non-compliance with NERC CIP standards:

$378,000	WECC2018019376	CIP-007-6	R5
	WECC2018019192	CIP-010-2	R1
	WECC2017018484	CIP-010-2	R1
	WECC2017018485	CIP-010-2	R2
	WECC2018019012	CIP-010-2	R2

$2,100,000	WECC2018019480	CIP-007-1
	WECC2017017880	CIP-007-1
	WECC2017017881	CIP-007-1
	WECC2017017882	CIP-007-1
	WECC2018019481	CIP-007-1
	WECC2017017883	CIP-010-2
	WECC2017017884	CIP-010-2

These control systems provide the capabilities required to achieve compliance with numerous reliability standards and requirements. For the electrical system these include the NERC standards BAL, COM, CIP, EOP, INT, PER, PRC, TOP, and VAR. For the gas system these include the PHMSA "Pipeline Safety: Control Room Management/Human Factors" rule (49 CFR Parts 192 and 195.)

The expenditure of these funds is necessary to operate Avista's electric and gas systems in a safe, reliable, and compliant manner.

In addition to the risks related to public and personnel safety, compliance risk would be increased without this investment. Non-compliant operational capabilities and practices would result in negative audit findings, significant financial penalties, and litigation expenses. Obsolete equipment would remain in service until failure. Additional capacity for growth may or may not be suitable for required expansions to meet other needs (e.g. Regulatory, Smart Grid.)

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

The proposed funding of this Business Case aligns with the following strategic vision, goals, objectives, and mission statement of Avista as follows:

Avista's Focus:

- Our Customers: Avista's gas and electric customers are benefited by the safe and reliable operation of our energy management systems in the control and protection of our electric and gas infrastructure assets serving all of our electric and gas customers.
- Our People: Avista's employees benefit from implementing and operating the latest control center technologies and increased morale in the opportunity to participate in the installation, maintenance, and ownership of these systems.
- Perform: Control Center technologies supported by this Business Case are required to affordably operate and maintain safe, clean, reliable generation and energy delivery infrastructure.
- Invent: Control Center technologies deployed by this Business Case are based on the most up-to-date and innovative vendor supplied systems available. For example, this Business Case will soon support the operation of the next-generation Advanced Distribution Management System that accommodates the integration of distribution control center operations and customer outage management systems.

Avista's Values:

- Trustworthy: By funding the secure operation of Avista's electric and gas energy management systems, customer trust is maintained when gas and electric service is not interrupted by cyber security attacks.
- Innovative: Avista's control center staff are continually looking for opportunities to more safely and efficiently operate and manage our control center systems within funding contstraints. One example is the migration of more systems toward virtual machine environments that eliminate hardware obsolence dependencies and the vulnerability to hardware failures.
- Collaborative: Avista's control center staff also collaborate with corporate experts in deploying the latest and company standard technologies to synergize in support of new system

deployments. One example is our recent firewall replacement projects migrating to a common platform that is used across the company. This also gains financial benefits by increasing our vendor licensing footprints and ability to benefit from quantity discounts.

It is essential in providing sufficient control center technology tools, situational awareness, and monitor/control capabilities to achieve reliable energy service.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

NERC reliability standards and TSA directives contain such requirements as the NERC CIP-007 Requirement R2 to track, evaluate, and apply cyber security patches or mitigation plans for electric and gas SCADA control systems that are found to have a security vulnerability. If control system hardware and application software is not replaced and/or upgraded on a frequent enough cycle, the hardware and application software reaches end of vendor support, beyond which it gets more difficult and costly for the vendors to provide for security support on these systems. This Business Case meets these NERC and TSA directive security requirements by providing for system upgrades in a timely enough cycle to keep the systems under vendor support to mitigate against security vulnerabilities.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The proposed Business Case solutions address expanding regulatory and business requirements to provide for replacement of existing technology, as well as for deployment of new applications and technology as required. Examples of previous work completed and how this work addressed these requirements follow:

NERC CIP-012 project – In 2022, routers were replaced with AT&T supplied routers to meet encryption requirements for the transmission of all Real-Time Monitoring and Real-Time Assessment data that is exchanged between Balancing Authority Control Centers. CIP-012, as of the July 1, 2023 effective date, requires Avista to protect the transmission of this data. This was the only option Avista had to choose from in that the new routers were pre-engineered by the Reliability Coordinator, RCWEST, in coordination with AT&T, that has been deployed by all Balancing Authorities in the WECC connecting to the WECC Wide Operational Network.

SCADA Switch Refresh project – In 2022, switches that are nearing end of support are being replaced with the latest model. Updated hardware will provide better reliability for our Control Center systems and better security adherence and postures to meet NERC CIP compliance requirements.

EMS Upgrade project – In 2021, the server hardware and applications for the main Energy Management System were all upgraded to the latest supported vendor versions. These systems were well past the end of Extended Support and very much in need of refresh since the last upgrade in 2010. This upgrade also brought along with it the replacement of physical server hardware with a new virtual machine environment for our NERC-CIP systems. This will allow us to replace physical

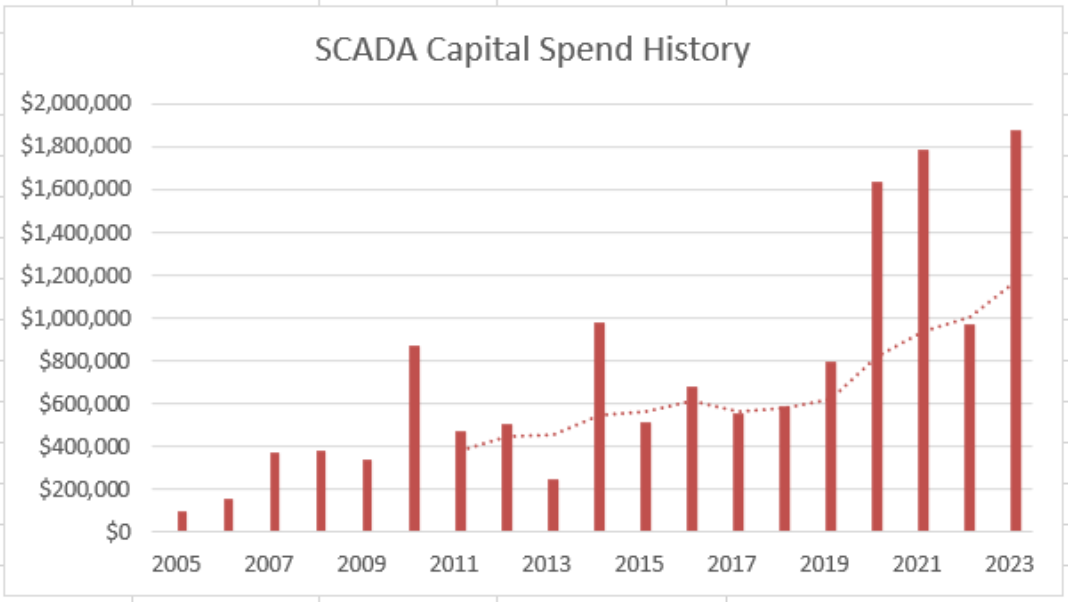
[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

hardware on a more rigorous schedule without having to replacing the very complex SCADA/EMS applications at the same time to better keep up with vendor supported hardware systems. While maybe not the most least cost alternative to configure a new virtual machine environment, it is the only solution to meet hardware obscesence constraints without impacting critical control system application software and also to mitigate against pre-mature hardware failures.

Again per above, the risk to Avista for hardware/software operations beyond Extended Support periods is increased O&M exposure, for example, should Avista require GE to backport security-related updates; additional O&M requirements could exceed over $200k.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

This capital request was prepared based on typical yet ever-increasing annual $800k to 1.2M costs required to meet the needs for this business case. Over $3M in additional funding is included for 2027 and 2028 when we plan to again upgrade our main EMS system recently upgraded in 2020 and 2021 per the spikes above typical costs as shown below.



2022 came higher at almost $1M as we took on several upgrade projects inclusive of the following projects for example:

- SCADA Switch Refresh
- SCADA Internal Firewall Refresh

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

- SCADA External Firewall Refresh
- SCADA SOO NetApp Refresh – network storage device
- Operator Training Simulator
- CIP-012 Protections Project

2023 came in at $1.9M as we migrated our $300k annual O&M licensing and support paid for GE's EMS software to a 5-year term license for $1.4M. In late 2023, our SCADA vendor required Avista to move from a perpetual EMS licensing agreement (O&M costs) to a five-year term license agreement that could be capitalized at an 80/20 split. Therefore, an additional $1.4M in capital costs were incurred in 2023 than were typically expected and originally planned for.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	EMS 5yr Term Licensing (80% cap)	$	$	$	$2M est	$
O&M	EMS 5yr Term - Perpetual diff	-$311k	-$363k	-$421k	-$560k	-$643K

Typically, there are no direct offset or savings associated with capital investments in this Business Case other than reduced overtime and O&M labor associated with the increased need for repair and maintenance on hardware that is operated into and beyond its Extended Support dates.

Direct offset or savings in O&M software support costs are expected as a result of this business case's funding for the 2028 renewal of this five year term EMS licensing for approximately $2M. Similar to the original five year term EMS licensing purchase, per Section 1.1.4 in the 2023 CPG funds change request for GE EMS licensing, annually escalating costs of $358k in perpetual licensing renewals will be reduced to $92k annually for EMS 5-year term licensing. In summary, assuming a 12.75% escalation of former annual perpetual licensing renewals, 5yr term licensing provides a break-even over five years.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	EMS Upgrade Project	$	$	$1M est	$0.3M est	$
O&M	GE security update back-port				$250k	$250k

Other direct offset or savings associated with the $1.3M labor portion of the 2027-2028 EMS Upgrade project. If this project is not completed, Avista's faces increased risk to additional O&M cost exposure should Avista require GE to backport security-related updates to out-of-support EMS software; additional O&M requirements to fund this effort could exceed over $200k. A recent 2024 quote listed hourly rates of $352/hr to $671/hr for back-porting new GE application code to our current older EMS version totalling over $200k just for GE's labor portion, not including additional labor Avista SCADA resources

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

would be required (i.e. estimate $25k to $50k???). In theory, this could occur every year past End-of-Support after 2027.

2.4 Summarize in the table and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no indirect offset or savings associated with capital investments in this Business Case other than reduced overtime and O&M labor associated with the increased need for repair and maintenance on hardware that is operated into and beyond its Extended Support dates. This labor savings will indirectly allow Avista's labor resources to be directed toward other important Business Case objectives.

An example indirect offset can be shown for a capital project, "SCADA Hardware Refresh", typically used to replace aging and end-of-support server and workstation hardware in a timely fashion before end-of-support. This mitigates against diverting labor resources away from capital projects and towards emergency troubleshooting and repair activities. A recent server failure resulted in SCADA resources spending over three days of labor replacing a failed server on overtime for a total cost of about $5,000 in O&M dollars (25 hr * 1.5 * $180/hr ~ $7,000). In 2024, for example, we will need to replace two virtual machine host servers costing about $50,000. An alternative could be to defer this replacement taking on risk of failure/recovery labor and an unquantifiable risk to the reliable operation of the Bulk Electric System. Upon failure, we would also be faced with loss of redundancy for the EMS systems while new hardware is either repaired or replaced and worse yet, further subjected to supply chain delays.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

The following is a list of example projects to be funded under this five year business case that are all driven by a need to replace equipment and software reaching the end of life

- SCADA Front-End upgrades,
- Inter-Control Center Communication server upgrades
- Energy Management System upgrade.

Alternative 1:

The above example projects involve replacing hardware and SCADA vendor-provided software. The alternatives that are considered in these projects are changing SCADA vendors, changing server hardware manufacturers, or changing the server hardware

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

platforms. Changing SCADA vendors is not a feasible consideration given that multiple systems would need to be changed all at once requiring a large capital project endeavor on the order of **$5 to $20M**. Changing server hardware manufacturers is a feasible and likely **net-zero** cost consideration, however, it would not line up with Avista's corporate IT model that has a particular server manufacturer in portfolio and under existing support contracts.

One alternative, however, that we have considered as part of these system upgrades over that past several years is moving from physical to virtual server hardware platforms. These virtual platforms have had sufficient time to prove their reliability and SCADA vendors have given their blessing on implementation and this alternative naturally lines up with Avista's corporate IT model for server hardware platforms. The benefit of virtual hardware gains Avista independence from hardware obsolescence in that we no longer have to upgrade an entire EMS system when hardware reaches end of life. We can simply replace the underlying virtual server hardware host for around **$25k/each** running the same virtual EMS software, thus deferring the physical hardware failure driven need for a major **$2M** capital project to also upgrade the entire EMS application software suite.

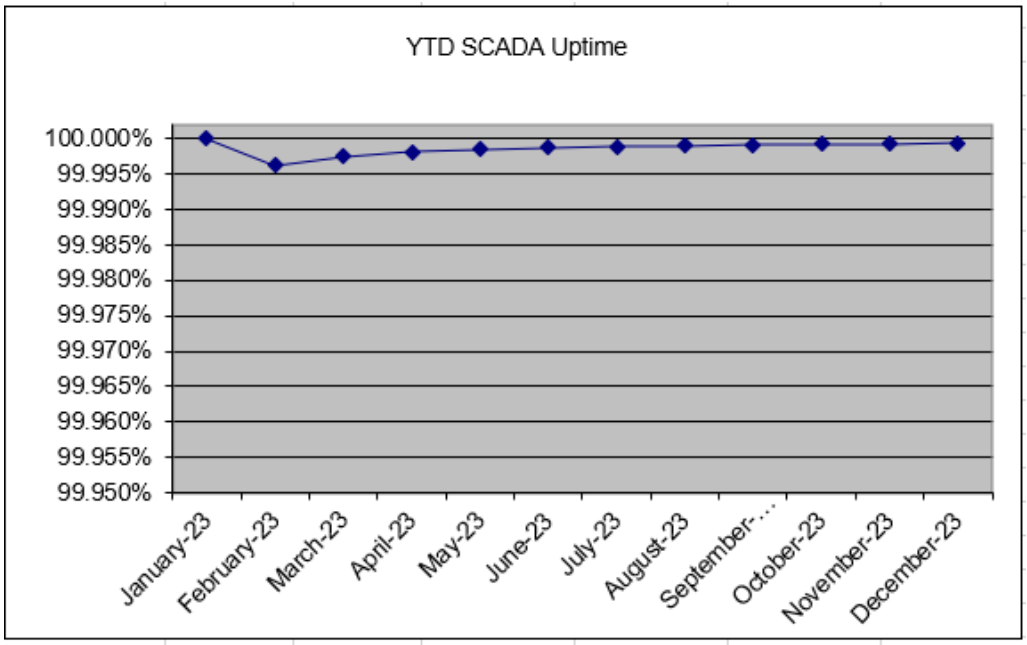
Alternative 2:

There is certainly a "No Funding" option available for any one of the individual projects under this Business Case. However, it needs to be recognized that there will be increased risk to the reliability and operational costs to the business. For example, funding was denied for the refresh and expansion of our backup storage system at the end of 2021. Risk therefore was increased of running out of sufficient disk space to keep SCADA server systems operational and the backups of those systems up-to-date in case of failure and the need for system recovery. Without a system backup to recover from, rather than taking four hours of one labor resource, it would require maybe 40 hours of SCADA engineering and possibly additional consultant assistance to rebuild an EMS server, for example, from the ground up. 40 hours at $280 per hour would come to $11,200.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

A metric that could be used to demonstrate how the investment delivered on remedying the obsolescence of hardware and software is SCADA's one-pager downtime log. SCADA's reliability target for keeping Avista's energy management systems running is 99.98% of the time. If we fail to meet this annual target specifically due to hardware and software failures or security breaches, this could be an indication the investment may not be meeting Business Case objectives. In 2023, for example, we met a year-to-date SCADA uptime target of 99.995%, well above the 99.98% objective.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 204 of 535



2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

This business case is comprised of multiple individual capital projects that all close upon completion over the course of the next five years, at which time they are transferred to plant and become used-and-useful. For example, here are some around multi-year projects that cause abnormal delays in transfer-to-plant above SCADA's normal $800k - $1.2M annually.

2025

- $3.3M EMS Upgrade project is expected to start in 2027 and complete by the end of 2028.

There are two "revolving" projects, however, SCADA Hardware Refresh and SCADA Expansion, that are for minor refresh and expansion items like computer servers, desktop pcs, monitors, etc. These projects are placed into service immediately and become used-and-useful right as they are purchased and deployed.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The steering committee/advisory group for initial and ongoing vetting and department priorization process includes the members from the entire SCADA team as needed, but more notably the following:

- Director of System Operations and Planning
- Manager of Energy Management Systems (EMS/ADMS)
- Sr. Security Engineer

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 205 of 535

Individual projects are governed by the SCADA team member assigned to the project as project lead who is tasked with scheduling and coordinating all the work associated with the project.

Project oversight is provided by the SCADA manager primarily, but also to the assigned project lead.

The steering committee provides governance and oversight of this business case.

The Manager of EMS/ADMS has multiple check-in meetings per week scheduled within the Energy Management Systems group during which to track progress of the various capital projects that comprise the total business case.

Decision-making, prioritization, and change requests at the individual capital project level are taken care of within the Energy Management Systems group under manager supervision.

Any need for substantial change requests to capital projects that would deviate from the original Capital Project Request (CPR) are documented and submitted to Project Accounting as a revised CPR. Change requests and resulting decisions that lead to significant changes in project scope are documented in the project charter documentation and revisions to the original version and stored in SCADA's SharePoint site.

Prioritization for each individual project within this business case is performed by the SCADA manager as part of the on-going updates to SCADA's annual capital budget spreadsheet. If the sum total of all SCADA capital projects is expected to exceed the approved Business Case funding, then a Business Case Change Request must be approved by the Steering Committee and submitted to Project Accounting.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *SCADA – SOO and BuCC* Business Case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Craig N. Figart	Date:	May 3, 2024
Print Name:	Craig N. Figart		
Title:	Mgr Energy Mgmt Systems		
Role:	Business Case Owner		

Signature:	Michael A Magruder	Date:	May 3, 2024
Print Name:	Michael A. Magruder		
Title:	Director, System Operations & Planning		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 206 of 535

Role:	Business Case Sponsor
Signature:	Craig N. Figart
Date:	May 3, 2024
Print Name:	Craig N. Figart
Title:	Mgr Energy Mgmt Systems
Role:	Steering/Advisory Committee Review

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 207 of 535

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Substation - West Plains System Reinforcement<Project Name>

EXECUTIVE SUMMARY

The West Plains area load has increased in the past few years and continues to grow at a rate outpacing Avista's average service territory load growth rate. Between 2018-2022, a 3 - 3 ½% growth rate has been observed and is forecasted to continue for the next 5-10 years. The growth has strained the transmission system to the extent that system reliability cannot be maintained while accommodating system outages as required under applicable operational performance requirements and NERC TPL-001-5. Government, tribal, public, and private entities have invested significant time and money in the area and are working to establish area backbone infrastructure. Avista is being asked to join these efforts by readying and fortifying the electric grid to accommodate future expanding economic development.

The West Plains area requires a new 230kV source into the area to support the system and improve reliability and operability while offloading existing 230/115kV transformers in Spokane. The new 230kV source will improve contingency situation results and give increased ability to meet existing and future customer demand. The project will reduce the potential of customer outages under heavy summer loading scenarios. Without the project, customers may have power turned off under certain outage combination conditions.

The scope of the project includes a new 230/115kV station near the West Plains at Garden Springs, new 230kV station to interconnect with the Bonneville Power Administration called Bluebird, and a new 12-mile 230kV transmission line. The new infrastructure is major investment in the transmission system which is needed to serve our customers. The total project cost of all aspects of West Plains is estimated to be almost $80M and will take over four years to engineer and construct.

The new 230kV source is critical to meet anticipated load growth in the area. The timing for completion is sensitive as operational performance have been observed in the operations time-horizon and performance is expected to worsen as new load connects to the system.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Karen Kusel / Glenn Madden/ John Gross*	*Initial draft of original business case*	*May 2023*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements Steve Carrozzo*	*05/12/2023*

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 208 of 535

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Substation - West Plains System Reinforcement<Project Name>

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$6,110,000	
2025	$23,150,000	
2026	$25,800,000	$5,000,000 (HV Breakers and Power Transformers)
2027	$18,600,000	$37,100,000
2028	$0	

Project Life Span	10 years
Requesting Organization/Department	Substation Engineering
Business Case Owner | Sponsor	Glenn Madden | Vern Malensky
Sponsor Organization/Department	M08
Phase	Planning
Category	Project
Driver	Performance & Capacity

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.

1.1. What is the current or potential problem that is being addressed?

The West Plains area is located west of the City of Spokane consisting of the City of Airway Heights, Medical Lake, City of Cheney, Fairchild Air Force Base, and the Spokane International Airport. Distribution service in the area is provided by Inland Power & Light as well as Avista. Avista is the only Transmission Service Provider, Transmission Operator, Transmission Planner, and Planning Coordinator in the area.

The transmission system in the West Plains area has several constraints due to lack of necessary transmission infrastructure serving the existing and future loads. The West Plains Study and Reinforcement Plan identifies projects mitigating transmission system performance issues in the West Plains Area related to transferring power from the existing 230 kV system to load located in the West Plains.

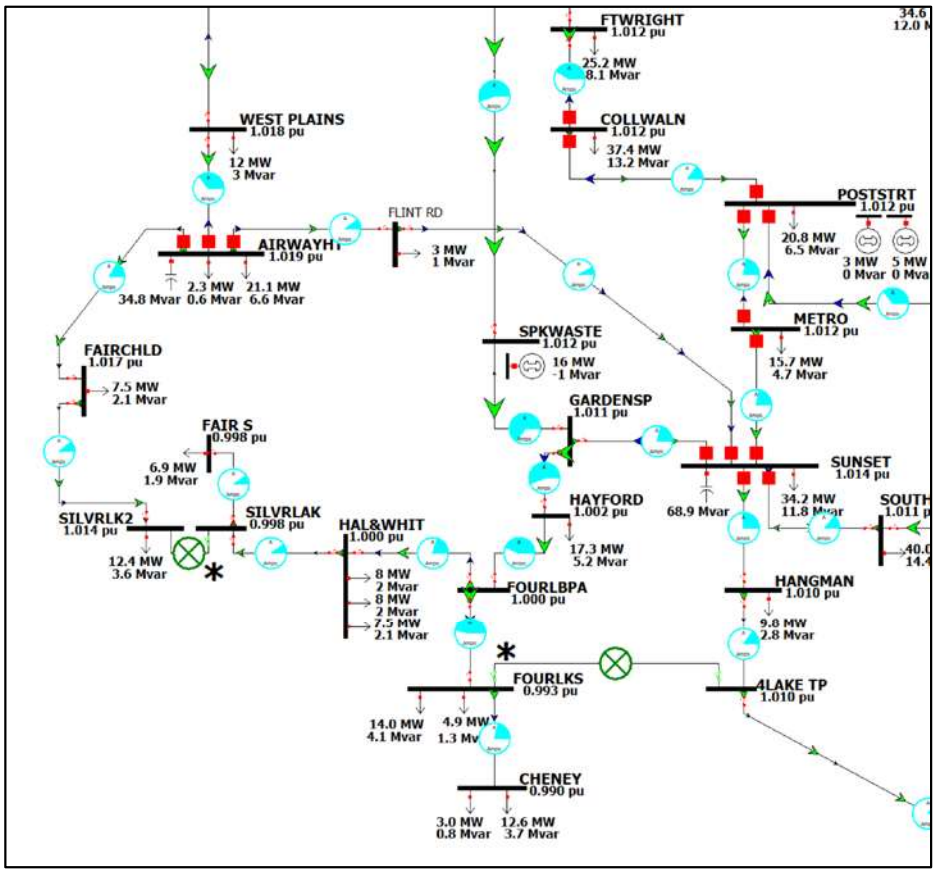
The West Plains Study and Reinforcement Plan is intended to be a long term and comprehensive plan. The plan includes projects improving transmission system performance issues, and addresses issues forecasted to occur in the planning horizon from a single utility approach.

The West Plains system is electrically supported through three stations: Westside, Sunset, and Devil's Gap Substations. The Westside Substation is located north of the West Plains and offers a strong 230kV source supported primarily from the Bonneville Power Administration (BPA)'s transmission system. Sunset Substation is located east of West Plains and brings energy to the West Plains through

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 209 of 535

DocuSign Envelope ID: 5697F0BB-C658-4212-801D-35AF9709388B

the downtown Spokane area, linking the reliability of these two strategic areas. Devil's Gap Substation is located northwest of West Plains and provides a sturdy source supported primarily from the Little Falls/Long Lake generation within Avista's system. The figure below provides a one line identifying the electrical transmission system supporting the West Plains.

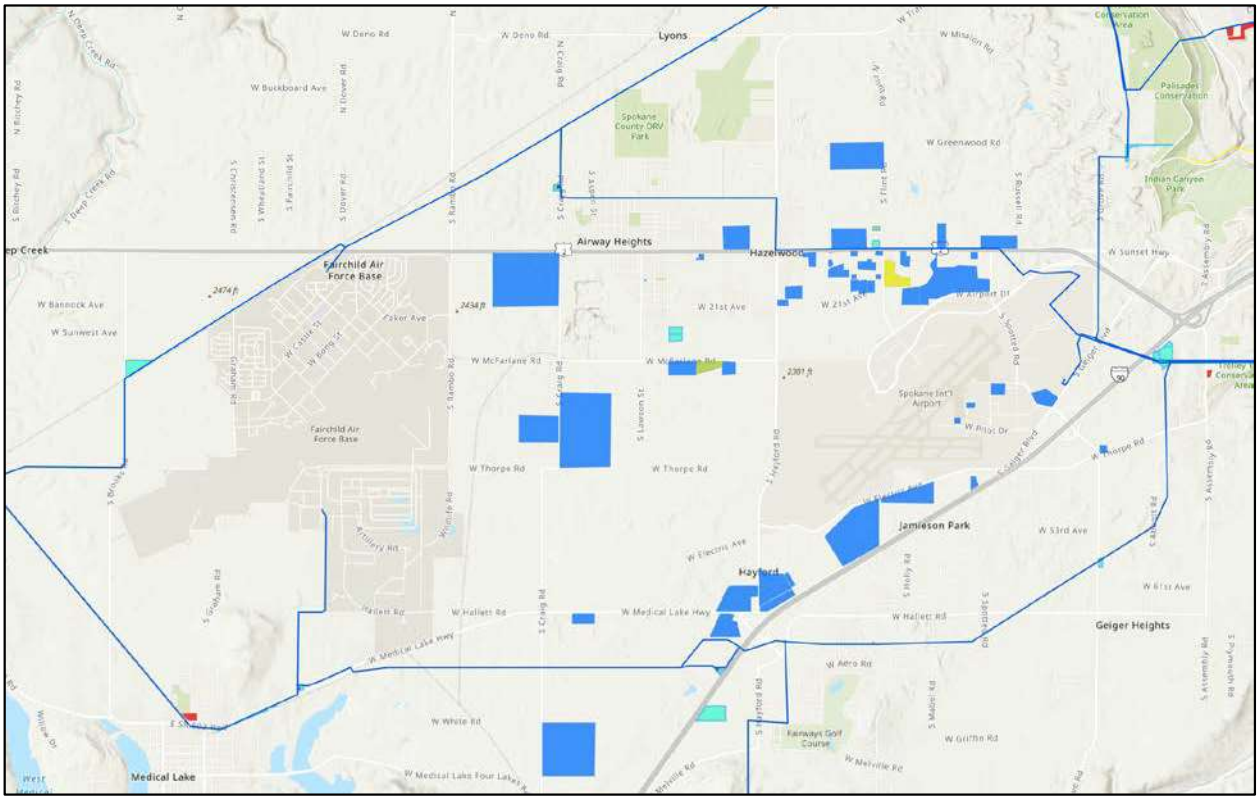


Load growth in Avista's service territory has been approximately 0.5% between 2010 and 2022. The West Plains area represents one of our fastest load growth areas. Between 2018-2022, a 3 - 3 ½% growth rate has been observed and is forecasted to continue for the next 5-10 years. This rate has been corroborated with the following local electric utilities in the area: the Bonneville Power Administration, the City of Cheney, and Inland Power & Light Co. Specific customer large load additions have been identified and are illustrated on the following map. Shaded polygons on the map represent a specific customer interconnection request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 210 of 535

DocuSign Envelope ID: 5697F0BB-C658-4212-801D-35AF9709388B

Substation - West Plains System Reinforcement<Project Name>



The growth in the West Plains area has accelerated by a concerted effort toward economic development and expansion. Government, tribal, public, and private entities have invested significant time and money toward this endeavor and are working to establish area backbone infrastructure that will be needed. Avista is being asked to join these efforts by readying and fortifying the electric grid to accommodate future expanding economic development. The following list are examples of significant monetary investments in infrastructure for future growth.

- Completion of a new railroad spur
- Accelerated transload facility project (efficient transfer between rail cars and trucks)
- Revised DOT trip requirements to include West Plains as single-day trip from ports
- Accelerated I-90 interchange projects at Geiger and Medical Lake
- Reconstruction of Geiger Boulevard
- Established airport acreage development area
- Formed PDA partnership (multi-jurisdictional focus between Spokane, Spokane County, and Fairchild)

By understanding these efforts, it is evident that West Plains Area entities are actively placing time, efforts, and monetary funds toward ensuring that the area load growth is sustained in the West Plains region.

There are existing system performance issues in the West Plains Area. Powerflow studies show the West Plains Area transmission infrastructure is unable to accommodate all required outage scenarios without overloads to the system. Four contingency scenarios are provided below as examples of insufficient system performance in the West Plains Area transmission system.

1. An outage of two transmission lines to Westside Substation results in exceedance of applicable facility ratings which requires forced outages to customers to reduce system loading.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 211 of 535

DocuSign Envelope ID: 5697F0BB-C658-4212-801D-35AF9709388B

2. A simultaneous outage of two transmission lines into the West Plains results in exceedance of applicable facility ratings which requires forced outages to customers to reduce system loading.
3. The loss of a Westside Substation transmission line into the West Plains area and the simultaneous loss of a Beacon-Ross Park transmission line results in exceedance of applicable facility ratings which requires forced outages to customers to reduce system loading.
4. A breaker failure outage on the bus tie breaker at Beacon Substation results in overloads to the existing system.

The system does not have the flexibility and resiliency needed for operating the system. Two examples depicting these operational limitations are provided below.

1. System Operators are restricted from opening the Sunset - Westside 115kV Transmission Line and the College & Walnut – Sunset 115kV Transmission Line without resulting in overloads to the system.
2. System Operators are unable to restore the system under the following condition:

   If generation is low in the downtown Spokane area (Upper Falls generation and Monroe Street generation) and the Spokane Waste-to-Energy plant is down for routine, mid-summer maintenance,
   And an outage occurs on the Sunset – Westside 115kV Transmission Line,
   Then the system is unrestorable resulting in customer outages until the forced outage can be repaired.

   This scenario presents itself annually in July in the daily operational studies work.

A Corrective Action Plan, as required in NERC TPL-001-5, is necessary to mitigate the performance issues. An effective Corrective Action Plan will include project(s) to mitigate the observed overloaded transmission lines and provide improved system resiliency for serving new customer growth in the area.

The system capacity concerns of the West Plains area are not only evident in the area transmission system but are also present in the area distribution system. The distribution system within the West Plains does not have the capacity needed for expected load requirements. Also, upgrades and additions are necessary to maintain adequate reliability and operational flexibility. Within the West Plains distribution system there are station configuration constraints, inadequate station redundancy and an absence of infrastructure in larger growth areas. The West Plains Reinforcement Plan considers these problems and their probable solutions in mind. However, distribution issues will be addressed in a separate document and justification will not be included as part of the West Plains Reinforcement Plan.

1.2. Discuss the major drivers of the business case.

The West Plains System Reinforcement Project primary driver is Performance and Capacity with a secondary driver of Mandatory and Compliance.

Performance and Capacity:
As outlined in Section 1.1, the transmission system performance does not meet applicable criteria due to lack of capacity to serve customer load in the West Plains Area.

Mandatory and Compliance:
NERC Standard TPL-001-5 requires Avista to establish performance criteria to be evaluated in the short and long-term planning horizons. When studies show the transmission system is unable to meet the applicable criteria, a Corrective Action Plan needs to be developed and eventually implemented. Obligations to implement Corrective Action Plans are not clearly defined within TPL-001-5. The objective of completing Corrective Action Plans is to ensure the transmission system can operate securely through the process of planning ahead and not reacting to events.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 212 of 535

DocuSign Envelope ID: 5697F0BB-C658-4212-801D-35AF9709388B

Components of the Customer Requested and Customer Service Quality and Reliability investment drivers may be associated with the West Plains System Reinforcement Project from a qualitative perspective. Customers are requesting new or increased service in the West Plains area. Without the construction of the West Plains System Reinforcement project, the transmission system will not be capable of serving the new customer load. Reliability impacts from transmission system issues are often difficult to describe as the system has been designed to minimize impacts to customers when there are outages on the system. The risk of not constructing the West Plains System Reinforcement project has the potential to result in reliability issues customer due to lack of sufficient redundancy built into the system during outage scenarios.

1.3. Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The West Plains System Reinforcement project is needed in the near future because performance issues identified in the planning horizon have begun to materialize in the operations time horizon. During summer conditions Operational Planning Analysis (next day studies) have shown forced transmission line or transformer outages may require the reduction of load (turning customers power off) to ensure the system can operate acceptably for the next possible outage as required with the Reliability Coordinators System Operating Limit Methodology.

Deferral of the project in past years has presented additional risk. Real time performance issues typically have low probability of occurrence but with high consequence. Continuing to defer the project will increase the probability of issues arising due to increased load in the area increase of the consequence as more load is needed to be shed to mitigate issues that arise. Load growth is expected to be 3% a year in the local area. Additional load growth in the greater Spokane area contributes to the issues defined in the problem statement.

The scope of the project includes large infrastructure investments which will require several years to construct. The project must be started in advance of the need or as soon as possible as the need has been seen in the operations time horizon. Construction of a new 12-mile 230kV transmission line through populated area will likely present challenging schedule issues. Deferring the project will also increase transmission line routing issues as the area becomes more populated as acquiring new right-of-way for the transmission line will impact more landowners.

1.4. Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

The West Plains System Reinforcement project provides additional capacity to the system which is “critical to serving our customers well and unlocking pathways to growth.” The Perform Focus Area of Avista’s focus goals is the primary alignment with the requested project but there are elements to the project which are aligned with the theme of our Vision, Mission, and Focus Areas.

Our Customers:
Existing and future customers in the West Plains area expect to have electrical service. Avista needs to deliver a system which can serve the customer demands and continue to meet the company’s defined reliability objectives.

Our People:
The portion of our company who will support the implementation of the project represents a core electric utility collection of our employees. These employees will take pride in the efforts of such a transformative project which will impact the West Plains community in a positive way.

Perform:

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 213 of 535

DocuSign Envelope ID: 5697F0BB-C658-4212-801D-35AF9709388B

With completion of the project, Avista will be unlocking growth potential in the West Plains area.

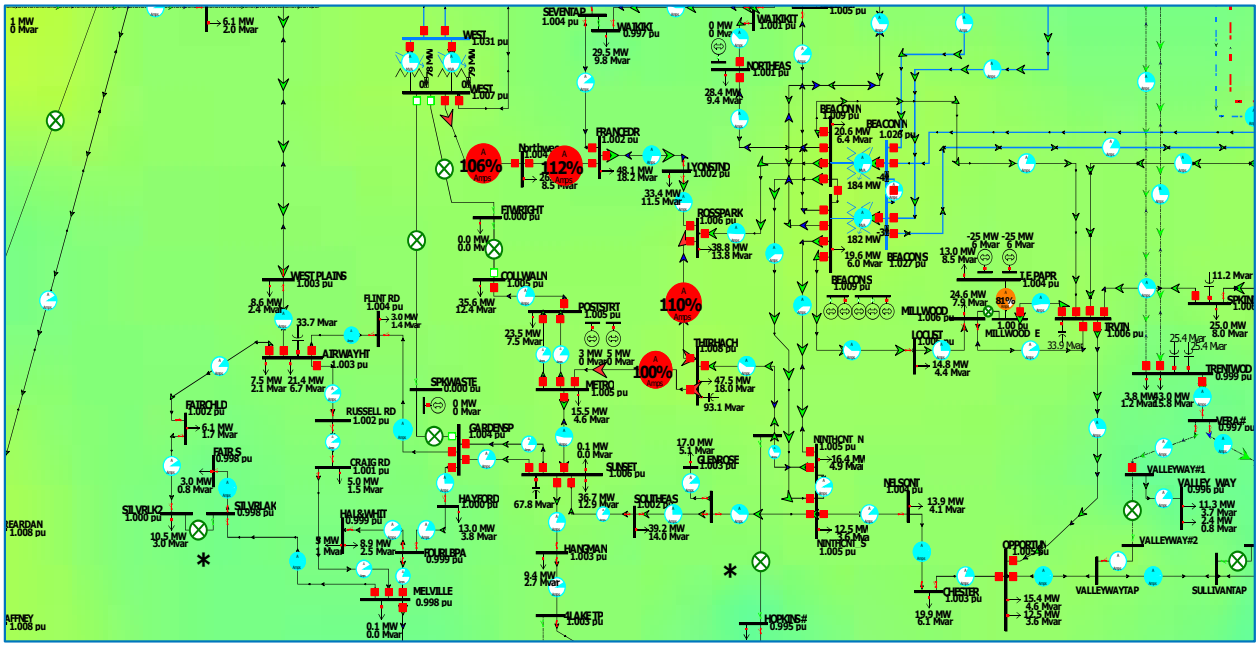
Invent:
Constructing transmission lines and substations are traditional project alternatives but Avista has the opportunity to improve the construction and delivery process as part of such a large-scale project.

Vision; Better energy for life:
Investment in the transmission system represents a long term invest of infrastructure which will be in place to serve our customers for several generations.

Mission; We improve our customers' lives through innovative energy solutions:
The West Plains System Reinforcement project has been identified as the most prudent energy solution to deliver the high-level capacity needed to serve the area. The additional capacity is needed to meet our customer's need for power.

1.5. Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

System Planning has completed a thorough system study for this project. Many of the details have been added to this business case document, for more details please see the full study: West Plains Study and Reinforcement Plan Version 2 (West Plains 2020 Study - V5.pdf). Additionally, the transmission system is analyzed bi-annually through the System Assessment process performed by the System Planning team. The most recent System Assessment is the 2021-2020 System Assessment Version 2 (2021-2022 Avista System Assessment-V2.pdf). An example of study results is shown in the below figure from the System Assessment which illustrates transmission line facility rating issues during outage scenario if the project is not constructed.



[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

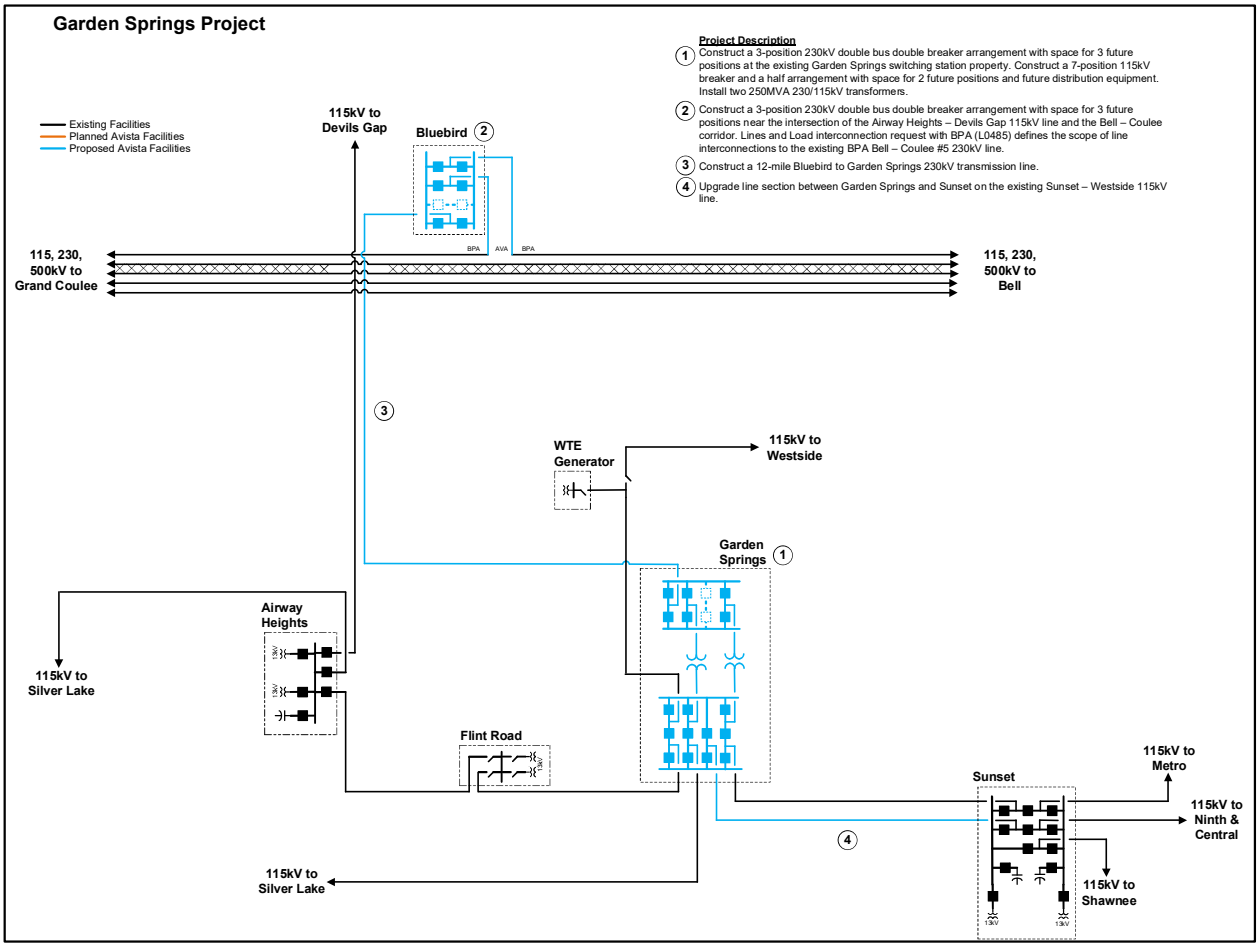
Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 214 of 535

DocuSign Envelope ID: 5697F0BB-C658-4212-801D-35AF9709388B

2. PROPOSAL AND RECOMMENDED SOLUTION - Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).

2.1. Please summarize the proposed solution and how it helps to solve the business problem identified above.

The following figure illustrates the intended scope of the West Plains System Reinforcement project.



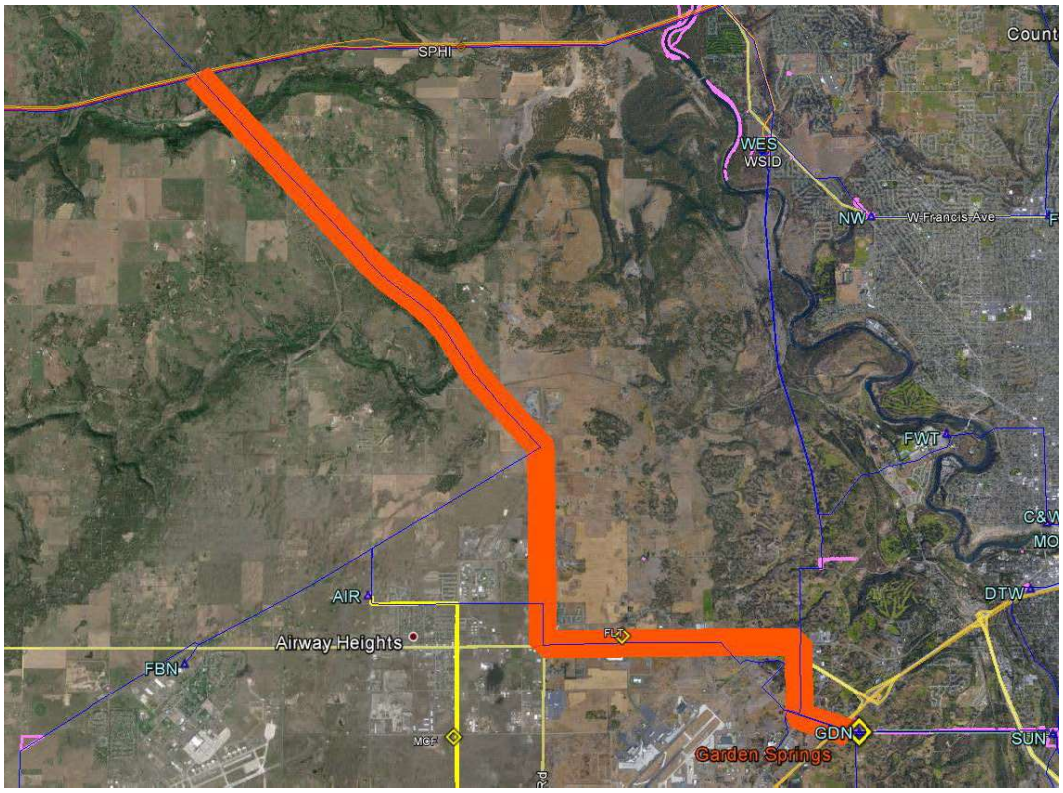
The West Plains Reinforcement Project will consist of a new 230kV connection to BPA's system, electrically placed near the strong generation source of the Coulee Dam. This connection will be made through a new station called Bluebird Substation, located off the BPA's Bell – Coulee #5 230kV Transmission Line. From Bluebird Substation a 230kV transmission line will carry energy south into the West Plains to Garden Springs Station. The Garden Springs Station will include two new 230/115kV, 250 MVA transformers, also addressing transformation capacity issues. The scope of this work includes:

• Construct a new 230kV substation at Garden Springs and include two 250MVA, 230/115kV transformers.
• Construct a new 230kV substation (Bluebird Station) near the Bell – Coulee corridor and loop in the Bell – Coulee #5 230kV Transmission Line

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 215 of 535

DocuSign Envelope ID: 5697F0BB-C658-4212-801D-35AF9709388B

• Construct a new (approximately 12.8 mile) 230kV transmission line from Garden Springs to the Bell – Coulee corridor.
Upgrade existing 115kV transmission line between Garden Springs and Sunset stations.



2.2. Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

Study reports prepared by System Planning can be referenced for the West Plains System Reinforcement Project. An example of work includes:

- Garden Spring Integration Project Feasibility Study - Version 0, 2013
- West Spokane Transmission Plan – Version 0, 2016
- West Plains Study and Reinforcement Plan – Version 2, 2020
- 2021-2022 Avista System Assessment – Version 2, 2022 (and previous versions)

The listed reports provide tabular study results showing improvement in system performance with the completion of the project. For example, without the project specific transmission lines are shown to exceed their applicable facility ratings under outage conditions and therefore the system does not

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 216 of 535

DocuSign Envelope ID: 5697F0BB-C658-4212-801D-35AF9709388B

meet performance criteria as required under NERC standard TPL-001. With completion of the project the system's performance is improved.

2.3. Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

New transmission infrastructure projects are required to safely and reliably serve customers. No direct offset or savings are expected as a result from this investment.

2.4. Summarize in the table, and describe below the INDIRECT offset4 (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

No indirect capital or O&M offsets are expected to result from this investment. Qualitatively the project reduces exposure to potential customer outages as described in the problem statement and avoidance of possible fines for non-compliance with NERC standards. Both examples of savings cannot be clearly defined with assumed values.

2.5. Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1 – Do Nothing / Status Quo: $0
This alternative is not recommended because it does not mitigate the expected capacity constraints and does not comply with applicable NERC transmission planning standards. Operating Procedures, such as not permitting outages related to other infrastructure projects and turning power off to customers under specific conditions, may be used to defer some system deficiencies.

Alternative 2 – Construct the West Plains New 230kV Substation: $80,000,000
This alternative includes constructing a new 230kV station in the West Plains area. The 230kV station would be sourced through a new 230kV transmission line interconnection with the Bonneville Power Administration (BPA) and/or with connections to Westside Substation. The 115kV portion of the new station is a part of the West Plains Transmission Reinforcement Plan which addresses reliability issues and provides operational flexibility. All system deficiencies identified will be mitigated. Costs of major components of this preferred alternative include:

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 217 of 535

DocuSign Envelope ID: 5697F0BB-C658-4212-801D-35AF9709388B

- $34,000,000 – New Garden Springs station
- $11,500,000 – New Bluebird station
- $28,000,000 – New 230kV transmission line

Alternative 3 – Airway Heights-Westside 115kV Transmission Line: $25,000,000
Constructing a new 9.5-mile 115kV transmission line from Airway Heights to Westside was considered as an alternative. Outages at the Westside station, including the P6 outage of both 230/115kV transformers and P7 outage of the 230kV double circuit into Westside, continue to cause performance issues. A new 230kV source to the Spokane area provides a more robust long-term solution.

Alternative 4 – Garden Springs 230kV Station with 230kV Transmission Line to Westside: $61,000,000
Constructing a 7.9-mile 230kV transmission line from Westside to a new Garden Springs station was considered instead of the proposed Bluebird-Garden Springs 230kV Transmission Line interconnection with BPA. Performance issues are not fully mitigated with this alternative. Specifically, the P7 outage of the 230kV double circuit into Westside continues to be an issue and right-of-way events between Westside and Garden Springs stations do not meet performance criteria. Costs of major components of this alternative include:

- $34,000,000 – New Garden Springs station
- $3,000,000 – Westside station new line position
- $24,000,000 – New 230kV transmission line, including rebuilding existing 115kV lines in same right of way.

2.6. Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Successful mitigation of the problem statement will be monitored as part of the bi-annual System Assessment conducted by System Planning. The project will be successful if performance criteria in short-term planning horizon studies can be met, and performance issues are not observed in the operations time horizon. Assumptions made in System Assessments are not static therefore projects are developed based on the best information available. For example, future load forecasts may show additional load growth not expected when a project is requested. If the project takes ten years to construct, it is possible the base line assumptions have changed, and additional projects will need to be justified.

2.7. Please provide the timeline of when this work is schedule to commence and complete, if known.

Schedule for new Bluebird 230kV Switching Station and the Garden Springs 230/115kV Station:
2023: Engineering Design, Major Equipment Purchases (1–2-year lead times)
2024: Engineering Design, Site Grading.
2025: Foundations, Structures and Electrical construction.
2026: Complete Electrical Construction.
2027: Commissioning and Testing, Final Project Closeout.
2026-2027: Construct new 230kV transmission line.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 218 of 535

DocuSign Envelope ID: 5697F0BB-C658-4212-801D-35AF9709388B

2.8. Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

For the West Plains Reinforcement Project, there will be a Project Manager, Construction Inspectors and Design Engineers (Transmission, Substation and Distribution) that will form the oversight group. The Engineering Roundtable will provide technical review of potential scope changes with the support of the System Planning and Operations department. Scope changes which require additional fund requests to the Capital Planning Group will be vetted at the Engineering Roundtable.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 219 of 535

DocuSign Envelope ID: 5697F0BB-C658-4212-801D-35AF9709388B

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *West Plains System Reinforcement Project* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Glenn J Madden 7D4B3D...	Date:	May-12-2023 | 5:25 PM PDT
Print Name:	Glenn Madden		
Title:	Substation Engineering Manager		
Role:	Business Case Owner		
Signature:	DocuSigned by: Vern Malensky 06C4FF5AB09E40B...	Date:	May-14-2023 | 6:01 PM PDT
Print Name:	Vern Malensky		
Title:	Electrical Engineering Director		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 220 of 535

DocuSign Envelope ID: 37473B22-E0D8-46C2-B56D-0375F2DEB494

EXECUTIVE SUMMARY

Unlike Asset Management studies and analysis that develop long-term facility failure models, the inspection protocols associated with the **Transmission Minor Rebuild Business Case** identify asset problems; that, if left unaddressed, will lead to near-term catastrophic structural failures. These structural failure conditions, if left unaddressed, will result in an increased risk of system failures, customers outages, and wildfires. This includes the follow-up work to Wood Pole Inspections, Aerial Patrol inspections, Ad Hoc ground inspections, and Air Switch Reliability complaints.

More specifically, this Business Case covers the Transmission rebuild and reconductor work necessary to maintain compliance with the North American Electric Reliability Corporation (NERC) Reliability Standard FAC-501-WECC-1 as applied through Avista's Transmission Maintenance Inspection Program (TMIP) This standard mandates that specific Transmission lines be inspected annually and assessed for corrective actions to be implemented to remedy any system performance deficiencies. The TMIP applies the same inspection methodology to the entire Avista system with the understanding that only a portion of the mitigation work is recognized as Mandatory and Compliance. The remaining work undertaken within this Business Case is recognized as Customer Requested, Failed Plant and Asset Condition.

During routinely scheduled inspections, issues are discovered regarding the condition of assets, including items such as rotten poles, broken/split/rotten crossarms, broken conductor or ground/shield wire, and air switches that no longer operate safely or reliably.

The implementation of this business case will be considered successful if these projects are all completed within the same year as inspection, on an annual basis, or the dates identified in the Engineering Roundtable Project List.

The recommended solution is to correct the issues found by these inspections either in the same year, or within 1-2 years afterwards. There are no expected business impacts to continuing this program in place. If Avista does not fully implement this business case, it runs an increased risk of system failures, customers outages, and wildfires. This Program will have a Service Code of Electric Direct and a Rate Jurisdiction of Allocated North.

An annual spend of $4,350,000 is needed to complete the mitigations as follows:

- ER 2057, BI AMT12 and AMT13 ($2,000,000): Wood and Steel Pole Inspections (FAC-501-WECC-1, TMIP)
- ER 2057, BI XT902 ($2,000,000): Aerial and ground inspections (FAC-501-WECC-1, TMIP, and Ad Hoc)
- ER 2254, BI AMT10 ($350,000): Planned/unplanned replacements based on failure or upgrade needs

By not funding this Business Case at the $4,350,000 projects are delayed, creating a bow wave of time sensitive projects moving into outer years. Because of the limited outage windows available for construction (six months out of the year) delaying a project typically means moving six months or over a year. Outage windows are further complicated by competing interests from other departments and Business Cases. The increased funding provides a flexibility in construction to offset this situation.

The customer benefits from this Business Case through increased overall system service reliability.

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VERSION HISTORY

Version	Author	Description	Date
1.0	*Ken Sweigart*	*Initial draft of original business case*	*3/12/2024*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	*Steve Carrozzo 5/1/2024*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	***$4,350,000***	***$4,350,000***
2025	***$4,350,000***	***$4,350,000***
2026	***$4,350,000***	***$4,350,000***
2027	***$4,350,000***	***$4,350,000***
2028	***$4,350,000***	***$4,350,000***
2029	***$4,350,000***	***$4,350,000***

Project Life Span	*Continuous Program*
Requesting Organization/Department	*TLD Engineering*
Business Case Owner | Sponsor	*Ken Sweigart/Vern Malensky*
Sponsor Organization/Department	*Energy Delivery/Electrical Engineering*
Phase	Execution
Category	Program
Driver	Multiple (see Executive Summary)

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. **BUSINESS PROBLEM -** This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.

   During routinely scheduled inspections, issues are discovered regarding the condition of assets, including items such as rotten poles, broken/split/rotten crossarms, broken conductor or ground/shield wire, and air switches that no longer operate safely or reliably.

   The recommended solution is to correct the issues found by these inspections either in the same year, or within 1-2 years afterwards. There are no expected business impacts to continuing this program in place. If Avista does not fully implement this business case, it runs an increased risk of system failures, customers outages, and wildfires.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 222 of 535

DocuSign Envelope ID: 37473B22-E0D8-46C2-B56D-0375F2DEB494

The customer benefits from this Business Case through increased service reliability.

1.1 What is the current or potential problem that is being addressed?

Avoidance of failure conditions; that, if left unaddressed will result in an increased risk of system failures, customers outages, and wildfires.

1.2 Discuss the major drivers of the business case (in descending propriety).

Customer Requested: A small portion of the projects in this Business Case are Customer Requested with an associated Contribution in Aid of Construction (CIAC) component.

Mandatory & Compliance: Both the Pole Inspection and Aerial Patrol Inspection programs for Transmission facilities are linked to NERC Standard FAC-501-WECC-1.

Failed Plant: Projects linked to Ad Hoc Inspections and critical Pole Inspection/Aerial Patrol Inspection results are implemented to address facilities that are a risk of imminent failure. These near-term (<1-2 year) projects make up a portion of this Business Case.

Asset Condition: Projects linked to Pole Inspections and Aerial Patrols that identified under a 2-5+ year need horizon make up a portion of the projects under this Business Case.

Customer benefits by having a Transmission System in compliance with Federal Standards, and one where identified near-term failure risks are proacitively addressed.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Unlike Asset Management studies and analysis that develop long-term facility failure models, the inspection protocols associated with this Business Case identify asset problems; that, if left unaddressed, will lead to near-term catastrophic structural failures.

Because of the limited outage windows available for construction (six months out of the year) delaying a project typically means moving six months or over a year, resulting in a bow wave of projects that accumulate with new annual inspections Outage windows are further complicated by competing interests from other departments and Business Cases. The requested funding provides a flexibility in construction to offset this situation

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

This program focuses on our Customers by making sure that our word and system are reliable, reducing outages and the risk of wildfire.

This program specifically supports the “Safety. Affordability. Responsibly” portion of the Avista Mission Statement.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 223 of 535

DocuSign Envelope ID: 37473B22-E0D8-46C2-B56D-0375F2DEB494

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

Asset Maintenance Wood Pole Management annual inspection reports
Transmission Line Design annual aerial patrol reports
Ad hoc inspections and or real-time notifications from area offices

The above documents identify assets that have reached end of life; and, via testing and visual inspection, are deemed likely to fail in the near term. These assets would typically be placed in 1-2 and 2-5+ year anticipated failure categories, with the most critical deemed likely to fail before end-of-year.

Outage requests on the Avista Transmission System are typically restricted to the lower load months of March -May and September-November. The months of December-February and June-August are Avista's Winter and Summer load peaking months respectively. During these months planned outages are restricted due to system capacity and flexibility constraints.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Proposed solution is to replace those assets deemed at risk of failing in the near term. Replacement greatly reduces risk of failure and it removes any delay or other consequence associated in replacing failed assets such as unplanned outages and potential wildfire implications.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.
[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

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The benefits of this Business Case are seen in something not happening. Pro-actively addressing near-term failures results in avoiding public safety risks including physical, electrical, and fire. A portion of this Business Case was previously funded through an Operations Business Case.

This program is in the Execution Stage with spend directed primarily at structure and structure component change-outs resulting in facility failure avoidance.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

Direct offsets associated with this project are the incremental costs associated with performing work under emergency conditions versus planned conditions. Emergency conditions would likey result in overtime wages and increased contractual expenditures. A lesser probability would be for an unplanned outage to affect other planned outages, or possibly cause load to be dropped. Unplanned outages negatively affect the overall Transmission System.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$2,720	$2,720	$2,720	$2,720	$2,720

There are no additional indirect offsets associated with projects between 2025-2029. The nature of the project (replacing poles, crossarms, or insulators only before end of life) does not change maintenance schedules. The $2,720 offset is related to the changing out of conductor associated with the 2023 Metro-Sunset Rebuild Project.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternatives under this Business Cases primarily resolve in a basic choice of either replacing or not replacing the identified asset. The amount of work completed each year is tailored to the available budget. When immediate replacements are required as a result of in-year inspection

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 225 of 535

DocuSign Envelope ID: 37473B22-E0D8-46C2-B56D-0375F2DEB494

additional monies may be requested. By not funding this Business Case at the $4,350,000 projects are delayed, creating a bow wave of time sensitive projects moving into outer years.

Alternative 1:

Do Nothing: Unlike Asset Management studies and analysis that develop long-term facility failure models, the inspection protocols associated with this Business Case identify asset problems; that, if left unaddressed, will lead to near-term catastrophic structural failures.

Alternative 2:

Reinforce: Only wood poles have an option for being reinforced rather than being replaced. This is identified in the Wood Pole Inspection notes. This is further evaluated by the Engineer to determine most cost effective response. The cost for reinforcing a pole is approximately $2,500, and is the solution of choice when there are no other extenuating circumstances.

Alternative 3:

Replace Identified Assets: See commentary for Alternative 2. Where assets are not reinforced the solution is to fully replace. The cost of replacing a pole leads to replacing the entire structure. Similar to most installation projects the unit cost of replacing a pole/structure can vary based on location, access, and other extenuating circumstances. $50,000 is generally a middle-of-the-road estimate for replacing a structure.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

As-Built confirmation of mitigation measures.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Outage requests on the Avista Transmission System are typically restricted to the lower load months of March -May and September-November. The months of December-February and June-August are Avista's Winter and Summer load peaking months respectively. During these months planned outages are restricted due to system capacity and flexibility constraints.

Some smaller projects can take place throughout the year. Most projects take place in the Spring or Fall months and Transfer to Plant in the June or November/December time frame.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The Engineering Roundtable functions as the Vetting Platform, Steering Committee, and Advisory Group.

Electrical Engineering Expected Spend Committee reviews on a monthly basis ongoing spend for projects approved by the ERT. Committee members include Managers, Project Managers, analysts, and the Electrical Engineering Director.

During the design phase these functions are processed through the Engineering Roundtable. During large project Contracted construction, Change Orders are processed through Supply Chain. On smaller in-house construction projects, changes are agreed upon at the Project Eneginer/Project Manager, and are documented in the As-Built process.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 226 of 535

DocuSign Envelope ID: 37473B22-E0D8-46C2-B56D-0375F2DEB494

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Transmission Minor Rebuild Business Case Justification Narrative* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Ken Sweigart 210C3[illegible]	Date:	May-02-2024 | 3:11 PM PDT
Print Name:	Ken Sweigart		
Title:	Manager, Transmission Line Design		
Role:	Business Case Owner		

Signature:	DocuSigned by: Vern Malensky 06C4FF[illegible]	Date:	May-03-2024 | 1:51 PM PDT
Print Name:	Vern Malensky		
Title:	Director of Electrical Engineering		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 227 of 535

DocuSign Envelope ID: D96B1413-B150-4E36-BB6B-C1DF5EED8DC0

Transmission Construction - Compliance

EXECUTIVE SUMMARY

The **Transmission Construction – Compliance Business Case** covers the Transmission rebuild and reconductor work necessary to maintain compliance with the NERC Reliability Standard TPL-001-4 – Transmission System Planning Performance Requirements ("Standard"). It 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. This standard mandates that an annual planning assessment be conducted and corrective actions be identified and implemented to remedy any system performance deficiencies. In addition, when Avista's system planning studies indicate any kind of problem that could arise in the transmission system, it must be remedied within specific timeframes. The Transmission Construction - Compliance Program provides funding to mitigate any identified reliability issues in order to remain in compliance with NERC requirements**. As of Spring 2024 there are thirty-four (34) structures that need to be replaced on seven (7) transmission lines with additional remediation expected as new Joint Use requests are received going forward.**

The implementation of this business case will be considered successful if these projects are all completed prior to the required compliance dates identified in the Engineering Roundtable Project List, which are copied from the Corrective Action Plans (within the annually published Avista System Planning Assessment).

The Transmission Construction – Compliance Business Case also covers the Transmission line rebuild for lines not meeting National Electric Safety Code (NESC) physical capacities for appropriate loading cases. These code minimums have also been adopted into the State of Washington's Administrative Code (WAC). These lines may have met the NESC criteria at the time of their original construction, but have been found to not be up to standards through anaysis either as a result of requests for facility additions, or identified past additions not analyzed at the time of installation.

The recommended solution is to build, rebuild, or reconductor transmission lines as identified in the Corrective Action Plans to stay in compliance with NERC mandatory and enforceable Reliability Standards (most notably TPL-001-4) and the NESC code (via WAC).

If Avista does not implement this business case, the company is at risk of violating NERC Reliability Standard Requirements and could be subject to penalties of up to $1M per day for the duration of any such violation. Following a "do nothing" option for this business case would likely be treated as an aggravating factor by the regulatory authority when assessing enforcement actions. If Avista does not fully implement this business case, it also runs the risk of being fined for not staying in compliance with the NESC code and WAC rules. There are no expected business impacts to continuing this program in place. A spend of $3,000,000 is needed to complete the planned 2025-2029 projects . This Program will have a Service Code of Electric Direct and a Rate Jurisdiction of Allocated North.

The 2025-2029 Business Case contains multiple identified and anticipated projects based on Joint Use attachment analyses.

The customer benefits from this Business Case through increased service reliability and avoided fines

VERSION HISTORY

Version	Author	Description	Date
1.0	*Ken Sweigart*	*Initial draft of original business case*	*3/12/2024*

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 228 of 535

DocuSign Envelope ID: D96B1413-B150-4E36-BB6B-C1DF5EED8DC0

BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	*Steve Carrozzo 5/01/24*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$1,000,000	$1,000,000
2025	$1,000,000	$1,000,000
2026	$500,000	$500,000
2027	$500,000	$500,000
2028	$500,000	$500,000
2029	$500,000	$500,000

Project Life Span	*Continuous Program and Individual Projects*
Requesting Organization/Department	*TLD Engineering*
Business Case Owner | Sponsor	*Ken Sweigart/Vern Malensky*
Sponsor Organization/Department	*Energy Delivery/Electrical Engineering*
Phase	Execution
Category	Program and Projects
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 229 of 535

DocuSign Envelope ID: D96B1413-B150-4E36-BB6B-C1DF5EED8DC0

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

The Transmission Construction – Compliance Business Case covers the Transmission rebuild and reconductor work necessary to maintain compliance with the NERC Reliability Standard TPL-001-4 – Transmission System Planning Performance Requirements ("Standard"). This standard mandates that an annual planning assessment be conducted and corrective actions be identified and implemented to remedy any system performance deficiencies. Corrective Action Plans must be completed within the required timeframe to meet the system performance requirements dictated by the Standard.

The Transmission Construction – Compliance Business Case also covers the Transmission line rebuild for lines not meeting National Electric Safety Code (NESC) physical capacities for appropriate loading cases. These code minimums have also been adopted into the State of Washington's Administrative Code (WAC). These lines may have met the NESC criteria at the time of their original construction, but have been found to not be up to standards through anaysis either as a result of requests for facility additions, or identified past additions not analyzed at the time of installation. **As of Spring 2024 there are thirty-four (34) structures that need to be replaced on seven (7) transmission lines with additional remediation expected as new Joint Use requests are received going forward. It is expected that 7-10 structures will be addressed per year once the initial group of structures are replaced.**

1.2 Discuss the major drivers of the business case.

Mandatory & Compliance: Customer benefits by having a Transmission System in compliance with Federal Code and State Law. If Avista does not implement this business case, the company is at risk of violating NERC Reliability Standard Requirements and could be subject to penalties of up to $1M per day for the duration of any such violation. State law (WAC) violations are expected to have severe consequences as well.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

2.9 Concealment or Intentional Violation:

NERC or the Regional Entity shall always consider as an aggravating factor any attempt by a violator to conceal the violation from NERC or the Regional Entity, or any intentional violation incurred for purposes other than a demonstrably good faith effort to avoid a significant and greater threat to the immediate reliability of the Bulk Power System.

2.10 Economic Choice to Violate:

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Penalties shall be sufficient to assure that entities responsible for complying with Reliability Standards do not have incentives to make economic choices that cause or unduly risk violations of Reliability Standards, or incidents resulting from violations of the Reliability Standards. Economic choice includes economic gain for, or the avoidance of costs to, the violator. NERC or the Regional Entity shall treat economic choice to violate as an aggravating factor when determining a Penalty.

2.15 Maximum Limitations on Penalties:

In the United States, the maximum Penalty amount that NERC or a Regional Entity will assess for a violation of a Reliability Standard Requirement is $1,000,000 per day per violation. NERC and the Regional Entities will assess Penalties amounts up to and including this maximum amount for violations where warranted pursuant to these Sanction Guidelines.

In the case of projects addressing NESC capacity inadequacies, Avista will be cognisant of not meeting the WAC. As of Spring 2024 there are thirty-four (34) structures that need to be replaced on seven (7) transmission lines with additional remediation expected as new Joint Use requests are received going forward.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link***.**

Avista Strategic Goals

This program specifically supports the "Safety. Affordability. Responsibly" portion of the Avista Mission Statement.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 231 of 535

DocuSign Envelope ID: D96B1413-B150-4E36-BB6B-C1DF5EED8DC0

Replacing overloaded poles helps guard against increasing risk for more failures and outages (in addition to reducing litigation risks). Transmission outages can have significant consequences, as they tend to impact a large number of customers and have the potential to start fires in dry areas. In addition to reliability issues, failure to properly invest builds a bow-wave of needed investments in the future, thus this program is crucial to maintaining operations.

The Transmission Construction – Compliance Business Case covers Transmission line rebuilds for lines not meeting National Electric Safety Code (NESC) physical capacities for appropriate loading cases. These code minimums have also been adopted into the State of Washington's Administrative Code (WAC). These lines may have met the NESC criteria at the time of their original construction, but have been found to not be up to standards through anaysis either as a result of requests for facility additions, or identified past additions not analyzed at the time of installation.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

APL-RAT 115kV Joint Use Request Structural Analysis (1/8-1/12 & 4/1-4/8)
M23-TVW 115kV Joint Use Request Structural Analysis (3/13)
9CE-OPT 115kV Joint Use Request Structural Analysis (5/16)
AIR-FLT 115kV Joint Use Request Structural Analysis (0/18, 1/11, 2/11 & 2/14)
CLW-LOL#1 115kV Joint Use Request Structural Analysis (4/5 & 4/6)
BEA-9CE#1 115kV Joint Use Request Structural Analysis (2/12-2/14)
9CE-3HT 115kV Joint Use Request Structural Analysis (3/3-3/14)

The above are all reports prepared in response to 3rd party Joint Use (JU) attachment requests showing an existing structural deficiency of 115kV structures beyond added JU responsibility.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 232 of 535

DocuSign Envelope ID: D96B1413-B150-4E36-BB6B-C1DF5EED8DC0

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

This is the continuation of an ongoing Program and requires the replacement of infrastructure to support compliance requirements.

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Proposed solution is to replace those assets (poles); that, by analysis, do not meet NESC minimum strength requirements. Analysis takes place when a Joint User entity requests attachment to an Avista Transmission pole. When analysis for a new attachment shows Avista has a structurally overloaded pole not caused by the Joint User, Avista is obligated to replace the pole. The NESC has been adopted by the Washington Administrative Code (WAC). Failing to replace these structures will place Avista in violation of the WAC.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

The benefits of this Business Case are seen in something not happening. Pro-actively replacing poles that are structurally overloaded and in violation of WAC adopted NESC standards results in avoiding high consequence public safety risks including physical, electrical, and fire. It also avoids, in the case of potential litigation, discovery of Avista knowingly being in violation of state law (WAC). It is reasonable that the consequences of such a situation would be severe.. If Avista does not implement this business case, the company is at risk of violating NERC Reliability Standard Requirements and could be subject to penalties of up to $1M per day for the duration of any such violation. State law (WAC) violations are expected to have severe consequences as well.

This program is in the Execution Stage with spend directed at structure change-outs resulting in asset failure avoidance.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$5,000	$5,000	$5,000	$5,000	$5,000

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 233 of 535

DocuSign Envelope ID: D96B1413-B150-4E36-BB6B-C1DF5EED8DC0

O&M		$	$	$	$	$

Direct offsets associated with this project are the incremental costs associated with performing work under emergency conditions versus planned conditions. Emergency conditions would likey result in overtime wages and increased contractual expenditures. A lesser probability would be for an unplanned outage to affect other planned outages, or possibly cause load to be dropped. Unplanned outages negatively affect the overall Transmission System.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no additional indirect offsets associated with projects between 2025-2029. The nature of the project (replacing poles) does not change maintenance schedules.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternatives under this Business Cases primarily resolve in a basic choice of either replacing or not replacing the identified asset. The amount of work completed each year is tailored to the available budget. When immediate replacements are required as a result of in-year inspection additional monies may be requested. By not funding this Business Case at the requested amount projects are delayed, creating a bow wave of time sensitive projects moving into outer years.

Alternative 1:

Maintain As-Is ($0 until a failure occurs): Proposed solution is to replace those assets (poles); that, by analysis, do not meet NESC minimum strength requirements. The NESC has been adopted by the Washington Administrative Code (WAC). Failing to replace these structures will place Avista in violation of the WAC. When a failure does occur Avista will be in a situation of not fixing an asset that was in violation of the WAC. Situation would be similar to a utility being shown to be deficient in maintenance or vegetation management resulting in a wildfire. If Avista does not implement this business case, the company is at risk of violating NERC Reliability Standard Requirements and could be subject to penalties of up to $1M per day for the duration of any such violation. State law (WAC) violations are expected to have severe consequences as well.

Alternative 2:

Reinforce ($2,500 per pole when applicable – almost never): Only wood poles have an option for being reinforced rather than being replaced. This is identified in the Wood Pole Inspection (WPI) notes, and would only be an option where the pole is not structurally overloaded but is recently identified as being available for reinforcement per WPI. This would be a rare situation where the

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

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structural analysis picks up info from a recent WPI not directly attributable to the structural overloading issue. Further evaluation by the Engineer would determine most cost effective response. The cost for reinforcing a pole is approximately $2,500, and is the solution of choice when there are no other extenuating circumstances.

Alternative 3:

Replace Identified Assets ($50,000 or more per structure): The cost of replacing a pole leads to replacing the entire structure. Similar to most installation projects the unit cost of replacing a pole/structure can vary based on location, access, and other extenuating circumstances. $50,000 is generally a middle-of-the-road estimate for replacing a structure.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

As-Built confirmation of mitigation measures in addition to project schedule tracking will clear the initial thirty-four (34) structures that need to be replaced on seven (7) transmission lines with additional remediation expected as new Joint Use requests are received going forward. It is expected that 7-10 structures will be addressed per year once the initial group of structures are replaced.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Outage requests on the Avista Transmission System are typically restricted to the lower load months of March -May and September-November. The months of December-February and June-August are Avista's Winter and Summer load peaking months respectively. During these months planned outages are restricted due to system capacity and flexibility constraints.

Some smaller projects can take place throughout the year. Most projects take place in the Spring or Fall months and Transfer to Plant in the June or November/December time frame.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The Engineering Roundtable functions as the Vetting Platform, Steering Committee, and Advisory Group.

Electrical Engineering Expected Spend Committee reviews on a monthly basis ongoing spend for projects approved by the ERT. Committee members include Managers, Project Managers, analysts, and the Electrical Engineering Director.

During the design phase these functions are processed through the Engineering Roundtable. During large project Contracted construction, Change Orders are processed through Supply Chain. On smaller in-house construction projects, changes are agreed upon at the Project Engineer/Project Manager, and are documented in the As-Built process. Any needed funding increases would be requested through the Capital Planning Group (CPG).

DocuSign Envelope ID: D96B1413-B150-4E36-BB6B-C1DF5EED8DC0

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Transmission Construction – Compliance Business Case Justification Narrative* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Ken Sweigart 210C354[illegible]	Date:	May-02-2024 | 3:07 PM PDT
Print Name:	Ken Sweigart		
Title:	Manager, Transmission Line Design		
Role:	Business Case Owner		

Signature:	DocuSigned by: Vern Malensky 06C4FF[illegible]	Date:	May-03-2024 | 1:53 PM PDT
Print Name:	Vern Malensky		
Title:	Director of Electrical Engineering		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 236 of 535

DocuSign Envelope ID: CE0A277F-5D1B-4AA0-A23C-C6C8C205C5B8

EXECUTIVE SUMMARY

The **Transmission Critical Crossing Reinforcements Business Case** identifies high failure consequence asset/structure locations; that, if subject to failure, would create life loss or injury conditions. This would lead to diminished brand image and likely a loss of trust with Avista's service territory community. Additional concern would be potential customer outages.

The triggering event for this Business Case is the "near miss" shown in the following photos:

The first photo shows a Benewah-Boulder 230kV h-frame structure located on the south side of Interstate I-90 crossing near Liberty Lake, WA. The second photo shows what took place. A single polymer insulator holding the I-90 crossing conductor broke. The only thing that prevented the conductor from falling in 70 mph traffic was the jumper splice (shown in the second photo). Jumper splices are not designed to hold full wire tension; and, under higher tension conditions, would have likely failed with the insulator. Avista doesn't have a way to inspect insulators for remaining life similar to wood poles. What Avista does have is an updated reinforced design that uses higher class steel structures and redundant insulator hardware (shown below).

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 237 of 535

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Transmission Critical Crossing Reinforcments

Avista's 230kV/115kV railroad line crossings have historically been reinforced through additional guying at time of construction, and would be considered as part of a replaced/rebuilt structure. This reinforcement originally was required by the railroads to protect their interests. The idea behind this concept should guide Avista's approach to other critical crossings. What this Business Case does is provide a heightened level of reinforcement (based on present-day construction matrerials) for freeways and highways.

The work within this Business Case is recognized as High Risk Asset Condition.

Review of Interstate and US Route Highways within Avista territory shows (56) 230kV/115kV line crossings. Of these most were constructed between the 1960's and 1980's, with some having been built in the 1940's and 1950's, encroaching on their end-of-life (typical wood structure estimated to have a 60-70 year life). It is expected that a review of State Route Highways will result in similar or greater risk results.

The implementation of this Business Case will be considered successful if these projects are all completed within the same year as planned, or according to the dates identified in the Engineering Roundtable Project List.

The recommended solution is to replace the existing wood pole freeway and highway crossings with an updated reinforced steel pole design. There are no expected business impacts to continuing this program in place. If Avista does not fully implement this business case, it runs an increased risk of high consequence failure events. This Program will have a Service Code of Electric Direct and a Rate Jurisdiction of Allocated North.

An annual spend of $2,000,000 is needed to complete the mitigations in an expedient manner. Prioritization will be based on age and location. Case-by-case complexities will determine cost to mitigate each crossing.

By not funding this Business Case at the $2,000,000 level projects are delayed, creating a bow wave of time sensitive projects moving into outer years. Because of the limited outage windows available for construction (six months out of the year) delaying a project typically means moving six months or over a year. Outage windows are further complicated by completing interests from other departments and Business Cases. The funding level provides flexibility in construction to offset this situation.

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The customer benefits from this Business Case through increased public safety and reliability.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Ken Sweigart*	*Initial draft of original business case*	*3/12/2024*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	*Steve Carrozzo 5/1/2024*

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 239 of 535

DocuSign Envelope ID: CE0A277F-5D1B-4AA0-A23C-C6C8C205C5B8

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$2,000,000**	**$2,000,000**
2025	**$2,000,000**	**$2,000,000**
2026	**$2,000,000**	**$2,000,000**
2027	**$2,000,000**	**$2,000,000**
2028	**$2,000,000**	**$2,000,000**
2029	**$2,000,000**	**$2,000,000**

Project Life Span	*Continuous Program Until Completion approx 10 yrs*
Requesting Organization/Department	*TLD Engineering*
Business Case Owner | Sponsor	*Ken Sweigart/Vern Malensky*
Sponsor Organization/Department	*Energy Delivery/Electrical Engineering*
Phase	Execution
Category	Program
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. **BUSINESS PROBLEM -** *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

During routinely scheduled inspections, issues are discovered regarding the condition of assets, including items such as rotten poles, broken/split/rotten crossarms, broken conductor or ground/shield wire, insulators, and air switches that no longer operate safely or reliably. These types of inspections cannot capture all the potential asset failures. Reinforcement by way of structure, insulator, hardware and conductor replacements of high consequence crossings is the solution.

Avista's 230kV/115kV railroad line crossings have historically been reinforced through additional guying at time of construction, and would be considered as part of a replaced/rebuilt structure. This reinforcement originally was required by the railroads to protect their interests. The idea behind this concept should guide Avista's approach to other critical crossings. What this Business Case does is provide a heightened level of reinforcement (based on present-day construction matrerials) for freeways and highways.

Review of Interstate and US Route Highways within Avista territory shows (56) 230kV/115kV line crossings. Of these most were constructed between the 1960's and 1980's, with some having been built in the 1940's and 1950's, encroaching on their end-of-life (typical wood structure estimated to have a 60-70 year life). It is expected that a review of State Route Highways will result in similar or greater risk results.

The recommended solution is to replace the existing wood pole freeway and highway crossing with an

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 240 of 535

DocuSign Envelope ID: CE0A277F-5D1B-4AA0-A23C-C6C8C205C5B8

updated reinforced steel pole design, similar to that used throughout the utility industry. There are no expected business impacts to continuing this program in place. If Avista does not fully implement this business case, it runs an increased risk of high consequence failure events.

The customer benefits from this Business Case through increased public safety and system reliability.

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1.1 What is the current or potential problem that is being addressed?

Avoidance of failure conditions; that, if left unaddressed will result in an increased consequence risk to public safety and system reliability.

Review of Interstate and US Route Highways within Avista territory shows (56) 230kV/115kV line crossings. Of these most were constructed between the 1960's and 1980's, with some having been built in the 1940's and 1950's, encroaching on their end-of-life (typical wood structure estimated to have a 60-70 year life). It is expected that a review of State Route Highways will result in similar or greater risk results.

1.2 Discuss the major drivers of the business case.

Asset Condition: Projects linked to wood pole critical freeway/highway crossings make up the projects under this Business Case.

The customer benefits from this Business Case through increased public safety and system reliability.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The previous failure event on the Benewah-Boulder 230kV Transmission Line shows the vulnerability of our critical crossing assets. Pre-emptively addressing these identified assets will reduce a high consequence risk. The risk profile is similar to that of Wildfire (low probability with a very high consequence resulting in a high risk profile).

Review of Interstate and US Route Highways within Avista territory shows (56) 230kV/115kV line crossings. Of these most were constructed between the 1960's and 1980's, with some having been built in the 1940's and 1950's, encroaching on their end-of-life (typical wood structure estimated to have a 60-70 year life). It is expected that a review of State Route Highways will result in similar or greater risk results.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

This program focuses on our Customers by making sure that our word and system are reliable, reducing outages and the risk to publice safety.

This program specifically supports the "Safety. Affordability. Responsibly" portion of the Avista Mission Statement.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 242 of 535

DocuSign Envelope ID: CE0A277F-5D1B-4AA0-A23C-C6C8C205C5B8

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

Critical Crossings Age and Material Summary Spreadsheet, summarized as:

- Between Interstate and US Route Roadways, there are (80) 230/115kV crossings
  - (47) Wood and (33) Steel
  - Majority of Wood Poles between 40-65 years old
  - Some younger Wood Poles (25-30 years old) may be able to be reinforced rather than replaced.
- Results for State Routes expected to yield higher number and percentage of wood poles

This Business Case allows immediate attention to those assets based on age and location. Failure to fully fund this Business Case will result in a bow wave of projects that are of the most time sensitive nature.

Outage requests on the Avista Transmission System are typically restricted to the lower load months of March -May and September-November. The months of December-February and June-August are Avista's Winter and Summer load peaking months respectively. During these months planned outages are restricted due to system capacity and flexibility constraints.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Proposed solution is to replace those assets deemed at risk of failing in the near term and at locations of highest risk consequence. Replacement greatly reduces risk of future failure.

Specifically the proposed solution is to fully replace wood structure crossings. $75k-$100k is generally a middle-of-the-road deadend estimate for replacing a structure, but complexities encountered around freeway/highway locations could easily increase the unit cost. It is expected 5-10 locations would be addressed per year.

More specifically, the replaced structures will either be direct embed or caisson foundation steel poles with redundant (double) toughened glass insulators. This design configuration is common in the utility undustry and will bring Avista's level of commitment to roadway crossings on a level of that with railroad crossings.

Steel structures are estimated to have a life span over 100-years. The existing wood poles are estimated to have life spans in the 60-70 year range. Some wood pole lines (HAT-M23) have shown wood pole life spans to be even lower.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

DocuSign Envelope ID: CE0A277F-5D1B-4AA0-A23C-C6C8C205C5B8

Transmission Critical Crossing Reinforcments

DocuSign Envelope ID: CE0A277F-5D1B-4AA0-A23C-C6C8C205C5B8

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

The benefits of this Business Case are seen in something not happening. Pro-actively addressing failures results in avoiding public safety risks including physical, electrical, and fire.

This program is in the Execution Stage with spend directed at structure and structure component change-outs resulting in asset failure avoidance.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$5,000	$5,000	$5,000	$5,000	$5,000
O&M		$	$	$	$	$

Direct offsets associated with this project are the incremental costs associated with performing work under emergency conditions versus planned conditions. Emergency conditions would likey result in overtime wages and increased contractual expenditures. A lesser probability would be for an unplanned outage to affect other planned outages, or possibly cause load to be dropped. Unplanned outages negatively affect the overall Transmission System.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no indirect offsets associated with projects between 2025-2029. The nature of the project (replacing poles, crossarms, or insulators only before end of life) does not change maintenance schedules. Indirect Risk Costs include outage claims as well as loss of life and property lawsuits.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

DocuSign Envelope ID: CE0A277F-5D1B-4AA0-A23C-C6C8C205C5B8

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternatives under this Business Cases primarily resolve in a basic choice of either replacing or not replacing the identified asset. The amount of work completed each year is tailored to the available budget. When immediate replacements are required as a result of in-year inspection additional monies may be requested. By not funding this Business Case at the $2,000,000 projects are delayed, creating a bow wave of time sensitive projects moving into outer years.

Alternative 1:

Do Nothing: See Sections 1.5, 2.1, and 2.2 for commentary. Replace only when asset fails. Direct offset cost is the difference between planned replacement and unplanned replacement. Avoided consequence cost would be much higher and should be considered in the same way we consider avoidance of wildfires.

Alternative 2:

Reinforce or replace hardware/components: Wood poles have an option for being reinforced rather than being replaced. If applicable, this partial solution option would only be employed as a temporary fix as part of a future full replacement in the event of funds or outage restrictions. The Engineer shall determine most cost effective response. A “best case” temporary fix would be to spend $5,000 to reinforce poles in anticipation of rebuilding structure within 6 months to 1 year (see Post Falls-Ramsey I-90 crossing).

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

As-Built confirmation of mitigation measures. We expect to complete 5-10 locations per year, resulting in a reduction in failure risk..

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Outage requests on the Avista Transmission System are typically restricted to the lower load months of March -May and September-November. The months of December-February and June-August are Avista’s Winter and Summer load peaking months respectively. During these months planned outages are restricted due to system capacity and flexibility constraints.

Some smaller projects can take place throughout the year. Most projects take place in the Spring or Fall months and Transfer to Plant in the June or November/December time frame.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The Engineering Roundtable functions as the Vetting Platform, Steering Committee, and Advisory Group.

DocuSign Envelope ID: CE0A277F-5D1B-4AA0-A23C-C6C8C205C5B8

Electrical Engineering Expected Spend Committee reviews on a monthly basis ongoing spend for projects approved by the ERT. Committee members include Managers, Project Managers, analysts, and the Electrical Engineering Director.

During the design phase these functions are processed through the Engineering Roundtable. During large project Contracted construction, Change Orders are processed through Supply Chain. On smaller in-house construction projects, changes are agreed upon at the Project Eneginer/Project Manager, and are documented in the As-Built process.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 247 of 535

DocuSign Envelope ID: CE0A277F-5D1B-4AA0-A23C-C6C8C205C5B8

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Transmission Critical Crossing Reinforcements Business Case Justification Narrative* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Ken Sweigart 210C35[illegible]98D	Date:	May-02-2024 | 3:08 PM PDT
Print Name:	Ken Sweigart		
Title:	Manager, Transmission Line Design		
Role:	Business Case Owner		

Signature:	DocuSigned by: Vern Malensky 06C4FF[illegible]4AF	Date:	May-03-2024 | 1:55 PM PDT
Print Name:	Vern Malensky		
Title:	Director of Electrical Engineering		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 248 of 535

DocuSign Envelope ID: 71A7FE08-C4C8-4D85-867A-E7838EE9820F

Transmission Major Rebuild – Asset Condition

EXECUTIVE SUMMARY

*The **Transmission Major Rebuild – Asset Condition Business Case** covers major rebuilds of transmission lines due to overall asset condition. Although line conductor will sometimes be included in the rebuild scope, the primary target of this business case is the replacement of aging wood infrastructure. Factors considered in prioritizing work include condition, sustained outages, accessibility, system reliability, wildfire risk, customer density, and reputation impact. Potential for joint facility improvements (i.e. communications build-out) are also considered in prioritizing this work. The projects within this program are developed through Asset Management's general analysis of Avista's Transmission System facilities that provides a risk-based ranking of over 100 Transmission Lines. Projects are chosen to maximize stakeholder value.*

Investments made under this program rebuild existing transmission lines based on overall asset condition. "Condition" is measured by useful life or the number of condition-related outages. Factors such as operational issues, ease of access during outages, and need to add automation or communications equipment may be included in the type of spending in this category. Replacing old and worn-out poles and cross-arms and other associated transmission equipment help guard against increasing risk for more failures and outages. Transmission outages can have significant consequences, as they tend to impact a large number of customers and have the potential to start fires in dry areas. In addition to reliability issues, failure to properly invest builds a bow-wave of needed investments in the future, thus this program is crucial to maintaining operations. When facilities reach an age when it is close to or at the end of its useful life, the Company preventively replaces it to maintain reliability and acceptable levels of service.

The implementation of this business case will be considered successful if these projects are completed as planned on time and on budget.

The recommended solution is to rebuild transmission lines as prioritized by the Engineering Roundtable group to ensure that Avista sufficiently addresses its aging Transmission Line infrastructure. There are no expected business impacts to continuing this program in place. This Program will have a Service Code of Electric Direct and a Rate Jurisdiction of Allocated North. A spend of $10,000,000 is needed to complete the projects as follows:

- *ER 2631, BI CT207 ($25,000,000): Pine Street-Rathdrum 115kV Transmission Line Rebuild Phases 2 through 3 (years 2023-2025)*
- *ER 2596, BI LT900 ($8,300,000): Lolo-Oxbow 230kV Transmission Line Rebuild Phase 3 (year 2024-2025)*
- *ER 2116, BI KT901 ($10,000,000): Noxon-Pine Creek 230kV Transmission Line Rebuild (year 2026)*
- *ER 2594, BI CT207 ($30,000,000): Benewah-Pine Creek 230kV Transmission Line Rebuild Phases 1 through 3 (year 2027-2029)*

Avista, KEC, and IP&L customers benefit from this Business Case through improved service reliability. Avista's brand image improves as showing commitment to all customers.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Ken Sweigart*	*Initial draft of original business case*	*3/13/2024*
BCRT	*BCRT Team Member – Joe Wright*	*Has been reviewed by BCRT and meets necessary requirements*	*5/2/24*

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 249 of 535

DocuSign Envelope ID: 71A7FE08-C4C8-4D85-867A-E7838EE9820F

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$11,300,000**	**$8,000,000**
2025	**$13,000,000**	**$16,300,000**
2026	**$10,000,000**	**$10,000,000**
2027	**$10,000,000**	**$10,000,000**
2028	**$10,000,000**	**$10,000,000**
2029	**$10,000,000**	**$10,000,000**

Project Life Span	*Continuous Program*
Requesting Organization/Department	*TLD Engineering*
Business Case Owner | Sponsor	*Ken Sweigart/Vern Malensky*
Sponsor Organization/Department	*Energy Delivery/Electrical Engineering*
Phase	*Execution*
Category	*Program*
Driver	*Asset Condition*

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

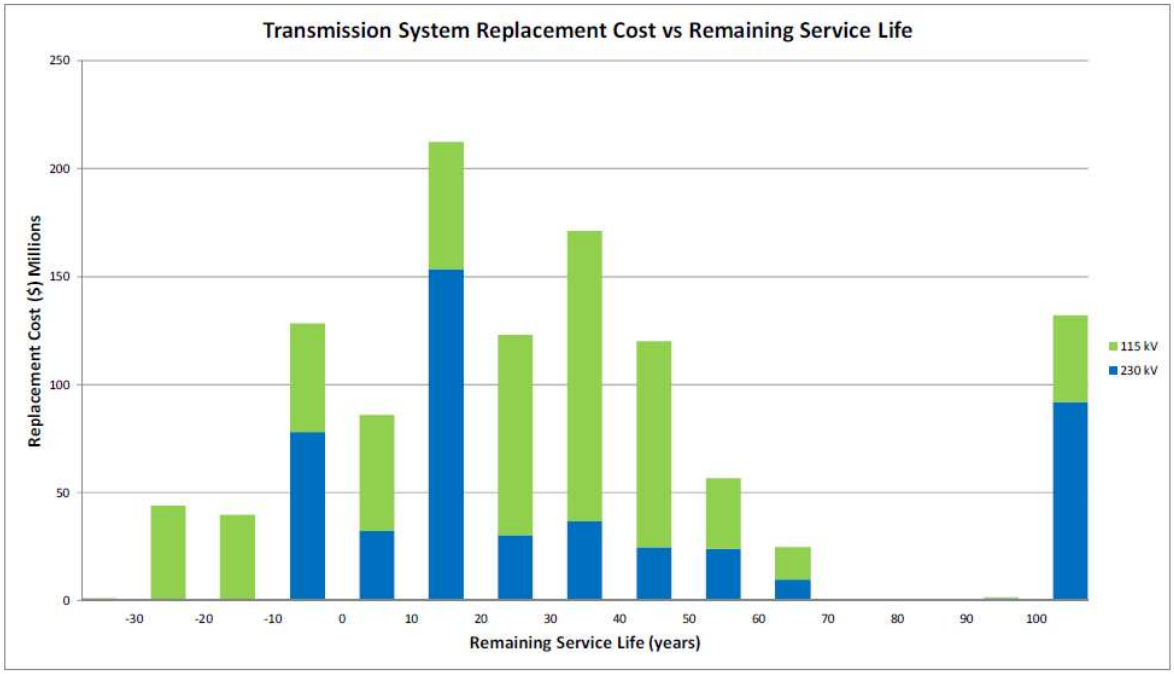
Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 250 of 535

DocuSign Envelope ID: 71A7FE08-C4C8-4D85-867A-E7838EE9820F

1. **BUSINESS PROBLEM -** *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

The Transmission Major Rebuild – Asset Condition Business Case covers investments made to rebuild existing transmission lines based on overall asset condition. "Condition" is measured by useful life or the number of condition-related outages. Factors such as operational issues, ease of access during outages, and need to add automation or communications equipment may be included in the type of spending in this category. Replacing old and worn-out poles and cross-arms and other associated transmission equipment, help guard against increasing risk for more failures and outages. Transmission outages can have significant consequences, as they tend to impact a large number of customers and have the potential to start fires in dry areas. In addition to reliability issues, failure to properly invest builds a bow-wave of needed investments in the future, thus this program is crucial to maintaining operations. When facilities reach an age when it is close to or at the end of its useful life, the Company preventively replaces it to maintain reliability and acceptable levels of service.

The below graph shows a snapshot of the system asset age as of 2016. We have a number of assets beyond their remaining service life. Some poles can make it past their service life and others failure much earlier, but the average is reflected in the graph. Trends show that "old growth" poles last longer than "new growth" poles, which may explain why we are seeing concerning failure trends in some lines 50-years old and less.



The following excerpt is taken from the 2016 AM Transmission System AM Plan Executive Summary:

Consistent with last year's assessment, the primary message of this asset management plan is that the company must commit itself to sustainably replace the bulk of the aging transmission system over the next three decades. This is essential to achieve the company's strategic objectives of maintaining reliability levels while minimizing total lifecycle costs, requiring over $624 million in capital replacement investment. As this represents a significant increase in capital investment as well as internal and external workloads from recent years, success demands strong

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company support and management. In order to be most effective and beneficial to customers and the company, it also requires fact-based prioritization and targeting of available funds to the riskiest elements of the system. Replacement budget recommendations remain relatively unchanged at $12 million for 115kV and $9 million for 230kV. Planned budgets for 2016 and 2017 are relatively close to this recommendation. Additional mandated, growth and reimbursable capital projects, as well as O&M work puts the total planned budget for Transmission Engineering at approximately $25 million for 2016 and is expected to remain at this level or increase for many years.

1.1 What is the current or potential problem that is being addressed?

Transmission outages can have significant consequences, as they tend to impact a large number of customers and have the potential to start fires in dry areas. In addition to reliability issues, failure to properly invest builds a bow-wave of needed investments in the future, thus this program is crucial to maintaining operations.

The Pine St.-Rathdrum (PIP-RAT) 115kV line is nearing end of life and showing signs of increased plant failures. While the remaining wood poles average approximately 20-years of remaining life, the most recent wood pole inspections noted (120) major components (poles/crossarms) needing closer inspection, reinforcement, or replacement; an indication of facilities nearing end-of-life.

Additionally, sustained outages experienced by PIP-RAT have increased over the past 5-years to average nearly two per year (see Section 2.2). This increase is another signal that the line's life span is trending shorter than the average.

The Lolo-Oxbow (LOL-OXB) 230kV Transmission Line was ranked #1 under the old Asset Management prioritizing system (see table in Section 1.3) and underwent two phases of reconstruction. The third phase of this project is funded to start in 2024, with completion in early 2025. Beyond 2025 the Lolo-Oxbow project is more of a placeholder and will be evaluated against other transmission if not chosen approved for a DOE Grant.

The Noxon-Pine Creek (NOX-PIN) 230kV line is nearing end of life and shows a significant increase in Wood Pole Management test failures. This line is scheduled for a 2024 Minor Rebuild to take care of the poorest condition structures, with the remaining structures to be replaced in 2026 under this Business Case. The testing failure increases are reflective of what took place on the recently rebuilt Hatwai-Moscow 230kV Line in 2022 under this Business Case. The NOX-PIN line was ranked #2 under the old Asset Management prioritizing system (see table in Section 1.3).

The Benewah-Pine Creek (BEN-PIN) 230kV Transmission Line was ranked #3 under the old Asset Management prioritizing system (see table in Section 1.3). At this time the BEN-PIN project is more of a placeholder and will be evaluated against other transmission lines for the 2027-2029 fiscal years.

1.2 Discuss the major drivers of the business case.

Asset Condition: Customer benefits by having a more reliable Transmission System capable of supporting service needs. Please see metric trends shown in table below:

DocuSign Envelope ID: 71A7FE08-C4C8-4D85-867A-E7838EE9820F

Performance Measure	Goal	2010	2011	2012	2013	2014	2015
Customer-Hours unplanned, extended outage due to transmission issues	113,142	255,426	64,453	82,908	238,861	200,977	262,949
# of customers of Tx related unplanned outages greater than 3 hrs	10,182	16,478	6,644	5,409	17,135	17,609	24,927
Tx emergency repair costs	$1,321,019	$1,442,969	$1,029,597	$1,409,972	$1,630,943	$3,040,313	$2,180,921

Once completed the Pine Street-Rathdrum 115kV line is expected to no longer show up on the top five most impacted lines (see tables in Section 2.2).

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Transmission outages can have significant consequences, as they tend to impact a large number of customers and have the potential to start fires in dry areas. In addition to reliability issues, failure to properly invest builds a bow-wave of needed investments in the future, thus this program is crucial to maintaining operations.

The Pine Street-Rathdrum (PIP-RAT) 115kV Transmission Line has the highest Risk Score of all Avista transmission lines based on the 2022 Asset Management model version (see below). This version was updated to include wildfire, customer density, and Avista brand reputation impacts. Of special note w/r the PIP-RAT is the number of "other" utility customers. Recently Kootenai Electric Cooperative (KEC) has become very vocal w/r outages on this line affecting their customers to the extent of making commission complaints and publicly blaming Avista in notifications to their customers.

Circuit ID	Voltage	Avista Owned Length (mi)	Risk Score	Condition Score
Pine St.-Rathdrum 115	115	33.24	9.79	3.15
Noxon-Pine Creek 230	230	43.51	9.29	3.50
Addy-Devil's Gap 115	115	43.66	9.01	3.05
Burke-Pine Creek #3 115	115	24.11	8.59	3.15
Sunset-Westside 115	115	10.04	8.39	2.45
Clearwater-Lolo #2 115	115	9.29	8.18	2.45
Ninth & Cent-Opportunity 115	115	7.13	7.80	2.75
Bell-Northeast Waikiki Tap 115	115	2.83	7.61	3.20
Beacon-Northeast 115	115	5.25	7.56	3.20
Beacon-Fr & Cedar Bell Tap 115	115	0.61	7.23	3.80
Grangeville-Nez Perce #2 115	115	37.17	7.14	2.90
Sunset-Westside South Fairchild Tap 115	115	11.99	7.09	2.35
College & Walnut-Westside 115	115	8.78	7.02	2.20
Moscow 230-South Pullman 115	115	12.07	6.93	2.70
Shawnee-Sunset 115	115	61.51	6.92	2.80
Hatwai-Lolo 230	230	8.27	6.91	2.60

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The Lolo-Oxbow (LOL-OXB) 230kV Transmission Line has the highest Risk Score of all Avista transmission lines based on the 2016 model version (see below). This model has since been updated to include wildfire, customer density, and Avista brand reputation impacts (see above). Although no longer prioritized No.1, it still shows up on the high end of the over 100 Transmission Lines within Avista's system.

Transmission Line Name	Voltage (kV)	Length (miles)	Replacement Value	Probability Index	Consequence Index	Risk Index
Lolo - Oxbow	230	63.41	$45,655,200	85.4	100.0	100.0
Noxon - Pine Creek	230	43.51	$31,327,200	80.5	87.8	82.8
Benewah - Pine Creek	230	42.77	$30,794,400	68.3	87.8	70.3
Walla Walla - Wanapum	230	77.78	$56,001,600	68.4	83.7	67.1
Benewah - Boulder	230	26.15	$18,828,000	67.1	72.9	57.3
Hot Springs - Noxon #2	230	70.05	$50,436,000	66.0	68.8	53.2
Dry Creek - Talbot	230	28.27	$20,354,400	51.4	78.3	47.1
Latah - Moscow	115	51.41	$21,592,200	96.0	41.7	47.0
Devils Gap - Stratford	115	86.19	$36,199,800	100.0	39.0	45.6
Post Street - 3rd & Hatch	115	1.76	$3,696,000	70	100	43
Benewah - Moscow	230	44.28	$31,881,600	61.1	59.3	42.5

Table 13: Top 20 Most at Risk Circuits according to the Reliability Risk Index

The important take away is the need to maintain a $10,000,000 annual spend to prevent a bow wave of aging infrastructure. Much of Avista's infrastructure is beyond its life expectancy.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

This program focuses on our Customers by making sure that our word and system are reliable, reducing outages and the risk of wildfire.

- *Avista, KEC, and IP&L customers benefit from this Business Case through improved service reliability. Avista's brand image improves as showing commitment to all customers.*

This program specifically supports the "Safety. Affordability. Responsibly" portion of the Avista Mission Statement.

- *Replacing old and worn-out poles and cross-arms and other associated transmission equipment help guard against increasing risk for more failures and outages. Transmission outages can have significant consequences, as they tend to impact a large number of customers and have the potential to start fires in dry areas. In addition to reliability issues, failure to properly invest builds a bow-wave of needed investments in the future, thus this program is crucial to maintaining operations.*

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1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

The following documents provide the basis for needed planned Condition replacements, prioritization lists, and project specific information:

2016 Lolo-Oxbow 230kV Model Asset Management Plan Rev a.docx

- *Original Asset Management Transmission Line plan document showing need for prioritized and levelized spend*

LOL-OXB – model results.pptx

- *Asset (Transmission Line) specific analysis recommending replacement approach.*

Transmission Lines List (Scored).xlsx

- *Updated prioritization of Transmission Line assests inclusive of wildfire and customer affects*

Transmission Lines Risk Index.pdf

- *Original prioritization of Transmission Line assests*

Engineering Project Request Template PIP-RAT Rebuild.docx

- *Project documentation used in presentation to Engineering Round Table advisory group*

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

This is the continuation of an ongoing Program and requires the replacement of aging infrastructure to support service levels. Please see Alternatives Prioritization within Section 1.3 tables for details.

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

*A **Major Rebuild** of the Pine Street-Rathdrum (PIP-RAT) line is the recommended alternative for construction years 2023-2025. The customers served off this line (Avista, KEC, and IPL) are currently experiencing substandard electric service due to the condition of our infrastructure. Rebuilding this line will demonstrate our commitment to holding our customers' interests at the forefront of our decisions. A major rebuild of this line will increase our service reliability and align with Avista's vision and core values.*

Additionally, the risk of wildfire ignition exists every time the line trips to ground. Rebuilding this line entirely will reduce this risk significantly, thus increasing the safety and resiliency of our infrastructure.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

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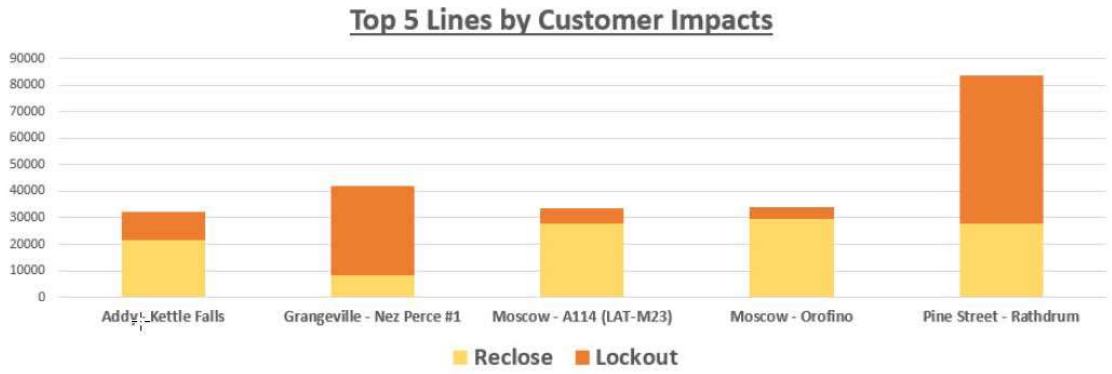
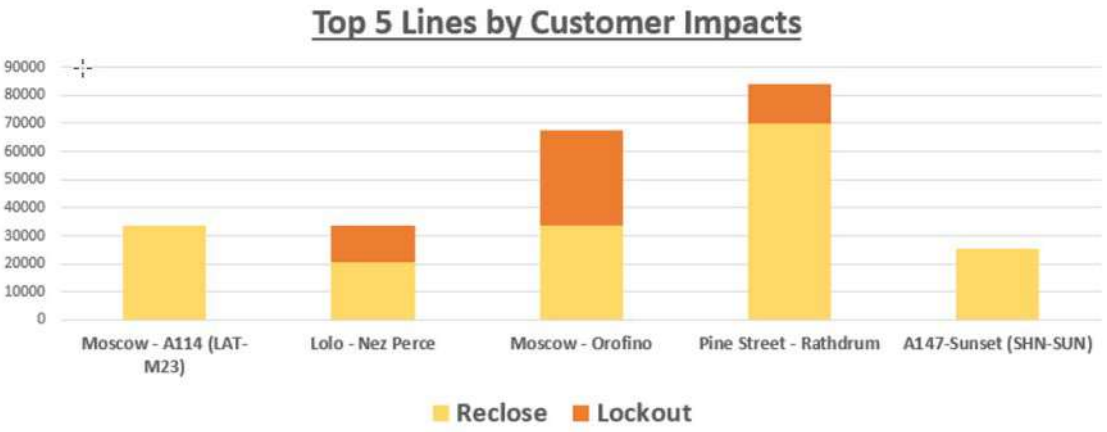
2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

The benefits of this Business Case are seen in something not happening. Pro-actively addressing near-term failures results in avoiding public safety risks including physical, electrical, and fire.

This program is in the Execution Stage with spend directed primarily at structure and structure component change-outs resulting in facility failure avoidance.

Below are Customer Impacts Results for 2021 and 2022 (PIP-RAT).





[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 256 of 535

DocuSign Envelope ID: 71A7FE08-C4C8-4D85-867A-E7838EE9820F

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$10,000	$10,000	$10,000	$10,000	$10,000
O&M		$10,000	$10,000	$10,000	$10,000	$10,000

Direct offsets associated with the projects within this Business Case are the incremental costs associated with performing work under emergency conditions versus planned conditions. Emergency conditions would likely result in overtime wages and increased contractual expenditures (Capital). A lesser probability would be for an unplanned outage to affect other planned outages, or possibly cause load to be dropped. Unplanned outages negatively affect the overall Transmission System (O&M).

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no indirect offsets associated with these projects. The nature of the projects (replacing poles, crossarms, or insulators only before end of life) does not change maintenance schedules, and therefore no offsets were/are realized.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternatives under this Business Cases primarily resolve in a basic choice of either replacing or not replacing the identified asset. The amount of work completed each year is tailored to the available budget. By not funding this Business Case at the $10,000,000 projects are delayed, creating a bow wave of time sensitive projects moving into outer years. Alternatives below refer to PIP-RAT.

Alternative 1:

Maintain As-Is *(Option #1: $0) is* ***not an option*** *because the increasing outages (cost to customers) and a significant risk of wildfire ignition (major cost associated with litigation), and a threat to Avista's brand image (3rd party customer outages leading to Utility Commission complaints).*

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

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Alternative 2:

*A **Minor Rebuild** (Option #2: TBD) of this line is **not a recommended** alternative. The work associated with a minor rebuild would be substantial and would only be a stopgap for maybe 20-years. After 20-years, all remaining wood poles would be at their end of life and require replacement. Mobilizing construction resources for significant rebuild work twice within 20-years is very cost-ineffective.*

Alternative 3:

*A **Major Rebuild** (Option #3: $25,000,000) of this line is the **recommended** alternative. The customers served off this line (Avista, KEC, and IPL) are currently experiencing substandard electric service due to the condition of our infrastructure. Rebuilding this line will demonstrate our commitment to holding our customers' interests at the forefront of our decisions. A major rebuild of this line will increase our service reliability and align with Avista's vision and core values.*

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

As-Built confirmation of mitigation measures.

The investment is considered successful when the targeted Transmission Line no longer shows up on the Customer Impacts Tables shown in Section 2.2.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Outage requests on the Avista Transmission System are typically restricted to the lower load months of March -May and September-November. The months of December-February and June-August are Avista's Winter and Summer load peaking months respectively. During these months planned outages are restricted due to system capacity and flexibility constraints.

The Pine Street-Rathdrum project will take place in the Spring or Fall months and Transfer to Plant in the June or November/December time frame. The Lolo-Oxbow project will take place over Winter months and likely Transfer to Plant in the March-April time frame.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The Engineering Roundtable functions as the Vetting Platform, Steering Committee, and Advisory Group. Committee members and Charter can be found under the System Planning SharePoint site via the Avenue.

Electrical Engineering Expected Spend Committee reviews on a monthly basis ongoing spend for projects approved by the ERT. Committee members include Managers, Project Managers, analysts, and the Electrical Engineering Director.

During the design phase these functions are processed through the Engineering Roundtable. During large project Contracted construction, Change Orders are processed through Supply Chain. On

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smaller in-house construction projects, changes are agreed upon at the Project Engineer/Project Manager and are documented in the As-Built process.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Transmission Major Rebuild – Asset Condition Business Case Justification Narrative and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Ken Sweigart 210C354...	Date:	May-02-2024 | 3:10 PM PDT
Print Name:	Ken Sweigart		
Title:	Manager, Transmission Line Design		
Role:	Business Case Owner		

Signature:	DocuSigned by: Vern Malensky 06C4FF...	Date:	May-03-2024 | 1:59 PM PDT
Print Name:	Vern Malensky		
Title:	Director of Electrical Engineering		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 259 of 535

2022 Transmission NERC Low Priority Ratings Mitigation

EXECUTIVE SUMMARY

The Transmission NERC Low Priority Lines Mitigation Business Case covers the work to reconfigure insulator attachments, and/or rebuild existing transmission line structures, or remove earth beneath transmission lines in order to mitigate ratings/sag discrepancies found between "design" and "field" conditions as determined by LiDAR survey data. This program was undertaken in response to the October 7, 2012 North American Electric Reliability Corporations (NERC) "NERC Alert" - Recommendation to Industry, "Consideration of Actual Field Conditions in Determination of Facility Ratings". This Capital Program covers mitigation work on Avista's "Low Priority" 230kV and 115kV transmission lines. Mitigation brings lines in compliance with the National Electric Safety Code (NESC) minimum clearances values. These code minimums have also been adopted into the State of Washington's Administrative Code (WAC). This program is expected to be completed in 2024.

The recommended solution is to correct the issues found in the LiDAR studies to stay in compliance with the NESC code and WAC. There are no expected business impacts to continuing this program in place. If Avista does not fully implement this business case, it runs the risk of being fined for not staying in compliance with the NESC code and WAC rules. A spend of $3,500,000 is needed to complete the mitigations by 2024. This Program will have a Service Code of Electric Direct and a Rate Jurisdiction of Allocated North.

The customer benefits from this Business Case through increased service reliability.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Ken Sweigart*	*Initial draft of original business case*	*4/28/2022*	
1.0				
1.1				
2.0				

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 260 of 535

GENERAL INFORMATION

Requested Spend Amount	$3,500,000
Requested Spend Time Period	*2 years*
Requesting Organization/Department	TLD Engineering
Business Case Owner | Sponsor	Josh DiLuciano/Heather Rosentrater
Sponsor Organization/Department	Energy Delivery/Electrical Engineering
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

The Transmission NERC Low Priority Lines Mitigation Business Case covers the work to reconfigure insulator attachments, and/or rebuild existing transmission line structures, or remove earth beneath transmission lines in order to mitigate ratings/sag discrepancies found between "design" and "field" conditions as determined by LiDAR survey data. This program was undertaken in response to the October 7, 2012 North American Electric Reliability Corporations (NERC) "NERC Alert" - Recommendation to Industry, "Consideration of Actual Field Conditions in Determination of Facility Ratings". This Capital Program covers mitigation work on Avista's "Low Priority" 230kV and 115kV transmission lines. Mitigation brings lines in compliance with the National Electric Safety Code (NESC) minimum clearances values. These code minimums have also been adopted into the State of Washington's Administrative Code (WAC).

1.1 What is the current or potential problem that is being addressed? *Clearance violations.*

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* **and the benefits to the customer** *Mandatory & Compliance: Customer benefits by having a Transmission System in compliance with Federal Code and State Law.*

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred *The North American Electric Reliability Corporations (NERC) "NERC Alert" originally identified Low Priority Transmission Line assessments to complete by December 31, 2013. Although a mitigation timeline did not include a penalty threat, we have been operating under a grace period that requires us to report progress every six months. Completing the program by 2024 will show us taking eleven years to complete the effort. Deferring completion is tempting greater scrutiny from NERC and delays mitigation of a compliance violations recognized by Washington State Law.*

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above. *As-Built confirmation of mitigation measures.*

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 261 of 535

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

CAN-0009_FAC-008 FAC-009.pdf

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Recommendation to Industry: Consideration of Actual Field Conditions in Determination of Facility Ratings

On November 30, 2010, NERC provided an update to the October 7, 2010 Recommendation to Industry entitled "Consideration of Actual Field Conditions in Determination of Facility Ratings." Transmission Owners and Generator Owners of bulk electric system facilities should review their current facility ratings methodology for their transmission lines to verify the methodology used is based on actual field conditions and determine if their ratings methodology will produce appropriate ratings when considering differences between design and field conditions. If entities have not previously verified that the facility design, installation, and field conditions are within design tolerances when the facilities are loaded at their ratings, entities are required by January 18, 2011, to describe its plans to complete such an assessment of all its transmission lines, with the highest priority lines assessed by December 31, 2011, medium priority lines by December 31, 2012, and the lowest priority by December 31, 2013. At the conclusion of each year, each Transmission Owner and Generator Owner must report to its Regional Entity a summary of the assessments and identification of all transmission facilities where as-built conditions are different from design conditions, resulting in incorrect ratings, and their associated mitigation timelines. Remediation is expected within one year from identification of the issue or on a schedule approved by the Regional Entity if longer than a year. Owners are also expected to coordinate with their respective operating and planning organizations to coordinate interim mitigation strategies.

Owner Information	
Entity Name	Avista Utilities
NCR#	
Region	WECC
Owner Type	Transmission Owner
Total High Priority	
Miles	227.50
Circuits	6.00
Total Medium Priority	
Miles	760.00
Circuits	54.00
Total Low Priority	
Miles	1270.00
Circuits	67.00
Grand Totals	
Miles	2257.50
Circuits	127.00

Overall Comments

1/16/2020 Update: Continue multi-phase rebuild projects with LiDAR NERC Alert components.

2. PROPOSAL AND RECOMMENDED SOLUTION

[Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation)]

Option	Capital Cost	Start	Complete
Mitigate Violations	*$3.5M*	*01-2023*	*12-2024*
[Alternative #1]	*$M*	*MM YYYY*	*MM YYYY*
[Alternative #2]	*$M*	*MM YYYY*	*MM YYYY*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:

- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

Reference key points from external documentation, list any addendums, attachments etc.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?)**. Include any known or estimated reductions to O&M as a result of this investment.**

This program is in the Execution Stage with spend directed primarily at structure change-outs resulting in greater ground clearance.

[Offsets to projects will be more strongly scrutinized in general rate cases going forward *(ref. WUTC Docket No. U-190531 Policy Statement)*, therefore it is critical that these impacts are thought through in order to support rate recovery.]

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Primary impacts are in the area of obtaining Transmission system outages and construction resources. Although Transmission Line Design has the ability to Contract for construction services on the large projects, internal construction resources typically perform the smaller jobs.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Raising structure heights is by far the go to alternative. In one instance the removal of earth was used. Earth removal can trigger permitting, which otherwise would not be necessary.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer.

Smaller projects can take place throughout the year. Most of the large projects take place in the Fall months and Transfer to Plant in the November time frame.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Aligns with Avista's Culture of Compliance.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Mitigation design solution performed within PLS-CADD, which is the industry leader in providing Transmission Line Design computer based programs. Designs are reviewed at multiple stages to ensure prudency and maximum Stakeholder value.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Many and varied throughout Avista.

2.8.2 Identify any related Business Cases

None

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 263 of 535

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The Engineering Roundtable functions as the Vetting Platform, Steering Committee, and Advisory Group.

3.2 Provide and discuss the governance processes and people that will provide oversight

Electrical Engineering Expected Spend Committee reviews on a monthly basis ongoing spend for projects approved by the ERT. Committee members include Managers, Project Managers, analysts, and the Electrical Engineering Director.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

During the design phase these functions are processed through the Engineering Roundtable. During large project Contracted construction, Change Orders are processed through Supply Chain. On smaller in-house construction projects, changes are agreed upon at the Project Eneginer/Project Manager, and are documented in the As-Built process.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 264 of 535

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Low Priority Rating Mitigation Business Case Justification Narrative* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	APPROVED By Ken Sweigart at 11:35 am, Sep 09, 2022	Date:	
Print Name:			
Title:			
Role:	Business Case Owner		
Signature:		Date:	9/9/2022
Print Name:	Josh DiLuciano		
Title:	Vice President - Energy Delivery		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 265 of 535

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EXECUTIVE SUMMARY

This section is reserved to provide a **brief** description of the business case and high-level summary of the projects or programs included. Please limit to no more than 2 paragraphs. Components that should be included:

1) NEEDS ASSESSMENT- a synopsis of the problem, the current state and recommended solution
2) COST- the cost of the recommended solution
3) DOCUMENT SUMMARY- benefit to the customer
4) RISK- of not approving the business case
5) APPROVALS- who reviewed and approved the recommended solution

<< Both the Executive Summary and Version History should fit into one page >>

The existing Westside #1 230/115 kV transformer exceeds its applicable facility rating for the P1 event of the Westside #2 230/115 kV transformer. System performance analysis indicates an inability of the system to meet the performance requirements in Table 1 of NERC TPL-001-4 in scenarios representing 2017 Heavy Summer for P1 events. While Avista intends to avoid proactively shedding customer load, an operating procedure to shed non-consequential load can be used until 2021 to mitigate system deficiencies (non-consequential load shedding is considered acceptable through the 84 month implementation of TPL-001-4). This project is approved and prioritized by the Engineering Roundtable Committee.

Westside Transformer Replacement is the recommended solution. Replace the existing Westside transformers with 250 MVA rated transformers and reconstruct both the 230 kV and 115 kV buses at the station to double bus, double breaker. All associated system deficiencies will be mitigated.

Service: ED – Electric Direct

Jurisdiction: AN – Allocated North

Engineering Roundtable Request Number: ERT_2017-47

Cost of Solution: $26,200,000

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Ken Sweigart	Initial Version	4/14/2017	Initial Version
2.0	Karen Kusel / Glenn Madden	Update to 2020 Template	6/2020	

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GENERAL INFORMATION

Requested Spend Amount	$26,200,000
Requested Spend Time Period	15 Years
Requesting Organization/Department	Transmission/System Planning
Business Case Owner | Sponsor	Glenn Madden | Josh DiLuciano
Sponsor Organization/Department	T&D
Phase	Execution
Category	Project
Driver	Mandatory & Compliance

1 BUSINESS PROBLEM

[This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement]

The existing Westside #1 230/115 kV transformer exceeds its applicable facility rating for the P1 event of the Westside #2 230/115 kV transformer. System performance analysis indicates an inability of the system to meet the performance requirements in Table 1 of NERC TPL-001-4 in scenarios representing 2017 Heavy Summer for P1 events. While Avista intends to avoid proactively shedding customer load, an operating procedure to shed non-consequential load can be used until 2021 to mitigate system deficiencies (non-consequential load shedding is considered acceptable through the 84 month implementation of TPL-001-4).

1.1 What is the current or potential problem that is being addressed?

System performance analysis indicates an inability of the system to meet the performance requirements in Table 1 of NERC TPL-001-4 in scenarios representing 2017 Heavy Summer for P1 events.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

Mandatory & Complaince - All associated system deficiencies will be mitigated with the completion of this project.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

While Avista intends to avoid proactively shedding customer load, an operating procedure to shed non-consequential load can be used until 2021 to mitigate system deficiencies (non-consequential load shedding is considered acceptable through the 84 month implementation of TPL-001-4).

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

Future System Planning Assessments which show mitigation of all prior deficiencies.

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1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

[List the location of any supplemental information; do not attach]

System Planning Assessments.

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Not Applicable.

2 PROPOSAL AND RECOMMENDED SOLUTION

[Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation)]

Westside Transformer Replacement is the recommended solution. Replace the existing Westside transformers with 250 MVA rated transformers and reconstruct both the 230 kV and 115 kV buses at the station to double bus, double breaker. All associated system deficiencies will be mitigated.

Project scope includes the following:

Phase 1: Replace the existing Westside #1 230/115 kV transformer and construct necessary bus work and breaker positions. $11 million, energize 2018

Phase 2: Continue bus work and breaker replacement: $8 million, energize 2019

Phase 3: Replace the existing Westside #2 230/115 kV transformer and complete bus work to single bus configuration: $6 million, energize 2020

Phase 4: Complete bus work to double bus, double breaker on both the 230 kV and 115 kV buses: $7 million, energize 2022. (2022 Note: Project is scheduled to complete in 2024 because of delays for getting planned outages.)

Alternative 1 - Status Quo/Do Nothing: This alternative is not recommended because it does not mitigate the expected capacity constraints and does not adhere to NERC transmission planning standards.

Solution/Alternative 2 - Westside Transformer Replacement: Replace the existing Westside transformers with 250 MVA rated transformers and reconstruct both the 230 kV and 115 kV buses at the station to double bus, double breaker. All associated system deficiencies will be mitigated.

Alternative 3- Garden Springs 230kV Station Integration: The Garden Springs 230 kV Station Integration project includes the installation of new 230/115 kV transformation in the Spokane area. The additional transformation will offload the Westside #1 and #2 230/115 transformers. In the future, the Garden Springs 230 kV Station Integration project will be necessary in addition to the Westside Transformer Replacement project.

Alternative 4 - Replace Westside Transformers without Station Rebuild: Replacing the existing Westside transformers to 250 MVA rated transformers will mitigate the transformer overload system deficiencies but will create a short circuit breaker rating exceedance. Additional P2 bus outage system deficiencies will exist.

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Option	Capital Cost	Start	Complete
[Recommended Solution] Westside Transformer Replacement	$32M	2015	2022
Alternative #1 Status Quo	$0M		
Alternative #3 Garden Springs 230kV Station Integration			
Alternative #4 Replace Westside Transformers without Station Rebuild			

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:
- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

Reference key points from external documentation, list any addendums, attachments etc.

System Planning Assessments.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

How will the outcome of this investment result in potential additional O&M costs, employee or staffing reductions to O&M (offsets), etc.?

[Offsets to projects will be more strongly scrutinized in general rate cases going forward *(ref. WUTC Docket No. U-190531 Policy Statement)*, therefore it is critical that these impacts are thought through in order to support rate recovery.]

2020 – $3,000,000

2021 - $3,500,000

2022 - $2,800,000

2023 - $2,000,000

2024 – $1,000,000

O&M costs will be comparible to what they were before this project.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

[For example, how will the outcome of this business case impact other parts of the business?]

System Operations will have improved functionality of the electric system.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

See Section 2.0 for alternative discussion.

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2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

[Describe if it is a program or project and details about how often in a year, it becomes used-and-useful. (i.e. if transfer to plant occurs monthly, quarterly or upon project completion).]

Construction will continue through 2024. Transfers to Plant will be at the close of each Phase.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

[If this is a program or compilation of discrete projects, explain the importance of the body of work.]

Mission: We improve our customers' lives through innovative energy solutions.

Vision: Better energy for life

The completion of this project leads directly to a dimished threat of customer outages.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

The scope for the project, which is to increase transformation capacity in the Spokane area is the least cost option that provides the needed functionality. Adhering to the scope and project objectives will be reviewed regularly by the project team including the project engineer and the project manager.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Electrical Engineering, Generation Production/Substation Support, Transmission Operations and System Planning and Operations

2.8.2 Identify any related Business Cases

[Including any business cases that may have been replaced by this business case]

Not Applicable.

3 MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

[Please identify and describe the steering committee or advisory group for initial and ongoing vetting, as a part of your departmental prioritization process.]

- Project Engineer/Project Manager (PE/PM)- Dana Gerbing/Zachary Curry
- Engineering Roundtable Committee

The assigned PE/PM holds stakeholder meetings to develop/confirm scope, schedule and costs. Also meets at time of pre-construction. Other meetings held as necessary.

This project has also been reviewed by the Engineering Roundtable.

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3.2 Provide and discuss the governance processes and people that will provide oversight

Engineering Roundtable meets several times a year to analyze current and future projects.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Project folders are saved to Engineering shared drives and Businesss Case Funds Requests are available on the Finance sharepoint site

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4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Westside 230/115kV Station Rebuild and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Glenn J Madden 7D4B3DE5CBD8463...	Date:	Jun-28-2022 | 3:36 PM PDT
Print Name:	Glenn Madden		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:	DocuSigned by: Josh DiLuciano A3C71874E6564DB...	Date:	Jul-05-2022 | 7:41 AM PDT
Print Name:	Josh DiLuciano		
Title:	Director, Electrical Engineering		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:	Damon Fisher		
Title:	Principle Engineer		
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

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Gas Above Grade Pipe Remediation Program, ER 3009

EXECUTIVE SUMMARY

Within the natural gas distribution system of all three states (WA, ID, & OR), there are sections of gas pipelines that are located above grade at crossings such as bridges, small ditches, irrigation canals, etc. These above grade crossings have a variety of construction techniques and supporting structures which vary in age, condition, design, compliance, and overall risk. This Business Case provides capital expenditure for remediating those sites where regular O&M maintenance activities (e.g. replacement of pipe supports and/or pipe wrap) are no longer appropriate. Facilities needing capital remediation will be identified and prioritized by applying a risk-based scoring methodology to all known above grade crossing locations. Each identified location will be unique in how it is remediated, and the costs will vary depending on the complexity of the project. These projects will typically involve either installing new pipe below grade or rebuilding the existing crossing.

Currently there are a total of 222 known above grade crossing sites across all three states. 155 in Oregon, 23 in Idaho, and 44 in Washington. All Oregon sites were risk assessed in 2019 and Washington/Idaho sites were assessed in 2023/2024. Starting in 2024, the annual capital budget for this program is divided between the three states based on risk and remediation scope.

Out of the original 159 sites risk assessed in Oregon, 33 were identified as exceeding the program's scoring threshold for allowable risk. Washington and Idaho assessments resulted in an additional 16 sites above the risk threshold for a total of 49 sites across all three states. The plan is for all sites above the risk threshold to be remediated over the next 10 years through the combination of both O&M and Capital dollars. Preliminary estimates forecast the need for approximately 43 capital projects with an average cost of $150,000 per site. This puts the total 10-year budget at about $6.5 million (today's dollars) with a recommended annual spend of $650,000 (+ 3% inflation) starting in 2024 (Year 2 of program). In general, this is enough to fund one or two large drill projects, two to four medium drill projects, or between five to seven small drill or rebuilt crossing projects per year. This work will ensure our gas pipeline facilities continue operating with reduced risk, resulting in a safe, compliant, and reliable system for our communities and customers. If this program is not continued, Avista will be at risk of fines from: State PUCs for being out of compliance with federal safety codes, pipeline failures if support structures fail, environmental fines if a pipeline failure results in a release of gas, and prolonged loss of service to gas customers.

Remediation of these sites using capital dollars can provide direct and indirect O&M cost saving benefits, as well as reputational benefits between Avista and the three State Commissions. Positive working relationships with state Commissions can lead to more favorable rulings during audits/inspections. The direct O&M cost savings are associated with quarterly patrol inspections, 3-year atmospheric corrosion inspections, and future maintenance work (e.g. pipe coating and hanger repairs) that can all be eliminated when using capital dollars to relocate the pipeline underground. In addition, relocating facilities underground will reduce Avista's risk of incurring Indirect O&M costs associated with regulatory fines, customer outages, and safety incidents.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Jeff Webb*	*Initial submission of original business case*	*7/8/2021*
2.0	*Mike Yang*	*Updated for 2022, Used new template*	*8/26/2022*
2.1	*Mike Yang*	*Updated to the refreshed 2023 Business Case Template*	*4/19/2023*
2.2	*Brock Benzel*	*Updated for 2024 with WA/ID assessment results.*	*4/15/2024*
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements*	*4/25/2023*

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GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025 (YR3)	**669,500**	**669,500**
2026 (YR4)	**689,500**	**689,500**
2027 (YR5)	**710,000**	**710,000**
2028 (YR6)	**731,500**	**731,500**
2029 (YR7)	**753,500**	**753,500**
2030 (YR8)	776,000	776,000
2031 (YR9)	799,500	799,500
2032 (YR10)	823,500	823,500

Project Life Span	***10 years***
Requesting Organization/Department	Gas Engineering/B51
Business Case Owner | Sponsor	Brock Benzel / Jeff Webb | Alicia Gibbs
Sponsor Organization/Department	Gas Engineering/B51
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

Aboveground main is required to be inspected once every three years for atmospheric corrosion per CFR 192.481. To properly inspect for corrosion, the entirety of the pipe must be available for visible assessment. Some legacy sites have pipe that is installed in a manner that makes it impossible to do a proper inspection. Additionally, gas mains in places or on structures with the potential for physical movement (i.e. bridges) must be patrolled 4 times a year in business districts and 2 times a year outside of business districts per CFR 192.721. The intent of these patrols is to ensure sound structures and hanging supports. Some of the sites on the list have hanger systems that are failing due to corrosion or concrete deterioration, resulting in improper support of gas pipes. This program provides capital dollars to address these deficiencies when an O&M solution is not preferred.

If the site is remediated with capital dollars by installing the pipe below grade, Avista eliminates the O&M expense of the once every three-year atmospheric corrosion inspection and the quarterly bridge inspection. Future O&M work to repair deteriorated pipe coatings and/or pipe hangers would also be eliminated by relocating the pipe below grade. Additionally, the Distribution Integrity Management Program (DIMP) will assess a lower risk score since below grade installations have much less of a chance of being damaged by an earthquake, flood, or vehicle incident. Major events such as an earthquake, flood, or vehicle incident have the potential to cause large scale customer

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 274 of 535

DocuSign Envelope ID: 295EB345-26ED-4B6E-9598-1809C6891E74

outages (500 or more outages) and/or large environmental risks associated with an uncontrolled release of gas from the pipeline.

1.1 What is the current or potential problem that is being addressed?

This program is addressing above grade gas pipeline crossings that are not in compliance with federal safety codes and/or have been deemed high risk through a risk evaluation performed by Gas Engineering and Gas Integrity. Within the natural gas distribution system of all three states, there are sections of gas pipelines that are located above grade. Some of these sites are no longer compliant with current safety codes and design practices, or the support structures are failing. Like other areas of the gas and electric system, over the years construction practices have changed due to stricter standards and improved construction methods. As a result, these above grade crossings have a variety of construction techniques and supporting structures with varying degrees of risk associated with each of them.

Currently there are a total of 222 known above grade crossing sites across all three states. 155 in Oregon, 23 in Idaho, and 44 in Washington. All Oregon sites were risk assessed and prioritized in 2019, while the Washington and Idaho sites were risk assessed across 2023 and 2024. Starting in 2024 the annual capital budget for this program is split amongst the three states based on risk, remediation scope, and Gas Engineering assessments.

Out of the 159 sites risk-assessed in Oregon, 33 were identified as exceeding the program's scoring threshold for allowable risk. Additionally, Washington and Idaho have 16 sites that exceed the risk threshold, which results in a grand total of 49 sites across all three states being considered high risk. Site remediations began in 2023 with 6 Oregon sites being bored or eliminated. Over the next 9 years, the remaining 43 sites will be remediated through the combination of both O&M and Capital dollars. Current estimates forecast the need for approximately 37 capital projects with an average cost of $158,000 per site. This puts the remaining 9-year budget at about $5.8 million with a recommended annual spend of $669,500 (+ 3% inflation).

This capital work will ensure our gas pipeline facilities continue operating with reduced risk, resulting in a safe, compliant, and reliable system for our communities and customers. If this program is not started, Avista will be at risk of fines from: State PUCs for being out of compliance with federal safety codes, pipeline failures if support structures fail, environmental fines if a pipeline failure results in a release of gas, and prolonged loss of service to gas customers.

1.2 Discuss the major drivers of the business case.

The major driver is Mandatory & Compliance. This remediation is necessary to stay in compliance with CFR 192 safety codes. Asset Condition is a secondary driver for remediating high risk above grade piping. Aboveground main is required to be inspected once every three years for atmospheric corrosion per CFR 192.481. To properly inspect for corrosion, the entirety of the pipe must be available for visible assessment. Some legacy sites have pipe that is installed in a manner that makes it impossible to do a proper inspection. Per CFR 190.223 Avista can be fined up to $257,664/day per violation with a maximum total fine limit of $2,576,627.

Another major driver of this business case is the risk of a pipeline failure due to major events such as earthquakes, floods, vehicular damages, etc. Above grade pipeline facilities assessed as being high risk are typically more susceptible to failure during one of these events and/or a failure could result in consequences that are deemed to be unacceptable. Consequences of an above grade pipeline failure could result in an uncontrolled release of gas into the air, as well as a prolonged (i.e. 24 hrs or more) loss of gas service to customers. The cost of a gas outage is estimated at $2,960

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per customer[1], which equates to around $296,000 for an outage of 100 customers or $1.48 million for an outage of 500 customers. There could also be negative reputational and customer safety impacts (i.e. no heat) associated with a prolonged loss of gas service.

This business case is intended to address and mitigate these compliance and asset condition risks.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The Oregon PUC delivered to Avista a Notice of Probably Violation (NOPV) for a bridge crossing in Roseburg, Oregon in their 2021 safety audit that requires action on the part of Avista to remediate. With this program in place, it shows the PUC in all three states (OR, WA, and ID) that Avista recognizes the shortcomings and has a plan to address them. This work is necessary now because we currently have pipeline crossings that are not in compliance, are at risk of failing, and are at risk of fines from State PUC Safety Departments.

There are several issues that are typical of these sites that need to be addressed. Each of these could cause Avista to be out of compliance with federal safety standards: the pipe wrap may have failed or deteriorated to the point of no longer being effective, the support hangers may be dislodged from their support structure (normally a bridge) and/or the support hangers may be the style that do not allow a complete inspection for atmospheric corrosion, the support structure may be failing and no longer able to provide adequate support for the gas pipe, or the warning signs may be missing.

In addition to more immediate threats such as flooding and vehicular damage, the threat of a major earthquake from the Cascadia Subduction Zone poses a significant threat to seismic vulnerable high risk pipeline facilities, especially in Western Oregon. Experts predict a 15-40% chance of a major earthquake within the next 50 years and if it happens before Avista is able to address these high-risk sites there could be significant financial, safety, and operational consequences.

If Avista chooses to do nothing about these sites, there is a high probability that State PUCs will fine Avista on future violations. Failing to take any action erodes trust and goodwill between Avista and State PUCs, so it's expected that the magnitude and frequency of these fines would increase over time with each successive violation. Per CFR 190.223 Avista can be fined up to $257,664/day per violation with a maximum total fine limit of $2,576,627.

See section 2.4 for more detail around risk and how it increases over time if nothing is done.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives, and mission statement of the organization. *See link Avista Strategic Goals*

One of Avista's core values is "Trustworthy." Taken from the principles and beliefs that drives us, "our word is reliable; we do what is right." By taking care of these pipeline facilities and making them as reliable as possible, we keep the public safe by preventing failures and ensues our facilities are not out of compliance. These preventive measures allow the performance of Avista to not be hindered and ensures that the gas pipeline facilities continue to operate with reduced risk, resulting in a safer and more reliable system for our customers.

[1] See Section 2.4 for more details on the estimated gas outage cost per customer

DocuSign Envelope ID: 295EB345-26ED-4B6E-9598-1809C6891E74

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.

In 2019, Gas Engineering assessed all known above grade pipe locations in the state of Oregon by visiting each site in person, taking pictures, evaluating the condition of the pipe, coating, and pipe support structures, reviewing the area for possible remediation options, and then finally using a risk scoring matrix developed with Gas Integrity to risk rank all 159 sites. Of these sites, 33 of them were classified as high risk/requiring remediation. In 2023 and 2024, Gas Engineering assessed a total of 67 sites, 23 in Idaho and 44 in Washington. This assessment also consisted of in person site visits, taking photos, and evaluation of the condition of pipe, coating, and pipe support structure. In addition, the Washington and Idaho risk assessments criteria expanded based on lessons learned during the Oregon risk evaluations. Additional criteria included: evaluation of bridge conditions, accessibility to pedestrians, vulnerability to vehicles, and the consequence of an outage at the crossing. Of the 67 site evaluations, 12 sites in Washington and 4 in Idaho were found to be above the risk threshold. Because the Washington and Idaho site evaluations gathered additional data points, the Oregon risk model contains a different scoring matrix than the WA/ID sites. However, both risk models share a common backbone and scoring technique. Sites above 65000 in Oregon are considered high risk while Washington and Idaho sites must be above 1400. As time allows in the future, Gas Engineering would like to reevaluate the Oregon sites to join all crossings into the same improved scoring matrix.

List of 33 above grade sites in Oregon that exceed 65000 risk score threshold:

Crossing Decription	Nearest Address	City	Water Name	Size of Pi	Operating Pressu	MAO	Pipe M	Instal	TOTAL RISK SCOI
Hwy 99 S/Bridge - S - Umpqua	8374 Old Hwy 99 S	Winston	South Umpqua River	6	intermediate	60	steel	1964	**134850**
Riverside Dr/Bridge - Days Cr	430 SE Riverside Dr	Myrtle Creek	South Myrtle Creek or Days Creek	2	intermediate	40	steel	1982	**134310**
Washington St/Bridge - S - Umpqua	303 W Harvard Ave	Roseburg	South Umpqua River	6	intermediate	60	steel	1963	**110160**
Rogue River	333 Classick Dr	Rogue River	Ward Creek	10	high	293	steel	1963	**108570**
S Main Elliot St/Bridge - Canyon Cr	535 S Main St	Canyonville	Canyon Creek	2	intermediate	60	steel	1964	**107670**
335 Pleasant View	335 Pleasant View Dr	Grants Pass	Tokay Canal	2	intermediate	60	steel	1964	**106470**
3500 Block Anderson Ave. Bridge	3520 Anderson Ave	Klamath Falls		2	intermediate	60	steel	1988	**105840**
1985 Taylor Bridge #121	1985 Taylor Rd	Central Point	Griffin Creek	6	intermediate	60	steel	1964	**105210**
1812 Talent Ave	1812 Talent Ave	Talent	Canal	6	high	470	steel	1963	**103950**
On Bridge over Rogue River	205 Upper River Rd	Gold Hill	Rogue River	10	high	293	steel	1963	**100725**
1975 Houston Rd	1975 Houston RD	Phoenix	Coleman Creek	6	high	470	steel	1963	**96720**
2908 Voorhies	2809 Voorhies Rd	Medford	Coleman Creek	6	high	470	steel	1963	**96720**
811 Crestbrook	2295 Crestbrook Rd	Medford	Lazy Creek	2	intermediate	60	steel	1959	**95460**
Waite St/Bridge Calapooia Cr	352 Waite St	Sutherlin	Sutherlin Creek	2	intermediate	60	steel	1998	**93330**
3028 Coleman Creek Rd	3020 Coleman Creek Rd	Medford	Coleman Creek	6	high	470	steel	1963	**90210**
3869 Jacksonville	3857 W Main St	Medford	Daisy Creek	3/4	intermediate	60	steel	1992	**89670**
2188 Fruitdale	2077 Rogue River Hwy	Grants Pass		1 1/4	intermediate	60	steel	2003	**82950**
401 S Rose	401 S Rose St	Phoenix		2	intermediate	60	steel	1965	**81270**
1013 Conklin	1013 NW Conklin Ave	Grants Pass		3/4	intermediate	60	steel	1899	**80850**
Hamlin St/Bridge - Canyon Cr	185 Hamlin Dr	Canyonville	Canyon Creek	2	intermediate	60	steel	1985	**80190**
237 Talent Ave	237 Talent Ave	Talent	Wagner Creek	6	high	470	steel	1963	**78960**
Kirtland Rd	2667 Kirtland Rd	Central Point	Whetstone Creek	6	high	470	steel	1963	**77190**
S Talent Ave	1 Corral Ln	Ashland	Bear Creek	2	intermediate	60	steel	1899	**74250**
1755 Gaffney	1755 Gaffney Way	Grants Pass	South Main Canal	2	intermediate	60	steel	1965	**73800**
109 Maple St	109 Maple St	Phoenix		1 1/4	intermediate	60	steel	1967	**73530**
1914 Archer	1895 Archer Dr	Medford	Phoenix Canal	2	intermediate	60	steel	1971	**73260**
247 Sky Crest	247 Sky Crest Dr	Grants Pass		2	intermediate	60	steel	1990	**73140**
3051 Coleman Creek Rd	3051 Coleman Creek Rd	Medford		6	high	470	steel	1963	**72750**
88 Greenway	87 S Greenway Dr	Medford		1 1/4	intermediate	60	steel	1969	**69930**
Douglas Ave/Bridge - Deer Cr	2525 NE Douglas Ave	Roseburg	Deer Creek	2	intermediate	60	steel	1985	**68970**
816 Black Oak	816 Black Oak Dr	Medford	Larson Creek	4	intermediate	60	steel	1964	**65520**
1899/1901 Hamilton	1797 Hamilton Ln	Grants Pass	South Main Canal	2	intermediate	60	steel	1969	**65520**
825 Murphy	825 Murphy Rd	Medford	Larson Creek	4	intermediate	60	steel	1960	**65520**

List of 16 above grade sites in Washington and Idaho that exceed the 1400 risk score threshold.

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Crossing Rank	Crossing Decription	Nearest Address	Size of Pipe	Operating Pressur	TOTAL RISK SCORE
1	Missouri Flat Crk @ Grand & Ritchie	615 N Grand Ave, Pullman, WA 99163	6	60	4485
2	3rd and Merriem	301 Merriam, Davenport, WA 99122	4	60	2996.25
3	Palouse River @ Grand Ave	305 N Grand Ave, Pullman, WA 99163 (East)	6	60	2981.5
4	Paradise Creek @ Alpine Clinic	4853 WA-270, Pullman, WA 99163	0.75	300	2904
5	Crawford Rd / Hwy 395 - HP 6"	507 W Crawford St, Deer Park, WA 99006	6	500	2613
6	Missouri Flat Crk @ Stadium Way	150 NE Stadium Way, Pullman, WA 99163	6	60	2173.5
7	Palouse River, Bridge St S of Main	120 S Bridge St, Palouse, WA 99161	2	60	2073.5
8	Mouth of 9 Mile	216 6th St, Wallace, ID 83873	4	60	2025
9	600 Arden Hill Rd	640 Arden Hill Rd	2	250	1943
10	Palouse River @ 6th St & Morton	1408 N Parkview Dr, Colfax, WA 99111	2	45	1859.25
11	Spring St @ Reaney Way	700 NE Reaney Way, Pullman, WA 99163	8	150	1780
12	Home St - West Park School	510 Home St, Moscow, ID 83843	2	60	1750
13	N Division St & W of Elm Ave, Suspended on W side of bridge	701 N Columbia St, Ritzville, WA 99169	2	30	1656.75
14	Mouth of Terror Gulch	106 Terror Gulch Rd, Osburn, ID 83849	4	60	1608.75
15	Sprague Access, W of Erie Hanging on S Overpass	1020 E Sprague Ave, Spokane, WA 99202	6	60	1567.5
16	Erie N of Sprague Overpass Vertical Along Wall	1020 E Sprague Ave, Spokane, WA 99202	6	60	1518

The ongoing assessment work conducted by Gas Engineering is all stored on the corporate network drive: c01d44\GASENGINEER\GAS DESIGN DOCUMENTATION\Engineer Documentation\M Yang\Programs & Committees\ER 3009 - Above Grade Pipe Remediation

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

It is recommended to spend $669,500 (plus 3% inflation) per year mitigating these sites. In general, this is enough to fund one or two large directional drill projects, two to four medium directional drill projects, or possibly between five and seven small directional drill or rebuilt crossing projects per year. This level of spending will allow the highest ranked projects to be remediated within a 10-year period. This mitigation work will ensure our gas pipeline facilities continue operating with reduced risk, resulting in a safe, compliant, and reliable system for our communities and customers.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).

The risk avoidance/reduction of this program would be to avoid the fines from WA, OR and ID State PUC's for being out of compliance with federal safety codes. Secondly, this program prevents pipeline failures by ensuring pipe supports are sound and therefore avoids environmental fines if a pipeline failure results in the release of gas. Lastly, by remediating the above grade pipe we are mitigating the loss of service risk to downstream gas customers and the resultant outage costs. See table below and Sections 2.3 and 2.4 for details on the cost offsets associated with this program:

ER 3009 Cost Offsets[2]	2025	2026	2027	2028	2029	2030 to 2043
O&M (Indirect) - Multiple	$162,831	$162,831	$162,831	$162,831	$162,831	$3,762,470
O&M (Direct) - Maintenance	$6,289	$6,289	$6,289	$6,289	$6,289	$94,340

[2] Reference Sections 2.3 and 2.4 of this document for offset details

DocuSign Envelope ID: 295EB345-26ED-4B6E-9598-1809C6891E74

O&M (Direct) - Patrols	$1,694	$3,388	$5,082	$6,776	$8,470	$237,160
Capital (Indirect) - Leaks	$12,500	$12,500	$12,500	$12,500	$12,500	$187,500

The projects listed below are the top ranked project locations and their initial estimates. These projects total $2,160k, which is about three years' worth of projects averaging $720k per year. Due to the magnitude of the Rogue River Bridge site, some shifting of funds and projects will need to happen to ensure timely completion. As we learn more about each of these sites from the maturing of the designs and permits, the project list may change as appropriate to balance available funds and risk mitigation.

- Hwy 99 S/Bridge – S Umpqua River – 6" IP Main – $450,000
- Riverside Dr/Bridge – Days Creek – 2" IP Main - $10,000
- 1812 Talent Ave – Canal Crossing – 6" HP Main - $90,000
- 1985 Taylor Bridge #121 – Griffin Creek – 6" IP Main - $100,000
- Washington St/Bridge – S Umpqua River – 6" IP Main - $170,000
- Rogue River Bridge – 10" HP Main - $1,250,000
- S Main Elliot St/Bridge – Canyon Creek – 2" IP Main - $75,000
- 335 Pleasant View Dr – Canal Crossing – 2" IP Main - $15,000

The Reference Offset Calcs spreadsheet that explains the Risk Avoidance Over Time can be found on department drive c01d44:\GASENGINEER\GAS DESIGN DOCUMENTATION\Budget\Business Cases Updates\ER 3009 Gas Above Grade Pipe Remediation and can be made available upon request.

2.3 Summarize in the table, and describe below the DIRECT offsets or savings (Capital and O&M) that result by undertaking this investment.

ER 3009 Cost Offsets	2025	2026	2027	2028	2029	2030 to 2043
O&M (Direct) - Maintenance	$6,289	$6,289	$6,289	$6,289	$6,289	$94,340
O&M (Direct) - Patrols	$1,694	$3,388	$5,082	$6,776	$8,470	$237,160

Several above grade pipeline locations per year require O&M maintenance to repair pipe coatings, warning markers, pipe hangers, etc. Over the next 40 years it is estimated that every high risk above grade pipe location will require at least two maintenance projects to keep the pipeline operational and compliant. It is expected over the next 10 years of this program that 35 sites will be relocated belowground, 3 sites will be remediated with aboveground piping, and 4 sites will be remediated with O&M maintenance (~42 high risk sites in total). Relocating these high-risk pipelines belowground eliminates the need for two future maintenance projects and replacing with aboveground pipe eliminates one future O&M maintenance project.

Avista is currently performing mandated quarterly patrol inspections and documentation for all above grade pipe crossings. When these pipes are relocated underground, the quarterly bridge crossing maintenance and documentation burden will be reduced eliminated as there will no longer be above grade piping at these sites to inspect. In addition to saving O&M dollars, this will allow employees to focus on higher priority work.

The Reference Offset Calcs spreadsheet that explains Direct Cost offsets can be found on department drive c01d44:\GASENGINEER\GAS DESIGN DOCUMENTATION\Budget\Business Cases Updates\ER 3009 Gas Above Grade Pipe Remediation and can be made available upon request.

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2.4 Summarize in the table, and describe below the INDIRECT offsets[3] (Capital and O&M) that result by undertaking this investment.

ER 3009 Indirect Cost Offsets	2025	2026	2027	2028	2029	2030 to 2043
O&M (Indirect) – Regulatory Fines	$128,831	$128,831	$128,831	$128,831	$128,831	$1,932,470
Capital (Indirect) - Leaks	$12,500	$12,500	$12,500	$12,500	$12,500	$187,500
O&M (Indirect) – Failures & Outages	$30,000	$30,000	$30,000	$30,000	$30,000	$1,350,000
O&M (Indirect) – Safety	$4,000	$4,000	$4,000	$4,000	$4,000	$480,000

If nothing is done to remediate high risk above grade pipe locations, company risk will continue to increase over the next 5 to 15 years until it becomes almost certain that Avista will experience an event resulting in significant O&M and/or Capital costs. The most significant costs would occur due to major regulatory fines, leaks, failures & outages, and safety incidents as described in previous sections of this document. The risk matrix below was created to characterize how the probability of each major item changes over time if nothing is done, and what the potential cost could be.

Risk Probability Definitions:

Very High (VH)	Risk event expected to occur	100%
High (H)	Risk event more likely to occur than not	50%
Probable (P)	Risk event may or may not occur	25%
Low (L)	Risk event less likely to occur than not	10%
Very Low (VL)	Risk event not expected to occur	1%

Risk Probability for Calculating Indirect Offsets:

Risk Avoidance Over Time and the Cost of Doing Nothing:

#	Risk	Risk Over Time (years)					Cost Estimate	Worst Case Cost Estimate
		1	2	5	10	15+		
1	Regulatory Fines*	L	P	P	H	VH	$257,664 per day per violation (Max) $2,576,627 Total (Max)	$ 2,576,627
2	Pipeline Leak	VL	L	P	H	VH	$5,000 to $250,000 per site (site dependent)	$ 250,000
3	Pipeline Failure & Outage	VL	VL	L	H	VH	$2,960/outage (ex. ~ $1.5 million for 500 outages)	$ 1,500,000
4	Reputational	L	P	H	VH	VH	Erosion of PUC and Public trust	N/A
5	Employee & Public Safety	VL	VL	VL	L	P	$250,000 to $2 million for Lost time, healthcare, lawsuits, etc. (varies)	$ 2,000,000

The indirect cost offsets table at the beginning of this section was created by taking the probability percentage at the 5-year mark, multiplying that probability by the worst-case cost estimate, and then dividing the cost across the 5-year timeline. The last column on the right was calculated in the same way, except the probability at 15+ years was used instead of probability at the 5-year mark. The cumulative costs at years 1-5 were subtracted from the 15+ year column so the costs weren't counted twice. See below for a breakdown of the indirect cost offsets.

[3] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

DocuSign Envelope ID: 295EB345-26ED-4B6E-9598-1809C6891E74

O&M Indirect Cost offsets:

#	Risk	O&M Indirect Offset years*						Total Cost per Risk Item
		2024	2025	2026	2027	2028	2029 to 2043	
1	Regulatory Fines	$ 128,831	$ 128,831	$ 128,831	$ 128,831	$ 128,831	$ 1,932,470	$ 2,576,627
3	Pipeline Failure & Outage	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 1,350,000	$ 1,500,000
5	Employee & Public Safety	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 480,000	$ 500,000
	TOTALS	$ 162,831	$ 162,831	$ 162,831	$ 162,831	$ 162,831	$ 3,762,470	$ 4,576,627

CAPITAL Indirect Cost offsets:

#	Risk	CAPITAL Annual Indirect Offsets*						Total Cost per Risk Item
		2024	2025	2026	2027	2028	2029 to 2043	
2	Pipeline Leak	$ 12,500	$ 12,500	$ 12,500	$ 12,500	$ 12,500	$ 187,500	$ 250,000

*Took probability at 5 year mark, multiplied by worst case cost, and then divided by 5 for cost/year over 5 years from 2024 to 2028. For 2029 to 2043 took probability at 15+ year mark, multiplied by worst case cost, and subtracted 5-year costs (2024 to 2028).

The Reference Offset Calcs spreadsheet that explains Indirect cost offsets and the associated risk matrix can be found on department drive c01d44:\GASENGINEER\GAS DESIGN DOCUMENTATION\Budget\Business Cases Updates\ER 3009 Gas Above Grade Pipe Remediation and can be made available upon request.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Option	Capital Cost	Start	Complete
Recommended Solution: Remediate above ground pipe sites at requested funding level –	$669,500	Jan	Dec
Alternative Solution 1: Remediate above ground pipe sites at a reduced funding level –	$335,000	Jan	Dec
Alternative Solution 2: Remediate above ground pipe sites at an increased funding level –	$1,339,000	Jan	Dec

DocuSign Envelope ID: 295EB345-26ED-4B6E-9598-1809C6891E74

Alternative 1: Lower Funding

This alternative solution would remediate the identified above ground pipe sites at half the recommended annual funding level. If the program is funded at a lower level, then the risk to the gas system and our customers will be reduced at a slower pace. Additionally, the slower remediation pace will increase our risk to potential fines from the utility commissions. Furthermore, it could be difficult to remediate a large, complex site with a low annual budget. This alternative is not advised.

Alternative 2: Increased Funding

This alternative solution would remediate the identified above ground pipe sites at double the recommended annual funding level. If the program receives double the annual funding, in theory, the program would remediate twice as many sites per year. However, due to the increased workload, it is likely that the additional budget would not be spent and instead be returned or reallocated. This alternative is not advised.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Success will be measured by a reduction in the number of high-risk sites from the original 33 on the current Oregon risk matrix, as well as a reduction in the 16 high risk sites identified during the 2023 WA & ID risk assessment.

Projects will be started each year, and in most cases will be completed within a year of beginning. Some sites may require unique permitting or specialty equipment that may extend that project timeline beyond a year. Once construction begins, an individual project will typically be completed within the same calendar year.

Progress is monitored by the Engineering team and more information can be made available upon request. In 2023, 6 high risk sites in Oregon were remediated.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

At this time, this is an ongoing program that will typically consist of multiple completed projects each year for a program timeline of 10 years to remediate an estimated 43 sites using capital dollars. Projects become used and useful and beneficial to customers upon the purging into service of the new pipeline and retirement of the high-risk pipeline.

Remediation projects commenced in 2023 where 6 high-risk sites were remediated in Oregon. There are 5 projects in the design phase for 2024 across Oregon, Washington, and Idaho.

The program will be reassessed every year to determine if adjustments are needed to the risk evaluation methodology, risk scoring results, program funding, and program timeline.

DocuSign Envelope ID: 295EB345-26ED-4B6E-9598-1809C6891E74

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The Gas Engineering department is responsible for the approval and oversight of this business case. The program's spend and budget will be reviewed monthly by the Gas Engineering Prioritization Investment Committee. If any changes to the budget for the year are needed, the Business Case Owner proposes a budget change and justification that must get approval from the Business Case Sponsor before it is brought before the Capital Planning Group. If additional funds are not approved, then the remaining work is reduced to remain within budget.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Above Grade Pipe Remediation Program, ER3009 and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Jeff Webb 5831FFAC45834CF...	Date:	May-21-2024 | 10:07 AM PDT
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	DocuSigned by: Alicia Gibbs 49C42855345E483...	Date:	May-21-2024 | 5:00 PM PDT
Print Name:	Alicia Gibbs		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 283 of 535

DocuSign Envelope ID: 94AEE31C-04DC-44F1-ADD7-3E6E28A7FAFF

Gas Cathodic Protection Program, ER 3004

EXECUTIVE SUMMARY

Cathodic Protection (CP) systems are used to stop corrosion on buried steel gas pipes. CP system compliance is mandated by Federal Rules within the Department of Transportation code 49 CFR 192, Subpart I. Failure to meet code requirements can result in financial penalties up to $2,675,627 per violation.

Some CP systems have been in service at Avista for extended periods of time, have exceeded their useful service life, and are no longer functional (or are showing signs of imminent failure). Natural gas leaks on corroded pipe, especially at or near buildings and residences, can result in a threat to life and property. Gas leaks can result in unsafe environments for customers and Avista's employees. These conditions warrant a replacement of those systems. It is often difficult to predict in advance when specific projects are required, because sudden component failures do occur. Anodes, a key component of the CP systems, are buried and not observable, they deteriorate at differing rates, and can become ineffective when they are physically depleted. Annual testing is required on all CP systems. Each test reading must fall within a certain numerical range to be compliant with pipeline code. Any test results that are not compliant are flagged for follow-up action. Repairs or adjustments must be made to the system - usually within 90 days to meet code requirements. Additionally, new anode beds are needed to provide additional CP to the growing gas system.

The estimated annual cost for this budget is based on past expenditures and allows for the installation of approximately 7 anode beds per year. Because of the unpredictable nature of these projects, it is not always known in advance how much of the funding will be allocated to each state. The annual program spend of $735,000 effectively protects millions of dollars worth of steel pipe that may need to be replaced if CP systems were not adequately maintained.

Additional expenditures in this budget also include the installation of system testing and monitoring equipment. These new technologies allow for remote monitoring and control of the CP systems. They alert technicians to system failures and reduce the number of trips needed to check system status, resulting in a reduction of O&M expenses. Customers benefit from this reduction in expenses as well as the improved safety and reliability of the gas system.

VERSION HISTORY

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 284 of 535

DocuSign Envelope ID: 94AEE31C-04DC-44F1-ADD7-3E6E28A7FAFF

Version	Author	Description	Date
1.0	*Tim Harding*	*Initial draft of original business case*	*4/03/2017*
1.1	*Jeff Webb*		*4/04/2017*
2.0	*Tim Harding*	*Revised for 2020 Oregon GRC Filing*	*2/17/2020*
2.1	*Tim Harding*	*Updated to the refreshed 2022 Business Case Template*	*8/31/2022*
2.2	*Shontelle Wilson*	*Updated to the refreshed 2023 Business Case Template*	*4/6/2023*
2.3	*Tim Harding*	*Updated to the refreshed 2023 Business Case Template*	*4/18/2023*
2.4	*Tim Harding*	*Updated Direct Offset section*	*11/27/23*
2.5	*Tim Harding*	*Updated for 2024 Business Case*	*4/15/24*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	*4/17/2024*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	**735,000**	**735,000**
2026	**755,000**	**755,000**
2027	**780,000**	**780,000**
2028	**805,000**	**805,000**
2029	**830,000**	**830,000**

Project Life Span	***Ongoing***
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Jeff Webb / Tim Harding | Alicia Gibbs
Sponsor Organization/Department	B51 – Gas Engineering
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 285 of 535

DocuSign Envelope ID: 94AEE31C-04DC-44F1-ADD7-3E6E28A7FAFF

1. **BUSINESS PROBLEM –** *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

Buried steel gas systems are protected from corrosion in two ways. First, they rely on coatings that prevent contact between the steel and the surrounding soil. Secondly, a technology called Cathodic Protection (CP) is used. CP systems use anodes that connect to the gas system, and the anodes corrode instead of the steel pipe.

Much of this program budget is used to install new CP anode beds to replace aging infrastructure. The sacrificial anodes are consumed as part of the CP process and the service life of one of these installations is approximately 20-30 years. There are approximately 250 anode beds installed across our service territory.

The operations of Avista's CP systems are largely governed by code requirements. Not performing this work will put Avista out of compliance with state and federal codes. If CP systems are not working properly, corrosion will occur on buried steel gas piping. This will result in system integrity risks (corrosion leaks), as well as regulatory fines. Federal fines are not prescribed but can range to a maximum daily fine of $257,664 per day and a maximum total of $2,675,627 per violation. Natural gas leaks on corroded pipe, especially at or near buildings and residences, can result in a threat to life and property. Gas leaks can result in unsafe environments for customers and potentially Avista's employees.

1.2 Discuss the major drivers of the business case.

The main drivers for this business case are Mandatory & Compliance and Asset Condition. Properly functioning cathodic protection systems are required by federal code. This code requires the systems to operate within specific parameters. Those parameters can only be met when the CP systems are regularly maintained and replaced when the anodes are depleted.

The secondary driver for this business case is cost savings. The cost to install, operate, and maintain a CP system is a small fraction of the financial benefit it provides. By funding this program as requested, Avista can protect hundreds of millions of dollars' worth of steel pipe infrastructure from corrosion, extending its useful life for decades.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The operations of Avista's CP systems are largely governed by code requirements. Not performing this work will put Avista out of compliance with state and federal codes. If cathodic protection systems are not working properly, corrosion will occur on buried steel gas piping. This will result in system integrity risks (corrosion leaks), as well as regulatory fines.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 286 of 535

DocuSign Envelope ID: 94AEE31C-04DC-44F1-ADD7-3E6E28A7FAFF

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

Cathodic Protection falls within Avista's goals for reliability, affordability, responsibility, and safety. Avista chose to install CP systems prior to when they became a federal requirement in the 1970's. Providing proper corrosion control on the gas systems has extended the useful life of the steel pipes by several decades. A study found that a significant amount of the steel gas system at Avista will have a service life of over 100 years. This would not have been possible without the early adoption of cathodic protection systems in the 1960's, along with the continued operation, maintenance, and improvements to these systems.

By extending the life the gas system, the need to replace aging infrastructure is reduced, keeping costs down. The reduction in corrosion prevents pipe degradation and system leaks. This reduces the need to make repairs and improves safety.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

Anode beds are installed for two reasons. The first is to replace an existing anode bed that has failed due to end of life. The second reason is to increase the amount of cathodic protection current available. Current requirements increase as the pipe coating degrades over time, which effectively puts more pipe surface in contact with the surrounding soil. Anode beds have a design life of approximately 25 years. With approximately 250 anode beds in the system, it would be expected that approximately 10 are replaced every year.

See below for information related to anode bed installations from 2017 through 2023. The average yearly anode bed replacement was 0.76% of the total anode beds in the system (About 2 per year). This low replacement rate is approximately 1/5th the rate to be expected on assets with a 25 year life expectancy. One reason that this is occurring is because over 50% of the existing anode beds in the system were installed in the last 20 years. During this timeframe the CP systems in all three states were substantially upgraded. Further analysis is needed to determine when the anode bed failure rate will begin increasing. This information will be important for forecasting future budget needs.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 287 of 535

DocuSign Envelope ID: 94AEE31C-04DC-44F1-ADD7-3E6E28A7FAFF

Year	New Anode Beds Installed	Replacement Anode Beds Installed	Total Anode Beds Installed	
2017	9	0	9	
2018	2	4	6	
2019	0	1	1	
2020	2	2	4	
2021	7	0	7	End of Year
2022	7	2	9	Anode Bed Count
2023	6	0	6	256
Total	33	9	42	

Based off the above findings, anode beds are currently being replaced at a fraction of the expected rate. In the future, failure rates are likely to increase, and more replacements will be needed each year. The current funding of this program only addresses the minimum installations required to stay compliant with code. Current funding levels are not high enough to allow for the proactive replacement of aging CP assets. In the future, possibly in 5-15 years, the program budget will need to increase substantially to fund the replacement of 10+ anode beds per year.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The program currently operates in a reactive manner. Annual testing identifies areas in the system where follow-up work is needed, whether that be replacing anode beds that have failed, or installing new anode beds to provide additional CP. The requested level of spending is the lowest cost option to keep these systems functioning and compliant with state and federal code. As mentioned in the above section, equipment replacement rates are nearly an order of magnitude lower than necessary to keep up with anticipated future failures. All these anode beds will eventually fail, and more analysis needs to be done to predict when that will happen. At some point in the future, failure rates will grow rapidly. A proactive approach that replaces the oldest or poorest performing anode beds would spread replacement costs out more evenly in the future and help avoid a future surge in failures.

DocuSign Envelope ID: 94AEE31C-04DC-44F1-ADD7-3E6E28A7FAFF

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

The requested amount is based on recent program spending and is the minimum cost that keeps Avista's CP system in compliance with federal and state codes. This budget primarily funds the installation of new and replacement anode beds. Cathodic protection systems are required by federal code, and the criteria under which they must be operated is specified in that code. Testing is performed on these systems annually. Any system deficiencies must be addressed to remain in compliance, the timeframe for this is 90 days based off WAC code 480-93-110. Since the actual spending requirement for each year is difficult to predict, mid-year adjustments are common. Overall, the annual cost of this program is low relative to the hundreds of millions of dollars' worth of steel pipe that the CP system protects. In addition, this program reduces the risk of corrosion related leaks that can range in severity from relatively minor to potentially catastrophic.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no direct offsets or savings associated with this Business Case as it is a mandatory, code required program.

2.4 Summarize in the table, and describe below the INDIRECT offsets (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	Addressed in Direct Offsets	$0	$0	$0	$0	$0
O&M	See note below	$18,500	$19,000	$19,500	$20,000	$21,000

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 289 of 535

DocuSign Envelope ID: 94AEE31C-04DC-44F1-ADD7-3E6E28A7FAFF

When installing new anode beds, Avista's cathodic protection technicians charge time to this capital budget that would otherwise be charged to O&M accounts. The above numbers are based on the installation of five deep wells each year.

Risk Probability Definitions:

Very High (VH)	Risk event expected to occur
High (H)	Risk event more likely to occur than not
Probable (P)	Risk event may or may not occur
Low (L)	Risk event less likely to occur than not
Very Low (VL)	Risk event not expected to occur

Risk Avoidance Over Time and the Cost of Doing Nothing:

#	Risk	Risk Over Time					Cost Estimate
		1 Year	2 Years	5 Years	10 Years	15+ Years	
1	Regulatory Fines	H	VH	VH	VH	VH	$257,664 per day per violation (Max)* $2,576,627 Total (Max)*
2	Pipeline Leak	L	L	P	H	VH	$5,000 to $150,000 per site (site dependent)
3	Pipeline Failure & Outage	L	L	P	H	VH	$150,000 to $3,000,000 per site (site dependent)
4	Negative Reputation	L	H	H	VH	VH	Erosion of PUC and Public trust
5	Employee & Public Safety	VL	L	P	H	VH	Lost time, lawsuits, healthcare , etc. (varies)

*Regulatory fines present a daily and overall maximum value per violation in accordance with 49 CFR Part 190.223. However, these values are not necessarily an accurate representation of how much Avista would be fined for any specific violation. The actual amount is likely to be much lower since Avista has an ongoing reputation and history of investing in programs related to safety and non-compliance issues. However, it is a bookend reminder from which to characterize the regulatory risk associated with chronic and/or egregious non-compliance, especially in the event of a pipeline safety incident (i.e. failure). Therefore, Avista must continue to demonstrate an ongoing commitment to compliance and pipeline safety to ensure favorable future outcomes with respect to regulatory penalties (actual penalty amount is at the discretion of the state or federal agency).

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1: Replace equipment at a faster rate

Replace equipment when it fails and add new equipment to keep the system in compliance. Proactively replace aging anode beds to avoid a future rush of replacements. When there is a rush of replacement to meet the 90-day repair

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 290 of 535

DocuSign Envelope ID: 94AEE31C-04DC-44F1-ADD7-3E6E28A7FAFF

requirement (required per code), this halts other programs and work. In these instances, the project must be rushed, and it becomes more expensive due to the expedited nature of the work.

Anode bed installations are needed both to replace failed beds, as well as to add more CP current to existing systems. Both of these needs are code-required and are just being met by the current funding level. As mentioned in section 1.5, current replacement rates are low and will increase in the future. Replacing 4% of the system's anode beds each year would allow the oldest and poorest performing beds to be removed from the system and reduce the chance of sudden failures. To achieve this, about 8 additional beds would need to be replaced each year, at the additional cost of approximately $600k ($1.265M total).

Alternative 2: Replace all steel pipe with plastic

Per Federal code, CP systems are required on all buried steel gas pipes. The only way to avoid having CP systems is to replace all steel piping with plastic piping. A project like this would cost well over $1 billion and require digging up thousands of miles of streets to install the new pipe.

As of 2022, Avista had 15 million feet of buried steel main and 5.5 million feet of service piping. In 2024 the average main replacement cost is $180/ft, and the average service replacement cost is $40/ft. Replacing all of Avista's steel gas piping with plastic piping would cost approximately $3 billion and take decades of construction accomplish.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Annual testing is required on all CP systems. The results of this testing are stored in Maximo and the data is audited by inspectors from the public utility commissions in all three states. Each test reading must fall within a certain numerical range to be compliant with pipeline code. Any test results that are not compliant are flagged for follow-up action. Repairs or adjustments must be made to the system - usually within 90 days per code.

All the processes, including follow-up actions, are tracked in Maximo. The CP group doesn't actively track metrics, but there is historical data available to review.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

This is an ongoing program with work being performed year-round. Anode beds are typically installed in the summer and fall. Each project is unique, but they generally take between one week and two months to complete. Projects are used and useful upon completion.

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2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The General Foreman of the Cathodic Protection group oversees projects done by the group. This program is monitored by an Engineer within Gas Engineering who has technical expertise in Cathodic Protection. If any changes to the budget for the year are needed, the Business Case Owner proposes a budget change and justification that must get approval from the Business Case Sponsor before it is brought before the Capital Planning Group. If additional funds are not approved, then the remaining work is reduced to remain within budget.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the ER 3004 Cathodic Protection and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Jeff Webb 5831FFAC45834CF...	Date:	May-01-2024 | 4:42 PM PDT
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	DocuSigned by: Alicia Gibbs 49C42858345E483...	Date:	May-02-2024 | 8:05 AM PDT
Print Name:	Alicia Gibbs		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Gas Facility Replacement Program (GFRP)
Aldyl-A Pipe Replacement

EXECUTIVE SUMMARY

In February 2012, Avista's Asset Management Group released findings in the "Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System" report. 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 twenty-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.

The Gas Facility Replacement Program (GFRP) was initiated in 2012 and is planned to continue for 20 years in Washington (until the end of 2031) and in Idaho and Oregon (until the end of 2037). It is the sole mission and charter for the GFRP to plan and execute the replacement of 737 miles of Aldyl-A main pipe and to rebuild 17,769 service tee transitions throughout Avista's service territories. The Aldyl-A main pipe replacement work includes Aldyl-A pipe that is 1-1/4" diameter through 4" diameter and with an install date prior to January 1, 1987, or a manufactured date prior to January 1985. As of March 2024, the GFRP has 298 miles of Aldyl-A remaining to be replaced across Avista's service territory and 325 STTR's left to address via construction or map correction.

Avista has a regulatory mandate in Washington State to complete this program by the end of 2031 and has a goal of investing in its infrastructure to achieve optimum life-cycle performance. The historical spending trend from 2018 through 2023 has been $21M-$30M annually. The requested budget amounts consider Avista's regulatory mandate to complete this program with full contractor and company crew complement and to adjust for labor, contract, paving and inflation costs. By completing Aldyl-A replacement on schedule, we are aligning with Avista's Distribution Integrity Management Program's (DIMP) evaluation of risk. This also meets Avista's goal of investing in its infrastructure to achieve optimum life-cycle performance. Inflation of approximately 4-6% has been planned for by escalating the annual forecasted budgets.

This targeted Aldyl-A pipe will eventually reach a level of unreliability that is not acceptable due to the tendency for this material to suffer brittle-like cracking leak failures. There is potential harm to the public through damage to life and property and a high likelihood of increased consequences from failures in Washington due to slow crack growth statistics. These statistics show that the number of slow crack growth failures in Washington have remained steady, despite nearly half of the Aldyl-A pipe having been replaced since the program's inception. This data is available in "Avista Utilities Aldyl-A Pipe Analysis (slow crack growth leaks in WA, ID, OR)".

GFRP UPDATE

In 2023 the GFRP completed a total of ten Major Main projects across three states. 28.20 miles of Aldyl-A was replaced by contract crews and pipe verification, while an additional 5 miles was completed by Avista crews. 6 miles were also removed through map corrections and editing. In total, 39.48 miles of Aldyl-A was removed in 2023, leaving 310 miles remaining in Avista's system.

The initial approved budget for 2023 was $27,437,251. The GFRP received three different funds requests throughout the year totaling $2.8M, bringing our final approved budget to $30,237,251. These additional funds helped provide work for Avista crews which allowed us to meet our mileage goals in Washington as well as keeping our contractor in Oregon working throughout the year. The GFRP's total spend in 2023 was $30,438,014.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 293 of 535

2023 Miles Completed		
State	**Miles Completed**	**Miles Remaining**
Washington	26.35	123.51
Idaho	2.67	65.23
Oregon	10.46	121.70
Total	**39.48**	**310.44**

In 2024, the GFRP plans to replace 30.48 miles of Aldyl-A. 24.28 miles will be completed by contract crews on ten GFRP Major Main projects across all three states. An additional 5 miles will be completed by Avista crews, including work in Ritzville and Goldendale, Washington. Work will also continue with the intent to complete all remaining STTRs in the system in 2025. The current approved budget for 2024 is $27,187,251. Total mileage of Aldyl-A remaining after 2024 is expected to be 279.96.

2024 Miles Planned		
State	**Planned Miles**	**Miles Remaining**
Washington	21.54	101.97
Idaho	1.21	64.02
Oregon	7.73	113.97
Total	**30.48**	**279.96**

In 2025, the GFRP plans to replace 31.02 miles of Aldyl-A. 26.02 miles will be completed by contract crews on nine GFRP Major Main projects in Washington and Oregon. An additional 5 miles will be completed by Avista crews, including work in Stevenson, Washington. The current requested budget for 2025 is $33,664,264. This budget will help support work for Avista crews and keep our program on pace to meet commission required mileage goals in Washington state by 2031.

2025 Miles Planned		
State	**Planned Miles**	**Miles Remaining**
Washington	22.35	79.62
Idaho	0.00	64.02
Oregon	8.67	105.30
Total	**31.02**	**248.94**

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Michael Whitby*	*Initial draft of original business case*	*2011*	
1	*Michael Whitby*	*Budget Change*	*2015*	*$1.8M approved*
2	*Michael Whitby*	*Budget Change*	*2016*	*$3M approved*
3	*Michael Whitby*	*Budget Change*	*2017*	*$2M returned*
4	*Michael Whitby*	*Budget Change*	*2018*	*$1M returned*
5	*Michael Whitby*	*Budget Change*	*2019*	*$1.5M returned*
6	*Karen Cash*	*Budget Change*	*2020*	*$2.53M returned*
7	*Karen Cash*	*Budget Change*	*2021*	
8	*Karen Cash*	*Budget Change*	*2022*	*$1.31M approved*
9	*Cody Lee*	*Budget Change*	*2023*	*$2.8M approved*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*		*Steve Carrozzo 4/30/2024*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	**$33,664,264**	**$33,664,264**
2026	**$33,802,675**	**$33,802,675**
2027	**$34,309,885**	**$34,309,885**
2028	**$35,575,667**	**$35,575,667**
2029	**$35,008,538**	**$35,008,538**

Project Life Span	20 years in Washington and 25 years in Idaho & Oregon
Requesting Organization/Department	Natural Gas / Gas Facility Replacement Program
Business Case Owner | Sponsor	Cody Lee / Alicia Gibbs
Sponsor Organization/Department	Energy Delivery / Natural Gas
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 295 of 535

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

For Avista, aside from third party excavation damage, the highest risks within our natural gas distribution system is Aldyl-A Main Pipe (Manuf. 1964-1984), and the bending stress that occurs on Aldyl-A service pipe where it is connected to steel main pipe.

The GFRP was initiated in 2012 and is planned to continue for 20 years in Washington (until the end of 2031) and in Oregon & Idaho (until the end of 2037). It is the sole mission and charter for the GFRP to plan and execute the replacement of 737 miles of Aldyl-A main pipe and to rebuild 17,769 service tee transitions. The Aldyl-A main pipe replacement work includes Aldyl-A pipe that is 1-1/4" diameter and great and with an install date prior to January 1, 1987, or a manufactured date prior to January 1985. As of March 2024, there are 298 miles of pipe remaining across Avista's service territories.

The GFRP's Service Tee Transition Rebuild (STTR) Program was structured to mitigate the risks associated with the "Bending Stress Services" category within a 5-year time frame. The STTR Program started in 2013 and was deemed substantially complete in December 2017. As of March 2024, there are 325 STTR's remaining in Avista's service territory and are continuing to be remediated by local gas districts.

1.2 Discuss the major drivers of the business case.

Avista has a regulatory mandate to complete this program and has a goal of investing in its infrastructure to achieve optimum life-cycle performance.

As of August 2011, the US Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) mandates gas distribution pipeline operators to implement Integrity Management Plans, or in Avista's case, a Distribution Integrity Management Plan (DIMP) in which pipeline operators are required to identify and mitigate the highest risks within their system. For Avista, aside from third party excavation damage, the highest risks within our natural gas distribution system is Aldyl-A Main Pipe (Manuf. 1964-1984), and the bending stress that occurs on Aldyl-A service pipe where it is connected to steel main pipe.

More specifically, and as related to the risks identified above, in February 2012 Avista's Asset Management Group released findings in the *"Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System"* report. 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 Idaho, Oregon, and Washington.

Subsequently, the Gas Facility Replacement Program's (GFRP) was formed as the operational entity committed to structuring and implementing a systematic approach to mitigating the Aldyl-A pipe risks as identified in the aforementioned report.

On December 31, 2012, the **Washington Utilities and Transportation Commission** (WUTC) issued its policy statement on Accelerated Replacement of Pipeline Facilities with Elevated Risks which requires gas utility companies to file a plan every two year for replacing pipe that represents an elevated risk of failure. The requirement to file a Pipe Replacement Plan (PRP) commenced on June 1, 2013. In response to this order, Avista's first 2-year PRP for 2014-2015 was submitted and approved in 2013 per Docket PG-131837, Order 01. Avista's second two-year PRP for 2016-2017 was submitted in 2015 and approved in 2016 per WUTC Docket PG-160292, Order 01. Avista has also submitted and received approval PRP's in 2017, 2019, 2021, and 2023. In Avista's filings, the *"Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System"*

report serves as the pipe replacement "Master Plan", and two-year pipe replacement goals which includes specific project locations, and the anticipated pipe replacement quantities.

On March 6, 2017 the **Oregon Public Utilities Commission** ("Commission") issued Order 17-084 (*Docket UM 1722, Investigation into Recovery of Safety Costs by Natural Gas Utilities)*, which in part required each of the natural gas distribution companies serving customers in Oregon to file with the Commission by September 30th each year an annual "Safety Project Plan" (or Plan).1 The purpose of the Plan is to increase transparency into the investments made by each utility that are based predominantly on the need to achieve important safety objectives. More specifically, the Plan is intended to achieve the following objectives:

• Explain capital and expenses needed to mitigate safety issues identified by risk analysis or new federal and state rules.

• Demonstrate the utility's safety commitment and priority to its customers.

• Provide a non-technical explanation of primary safety reports each utility is required to file with the Commission's pipeline safety staff; and

• Identify major regulatory changes that impact the utility's safety investments.

The **Idaho Public Utilities Commission** (IPUC) has not required gas utility companies to submit an action plan, Avista has submitted the *"Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System"* report for review and communicates annual pipe replacement goals which includes specific project locations, and the anticipated pipe replacement quantities.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

This work is needed now to ensure Avista fulfills the regulatory mandate to complete this program and mitigate risk per DIMP modeling. The need to conduct this program has been identified in "Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System" report. Further, and more specifically, due to the tendency for this material to suffer brittle-like cracking leak failures, Aldyl-A will eventually reach a level of unreliability that is not economically responsible to maintain and repair rather than replace. There is a potential harm to the public through damage to life and property and there is a high likelihood of increasing regulatory scrutiny from increasing failures. Not approving or deferring this body of work would further exacerbate the risks as identified above.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

The Gas Facilities replacement Program (GFRP) is responsible for Aldyl-A pipe replacement which aligns with Avista's mission to operate and maintain a "Safe and Reliable Infrastructure". Avista has a goal of investing in its infrastructure to achieve optimum life-cycle performance.

The objective of this investment and structured replacement program is to reduce risk and prevent future catastrophic natural gas incidents. We are holding our customers interests at the forefront of all our decisions by choosing to replace these natural gas facilities. The GFRP also aligns with Avista's strategic vision by doing this in a safe, responsible, and affordable manner.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 297 of 535

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

a. On December 31, 2012, the Washington Utilities and Transportation Commission (WUTC) issued its policy statement on Accelerated Replacement of Pipeline Facilities with Elevated Risks which requires gas utility companies to file a plan every two years for replacing pipe that represents an elevated risk of failure. The requirement to file a Pipe Replacement Plan (PRP) commenced on June 1, 2013.

b. February 23, 2012 – Avista Utilities Asset Management "Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utilities' Natural Gas System."

c. April 11, 2013 - Revised Avista Utilities Asset Management "Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utilities' Natural Gas System."

d. July 2013 – ARMS Reliability Report – Avista Study of Aldyl-A Mainline Pipe and Bending Stress Point Leaks

e. Avista's first 2-year PRP to the WUTC for 2014-2015 was submitted and approved in 2013 per Docket PG-131837, Order 01.

f. Avista's second 2-year PRP to the WUTC for 2016-2017 was submitted in 2015 and approved in 2016 per WUTC Docket PG-160292, Order 01.

g. Order of the Public Utility Commission of Oregon in Docket UM 1722, Investigation into Recovery of Safety Costs by Natural Gas Utilities. March 6, 2017.

h. Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System report serves as the pipe replacement "Master Plan", and two-year pipe replacement goals which includes specific project locations, and the anticipated pipe replacement quantities.

i. April 2018 – ARMS Reliability Report - Avista Study of Aldyl-A Mainline Pipe Leaks 2018 Update.

j. August 2020 - Avista Utilities Asset Management "Aldyl-A Pipe Analysis (slow crack growth leaks in WA, ID, OR)".

k. September 2022 – Avista Utilities Asset Management "Study of Aldyl-A Pipe Leaks 2022 Update".

l. Avista's sixth 2-year PRP to the WUTC was approved in 2023 per WUTC Docket PG-230390, Order 01.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 298 of 535

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

"Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System" report details the various time horizons modeled for the Aldyl-A Pipe Replacement program. The Aldyl-A Pipe Replacement effort has been proposed and planned as a systematic 20–25-year pipe replacement program. The program is expected to have a nominal impact to existing business resources, functions, and processes since the GFRP has been structured to function as a "stand alone" program consisting of mostly dedicated internal resources. The primary functions established for these internal resources are to plan, design, oversee, manage, and administer the significant body of projectized work as assigned to "external" contract construction resources.

Periodically, on an as-needed basis, the GFRP will call on other business units for support. Since pipe replacement work is a capital expenditure, the impact to O&M cost has been minimal. Occasionally GFRP projects will encounter circumstances that necessitate O&M expenditures. When known, these O&M costs are estimated prior to construction. The GFRP tracks and monitors O&M costs monthly.

Option	Capital Cost	Start	Complete
Replace priority high-risk Aldyl-A pipe in a 20–25-year timeframe	≈ $650M	January 2012	December 2037

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

The 2013 Avista Study of Aldyl-A Mainline Pipe Leaks was updated in 2018 based on the current leaks and replacements statistics through the end of 2017. The study incorporated leak reduction and risk avoidance in the analysis.

After updating the model with leaks and replacements from 2013-2018 the expected number or leaks for the remaining period (2018-2088) reduced from 26,792 to 12,335 due to the large amount of at-risk pipe already replaced.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 299 of 535

Scenario	Leaks from 2018 through 2088	IRR	Levelized Gr. Mar. Requirement*	Lev ROE*	NPV equity*
Baseline with effects - 2013	26,792	9.21%	$16,417	$0	$0
20 Year Replacement with effects - 2013	255	6.04%	$23,229	$6,513	$93,490
Baseline with effects - 2018	12,335	18.04%	$10,785	$0	$0
20 Year Replacement with effects - 2018	246	3.87%	$36,147	$12,214	$177,848

* In thousands

Safety risks and criticality were also considered as part of the study update. It is understood that each failure event (leak) does not always result in an injury, and this is incorporated as a percentage of events that result per Avista standard modeling guidelines. The severities used are shown in table below. The projected number of catastrophic events drop from 258 to 5 events over the next 70 years by replacing the Aldyl-A pipe.

Effect	Severity	% of Failures Where Effect Occurs
Catastrophic event	50 Years	1.82%
Craft injury, WITH Lost Time/Light Duty	1 Year	0.11%
Craft injury, NO Lost Time	3 Months	0.29%

While Avista's structured replacement program has proven to reduce the highest risk in the early years of the program, the continuation of this structured replacement program is both necessary and prudent to mitigating the remaining risks within the system, and to achieving Avista's goal of operating and maintaining a safe and reliable natural gas distribution system.

The 2013 study predicted a total of 26,792 leaks on Aldyl-A mainline pipe from 2018 through 2088 years without any form of a proactive replacement program. Based upon the proactive replacements that have occurred, the number of leaks predicted over the same period has reduced to 12,335 with 246 catastrophic events if the proactive replacement were to not continue. With the current replacement of all Aldyl-A pipe by 2035, the number of predicted leaks from 2018 to program completion reduces slightly, moving from 255 to 246 leaks of which 4 have the potential to be catastrophic events. The offsets to the GFRP, include but not limited to, regulatory fines, pipeline leaks, pipeline failures and outages, negative company reputation, and elevated safety concerns. See below for a list of the relevant pipeline safety regulations pertaining to the GFRP, as well as a breakdown of each risk over time assuming nothing is done to remediate the Aldyl-A pipe.

Risk Probability Definitions:

Very High (VH)	Risk event expected to occur
High (H)	Risk event more likely to occur than not
Probable (P)	Risk event may or may not occur
Low (L)	Risk event less likely to occur than not
Very Low (VL)	Risk event not expected to occur

Risk Avoidance Over Time and the Potential Cost of the "Do Nothing" Alternative.

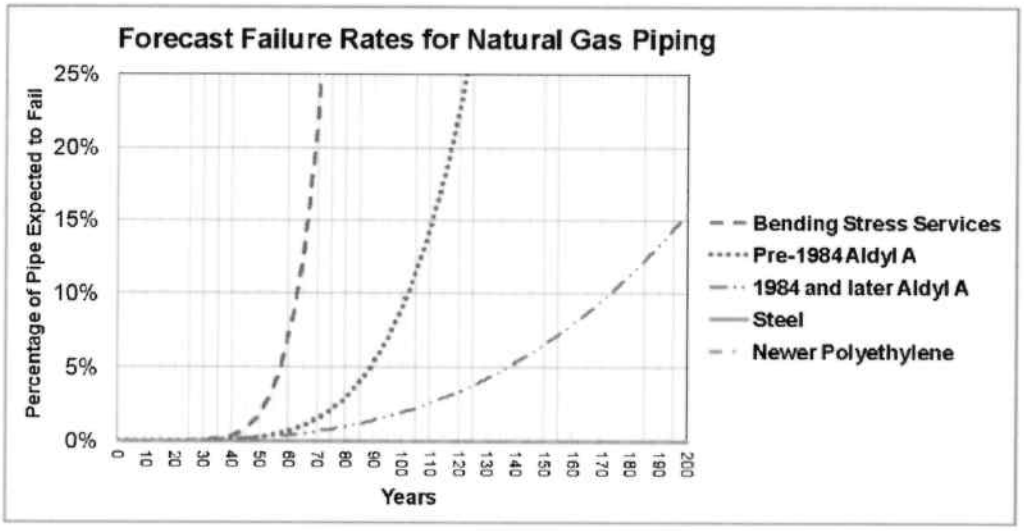
Potential Risk	Potential Risk Over Time					Cost Estimate
	1 Year	2 Years	5 Years	10 Years	15+ Years	
Regulatory Fines	L	P	H	VH	VH	$225,134 per day per violation (Max)* $2,252,334 Total (Max)*
Pipeline Leak	H	H	VH	VH	VH	$5,000 to $150,000 per site (site dependent)
Pipeline Failure & Outage	L	L	P	P	VH	$150,000 to $3,000,000 per site (site dependent)
Negative Reputation	L	P	H	VH	VH	Erosion of WUTC and Public Trust
Employee & Public Safety	VL	L	P	H	VH	Lost time, healthcare, lawsuits, etc. (varies)

*Regulatory fines present a daily and overall maximum value per violation in accordance with 49 CFR Part 190.223. However, these values are not necessarily an accurate representation of how much Avista would be fined for any specific violation. The actual amount is at the discretion of the enforcement agency and is likely to be much lower due to Avista's ongoing reputation and history of investing in programs related to safety and non-compliance issues. However, it is a bookend reminder from which to characterize the regulatory risk associated with chronic and/or egregious non-compliance, especially in the event of a pipeline safety incident (i.e., failure). Therefore, Avista must continue to demonstrate an ongoing commitment to compliance and pipeline safety to ensure favorable future outcomes with respect to regulatory penalties.

It has been determined that this type of pipe is at risk and is approaching unacceptable levels of reliability without prompt attention. The "Do Nothing" option exposes Avista to increased operational risks, decreased system reliability, and worse, is a potential harm to customers and the public through damage to life, property, and the environment. There would be a high likelihood of legal action against Avista, regulatory fines, and negative reputation. The Aldyl-A pipe will eventually reach a level of unreliability that is not acceptable due to the tendency for this material to suffer brittle-like cracking leak failures. There is a potential harm to the public through damage to life and property and there is a high likelihood of increasing regulatory scrutiny from increasing failures. Not approving or deferring this body of work would further exacerbate the risks as identified above. Additionally, the GFRP would not be able to address some of the highest risk/threats in the natural gas distribution system that have been identified by Avista's Distribution Integrity Management Plan (DIMP).

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 301 of 535

As shown in the graph below and outlined in "Forecasting Results" section of "*Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System*" report, Avista's forecast modeling tool "Availability Workbench Modeling" evaluates several classes of pipe which are represented as "curves" showing the percentage of the amount of pipe class that is projected to fail in each year of the forecasted period.



The chart below identifies the expected number of material failures in Avista's Priority Aldyl-A piping in two cases: Replacement Case – piping replaced over a 20-year time horizon, and Base Case – assumed that priority piping was not remediated under any program.

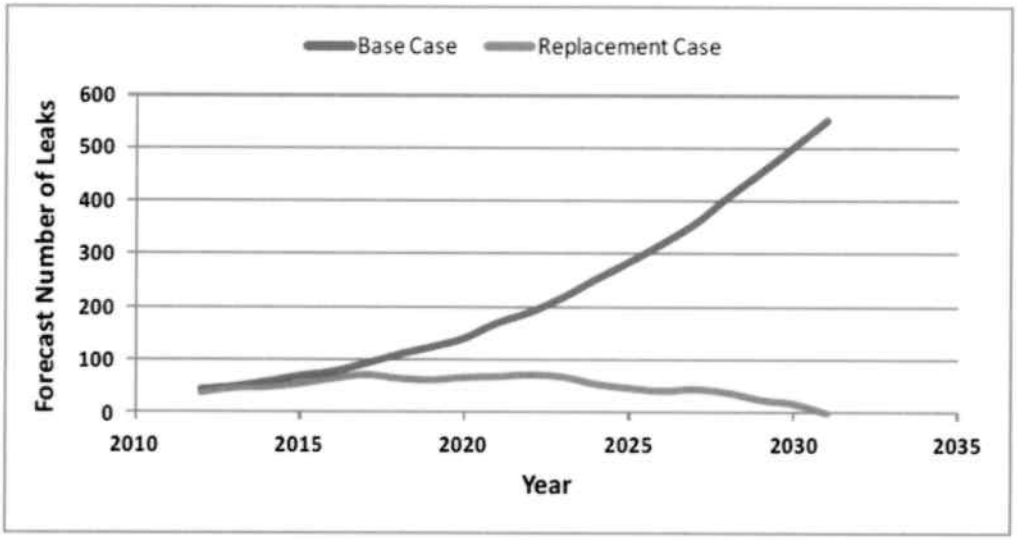


Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 302 of 535

2.3 Summarize in the table and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M	Leak Survey Cost Avoidance	$114,539	$121,439	$127,908	$133,671	$139,836

Aldyl-A gas main is leak surveyed by a contractor on an annual basis rather than the standard five-year cycle of other intermediate pressure natural gas mains. The 2024 contracted cost to survey one linear foot of gas main is $0.0467. The 439 miles of Aldyl-A that has already been removed from Avista's system since 2012 and the forecasted 2025-2029 replacement schedules are calculated cumulatively for the above O&M direct cost savings. This calculation does not consider, CPI increases, per diem or Grade 1 standby cost.

Other considerations of direct offsets were also taken into account but not calculated such as reduced system maintenance, leak rates, etc. The GFRP will work with Gas Compliance to establish how we can track and quantify these cost savings in the future.

2.4 Summarize in the table and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	Mitigatable Risk Cost Value	$31,743	$62,620	$90,886	$117,370	$144,274
O&M		$	$	$	$	$

The above cost savings represent the probabilistic risk value that is mitigated by removing vintage Aldyl-A gas main from our system. The value is calculated by analyzing the probability of failure times the consequence of failure and takes into account geographic location, ground composition and history of previous failures. The 439 miles of Aldyl-A that has been removed since 2012 is not calculated since it is no longer in service. The mitigatable risk value is calculated per year and will continue to compound and increase if nothing is done to remediate the Aldyl-A. This model is re-run annually as risk values increase with the age and degradation of the facility.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 303 of 535

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

To establish context, Avista's goal is to operate a safe, reliable, and cost-effective gas distribution system. Specifically, as related to the above statement, Avista's original 20-year plan is outlined in *"Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System"*. This report details the various time horizons originally modeled for the Aldyl-A Pipe Replacement program. It proposed and suggested that a systematic replacement program conducted over a 20-year timeline was the optimum timeframe to prudently manage risk based on the forecasted number of leaks, risks, and the rate impact to our customers.

Since the inception of the GFRP, Avista's Asset Management and Distribution Integrity Management teams have continued to analyze expected trends and potential consequences, making program adjustments as appropriate. The most recent changes made to program timelines are the extension of Oregon and Idaho Aldyl-A pipe replacement to 2037. This is due in part to the reduction of slow crack growth failures in Oregon and Idaho coupled with the number of failures in Washington remaining steady despite nearly half of the Aldyl-A pipe having been replaced since the program's inception. Extending Avista's Aldyl-A replacement work in these states to 2037 will allow us the opportunity to balance affordability and overall impact to our customers. The supporting data and analysis from Avista's Asset Management group shows that risk is continuing to be mitigated and that extending work in Oregon and Idaho will not increase the risk of catastrophic failure.

If funding is not approved for this work, annual reductions in mileage will have to be made that impact completion dates of our Aldyl-A replacement in Oregon and/or Idaho. For example, if funding is reduced by $3M each year, the GFRP will have to reduce pipe replacement by 2.7 miles in either Oregon or Idaho annually. Over a five-year period, this will cause a shortfall of mileage replaced by 13.5 miles. The impact of this is extending work an additional two years past 2037 to 2039.

Alternative 1:

Do Nothing:

It has been determined that this type of pipe is at risk and is approaching unacceptable levels of reliability without prompt attention. The "Do Nothing" option exposes Avista to increased operational risks, and worse, is a potential harm to our customers and the public through damage to life and property, and a high likelihood of legal action against the Company and likely regulatory fines. For this reason, it was deemed "not prudent" and is not a serious consideration.

Alternative 2:

Less than 20 Year Pipe Replacement Program:

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 304 of 535

Avista found that a timeline less than 20 years resulted in a greater cost impact to customers in the near term, and that it did little to reduce the forecast number of leaks expected each year. This approach did not effectively optimize the potential risks and rate impacts.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

See findings in section 2.2, 2.3, 2.4

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Washington
Start: 2012
Expected End: December 2031

Oregon & Idaho
Start: 2012
Expected End: December 2037

The annual list of projects in each of the three states (ID, OR, and WA) are established as unique "blanket projects" that transfer to plant (TTP) each month as they are "used & useful".

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The Gas Facility Replacement Program (GFRP) Advisory Group consists of the Manager of GFRP, Gas Operations Contract Construction Manager, GFRP Business Analyst II, Director of Natural Gas, and the Manager of Gas Design & Measurement. This group meets monthly to review program wide Earned Value results, the status of the delivery of the individual projects, budget allocations and variances, internal resource demands, customer care results and issues, contractor performance, and to communicate potential program risks and shortfalls.

In addition, Avista's Distribution Integrity Management Plan and Asset Management groups provide periodic input, and/or validation of the replacement plan and schedule.

Each year an annual portfolio of projects is derived from Avista's Distribution Integrity Management Program (DIMP) Aldyl-A prioritization list which currently identifies unique priority project areas (polygons) throughout the natural gas system in ID, OR, and WA. The portfolio of projects is sized to meet jurisdictional commitments. Then individual priority projects are planned, phased, scoped, designed, and detailed estimates are prepared. Once the individual project estimates are finalized, the overall program-wide capital budget is refined to reflect a more precise budget. The requested spend level has historically been determined based upon Avista's experience in the management of the Aldyl-A pipe facilities across Avista's service territories coupled with any changing costs of construction year to year.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 305 of 535

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Gas Facilities Replacement Program Business Case* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Cody Lee	Date:	4/29/2024
Print Name:	Cody Lee		
Title:	Manager, GFRP		
Role:	Business Case Owner		
Signature:	Alicia Gibbs	Date:	4/30/24
Print Name:	Alicia Gibbs		
Title:	Director, Natural Gas		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

DocuSign Envelope ID: 33DE473C-7232-491E-811F-32AA475F77B7

EXECUTIVE SUMMARY

In accordance with a Stipulated Agreement between Avista and the Washington State Utility Commission (WUTC), and to maintain compliance with the Code of Federal Regulations 49 CFR 192.455, 192.457 and 192.465 Avista implemented an "Isolated Steel Identification and Replacement Program" (program) beginning in 2011. The initial goal of the program was to inspect, identify and remediate steel pipe and risers that are cathodically isolated or lack required cathodic protection within Avista's Washington State natural gas pipeline systems. Inadequate cathodic protection can result in corrosion of steel pipe and leaks related to corrosion. Natural gas leaks on corroded pipe, especially at or near buildings and residences, can result in a threat to life and property. Gas leaks can result in unsafe environments for customers and potentially Avista's employees. As part of the program evolution, and to be prudent in our operations, our efforts in recent years have expanded into Avista's Idaho and Oregon service territories. Work completed under this program helps maintain Federal and State compliance requirements and results in a safer gas distribution system, both for the communities we serve and for Avista employees. Over the long term, this investment will help to reduce operating and maintenance costs for Avista as we will no longer be required to spend time and money locating and mitigating unknown isolated steel facilities. In general, the corresponding O&M inspection program is focused on finding isolated steel services and service risers by testing cathodic protection at each riser. It is important to note, however, that there are other isolated steel service and mainline remediation projects completed under this Program that are identified outside of the associated inspection program in all three states.

Remediation efforts in Washington State were completed in 2021 and approved by the WUTC as outlined within a 2022 Closure Letter for the Stipulated Agreement. As this program has been completed in Washington, the focus of the Gas Isolated Steel Replacement Program shifted into Idaho and is now primarily in Oregon. Avista has finished identifying isolated steel in Idaho and is now about halfway through the program inspections required to identify isolated steel in Oregon. Remediation of identified sections of isolated steel pipe is ongoing in both Idaho and Oregon to reduce the risk of hazardous leaks caused by continued corrosion of isolated steel pipe in our distribution system. Most of the remediation in Idaho has been completed with only a few known projects remaining. Due to the amount of isolated steel that needs to be identified and remediated in OR, this will need to be an ongoing capital program. It is estimated, with the requested level of capital funding, that the program will require approximately 7-10 additional years to complete. Many of the replacement jobs generated during the inspection process have a quick timeline (90-days to 1-year) for remediation to re-establish compliance. The remaining jobs have longer term (10-year) replacement timelines from the date they are discovered. This is because they comply with the Code requirements for cathodic protection, but they are still isolated and require remediation as a best practice. This business case helps define the scope of the Gas Isolated Steel Replacement Program.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Jeff Webb*	*Initial draft of original business case*	*3/16/2017*
1.1	*Jeff Webb*	*Revisions*	*4/07/2017*
1.2	*Jenn Massey*	*Revised for 2020 Oregon GRC Filing*	*2/17/2020*
1.3	*Nick Messing*	*Updated to the refreshed 2020 Business Case Template*	*7/10/2020*
1.4	*Nick Messing*	*Updated to the refreshed 2022 Business Case Template*	*5/05/2022*
1.5	*Seth Samsell*	*S. Samsell took over Program and revised Business Case Template*	*8/25/2022*
1.6	*Shontelle Wilson/Seth Samsell*	*Updated to the refreshed 2023 Business Case Template*	*4/14/2023*
1.7	*Seth Samsell*	*Revised 2024 Business Case*	*4/15/2024*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	*4/22/2024*

DocuSign Envelope ID: 33DE473C-7232-491E-811F-32AA475F77B7

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	**3,000,000**	**3,000,000**
2026	**4,000,000**	**4,000,000**
2027	**5,000,000**	**5,000,000**
2028	**5,000,000**	**5,000,000**
2029	**5,000,000**	**5,000,000**

Project Life Span	***Ongoing. Estimate 7-10 Additional Years***
Requesting Organization/Department	R08 – Gas Programs
Business Case Owner | Sponsor	Seth Samsell / Jeff Webb | Alicia Gibbs
Sponsor Organization/Department	B51 – Gas Engineering
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

There is an unknown amount of "isolated" steel pipe in Avista's Oregon natural gas systems. Isolated steel pipe is defined as pipe that does not have adequate cathodic protection or is protected but may be isolated from a cathodic system. Cathodic protection is required by Federal Code to help prevent buried steel from corroding below grade. Corrosion can cause leaks at or near service points resulting in conditions that may be hazardous to life and/or property. This program originally began in Washington State as result of a failed audit in which Avista was found to be in violation of Code due to unknown and unprotected steel service piping. As a result, we entered into a Stipulated Agreement with the WUTC, to identify, document and remediate all unknown sections of isolated steel pipe including isolated steel main, services and service risers within a specified timeframe. These efforts were carried over into Idaho and are now ongoing primarily in our Oregon service areas.

DocuSign Envelope ID: 33DE473C-7232-491E-811F-32AA475F77B7

1.2 Discuss the major drivers of the business case.

The major drivers for this business case include the categories “Mandatory and Compliance” as well as aspects of “Customer Service, Quality and Reliability.” Isolated (unprotected) portions of steel pipe, including main, service pipe and risers, do not comply with the Code of Federal Regulations. Per Federal rules 49 CFR 192.455 & 192.457 steel gas pipelines installed below ground must be cathodically protected to prevent corrosion of the steel material. When steel pipe is found to be not cathodically protected, Federal rule, 49 CFR 192.465 states that the issue needs to be remediated “promptly”. Washington Administrative Code (WAC) 480-93-110 defines promptly as “within 90 days”. This is the standard that the original Washington program was based upon, and it is also the recommended practice by the National Association of Corrosion Engineers (NACE). Isolated (protected) portions of steel pipe are allowed by Federal Code, if they are monitored every 10-years to ensure the cathodic protection is still adequate and maintained.

Per the initial Stipulated Agreement in Washington, Avista was required to replace all isolated steel pipe identified through the Washington inspection program within a period of 90-days (if unprotected) or 10-years (if protected) to eliminate the potential risk for non-cathodically protected steel and corrosion related leaks in the future. Keeping in line with this practice, when isolated steel pipes have been found through cathodic inspections in Idaho and Oregon (program and non-program), we have historically replaced them to meet the requirements of 49 CFR 192.455 and 192.465. Avista incorporated this standard of 90-day (isolated & unprotected) and 10-year (isolated & protected) replacement timeframes as a means to stay compliant in all three states. The alternative to replacement, to maintain Federal and State compliance, would be to re-establish cathodic protection and monitor these locations every 10-years per 192.465. Not maintaining the effort to locate and remediate isolated steel pipe within the specified timeframes could mean that Avista would be increasingly out of compliance with mandatory Federal and State regulations. This is a significant risk and a required action in Avista’s Integrity Management Plan.

Since the initial Washington program requirements have been satisfied, Avista has shifted the program forward in Idaho and is working primarily in the Oregon service areas to identify and remediate isolated steel pipe. Work under this program for Idaho and Oregon is currently being completed to the same standard as in Washington. Proactively locating and mitigating isolated steel pipe will result in a safer gas distribution system for Avista’s customers as well as our employees. When steel pipes do not have proper cathodic protection, the risk of corrosion and related corrosion leaks become significantly greater over time. We are not able to predict the condition of the pipe or how long this pipe has been unprotected. We do know some of steel pipe has been in the ground since the 1950s. Natural gas leaks on corroded pipe, especially at or near buildings and residences, can result in a threat to life and property. Gas leaks can result in unsafe environments for customers and potentially Avista’s employees. In circumstances where a corrosion related leak might require an unplanned outage to repair, customer service, quality and reliability suffer as well. These risks only continue to increase the longer this isolated steel pipe remains in the ground and undetected.

DocuSign Envelope ID: 33DE473C-7232-491E-811F-32AA475F77B7

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

This work is needed now to comply with the Federal and State regulations and Avista's standards as discussed in previous sections. Per Avista Gas Standards Manual Spec 5.14 "When facilities under cathodic protection are found with pipe-to-soil (P/S) potentials below adequate levels, the facilities must be scheduled for restoration. Areas shall be restored within 90-days from the date they are found below adequate levels of protection in Washington and should be restored within 90-days in Idaho and Oregon as a best management practice." The goal of this program, moving forward, is to maintain the same quality of work that was completed in Washington for the states of Idaho and Oregon. Failure to complete the program to this same standard may result in danger to life, property, and the environment. Other increased risks include operational and financial penalties determined by Federal and State regulators. These penalties could range from thousands of dollars to multi-millions of dollars depending upon the severity of the incidence or violation. There is no effective way to predict what the severity of an incident or penalty might be. However, by maintaining and expanding this program, Avista is making an effort to locate isolated steel within our natural gas system and to operate in compliance within Federal and State regulations. The intent is to reduce the risk of corrosion on steel piping systems and thereby reducing the chance for future leaks associated with these pipes. Work completed under this program results in a safer, more reliable natural gas distribution system in all the communities we serve, for Avista's customers as well as our employees.

It is important to clarify that programmatic inspection work (O&M) creates follow-up work (Capital) that is required to be completed within either a 90-day or a 10-year timeframe to remain in compliance with the Code of Federal Regulations and Avista's Standards for Gas Construction. Failure to replace pipe or re-establish CP within 90-days or to meet other required compliance timeframes could lead to potential violations with the Oregon Public Utility Commission. Deferring the budget request will limit the Program's ability to complete the Program in the estimated timeline as well as mitigate the risks associated with this compliance and integrity issue.

Additional system risks and estimates of their associated costs are listed in the table on the following page. The exact cost of all these risks cannot always be predicted. For that reason, cost ranges are provided.

DocuSign Envelope ID: 33DE473C-7232-491E-811F-32AA475F77B7

Risk Probability Definitions:

Very High (VH)	Risk event expected to occur
High (H)	Risk event more likely to occur than not
Probable (P)	Risk event may or may not occur
Low (L)	Risk event less likely to occur than not
Very Low (VL)	Risk event not expected to occur

Risk Avoidance Over Time and the Cost of Doing Nothing:

#	Risk	Risk Over Time (years)					Cost Estimate
		1	2	5	10	15+	
1	Regulatory Fines*	L	P	H	VH	VH	$257,664 per day per violation (Max) $2,576,627 Total (Max)
2	Pipeline Leak	P	P	H	VH	VH	$5,000 to $50,000 per site (site dependent)
3	Pipeline Failure & Outage	L	L	L	P	H	$50,000 to $200,000 per site (site dependent)
4	Negative Reputation	L	P	H	VH	VH	Erosion of PUC and Public trust
5	Employee & Public Safety	L	P	P	H	VH	Loss of life, property, lost time, lawsuits, healthcare , etc. (varies)

*Regulatory fines present a daily and overall maximum value per violation in accordance with 49 CFR Part 190.223. However, these values are not necessarily an accurate representation of how much Avista would be fined for any specific violation. The actual amount is likely to be much lower since Avista has an ongoing reputation and history of investing in programs related to safety and non-compliance issues. However, it is a bookend reminder from which to characterize the regulatory risk associated with chronic and/or egregious non-compliance, especially in the event of a pipeline safety incident (i.e. failure). Therefore, Avista must continue to demonstrate an ongoing commitment to compliance and pipeline safety to ensure favorable future outcomes with respect to regulatory penalties. (actual penalty amount is at the discretion of the state or federal agency).

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 311 of 535

DocuSign Envelope ID: 33DE473C-7232-491E-811F-32AA475F77B7

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

This program aligns with Avista's organizational focus on our responsibility to maintain a safe and reliable infrastructure in all the communities we serve, for all our customers and for our employees who maintain these systems each day. By proactively identifying and mitigating isolated steel pipe, we are staying in compliance with Federal and State regulations, remaining innovative, and improving our existing distribution systems. This program further demonstrates to our customers that we are a responsible operator that puts customer safety first. Corrosion related leaks cannot only cause outages but can compromise the safety of Avista customers and our employees. As a best practice, Avista should continue with this program to prevent corrosion leaks on steel pipe and help prevent associated incidents or outages by proactively locating and establishing cathodic protection or replacing isolated steel pipe.

The Gas Isolated Steel Replacement Program is in line with meeting Federal and State code requirements. The program also follows Avista Gas Standards Manual Spec 5.14 Cathodic Protection Maintenance, as quoted above in section 1.3 of this business case justification. This program will locate and mitigate currently unknown pipe that is not adequately protected cathodically and is at high risk for corrosion. By working to comply with 49 CFR 192.455 and 192.465 this program works to maintain safe and reliable natural gas systems and helps prevent future corrosion related leaks at or near buildings which places Avista's customers and employees at risk. All of this is in accordance with Avista's Standards and Integrity Management Plan.

DocuSign Envelope ID: 33DE473C-7232-491E-811F-32AA475F77B7

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

During the Washington program, beginning in 2011, approximately 175K inspections were completed resulting in over 4,780 follow-up jobs ranging from additional required inspections to full replacements of service risers or service lines. From these findings Avista determined that continuing this program will address significant risk in our Idaho and Oregon service territories as well. It is in Avista's best interest to address these risks sooner rather than later. Idaho inspections are now complete and there were approximately 1,500 follow-up jobs from over 58K locations inspected. There are only a handful of replacement jobs remaining in Idaho, and these should be completed over the next year or two.

Currently, of approximately 89K service locations in Oregon, more than 45K locations still require inspection. The nature of the program often requires multiple inspections at an individual location. At this time, it is estimated that more than 58K visits will be required to complete the Oregon inspection process. Since Oregon inspections began (in 2020) we have been finding isolated steel replacement jobs at a higher rate (1.5x-2x) than that for Washington and Idaho. Because our sampling rate for steel inspections is small, relative to the entire Oregon system, it is unknown if this high rate of isolated steel discovery will continue in Oregon. What we do know, with the information we have currently, is that we estimate there may be anywhere between 1,500 and 2,000 jobs in Oregon that would require remediation within a 90-day period to re-establish compliance. We also estimate there may be up to 600-800 additional jobs that would require remediation up to 10-years from the date they are discovered. These are locations where we are compliant with cathodic protection requirements, but replacement of a riser or service line is recommended as a best practice due to the nature of the cathodic protection or the construction practices used at the time of installation.

An isolated steel service replacement job in Oregon costs, on average, about $10K to complete. A riser replacement is less cost; however, we do not always know what mitigation will be required until the inspection process is completed, or the pipe is exposed by a crew. Service replacements at these quantities and costs are estimated to result in a capital investment of $15-20M to re-establish compliance. It is projected an additional $6-8M will be required to mitigate remaining isolated steel services estimated to be in the system long term. In total, it is estimated it will cost Avista approximately $20-$30M in capital funding to complete the project. Capital funding levels can limit the number of jobs that can be created and remediated each year. Current operational resources can also limit the number of remediation jobs we can complete each year. It is believed that the Program will require approximately 7-10 additional years to complete. These forecasts are based upon requested funding levels. We believe the proposed capital funding will help us to generate the information we require to continue to fine tune these estimates. Regardless, we will continue to reduce risk within our natural gas system both from an operational and a compliance standpoint through this program.

DocuSign Envelope ID: 33DE473C-7232-491E-811F-32AA475F77B7

2. PROPOSAL AND RECOMMENDED SOLUTION – *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

As the program is now complete in Washington state, and mostly complete in Idaho, the proposed solution in Oregon is to maintain similar standards and practices set out for the original Washington program. The goal is to systematically identify and remediate all sections of isolated steel pipe and service risers in our Oregon operational areas. Replacement of these isolated steel pipes and risers maintains compliance with Federal Code 49 CFR 192.465, WAC 480-93-110, NACE, and Avista's Standards. It also fulfills Avista's goal to maintain our responsibility of operating a safe and reliable infrastructure in all the communities we serve, for our customer's as well as our employees.

There are approximately 45K locations remaining in Oregon that potentially require multiple inspections to determine whether they have isolated steel. Ideally, we would approach this program by completing all remaining inspections over a 3-4 year period and at the same time be addressing the remediation efforts as follow-up in up to a 10-year period post inspection, similar to the Washington program. With the information we have currently, we estimate there may be anywhere between 1,500 and 2,000 replacement jobs in Oregon that would require remediation within a 90-day period to re-establish cathodic protection and compliance. We also estimate there may be 600-800 additional jobs that would require remediation within 10-years from the date they are discovered. These additional locations are those where we are compliant with cathodic protection requirements, but replacement of a riser or service line is recommended as a best practice due to the nature of the cathodic protection, materials or the construction practices used at the time of installation. Each season we fine tune these estimates to update this business case to reflect the latest data. Since the program O&M inspections generate capital replacement jobs, the level of approved capital to support additional remediation work ultimately will control the number of inspections that can be completed. The more inspections we can complete, the better the data will be to be able to fine tune the scope and timeline for the remaining program in Oregon. It is estimated, with the requested level of capital funding, that the program will require approximately 7-10 additional years to complete. The challenge with this program will be to manage the approved budget and the resources required to complete the amount of required replacement work within the required 90-day or 10-year timelines.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

DocuSign Envelope ID: 33DE473C-7232-491E-811F-32AA475F77B7

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits, or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

This business case is intended to address risk reduction and Avista's ability to maintain compliance in the states we operate within. The program is aimed at maintaining safe and reliable systems for our customers and not so much a cost benefit or return on investment. As part of the original Stipulated Agreement with the WUTC, Avista was required to address isolated steel at levels that were not known prior to the establishment of the program. Like the Washington program proved, we believe that isolated steel is a significant integrity issue in our Oregon system. We believe this risk is significant enough that the investment should be made now to maintain compliance and eliminate these risks. This is supported by thirteen years of isolated steel inspections and data dating back to 2011. The ultimate threat is a catastrophic event that would pose risk to life and property. That said, isolated steel pipe and service replacements put new, more reliable plant in the ground as a capital investment which improves the overall reliability of our system.

The requested funding amounts in this business case are being made based on the number of remaining jobs in Idaho and Oregon, estimating the number of unknown jobs in Oregon, comparing the average replacement costs in each state, and by reviewing previous years' budgets along with the volume of work completed by the program each year. As mentioned before, with the information we have currently, it is estimated there may be anywhere between 1,500 and 2,000 replacement jobs in Oregon that would require remediation within a 90-day period to re-establish cathodic protection and compliance. We also estimate there may be 600-800 additional jobs that would require remediation within 10-years from the date they are discovered.

In 2022, with an approved capital budget of $850K, additional approved requests of $280K, and additional spend we were able to complete approximately 150 replacement jobs at a final cost of approximately $1.5M. In 2023, this level of replacement increased to approximately 275 jobs at a final cost of approximately $2.3M and we were able to perform 775 additional inspections on steel risers with the increased level of capital funding.

Full service isolated steel replacement jobs are costing on average about $10K in Oregon and we have seen single service replacement jobs as high as $25K depending on the circumstances involved. These costs and the risk associated with the issue are only increasing with time. Replacement at these quantities and cost requires a significant capital investment ($20M to $30M) and additional resources to complete the work in the required timeframes. This is work that will need to be completed to stay in compliance and mitigate the risk. Deferring the work will only increase the overall costs of replacement and place us at a greater compliance risk.

The data is constantly changing as more inspection and replacement cost information is gathered. As this happens the forecasting will be improved, and the business case updated to align requests moving forward with the amount of work required to mitigate isolated steel in all Avista's service territories.

DocuSign Envelope ID: 33DE473C-7232-491E-811F-32AA475F77B7

2.3 Summarize in the table and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	-	$0	$0	$0	$0	$0
O&M	Reduced Costs of Inspection and O&M Related Follow-Up	$0	$0	$0	$0	$150K

The program goal is to identify and mitigate all the isolated steel pipe in our system which will eliminate the need to perform additional survey inspection work. We estimate there will be approximately 58K inspections required at over 45K locations. At current costs, this would be approximately $600K over the life of the remaining inspection project or about $150K/year. Depending on the level of capital available, we might be able to support completing the inspections in as soon as 3-4 years. This is the assumption shown above.

Over time, the program will also reduce or eliminate the need to have Cathodic Technicians performing isolated steel follow-ups created by the inspection orders. At the volumes we estimate now, this could be a savings up to about $50K/year that could be dedicated to other Cathodic Protection work within our systems. We could potentially see these savings in as soon as 6-7 years. This would depend on the rate at which we find isolated steel, the number of jobs we can complete each year, as well as how long it would take for the Cathodic Technicians to complete all the follow-up work orders generated from the inspections.

Over the long term, this investment will help to reduce operating and maintenance costs for Avista as we will no longer be required to spend time and money locating and mitigating unknown isolated steel facilities.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

DocuSign Envelope ID: 33DE473C-7232-491E-811F-32AA475F77B7

2.4 Summarize in the table and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	N/A	$0	$0	$0	$0	$0
O&M	Cathodic Protection	$5000	$5000	$5000	$5000	$5000

Most of the offsets that would result by completing the isolated steel replacement work are direct and are described in Section 2.3. The program, however, will reduce the number corrosion leaks on isolated steel pipe as well as the number of issues encountered when identifying and repairing the cathodic protection system allowing Cathodic Technicians to focus on long term cathodic protection of the pipelines and not locations where we have inadequate protection. The estimated savings of $50K per year would apply in this case as well since it would enable the labor charges to go to higher priority work on the cathodic system. It is not likely these costs would be observed within the next 5-years of the program.

This program will also reduce the risk of outages caused by corrosion related leaks. Most outages related to a corrosion leak on isolated steel would only impact a single customer or service line at a time. It is estimated a single outage might cost $5K, but the probability of an outage being caused by a corrosion leak is relatively low.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1

One alternative to the proposed solution is to locate and remediate isolated steel in Idaho and Oregon at reduced funding levels. The inspection program, over the past three years in Oregon, has focused on clearing and verifying PE riser locations (not isolated). It has been limited on the number of steel inspections completed in order to limit the number of follow-up jobs created to be within approved capital funding levels. In 2-3 years, there will only be steel risers left to inspect. Maintaining reduced funding levels will serve to perpetuate a reduced quantity of steel inspections each year as costs continue to increase. We will only be able to complete inspections until the maximum level of created jobs is met based on the level of program funding. This will, in effect, delay the identification of isolated steel in Oregon, which already exists in our systems, thus deferring our ability to identify and fix the problem.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

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Deferring the costs to replace or remediate these integrity issues will extend the program above and beyond the estimated timeframe. The identification and mitigation of these facilities is inevitable as they are not in compliance with Federal and State codes until they are cathodically protected. The longer we wait to identify the location of these isolated steel pipes, the higher the risk becomes that the unprotected steel pipes will corrode, develop leaks, and become hazardous to life, property, and the environment. Delaying the Oregon program would not align with Avista's current practice of mirroring the Washington program timeframe for Idaho and Oregon and would put Avista at a much higher risk of being increasingly out of compliance.

Estimated Cost of Alternative 1: $20M to $30M plus inflation and increased costs of replacement over the deferred timeframe. In addition, any additional O&M costs related to deferring the work.

Alternative 2:

An additional remediation alternative is to install temporary anode protection on service pipes to meet the compliance requirements of 49 CFR 192.465 around re-establishing cathodic protection within 90-days. It was determined in 2023 that the installation of anodes on service piping can be capitalized. Installing anode protection may allow for additional inspections to be completed because it could extend the remediation timeframes. Anode installation may be a way to meet compliance, however these pipes will likely still need to be replaced within 10-15 years, depending on their condition and future cathodic evaluation. We do not know, and are not able to determine, the current condition of steel pipe in the ground or how long these pipes have been unprotected. The only way to know this would be to spend O&M dollars to dig all of them up and perform direct assessment on them, which would be very costly and disruptive.

In 2023, we performed a pilot program in Medford, OR to install anodes on services lacking proper cathodic protection. The goal was to complete more inspections on steel pipe and to better understand the use of anodes and the installation process. The average cost of mitigation using an anode was approximately $2500 - $3500, 50%-90% higher than originally expected. We estimate additional capital costs in the range of $7M to $10M would be required to mitigate the estimated number of isolated locations using anodes. In general, anode installation is a viable alternative in locations where we need to buy time (e.g., moratorium streets) prior to a full replacement. However, since most of these locations would require eventual full replacement, this would be additional cost to the proposed alternative described in Section 2.1. It is recommended that anodes be used as a mitigation tool available to our Construction Districts, but not as a primary long-term solution.

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2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

The Gas Isolated Steel Replacement Program will be successful if the unknown isolated steel riser/service count drops to zero in all Avista's service areas. This was a Washington requirement and is a best practice for Idaho and Oregon.

The Washington program eliminated all known isolated steel and Idaho has 3 open 10-year isolated steel service replacement jobs remaining. Oregon has about 700 known isolated steel service replacement jobs open, but it is important to note that Oregon's numbers only reflect the number of isolated steel replacement jobs currently open in our Maximo system. The ongoing inspection program is continuing to identify isolated steel in Oregon. Therefore, the job count in Oregon will increase as the inspection program and replacements continue. Newly identified sites will be added to the Oregon number for remediation. Approximately 89K services were identified in Avista's GIS system, which have been flagged for inspection in Oregon. The data shows that there are approximately 45K service locations that still require inspection. This data and information are housed and processed through an MXD system in AFM that is monitored by the Gas Programs department. The capital jobs or work orders created under ER 3007 are documented in Maximo and monitored by Gas Compliance Specialists.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Idaho mitigation projects should be completed in the next year or two. However, there is currently not a set completion date for the Oregon program. It is estimated, with the requested level of capital funding, that the program will require approximately 7-10 additional years to complete. Ideally, we would pattern Oregon after Washington and establish a 10-year plan to complete the work, however the volume of work that may result from the Oregon inspections, may require more time.

DocuSign Envelope ID: 33DE473C-7232-491E-811F-32AA475F77B7

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The governing committee for the program consists of the Manager of Gas Programs, The Isolated Steel Program Coordinator, the Manager of Gas Compliance (B54), the Manager of Gas Engineering (B51) and the Cathodic Protection group. This team helps to determine the direction of the program as it relates to both inspection work and capital replacement work.

The Manager of Gas Programs (R08) and the Isolated Steel team are responsible for this business case as well as monitoring and administering ER 3007 – Gas Isolated Steel Replacement Program. Gas Programs is also responsible for monitoring and administering the inspection process. The inspections are completed on a separate O&M budget, but they generate the jobs that are created as part of this capital replacement program. The data and information for the inspection program is documented in the ArcGIS system as part of an MXD program. The capital jobs or work orders created under ER 3007 are documented and tracked in Maximo.

Each new year, Gas Programs and the Isolated Steel team distribute the approved capital spend to each of the local construction districts to complete replacement projects in their respective areas. As these replacement projects are completed the costs are reported back through Gas Programs each month. This information is used to forecast current and expected remaining program spend for the year. These results are reported back to accounting and the Capital Planning Group through the Manager of Gas Engineering. This monthly reporting is used to identify whether budget targets are met and to track overall completion levels in each area. Changes to the business case or any funds returns/requests are also submitted through Gas Engineering. All these groups report to the Director of Natural Gas.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 320 of 535

DocuSign Envelope ID: 33DE473C-7232-491E-811F-32AA475F77B7

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Gas Isolated Steel Replacement Program* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Jeff Webb 5831FFAC45834CF...	Date:	May-03-2024 | 9:24 AM PDT
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	DocuSigned by: Alicia Gibbs 49C42855345E483...	Date:	May-03-2024 | 9:39 AM PDT
Print Name:	Alicia Gibbs		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

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EXECUTIVE SUMMARY

The work completed under this Business Case is typically unscheduled and is initiated by either customers or Avista maintenance crews. Gas Engineering establishes the overall budget based on historical spend patterns and reports monthly updates to the Capital Planning Group based on feedback from the Local Districts. Gas Engineering is responsible for projects under ER 3005 that require substantial design efforts such as farm tap retirements, highway or river crossings, and replacing steel pipelines with plastic pipe, but the local Districts manage the work.

The work in this annual program is mostly reactionary, unscheduled work and is difficult to predict aside from using historical trends. The following situations are typical triggers for work in the program: shallow facilities found by excavation (the excavation may or may not be related to gas construction), relocation of facilities as requested by others (except for road and highway relocations), leak repairs on mains or services, farm tap elimination, and overbuilds. Gas Overbuilds (ER 3006) are now part of this Business Case starting in 2024. The previous Business Case supporting overbuilds is ending, since all known overbuilds in Oregon have been remediated with the exception of the projects in the Medford District. Unforeseen overbuild projects will likely only come up occasionally, which is why this category of work is being added to this Business Case.

Customer related benefits include reduced operations and maintenance (O&M) costs and improved safety and reliability. Ensuring facilities are installed at the proper depth and in locations where maintenance can be performed improves safety for customers and company personnel. Leak rates are reduced when new plastic pipe is installed, versus leaving the older steel pipe in-place. When reducing leak rates, it also reduces unscheduled outages due to performing leak repairs and therefore raises customer satisfaction. The business needs and solutions identified in this Business Case impact gas customers across all of Avista's service territories.

DocuSign Envelope ID: 39C11A18-5DEC-41A3-AC8E-27F1B65FF2D3

VERSION HISTORY

Version	Author	Description	Date
1.0	*Jeff Webb*	*Initial draft of original business case*	*3/16/2017*
1.1	*Jeff Webb*	*Updates to initial draft*	*4/05/2017*
2.0	*Jeff Webb*	*Revised for Oregon 2020 GRC filing*	*2/17/2020*
3.0	*Jeff Webb*	*Updated to the refreshed 2022 Business Case Template*	*5/31/2022*
3.1	*Shontelle McGrath*	*Updated to the refreshed 2023 Business Case Template*	8/14/2023
3.2	*Jeff Webb*	*Updated data for 2024*	*4/15/2024*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	*4/22/24*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	**10,580,000**	**10,580,000**
2026	**10,897,400**	**10,897,400**
2027	**11,224,322**	**11,224,322**
2028	**11,561,052**	**11,561,052**
2029	**11,907,883**	**11,907,883**

Project Life Span	***Ongoing***
Requesting Organization/Department	B51 / Gas Engineering
Business Case Owner | Sponsor	Jeff Webb | Alicia Gibbs
Sponsor Organization/Department	B51 / Gas Engineering
Phase	Execution
Category	Program
Driver	Failed Plant & Operations

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 323 of 535

DocuSign Envelope ID: 39C11A18-5DEC-41A3-AC8E-27F1B65FF2D3

1. **BUSINESS PROBLEM -** *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

The work in this annual program is mostly reactionary, unscheduled work and is therefore difficult to predict aside from using historical trends. The following situations are typical triggers for such work: shallow facilities found by excavation (the excavation may or may not be related to gas construction), relocation of facilities as requested by others (except for road and highway relocations), leak repairs on mains or services, remediation of cathodic protection (CP) issues, farm tap elimination, and overbuilds. Each of these work types have different concerns that are being addressed and are further described below. Customer related benefits include reduced operations and maintenance (O&M) costs and improved safety and reliability from having facilities at the proper depth and from reduced leak rates of new plastic pipe versus older steel. The business needs and potential solutions identified in this Business Case impact gas customers across all of Avista's service territory.

When shallow facilities are discovered, an appropriate response to the situation is determined by Local District Management. A shallow gas facility is defined as not buried to the proper depth (having less cover and protection than is required by Federal Rules). If the response to the situation is capital in nature, then the repair is funded from this program. These types of projects allow Avista to remain in compliance and operate the gas facilities in a safe and reliable manner. 15% of the dig-in damages on Avista's gas system are on pipes that are less than 18" deep.

If requested by others (typically customers) to relocate facilities, Avista is bound by state tariffs to do so at the customer's expense. Under certain circumstances, Avista may choose these opportunities to perform additional work beyond the immediate request to improve or update the gas system. Local District Management and field personnel will evaluate the circumstances and make an appropriate decision based on a holistic view of the situation. Guidance to help evaluate the scenario is established in the Company Gas Standards Manual. An example might be to replace an entire existing steel service with modern plastic material instead of just replacing a section of the steel service that conflicts with a customer's home improvement project. This would eliminate the possibility of future deficiencies with the cathodic protection system on the steel pipes and reduce future maintenance related to that steel service. The charges for this additional work are put against this program.

When leaks are found on the gas system, it is sometime advantageous to replace a section of main or service as opposed to repairing the leak with a temporary leak clamp. The Local District considers the long term impacts when possible, not just addressing the immediate concern when determining the right thing to do in each of these situations. This type of betterment falls under this program.

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If a section of steel main is found to be isolated electrically from the CP system, a CP Technician will evaluate the situation and give directions to the district to fix. If the solution is a capital main replacement, it will fall under this program. Isolated steel services fall under ER 3007.

A single service farm tap (SSFT) installed on a high pressure main is a common way to provide gas service to a small number of customers. The alternative is to install distribution main from an adjacent distribution system to serve the customer which may be cost prohibitive at the time. Many of these farm taps are reaching the end of their service life or need to be replaced for maintenance reasons. In areas of high concentrations of farm taps that have maintenance concerns, it is sometimes advantageous to rebuild one of them as a traditional regulator station (pressure reduction station), install distribution main to the other services from the adjacent farm taps, and then retire the other farm taps. This reduces O&M by having fewer stations to maintain and increases safety by having fewer above grade facilities that are exposed to potential vehicular damage.

Overbuild conditions normally occur when a structure is placed or constructed over an existing gas pipe. The close proximity of these structures makes gas system maintenance and inspection difficult, can be against state and federal code, and can be a potential safety hazard for the occupants. Except for the Medford District, starting in 2024 Overbuild remediation work was transitioned to this Business Case. This was done because all known Overbuild projects had been completed and any future projects in the other districts, should they be discovered, will likely be minor in scope. The known Overbuild remediation work in the Medford District will continue under the Business Case associated with ER3006.

Figure 1 shows how the budget is typically spread across the different project types discussed above.

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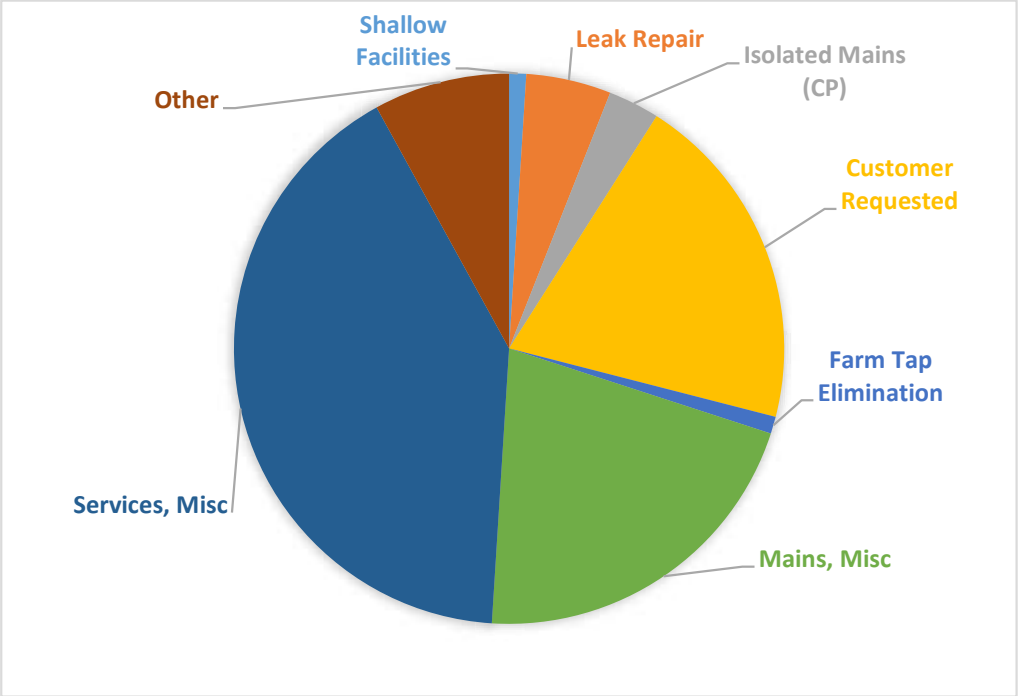

Figure 1. ER 3005 Spend by Project Type

1.2 Discuss the major drivers of the business case.

Due to most of this work being unscheduled replacement, the major driver is Failed Plant & Operations. The percent of Customer Requested work is small compared to the other work in this program.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Each different type of problem addressed under this Business Case mitigates different risks.

Shallow facilities – Lowering gas mains and services is not required by Federal Rules, but it is prudent to ensure the gas pipes are buried to a safe depth. It reduces the risks of damage caused by excavation over and around the gas facilities. This is critical because damage from excavation is the highest risk to gas facilities. Excavators are expecting gas pipes to be at the depths they are originally installed at. When they are shallow because of grade changes that have been caused by others since installation, there is an increased risk of damage and threat to public safety.

If not approved, Avista would experience higher instances of pipe damages and associated gas leaks. As noted above, approximately 15% of dig-in damages occur when the gas pipes are less than 18” deep.

DocuSign Envelope ID: 39C11A18-5DEC-41A3-AC8E-27F1B65FF2D3

Requested by others & leak repair – Betterment of the gas system when opportunities arise is the prudent way to operate a gas distribution system. Mobilizing crews and equipment to a site often covers the bulk of the costs for small projects, so making the most of their time once on-site is a practical way to operate. Betterments as described above are driven by Company Standards and best practices.

If not approved, Avista would miss the opportunity to better the system while crews are already on-site doing work. This is shortsighted because we increase the chances of having to be back at the site to remedy other maintenance items later that could have been taken care of the first time we were there. The decision to simply repair the leak or perform the customer requested work (quickest and easiest thing to do) eliminates the opportunity to improve the system while already onsite to do work and increases the chances of having to be back at the site later to fix another leak or maintenance concern. If leaks are not repaired, the release of greenhouse gases can negatively impact the environment and the leaks must be monitored and re-evaluated on a periodic schedule to ensure they are not becoming a greater hazard to the public.

Isolated mains (CP) – Electrically isolated portions of steel main will be replaced as required to meet the requirements of Federal code 49 CFR 192.455 & 192.457. This is a safety related requirement as a steel pipe will corrode if it does not have sufficient Cathodic Protection on it.

If not approved, Avista will be at risk of fines for being out of compliance and the steel piping system will not be safe for the employees and customers.

Farm tap elimination – When there are many farm taps located near each other and when those stations have reason to be rebuilt, then it is wise to rebuild just one of them and install distribution main to the other stations to provide a new source of gas. This allows the adjacent (old) farm taps to be retired, reducing O&M and improving public safety. Triggers for rebuilding a farm tap may include: replacement of inadequate or obsolete equipment that is no longer supported, poor location of station (safety concerns), replacing leaking threaded connections with welded connections, inability to perform proper maintenance, and capacity constraints. Customers benefit from these types of projects by having a safer, well maintained distribution system. Also, this is a prudent way to manage resources because many deficiencies at stations can be remedied under just one project. If Avista is not allowed to optimize the gas distribution system by reducing the number of farm taps that are maintenance intensive, then eventually more staff will be required to perform this federally mandated maintenance work. On average, one field technician can maintain only four of these stations in an eight-hour day.

Additionally, farm taps are normally located between the driving lane and the property line, are low profile, and are sometimes difficult for the public to see. This puts them at risk of vehicle damage, so having fewer of them on the system helps to improve safety.

Overbuilds – Overbuilt gas pipes pose a safety risk for occupants in the area. Leaking gas can accumulate under mobile homes and storage sheds. If the

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overbuilt pipe is not relocated, Avista could also be at risk of fines due to being in violation of state or federal codes.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

This program aligns with Avista's values of being Trustworthy and Innovative. Each project completed under this program addresses a customer or safety concern while simultaneously bettering the gas system. Completing these types of projects shows that Avista makes wise, long-term decisions and takes steps to optimize the gas system when the opportunities arise. We prioritize customers through this work because it results in a safer, more reliable gas system. In addition, by completing customer requested work, we let customers know that their interests are important to us.

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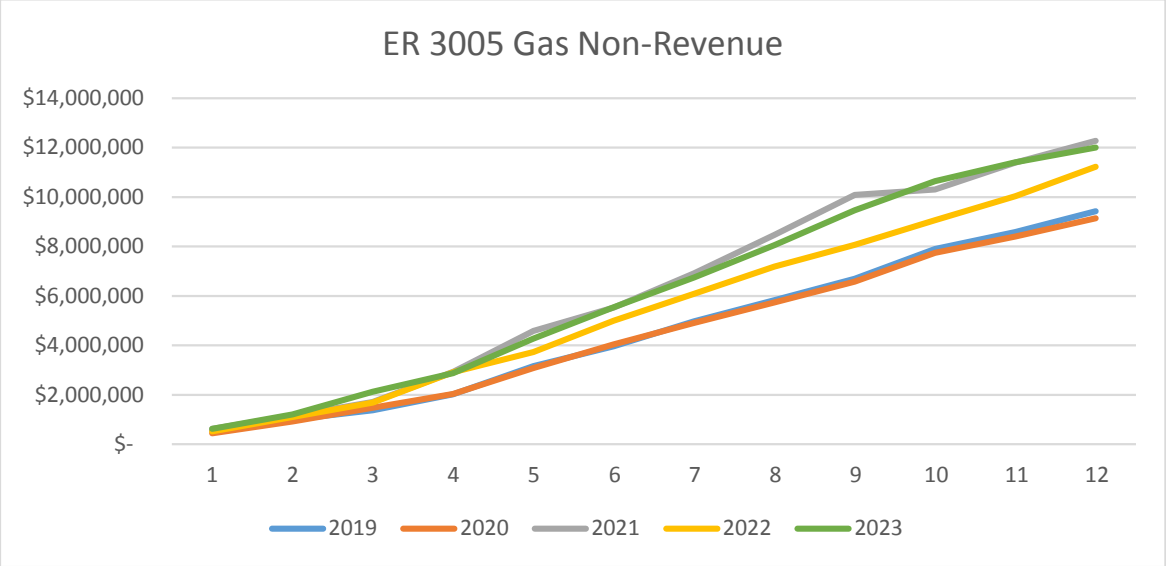
1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

The work completed under this Business Case is reactionary. Projects are discovered throughout the year and resolved promptly thereafter. Most of this work is managed at the local district level and Gas Engineering is not involved with the scope and schedule of the individual projects. The budget for this Business Case is based on historical spend. The graph below shows the annual spend for the last five years.



2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Each project and solution are unique. Below are common solutions to each type of project.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

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Shallow Facilities: For gas facilities that are discovered to be shallow, the solution is to lower the facilities. This is typically achieved by either lowering the facility in-place or installing new facilities at an appropriate depth and abandoning the shallow facilities. This ensures adequate protection of gas facilities to reduce the risk of excavation damages. If lowering existing facilities chosen over installing new, this would be an O&M expense and not fall under this Business Case.

Requested by Others & Leak Repair: When customer requested work and leak repairs come in, the request is reviewed, and the local gas system is looked at to see if there are any recommended improvements. If there are potential improvements, the Local District Manager uses their judgment, the Company Standards, and best practices to develop an appropriate resolution. Oftentimes, improving the system by installing new gas facilities is a better option than simply repairing or relocating a small section of pipe. This improves the safety of the gas system and reduces the chances of returning to the same location to address additional safety or maintenance concerns in the future.

Isolated Mains (CP): When electrically isolated portions of main are discovered, the solution is to install a method of cathodic protection (CP) to ensure the pipe is protected. The method of CP remediation depends on where the isolated main is located and is determined by the CP Technician. Ensuring steel pipe is properly protected from corrosion is required by Federal Code. By addressing isolated mains, we reduce the risk of steel pipe corroding and leaking. In addition, not addressing isolated mains would result in Avista being subject to fines for not meeting Federal Code requirements.

Farm tap elimination: When there are several farm tap stations located near each other and one or more are due to be rebuilt, the most beneficial solution is to rebuild one station and install distribution main to the other station locations. This allows the other farm tap stations to be retired, reducing future O&M and improving public safety. Many deficiencies can be addressed through one project using this approach.

Overbuilds: When pipe is discovered under a mobile home, building, carport, or other structure that may entrap gas, the solution is to relocate all facilities that are overbuilt and abandon the overbuilt facilities (assuming the structure causing the condition can’t be moved). This reduces the safety risk of gas entrapment and ensures gas facilities are installed in compliance with federal codes and best practices.

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2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

Each type of project completed under this program reduces risk, and some also reduce future O&M costs.

Shallow facilities: The risk of damage to gas facilities is higher for shallow facilities. Excavators expect gas facilities to be at the current, standard burial depths. This is not always the case for facilities in locations where grade changes have occurred since installation. External damage by excavation is one of the highest risks to gas facilities. By lowering shallow facilities when they are discovered, the risk of damage by excavators is reduced. This also reduces the potential for greenhouse gas emission related to gas leaks associated with dig-in damage.

Requested by others & leak repair: By completing system enhancements when company crews are already onsite completing work requested by others, the risk of customer dissatisfaction is reduced. If only the bare minimum work were to be completed, there is a risk of having to return to the same site later for additional maintenance. This is also a more cost-effective way to operate, as the cost of mobilizing a crew can be most of the project cost. Similarly, with leak repairs, it is likely that if the leak is simply patched that a crew will need to visit the same location in the future for additional maintenance. By improving the system in response to a leak, the risk of having to revisit the same site in the future is reduced. Again, this also reduces future O&M costs and the potential for greenhouse gas emission related to gas leaks.

Isolated Main (CP): By addressing isolated steel main, we reduce the risk of pipe corroding. In addition, ensuring steel pipe is protected is mandated by federal code. Avista would be at risk of federal fines if isolated mains were not addressed.

Farm tap elimination: There are different reasons a farm tap may be due for replacement. These include: inadequate or obsolete equipment that is no longer supported, poor location of station (safety concerns), replacing leaking threaded connections with welded connections, inability to perform proper maintenance, and capacity constraints. By rebuilding and/or eliminating station locations that

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

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face these concerns, several types of risk can be reduced. If a station has inadequate or obsolete equipment and it were to fail, there is a risk of an unplanned customer outage due to the station failure. There are a few risks associated with stations in poor locations, many of these sites are located just off the roadway, between the traffic lane and property line. For these stations, there is a risk of vehicular damage to the station, as well as a safety risk to Avista personnel while performing required maintenance. If proper maintenance cannot be performed, Avista is at risk of fines for not being compliant with mandated maintenance requirements. If a station has capacity constraints, there is a risk of unplanned customer outages if a station cannot support all downstream customer loads. In addition, by eliminating farm tap locations, future O&M costs associated with required station maintenance can be reduced.

Overbuilds: For gas facilities that are overbuilt, there is a safety risk. Gas can accumulate under structures, which poses a risk to public safety.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$0	$0	$0	$0	$0
O&M		$0	$0	$0	$0	$0

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$0	$0	$0	$0	$0
O&M	Temporary Leak Repair	$2,287,000	$2,287,000	$2,287,000	$2,287,000	$2,287,000

If the capital funding under this Business Case was not available, a portion of Avista labor and transportation would likely be charged to expense work. 32% of the annual spend is associated with labor and transportation. The O&M cost

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

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offsets were calculated assuming those charges would be split 50/50 between capital and expense. This is estimated to be $2,287,000 per year.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1:

For shallow facilities, the only alternative is to leave them in place. This is not recommended. The risk of excavation damage is higher for shallow facilities, and excavation damage remains one of the highest risks to gas facilities.

Alternative 2:

For work requested by others & leak repair, the alternative is to do the absolute minimum and only address the gas facilities that are either in conflict or leaking. This is not recommended because it is not a prudent way to operate a gas system. If system enhancements are not completed while crews are already mobilized and onsite, it is likely that crews will have to return to the same site to perform additional maintenance in the future on these aging facilities.

Alternative 3:

There is no alternative to addressing isolated steel main. This work is mandated by federal code and would result in regulatory fines if not completed. Regulatory fines can be up to $225,134 per day per violation, up to a $2,251,334 total.

Alternative 4:

The only alternative to farm tap eliminations is to rebuild each farm tap in place as the need arises. This alternative is not advised. Farm tap stations require regular O&M maintenance. If Avista is not allowed to optimize the gas system by strategically eliminating farm taps where it makes sense, additional personnel may need to be hired to perform the federally mandated maintenance.

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Alternative 5:

There is no alternative to replacing known overbuilds. Leaving known overbuilds in place would be a violation of code and standard practices. Regulatory fines can be up to $225,134 per day per violation, up to a $2,251,334 total.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Each individual project under the different project types supported by this Business Case has a Maximo work order. Success can be measured by tracking all the completed work orders. Here are additional metrics for a few of the project types:

Shallow facilities: When damages occur on Avista's gas facilities, the cause for damage is documented. As shallow facilities are discovered and fixed, less damages should be correlated with improper depth of cover.

Requested by others & leak repair: Customer satisfaction, or lack of complaints, due to not having multiple visits to the same address would indicate we are managing the system properly by bettering it when we have the opportunity. Lower leak rates over time due to newer gas facilities can also be tracked.

Farm tap elimination: As farm tap stations are eliminated, success can be measured through lower O&M costs associated with station maintenance.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

The work in this program is comprised of small projects that are typically completed within the same month they are started. As such, the funds transfer to plant each month throughout the year. The graph in section 1.5 shows a relatively steady spend throughout the year.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Gas Engineering monitors the spend and reports back to the District Managers monthly. The oversight occurs through email and Gas Engineering will prepare the appropriate documents for the Director of Natural Gas to present at the CPG should changes be needed throughout the year.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 334 of 535

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3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Non-Revenue Program, ER 3005* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Jeff Webb 5831FFAC456834CF...	Date:	May-03-2024 | 12:25 PM PDT 10/11/2023
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		
Signature:	DocuSigned by: Alicia Gibbs 49C42855345E483...	Date:	May-04-2024 | 11:28 AM PDT
Print Name:	Alicia Gibbs		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

DocuSign Envelope ID: D311AD81-9D31-47AE-AFA4-AD3DB44CB764

EXECUTIVE SUMMARY

Avista is required by state commission rules and tariffs in WA, ID, and OR to annually test gas meters for accuracy and ensure proper metering performance. Execution of this program on an annual basis ensures the continuation of reliable and accurate gas measurement for our customers and compliance with the applicable state tariffs. Customers benefit from this program because it ensures that they are not overpaying for gas consumption if their meter's accuracy is out of specification. In some situations, a customers' meter could measure higher energy usage than the customer is actually using, resulting in the customers' bill being too high. Avista also benefits from this program because it helps identify slow meter families, which are meters that are registering under 100% accuracy. In these situations, the meter is undermeasuring the energy that is being used by the customer; therefore, the customer is being billed for less energy than they are actually using.

The Planned Meter Change-out (PMC) Program uses a statistical sampling methodology based on ANSI Z1.9 "Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming". Sample sizes and acceptance criteria are defined in the ANSI standard. The annual test results of gas meters that have been removed from the field are analyzed and a determination of the accuracy of each meter family is made. If the analytics determine a meter family, defined as a manufacturer year and model/size, is no longer metering accurately enough to meet the tariff, then that entire meter family will be replaced. Conversely, if the analytics determine a meter family is testing well, the sample size can be reduced. The sample size is defined as the number of meters in that family required to be tested. These analytics help control costs and remove meters quickly that are not performing well.

This testing and replacement approach controls the cost of the program to provide the best value for customers compared to other meter replacement strategies, for example replacing meters after a prescribed number of years. Statistical analysis has proven that older meter families can retain their accuracy and perform like a new meter; therefore, there is no benefit to customers to replace older meters that are performing within the accuracy specifications.

The program also provides Avista with the statistical data necessary to identify drifts in meter accuracy. If a meter family shows a consistent drift in mean accuracy, the meter reading may be corrected by adjusting the entire family's Installation Constant value in the Meter Data Management system, rather than removing the meters from service. This approach allows Avista to adjust and leave meters in service that would have otherwise needed to be replaced, while still accurately billing customers.

This program includes only the labor and minor materials associated with the PMC Program. Major materials (meters, pressure regulators, and Encoder Receiver Transmitter (ERT)) will be charged to the appropriate Gas Growth Programs. The annual cost for the program varies depending on the results of the previous year's statistical analysis. Yearly budgets are projected using a calculation based on the estimated number of failed family meters, PMC's, and overpulls for the year, as well as the average cost per meter based on the previous year's data.

Avista would not be in compliance with state commission rules and tariffs in WA, ID, and OR if this program is not completed annually. This would put Avista at risk of receiving a public violation, which would result in the erosion of public trust and potential fines. State fines are not prescribed, and it is up to each state to determine the fine amount.

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VERSION HISTORY

Version	Author	Description	Date
1.0	*Jeff Webb*	*Initial draft of original business case*	*3/16/2017*
1.1	*Jeff Webb*		*4/07/2017*
2.0	*Dave Smith*	*Revised for 2020 Oregon GRC Filing*	*2/17/2020*
2.1	*Dave Smith*	*Updated to the refreshed 2020 Business Case Template*	*6/24/2020*
2.2	*Dave Smith*	*Updated to the refreshed 2022 Business Case Template*	*5/05/2022*
2.3	*Shontelle Wilson*	*Updated to the refreshed 2023 Business Case Template*	*3/20/2023*
2.4	*Dave Smith*	*Updated per BCRT Feedback*	*3/29/2023*
2.5	*Doug Brummett*	*Updated 2.6*	*4/16/2024*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	*4/25/2024*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	**4,300,000**	**4,300,000**
2026	**3,600,000**	**3,600,000**
2027	**3,700,000**	**2,600,000**
2028	**3,800,000**	**3,800,000**
2029	**3,800,000**	**3,800,000**

Project Life Span	***Ongoing***
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Doug Brummett / Jeff Webb | Alicia Gibbs
Sponsor Organization/Department	B51 – Gas Engineering
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

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1. **BUSINESS PROBLEM -** *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

Avista is required by state commission rules and tariffs in WA, ID, and OR to test meters for accuracy and ensure proper metering performance. Execution of this program on an annual basis ensures the continuation of reliable gas measurement and compliance with the applicable tariffs. If Avista does not complete this annual program, we will be out of compliance with state rules and tariffs which could result in a violation (which is made public) and erosion of public trust.

1.2 Discuss the major drivers of the business case.

This program is a mandatory requirement to be in compliance with state commission rules and tariffs in WA, ID, and OR.

The following state rules regulate Avista's PMC Program:

Oregon:

- OAC 860-023-0015 "Testing Gas and Electric Meters"
- Tariff Rule #18

Idaho:

- IDAPA 31.31.01.151 through .157 "Standards for Service"

Washington:

- WAC Chapter 480-90-333 through -348 "Gas companies – Operations"
- Tariff Rule #170

Being out of compliance with these rules and tariffs could result in a violation and potential fines. State fines are not prescribed and it is up to each state to determine the fine amount.

The customers benefit from this program because it assures that natural gas consumption is measured accurately in all jurisdictions. Accurate measurement ensures accurate customer billing.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Avista would not be in compliance with state commission rules and tariffs in WA, ID, and OR if this program is not completed annually. Also, the accuracy of measurement of our customers' natural gas usage could not be assured. See below for breakdown of these risks:

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Risk Probability Definitions:

Very High (VH)	Risk event expected to occur
High (H)	Risk event more likely to occur than not
Probable (P)	Risk event may or may not occur
Low (L)	Risk event less likely to occur than not
Very Low (VL)	Risk event not expected to occur

Risk Avoidance Over Time and the Cost of Doing Nothing:

#	Risk	Risk Over Time (years)					Cost Estimate
		1	2	5	10	15+	
1	Regulatory Fines*	H	H	VH	VH	VH	$257,664 per day per violation (Max) $2,576,627 Total (Max)
2	Pipeline Leak	Not Applicable					Not Applicable
3	Pipeline Failure & Outage	Not Applicable					Not Applicable
4	Negative Reputation	H	H	VH	VH	VH	Erosion of PUC and Public trust
5	Employee & Public Safety	Not Applicable					Not Applicable

*State fines are not prescribed and it is up to each state to determine the fine amount. Federal regulatory fines present a daily and overall maximum value per violation in accordance with 49 CFR Part 190.223. However, these values are not necessarily an accurate representation of how much Avista would be fined for any specific violation. The actual amount is likely to be much lower since Avista has an ongoing reputation and history of investing in programs related to safety and non-compliance issues. However, it is a bookend reminder from which to characterize the regulatory risk associated with chronic and/or egregious non-compliance, especially in the event of a pipeline safety incident (i.e., failure). Therefore, Avista must continue to demonstrate an ongoing commitment to compliance and pipeline safety to ensure favorable future outcomes with respect to regulatory penalties (actual penalty amount is at the discretion of the state or federal agency).

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

This program aligns with Avista's Strategic Goals of Reliability and Trustworthiness for our customers. When meter accuracy is outside of the 2% tolerance customers may be overcharged. This would cause customer dissatisfaction and could hurt the reputation of Avista. "Our word is reliable; we do what is right." The PMC Program aligns with Avista's focus on giving customers a high quality of service.

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1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

- Gas PMC Program Standard Operating Procedure
  - This procedure covers the methodology, testing requirements, and annual reporting guidelines for Avista's gas meter measurement performance testing program (PMC Program) for new and in-service meters.
- ANZI Z1.9 "Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming"
  - This is the methodology for sample sizes and analysis for the meter testing program.
- The following state rules and tariffs require Avista to administer a meter sampling program:

Oregon:

- OAC 860-023-0015 "Testing Gas and Electric Meters"
- Tariff Rule #18

Idaho:

- IDAPA 31.31.01.151 through .157 "Standards for Service"

Washington:

- WAC Chapter 480-90-333 through -348 "Gas companies – Operations"
- Tariff Rule #170

These documents are saved on the Avista network drive c01d44 and can be made available upon request.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The program is completed between January and December of each year. Gas Engineering, Gas Operations, Gas Meter Shop, and Technical Services work together to administer the PMC program. Gas Operations and the Gas Meter Shop personnel remove the meters from the customer's premise and install new ones. If a large meter family fails, Avista may hire a contractor to assist in the removal of the meters. The Gas Meter Shop completes physical calibration tests on the meters and the Technical Services group then analyzes the test results at the end of the year to determine the status of each family of gas meters. The results of this analysis will define the meter removal and testing requirements for the following year. Gas Engineering develops an annual report which is made available to the state commissions upon request.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

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The program also provides Avista with the statistical data necessary to identify drifts in meter accuracy. If a meter family shows a consistent drift in mean accuracy, the meter reading may be corrected by adjusting the entire family's Installation Constant value in the Meter Data Management system rather than removing the meters from service.

Execution of this program on an annual basis ensures the continuation of reliable gas measurement and compliance with the applicable tariffs, which is state mandatory in WA, ID, and OR. The recommended solution is to complete this mandatory programmatic work. Completion of this program will keep Avista in compliance with state rules and tariffs and assure that our customers' natural gas use is measured accurately. Partial completion of this program will result in Avista being out of compliance with state rules and tariffs.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

The PMC Program uses a statistical sampling methodology based on ANSI Z1.9 "Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming". Sample sizes and acceptance criteria are defined in the ANSI standard. The annual test results of gas meters that have been removed from the field are analyzed and a determination of the accuracy of each meter family is made. If the analytics determine a meter family (defined as a manufacturer year and model/size) is no longer metering accurately enough to meet the tariff, then that entire meter family will be replaced. Conversely, if the analytics determine a meter family is testing within tolerance (close to 100% accurate), the sample size (number of meters in that family required to be tested) can be reduced. These analytics help control costs and remove meters quickly that are not performing well.

The meter accuracy testing results collected annually from the program are documented and analyzed in an Excel spreadsheet. This spreadsheet performs calculations based on ANSI Z1.9 to determine the following year's sampling requirements and identify which meter families do not meet the accuracy standards and must be removed. This analysis also checks that the Installation Constant value assigned to meters that have a consistent drift in mean accuracy are measuring within the specified accuracy range, and the Installation Constant value adjusted as necessary. All results are saved and then presented on the annual Gas Meter Measurement Performance Report. This can be made available upon request.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

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2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$0	$0	$0	$0	$0
O&M		$0	$0	$0	$0	$0

No direct offsets could be identified for this program.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	Avoid Meter Replacements by Adjusting the Installation Constant	$5.2MM	$5.3MM	$5.5MM	$0*	$0*
O&M		$0	$0	$0	$0	$0

*Per the PMC Program Standard Operating Procedure failed family replacement timelines, 25% of the total 87,000 meters would need to be replaced each year starting in 2024 and ending in 2027.

Completing the annual PMC Program provides indirect savings. The program provides Avista with the statistical data necessary to identify drifts in meter accuracy. If a meter family shows a consistent drift in mean accuracy, the meter reading may be corrected by adjusting the entire family's Installation Constant value in the Meter Data Management system rather than removing the meters from service. This approach has allowed Avista to adjust and leave approximately 86,000 meters in service that would have otherwise needed to be replaced. See the file titled *ER 3055 PMC Program Offset Calculations 2023.xlsx* showing the calculations for the indirect savings.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1:

The only alternatives are to either partially fund this program or to not fund it at all. If this program was not completed fully, Avista would be out of compliance with state rules and tariffs and could be exposed to fines from the various state utility commissions. There are

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

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not prescribed fine ranges for state violations, and it is up to state staff to determine the amount of any fines. Also, the accuracy of measurement of our customers' natural gas usage could not be assured.

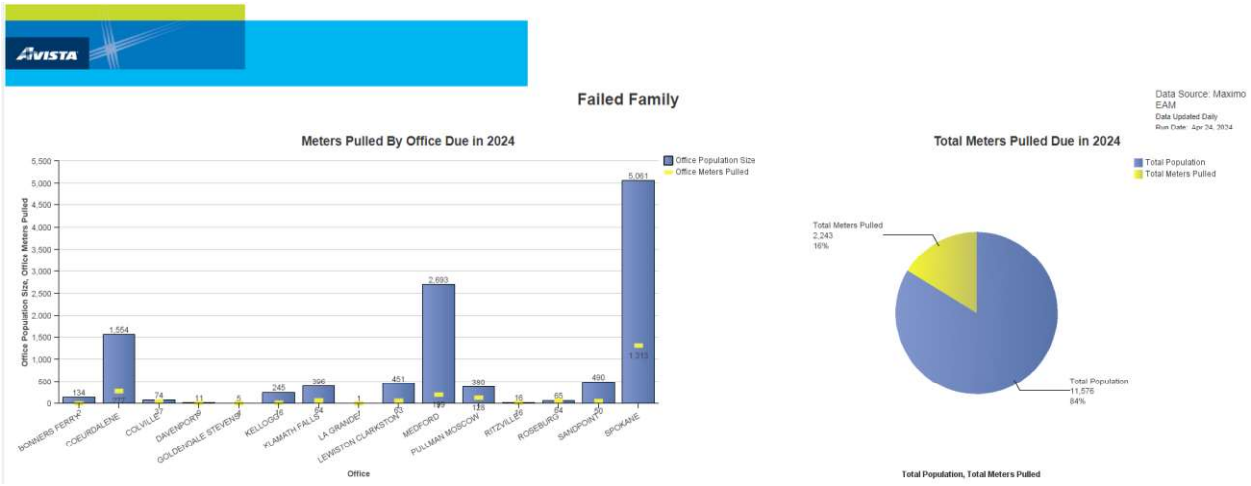
2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

All the meters in the random sampling program will be identified by a "flag" in Avista's Service Suite mobile application at the beginning of a calendar year. Meters shall be chosen at random and in sufficient quantities to meet the guidelines for sampling as detailed in the standard. Once the required number of meters in each family is removed for testing the "flag" will be removed in Service Suite indicating that no more meters in that family are required for testing.

Meters identified as a failed family meter will have a Maximo work order created to remove them from service. These work orders are used to track progress throughout the year.

There is a Gas PMC FF Meters dashboard available from the gas wiki site that will be replacing the previous weekly Cognos report MR 130121 Gas PMC FF Meters Pulled and Tested.xlsx. The dashboard contains the total number of failed families broken up by district along with how many meters have been pulled and how many are remaining. Additionally, there is a tab for the PMC meters that shows all the meter families and the sampling requirement for that family. Lastly, the final tab tracks the meters that have been pulled and tested and how many remain to be tested. This is broken up by meter family.

Below is a screen shot of the dashboard showing the representative content.



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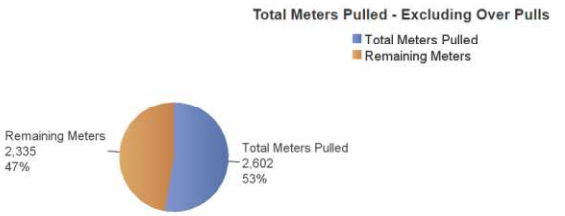
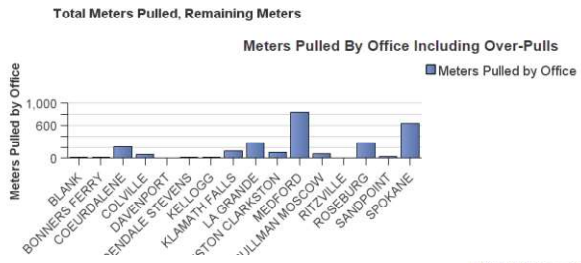


Total Over-Pulls - -2,440

Data Updated D
Run Date: Apr

Sampling Group - Assets	Sampling Template Final	Meters Pulled	Meters Remaining
5B_1960	50	11	39
5B_1962	35	11	24
AC250_1983	35	9	26
AC250_1985	35	6	29
AC250_1986	50	16	34
AC250_1987	35	8	27
AC250_1988	50	18	32
AC250_1990	75	70	5
AC250_1991	75	57	18
AC250_1994	100	39	61
AC250_1995	35	12	23
AC250_1996	100	63	37
AC250_2001	100	27	73
AC250_2003	100	81	19
AC250_2004	35	27	8
AC250_2012	100	62	38
AC250_2013	100	60	40
AC250_2014	100	28	72
AC250_2015	75	14	61
AC250_2016	75	21	54
AC250_2017	50	8	42
AC250_2018	100	83	17
AC250_2019	35	14	21
AC250_2020	75	21	54
AC630_1998	20	7	13
AC630_1999	15	3	12
AC630_2000	25	1	24
AC630_2001	15	0	15
AC630_2002	15	0	15



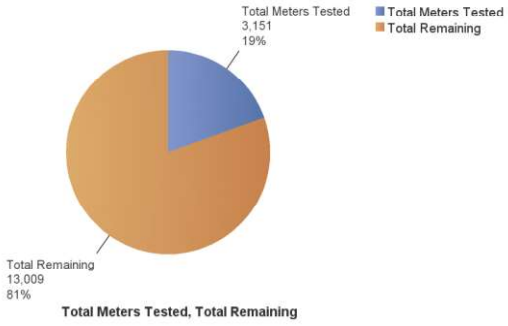
PMC/FF Weekly Summary Meters Tested

Gas Meters tested by Meter Family. The Total Remaining shown includes all Failed Family meters due in 2024 and 2025

Test Families will display when at least 1 Meter is Tested *

White rows indicate a PMC family that has not had the required number of meters pulled from the field. Continue pulling these meters.
Green rows indicate a PMC family that has had the required number of meters pulled from the field. Stop pulling these meters.
Red rows indicate a PMC family that has had more than the required number of meters pulled from the field.

Sampling Group	MFG Year	Model #	Sampling Template Final	Meters Tested	Remaining Tests	% Complete - Meters Tested
5B_1959	1959	5B	50	46	4	92%
5B_1960	1960	5B	50	8	42	16%
5B_1961	1961	5B	50	10	40	20%
5B_1962	1962	5B	35	10	25	29%
5B_1963	1963	5B	50	40	10	80%
AC250_1980	1980	AC250	100	40	60	40%
AC250_1983	1983	AC250	35	8	27	23%
AC250_1984	1984	AC250	25	38	-13	152%
AC250_1985	1985	AC250	35	3	32	9%
AC250_1986	1986	AC250	50	10	40	20%
AC250_1987	1987	AC250	35	9	26	26%
AC250_1988	1988	AC250	50	11	39	22%
AC250_1989	1989	AC250	50	33	17	66%
AC250_1990	1990	AC250	75	53	22	71%
AC250_1991	1991	AC250	75	35	40	47%
AC250_1992	1992	AC250	75	53	22	71%
AC250_1993	1993	AC250	100	55	45	55%
AC250_1994	1994	AC250	100	20	80	20%
AC250_1995	1995	AC250	35	4	31	11%
AC250_1996	1996	AC250	100	26	74	26%



2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

This is an annual program that needs to be completed every year to maintain compliance with WA, ID, and OR state commission rules and tariffs. The Gas Meters are purchased under ER 1050.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Gas Engineering, Gas Operations, Gas Meter Shop, and Technical Services work together to administer the PMC Program and ensure compliance with the various state rules and tariffs related to gas meter testing. Gas Engineering is responsible for developing the annual Gas Meter Measurement Performance Report which defines future work under the program. Gas Engineering then determines the annual budget requirements based on the number of meters that need to be removed to satisfy the program requirements.

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3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Gas PMC Program, ER 3055* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Jeff Webb 5831FFAC43834CF...	Date:	Apr-30-2024 | 10:55 PM PDT
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	DocuSigned by: Alicia Gibbs 49C42856346E483...	Date:	May-01-2024 | 8:49 AM PDT
Print Name:	Alicia Gibbs		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

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EXECUTIVE SUMMARY

This annual program will replace or upgrade existing, at-risk Gate Stations, Regulator Stations, Single Service Farm Taps, and Industrial Meter Sets (collectively referred to as "stations") located throughout Avista's gas territory in WA, ID, and OR that are at the end of their service life and/or not meeting current Avista standards. Additionally, it will address enhancements that will improve system operating performance (such as increasing the capacity of stations to meet our growing system demands), enhance public and employee safety, replace inadequate or antiquated equipment that is no longer supported, and ensure the reliable operation of metering and regulating equipment.

Proper functioning of these stations is required to ensure safe, reliable delivery of natural gas to all Avista customers. All stations require maintenance per 49 CFR 192.739. If the equipment at the station is obsolete and replacement/maintenance parts are no longer available, then proper maintenance cannot be completed. Incomplete maintenance could cause Avista to be out of compliance. When Avista is out of compliance, we are exposed to fines from multiple state utility commissions: Washington, Idaho, and Oregon[1].

Another common driver for these upgrade projects is public and employee safety. Many stations that are upgraded are also moved to a safer location. For example, moved further from the roadway where they are less likely to be hit by a vehicle and where Avista employees can have a safe parking area to access the station for maintenance. Many old stations do not have a parking space, forcing Avista employees to park on the shoulder of the road to access the station. This puts the employee and the traveling public at greater risk of an accident.

Avista's gas customers from all jurisdictions benefit from these types of projects by having a safer, more reliable, and well-maintained distribution system. Performing these upgrades is a prudent way to spend resources because many deficiencies at a station can be remedied under just one project, and proactive replacements cost less than reactive replacements.

There is already a backlog of stations needing replacement; therefore, this work is needed now. The list of stations needing replacement continues to expand as stations meet the end of their service life. Postponing this replacement program will cause the list of stations needing replacement to outpace the number of stations remediated.

Annual cost to fund this program has historically been approximately $1,000,000. The cost to rebuild a station varies greatly from project to project based on several factors, some of which include the type of station, size of station components, location, and

[1] State fines are not prescribed and it is up to each state to determine the fine amount. Federal regulatory fines present a daily and overall maximum value per violation in accordance with 49 CFR Part 190.223.

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crew resources (company crews or contractor crews). Below are estimated average costs to rebuild each type of station based on historical projects:

Gate Station:	$500,000
District Regulator Station:	$100,000
Industrial Meter Set:	$ 50,000
Single Service Farm Tap:	$ 5,000

Proactive replacement of these stations is much more cost effective than reactive replacement. A recent station replacement that was completed as an emergency response to a station that was damaged by a vehicle cost approximately five times more than a planned replacement project. In addition, proactive replacement is preferred due to material availability. Long lead-times on materials necessary for these rebuild projects may mean that if stations run to failure, we may not have the materials necessary for replacement.

Updated stations are also typically easier to maintain than older designs; therefore, future maintenance costs are reduced. On average, a new station takes about 1 hour less to maintain than an obsolete station, which is a direct O&M savings. These O&M savings compound each year as more stations are rebuilt. Over 40 years, the average lifespan of a station, these O&M savings are estimated to be $3,250,000.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Jeff Webb*	*Initial draft of original business case*	*3/17/2017*
1.1	*Jeff Webb*		*4/07/2017*
2.0	*Jeff Webb*	*Revised for 2020 Oregon GRC filing*	*2/17/2020*
2.1	*Dave Smith*	*Updated to the refreshed 2020 Business Case Template*	*6/24/2020*
2.2	*Dave Smith*	*Updated to the refreshed 2022 Business Case Template*	*5/5/2022*
2.3	*Shontelle Wilson*	*Updated to the refreshed 2023 Business Case Template*	*3/9/2023*
2.4	*Dave Smith*	*Updated per BCRT Feedback*	*3/31/2023*
2.5	*Jarriq White*	*Updated per BCRT Feedback*	*4/12/2024*
BCRT *BCRT Team Member* *Has been reviewed by BCRT and meets necessary requirements* *4/3/2023*	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	*4/17/2024*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	**1,110,000**	**1,110,000**

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 347 of 535

DocuSign Envelope ID: 35775496-6BA9-40DE-892C-B2DB717DABCB

2026	**1,135,000**	**1,135,000**
2027	**1,170,000**	**1,170,000**
2028	**1,205,000**	**1,205,000**
2029	**1,240,000**	**1,240,000**

Project Life Span	***Ongoing***
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Jarriq White / Jeff Webb | Alicia Gibbs
Sponsor Organization/Department	B51 – Gas Engineering
Phase	Execution
Category	Program
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

Existing stations located throughout Avista's gas territory in WA, ID, and OR have a finite service life. If they are not periodically replaced and updated, the stations will no longer meet Avista's current design standards, the equipment will become obsolete, and the stations may develop operational or safety issues that need to be addressed to deliver safe and reliable gas service to customers.

Public and employee safety is another common driver for these upgrade projects. Many stations that are upgraded are also moved to a safer location. For example, moved further from the roadway where they are less likely to be hit by a vehicle and where Avista employees can have a safe parking area to access the station for maintenance. Many old stations do not have a parking space, this causes Avista employees to park on the shoulder of the road to access the station for maintenance. This puts the employee and the traveling public at greater risk of an accident.

Gas Engineering maintains a Station Evaluation Spreadsheet that summarizes the condition of each station. This spreadsheet is used to help identify which stations are the highest risk and assists in prioritizing the work under this program. Below is a partial screen shot example from that list.

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Station	Year Assesse	Score	Station Ty	Location	Paint	Corros	Welds Pass Visi	Threaded Fittin	Bypass	Sense Line Configurati	Height	Pipe Settli	Supports	External For	Pressu
232	2020	56	GS		Good	None	No	Yes on HP, Yes on IP	Single Valve Isolation	Blank	Too Short	None	Yes, Non Adjust	Major	Adequ
22	2021	55.5	DR		Cracking/Flaking	Minor	No	Yes on HP, Yes on IP	Hard	Short	Requires ladder/platform	None	Not Needed	None	Adequ
13	2021	54.5	DR		Cracking/Flaking	Minor	No	Yes on HP, Yes on IP	None	Short	Adequate	None	Not Needed	None	Blank
278	2020	54	DR		Cracking/Flaking	None	Blank	Yes on HP, Yes on IP	Single Valve Isolation	Blank	Adequate	None	Not Needed	Minor	Not Ad
28	2021	51.5	DR		Cracking/Flaking	Minor	No	No	Hard	Short	Requires ladder/platform	None	Not Needed	None	Adequ
36	2021	49	DR		Cracking/Flaking	Minor	No	No	Hard	Short	Requires Ladder/Platform	None	Not Needed	None	Blank
~~31~~	~~2021~~	~~48~~	~~DR~~		~~Cracking/Flaking~~	~~None~~	~~No~~	~~No~~	~~Hard~~	~~short~~	~~Too Short~~	~~None~~	~~Not Needed~~	~~None~~	~~Adequ~~
33	2021	47	DR		Cracking/Flaking	None	No	No	Hard	Short	Adequate	None	Not Needed	None	Adequ
~~27~~	~~2021~~	~~45.5~~	~~DR~~		~~Cracking/Flaking~~	~~Minor~~	~~No~~	~~No~~	~~Lead/Lag~~	~~short~~	~~Requires Ladder/Platform~~	~~None~~	~~Not Needed~~	~~None~~	~~Adequ~~
34	2021	45	DR		Cracking/Flaking	Minor	No	No	Hard	short	Requires Ladder/Platform	None	Not Needed	None	Adequ
1343	2021	44.5	SSFT	5509 W Lawton	Cracking/Flaking	Significant	Blank	yes on HP, yes on IP	Soft	Blank	Adequate	None	Not Needed	None	Adequ
26N05	2020	43	GS		Good	None	Blank	Yes on HP, Yes on IP	None	Blank	Too Short	None	Blank	None	Not Ad

1.2 Discuss the major drivers of the business case.

This program's primary driver is asset condition. By proactively replacing obsolete stations, we will continue to deliver safe and reliable gas service to customers. On average, a typical station has a useful life of approximately 40 years[2]. This is because when equipment is antiquated, parts are no longer readily available causing station reliability to be diminished. Obsolete stations are often more difficult and take longer to maintain, which increases O&M costs to the company. On average, an obsolete station takes approximately 1 hour longer to maintain than a new station. This additional 1 hour of labor is entirely O&M. See section 2.2 for O&M savings calculations.

Public and employee safety is another common driver for these upgrade projects. Many stations that are upgraded are also moved to a safer location. For example, moved further from the roadway where they are less likely to be hit by a vehicle and where Avista employees can have a safe parking area to access the station for maintenance. Many old stations do not have a parking space, this causes Avista employees to park on the shoulder of the road to access the station for maintenance. This puts the employee and the traveling public at greater risk of an accident. In a severe case, vehicle damage to a station may cause a customer outage. It is hard to predict the severity of the outage because the number of customers downstream of each station varies greatly across the system.

The cost of an outage is estimated at $2,960 per customer[3]. This cost includes the cost for Avista to restore service and the potential economic impacts to the customer. The calculation assumes that restoration will be completed within 24 hours, which is Avista's restoration goal. A severely damaged station may take longer than 24 hours to repair and bring back into service.

[2] The average life of a typical station was estimated by looking at the age of historical stations that were rebuilt under this program

[3] The Interruption Cost Estimate (ICE) Calculator was used to estimate the economic impacts to the customer at $116 per hour per customer. An estimated restoration cost of $176 per customer is based on the actual restoration costs incurred during the 2022 Crestline outage in Spokane. Therefore the total cost per customer is estimated to be $116 x 24 hours + $176 = $2,960.

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Below are potential outage costs for varying degrees of customer outages:

Number of Customers Out of Service	Potential Cost
1	$2,960
10	$29,960
100	$296,000
1,000	$2,960,000

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

This work is needed now because, according to our Station Evaluations spreadsheet, there is already a backlog of approximately 50 stations deemed high-risk and in need of replacement. Additionally, the list of stations needing replacement continues to grow by an estimated 2-5 stations per year as stations meet the end of their service life. Postponing the work will cause the list of stations needing replacement to outpace the number of stations remediated. When this happens, there becomes a greater risk to having equipment fail due to outdated/unsafe conditions or an employee or public safety incident.

Risk Probability Definitions:

Very High (VH)	Risk event expected to occur
High (H)	Risk event more likely to occur than not
Probable (P)	Risk event may or may not occur
Low (L)	Risk event less likely to occur than not
Very Low (VL)	Risk event not expected to occur

Risk Avoidance Over Time and the Cost of Doing Nothing:

#	Risk	Risk Over Time (years)					Cost Estimate
		1	2	5	10	15+	
1	Regulatory Fines*	L	L	L	L	L	$257,664 per day per violation (Max) $2,576,627 Total (Max)
2	Pipeline Leak	L	P	P	H	VH	$5,000 to $150,000 per site (site dependent)
3	Pipeline Failure & Outage	L	L	P	P	H	$150,000 to $3,000,000 per site (site dependent)
4	Negative Reputation	L	L	L	P	P	Erosion of PUC and Public trust
5	Employee & Public Safety	L	P	P	H	H	Lost time, lawsuits, healthcare , etc. (varies)

*State fines are not prescribed, and it is up to each state to determine the fine amount. Federal regulatory fines present a daily and overall maximum value per violation in accordance with 49 CFR Part 190.223. However, these values are not necessarily an accurate representation of how much Avista would be fined for any specific violation. The actual amount is likely to be much lower since Avista has an ongoing reputation and history of investing in programs related to safety and non-compliance issues. However, it is a bookend reminder from which to characterize the regulatory risk associated with chronic and/or egregious non-compliance, especially in the event of a pipeline safety incident (i.e., failure). Therefore, Avista must continue to demonstrate an ongoing

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commitment to compliance and pipeline safety to ensure favorable future outcomes with respect to regulatory penalties (actual penalty amount is at the discretion of the state or federal agency).

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

Mission Statement excerpt: "By delivering energy safely, responsibly, and affordably, Avista helps empower our customers to live their lives to the fullest." By proactively replacing obsolete or unsafe stations, we continue to provide safe, reliable service for our customers and ensure that customers will not experience an unplanned interruption of gas service.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[4]

The Gate Station, District Regulator Station, SSFT, and Industrial MSA Evaluation Form is filled out by Gas Operations who perform station maintenance. This form helps to risk rank each station based on many criteria including station condition, equipment, location and access, and inlet and outlet valves. The data from these forms is consolidated into a master spreadsheet which then calculates a score for each station. The higher the score, the higher priority the station is for replacement. Below is what the Evaluation Form looks like.

[4] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

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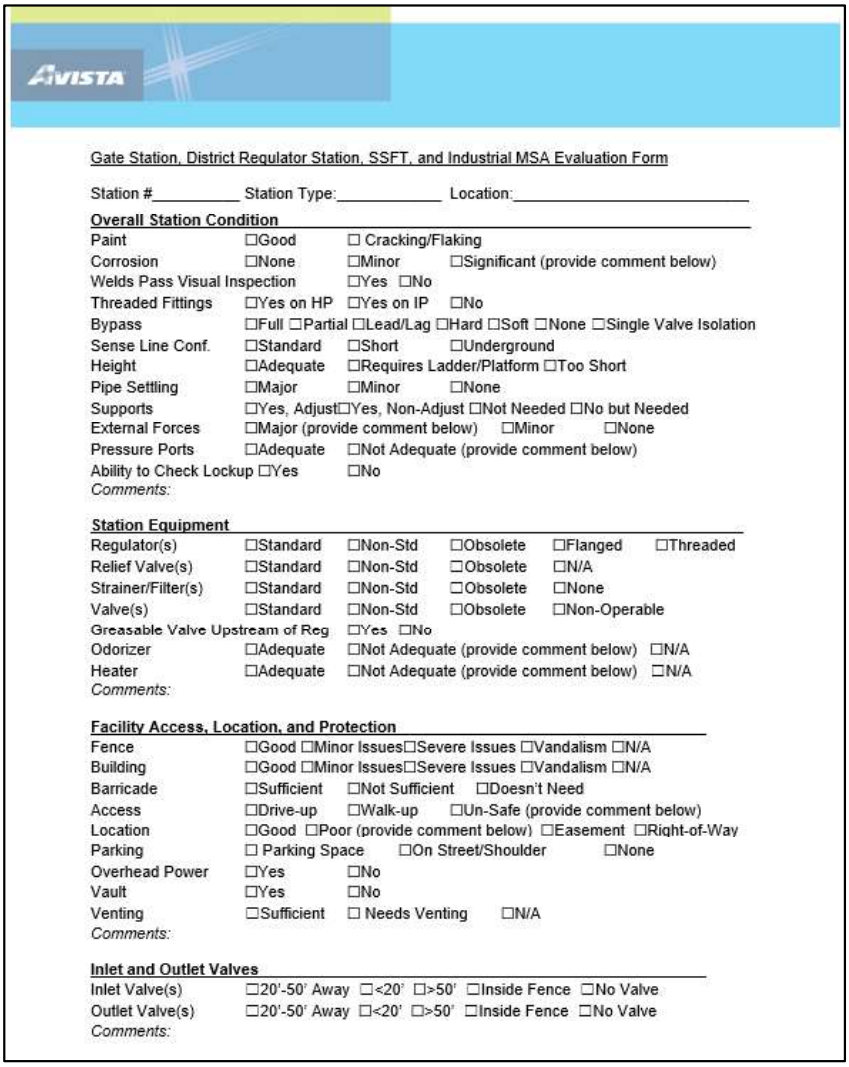

Gate Station, District Regulator Station, SSFT, and Industrial MSA Evaluation Form

Station #_____ Station Type:_____ Location:_____

Overall Station Condition

Paint	☐Good	☐ Cracking/Flaking	
Corrosion	☐None	☐Minor	☐Significant (provide comment below)
Welds Pass Visual Inspection	☐Yes ☐No		
Threaded Fittings	☐Yes on HP	☐Yes on IP	☐No
Bypass	☐Full ☐Partial	☐Lead/Lag	☐Hard ☐Soft ☐None ☐Single Valve Isolation
Sense Line Conf.	☐Standard	☐Short	☐Underground
Height	☐Adequate	☐Requires Ladder/Platform	☐Too Short
Pipe Settling	☐Major	☐Minor	☐None
Supports	☐Yes, Adjust	☐Yes, Non-Adjust	☐Not Needed ☐No but Needed
External Forces	☐Major (provide comment below)	☐Minor	☐None
Pressure Ports	☐Adequate	☐Not Adequate (provide comment below)	
Ability to Check Lockup	☐Yes	☐No	

Comments:

Station Equipment

Regulator(s)	☐Standard	☐Non-Std	☐Obsolete	☐Flanged	☐Threaded
Relief Valve(s)	☐Standard	☐Non-Std	☐Obsolete	☐N/A	
Strainer/Filter(s)	☐Standard	☐Non-Std	☐Obsolete	☐None	
Valve(s)	☐Standard	☐Non-Std	☐Obsolete	☐Non-Operable	
Greasable Valve Upstream of Reg	☐Yes ☐No				
Odorizer	☐Adequate	☐Not Adequate (provide comment below)	☐N/A		
Heater	☐Adequate	☐Not Adequate (provide comment below)	☐N/A		

Comments:

Facility Access, Location, and Protection

Fence	☐Good ☐Minor Issues	☐Severe Issues	☐Vandalism	☐N/A
Building	☐Good ☐Minor Issues	☐Severe Issues	☐Vandalism	☐N/A
Barricade	☐Sufficient	☐Not Sufficient	☐Doesn't Need	
Access	☐Drive-up	☐Walk-up	☐Un-Safe (provide comment below)	
Location	☐Good ☐Poor (provide comment below)	☐Easement	☐Right-of-Way	
Parking	☐ Parking Space	☐On Street/Shoulder	☐None	
Overhead Power	☐Yes	☐No		
Vault	☐Yes	☐No		
Venting	☐Sufficient	☐ Needs Venting	☐N/A	

Comments:

Inlet and Outlet Valves

Inlet Valve(s)	☐20'-50' Away	☐<20'	☐>50'	☐Inside Fence	☐No Valve
Outlet Valve(s)	☐20'-50' Away	☐<20'	☐>50'	☐Inside Fence	☐No Valve

Comments:

The *Station Evaluation Spreadsheet* is the master spreadsheet that contains the evaluation scores for each station. A partial screenshot of this spreadsheet is shown below.

Station	Year Assesse	Score	Station Ty	Location	Paint	Corros	Welds Pass Visi	Threaded Fittin	Bypass	Sense Line Configurati	Height	Pipe Settli	Supports	External For	Pressu
232	2020	56	GS		Good	None	No	Yes on HP, Yes on IP	Single Valve Isolation	Blank	Too Short	None	Yes, Non-Adjust	Major	Adequ
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278	2020	54	DR		Cracking/Flaking	None	Blank	Yes on HP, Yes on IP	Single Valve Isolation	Blank	Adequate	None	Not Needed	Minor	Not Ad
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36	2021	49	DR		Cracking/Flaking	Minor	No	No	Hard	Short	Requires Ladder/Platform	None	Not Needed	None	Blank
~~31~~	~~2021~~	~~48~~	~~DR~~		~~Cracking/Flaking~~	~~None~~	~~No~~	~~No~~	~~Hard~~	~~short~~	~~Too Short~~	~~None~~	~~Not Needed~~	~~None~~	~~Adequ~~
33	2021	47	DR		Cracking/Flaking	None	No	No	Hard	Short	Adequate	None	Not Needed	None	Adequ
~~27~~	~~2021~~	~~45.5~~	~~DR~~		~~Cracking/Flaking~~	~~Minor~~	~~No~~	~~No~~	~~Lead/Lag~~	~~short~~	~~Requires Ladder/Platform~~	~~None~~	~~Not Needed~~	~~None~~	~~Adequ~~
34	2021	45	DR		Cracking/Flaking	Minor	No	No	Hard	short	Requires Ladder/Platform	None	Not Needed	None	Adequ
1343	2021	44.5	SSFT	5509 W Lawton	Cracking/Flaking	Significant	Blank	yes on HP, yes on IP	Soft	Blank	Adequate	None	Not Needed	None	Adequ
26N05	2020	43	GS		Good	None	Blank	Yes on HP, Yes on IP	None	Blank	Too Short	None	Blank	None	Not Ad

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2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The requested level of spending for this program allows the high priority projects to be completed every year. The list of new requests continues to grow as stations meet the end of their service life. The workforce available to do this type of work is responsible for both maintenance of these stations and the rebuild efforts. This level of spend complements their available time as well, without requiring additional labor resources.

On average, 10 to 20 high priority projects get funded each year. The actual number of projects completed per year vary based on the type of station and the scope of the project. Some larger projects span multiple years to allow for long lead time material planning as well as design.

This program is meant to be proactive (preventive) rather than reactive. These stations are vital to providing customers with reliable gas service. Planned replacement work is preferred over unplanned work. With proactive work, a plan can be put into place to ensure that customers do not lose gas service while the project is being completed. Reactive replacement work during times of high gas use can be more difficult to perform, have negative impacts to customers, and can inadvertently cost the company more money in resources spent than the preventive measures would. Also, due to worldwide supply chain issues, some of the equipment at these stations have very long lead times; therefore, taking a proactive replacement approach helps maintain reliable service.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[5]

Proactively replacing a station is much more cost effective than reactively replacing one that has failed or was damaged by outside forces. To illustrate, regulator station #66 located at the intersection of Regal St and Gordon Ave in Spokane was hit by a car in 2018. The incident happened after normal business hours and required an emergency response by Avista. This station is a typical farm tap style station. The station needed to be replaced due to extensive damage caused by the vehicle, and the cost to replace the station was approximately five times higher than what it would have cost to replace the station under a planned project. The major contributor to the cost being so

[5] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

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much higher is crew overtime, as these emergency events must be worked until made safe and service restored. The cost to replace the damaged station was approximately $15,000 whereas the cost to proactively replace the station would have been approximately $3,000 in 2018.

Emergency repair or replacements can also increase the risk of a customer outage versus a planned replacement project. Public and employee safety is of utmost importance during a gas emergency, therefore under most circumstances quickly isolating the affected system takes priority over maintaining service to customers. If a station failed or was damaged by an outside force resulting in a gas leak or a system abnormal operating condition, it is likely that first responders will isolate the system which may result in customer outages. During planned worked there are measures taken to maintain gas service to customers, for example installing a bypass around the work zone. These measures to maintain service to downstream customers take additional time to install in the field and therefore may not be appropriate or available during a gas emergency.

Another risk associated with running a station to failure is equipment and material availability. Many stations have long lead time equipment and materials that may not be available when needed. If equipment or materials are not available, temporary equipment or materials may have to be installed in order to restore service to customers. These temporary items may have to be replaced with the appropriate permanent items at a later date, further increasing costs associated with the event.

2.3 Summarize in the table and describe below the DIRECT offsets[6] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$0	$0	$0	$0	$0
O&M	Reduced Station Maintenance Time	$3,400	$5,300	$7,200	$9,300	$11,500

Gas Engineering, Gas Operations, and the Gas Meter Shop work together to prioritize and administer the work for the year. The work is generally prioritized early in the year and then implemented throughout the spring, summer, and fall. The work is typically comprised of several individual station replacement projects.

[6] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

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Completion of this work will reduce O&M costs because stations that are at the end of the end of their service life and/or are not up to Avista's current standards typically take longer to maintain. Refer to spreadsheet titled *Offset Calcs ER 3002.xlsx showing* the calculations for the direct savings shown in the table above.

2.4 Summarize in the table and describe below the INDIRECT offsets[7] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$0	$0	$0	$0	$0
O&M	Outage Avoidance	$76,960	$76,960	$76,960	$76,960	$76,960

Completing this annual program will reduce the potential for a customer outage due to equipment failure or a physically damaged station. The estimated cost of an outage is estimated at $2,960 per customer[8]. This cost includes the cost for Avista to restore service and the potential economic impacts to the customer. The calculation assumes that restoration will be completed within 24 hours, which is Avista's restoration goal. A severely damaged station may take longer than 24 hours to repair and bring back into service.

Below are the potential restoration and customer economic costs for varying numbers of customer outages:

Number of Customers Out of Service	Potential Cost	Likelihood of Event
1	$2,960	1
10	$29,960	0.5
100	$296,000	0.1
1,000	$2,960,000	.01

See spreadsheet *Offset Calcs ER 3002 – Reg Reliability 2023.xlsx* for assumptions and calculations.

[7] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

[8] The Interruption Cost Estimate (ICE) Calculator was used to estimate the economic impacts to the customer at $116 per hour per customer. An estimated restoration cost of $176 per customer is based on the actual restoration costs incurred during the 2022 Crestline outage in Spokane. Therefore the total cost per customer is estimated to be $116 x 24 hours + $176 = $2,960.

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2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Option	Capital Cost	Start	Complete
Recommended Solution: Replace at risk stations at requested funding level – Reduce Backlog	$1,070,000	January	December
Alternative Solution 1: Replace at risk stations at a reduced funding level – Maintain Backlog	$500,000	January	December
Alternative Solution 2: Replace at risk stations at a reduced funding level – Increase Backlog	$250,000	January	December

Alternative 1:

This alternative solution would be to replace at risk stations at a reduced funding level. There is already a backlog of approximately 50 high-risk stations that need to be replaced throughout our entire system. Meanwhile, an estimated 2-5 new stations are upgraded to high-risk every year due to aging infrastructure. This alternative would only allow us to maintain the current backlog of 50 stations (depending on how many stations were upgraded to high-risk status that year). This alternative is not advised since no progress could be made in reducing the backlog of high-risk stations. When this happens, there becomes a greater risk of running equipment to failure. The implications of this are discussed in Sections 1.3 and 2.2.

An alternative to rebuilding the entire station would be to replace only the individual components that are antiquated or outdated. If this short-sided course were chosen, the work would be less productive and the opportunity to bring the entire station up to current standards would be lost. Often, older stations that have antiquated or outdated equipment are also difficult to maintain due to outdated configurations, for example: short sensing lines, limited valve locations, and equipment being installed high above ground or in vaults. This option is not recommended. Another downside to this approach would be the loss of opportunity to right size the capacity of the rebuilt station. Often, station capacity is increased when the station is rebuilt to support future demands.

Alternative 2:

This alternative is similar to Alternative 1, except the further reduction in funding would likely cause an increase in our backlog of high-risk stations. Not only limiting our ability to maintain our current system, but likely causing the overall health of the system to decrease each year that it's funded at this level. If the program were to be funded at this level, Avista would be forced to

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operate at-risk stations in an unsafe, unreliable, and sometimes non-code compliant manner. Like Alternative 1, this alternative increases the risk that equipment will run to failure. The risk associated with Alternative 2 is higher than Alternative 1, since more high-risk stations will be operating. The many implications associated with this increased risk are discussed in Sections 1.3 and 2.2. This option is not recommended.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Success can be measured through the *Station Evaluation Spreadsheet*, which is the master spreadsheet that contains the evaluation scores for each station. A partial screenshot of this spreadsheet is shown below.

Station	Year Assesse	Score	Station Ty	Location	Paint	Corrosi	Welds Pass Visi	Threaded Fittin	Bypass	Sense Line Configurati	Height	Pipe Settl	Supports	External For	Pressu
232	2020	56	GS		Good	None	No	Yes on HP, Yes on IP	Single Valve Isolation	Blank	Too Short	None	Yes, Non-Adjust	Major	Adequ
22	2021	55.5	DR		Cracking/Flaking	Minor	No	Yes on HP, Yes on IP	Hard	Short	Requires ladder/platform	None	Not Needed	None	Adequ
13	2021	54.5	DR		Cracking/Flaking	Minor	No	Yes on HP, Yes on IP	None	Short	Adequate	None	Not Needed	None	Blank
278	2020	54	DR		Cracking/Flaking	None	Blank	Yes on HP, Yes on IP	Single Valve Isolation	Blank	Adequate	None	Not Needed	Minor	Not Ad
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36	2021	49	DR		Cracking/Flaking	Minor	No	No	Hard	Short	Requires Ladder/Platform	None	Not Needed	None	Blank
~~31~~	~~2021~~	~~48~~	~~DR~~		~~Cracking/Flaking~~	~~None~~	~~No~~	~~No~~	~~Hard~~	~~short~~	~~Too Short~~	~~None~~	~~Not Needed~~	~~None~~	~~Adequ~~
33	2021	47	DR		Cracking/Flaking	None	No	No	Hard	Short	Adequate	None	Not Needed	None	Adequ
~~27~~	~~2021~~	~~45.5~~	~~DR~~		~~Cracking/Flaking~~	~~Minor~~	~~No~~	~~No~~	~~Lead/Lag~~	~~short~~	~~Requires Ladder/Platform~~	~~None~~	~~Not Needed~~	~~None~~	~~Adequ~~
34	2021	45	DR		Cracking/Flaking	Minor	No	No	Hard	short	Requires Ladder/Platform	None	Not Needed	None	Adequ
1343	2021	44.5	SSFT	5509 W Lawton	Cracking/Flaking	Significant	Blank	yes on HP, yes on IP	Soft	Blank	Adequate	None	Not Needed	None	Adequ
26N05	2020	43	GS		Good	None	Blank	Yes on HP, Yes on IP	None	Blank	Too Short	None	Blank	None	Not Ad

Station scores typically range from 0-60+, with the following categorization:

Low risk/priority: 0-20

Medium risk/priority: 20-40

High risk/priority: 40 and above

Some examples of recently rebuilt stations and their updated scores include:

Station	Original Score (risk level)	Rebuild Date	New Score (risk level)
#27	45.5 – High	2022	0 – Low
#31	48 – High	2022	1 – Low
#562	21 – Medium	2023	0 – Low
#36	49 – High	2023	0 – Low

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

The program will be completed between January and December of each year. The investments become used and useful to the customer at the completion of each station rebuild project.

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2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Gas Engineering, Gas Operations, and the Gas Meter Shop work together to prioritize and administer the work for this program. The project engineer puts together the project estimate which is then approved by the gas design manager and director. Monthly budget updates are completed in Tablaeu to make sure the program remains on budget throughout the year. The project engineer is also responsible to update the Station Evaluation Spreadsheet with the station's new score at the conclusion of the project.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Gas Regulator Station Replacement Program, ER 3002* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Jeff Webb 5831FFAC45834CF...	Date:	May-03-2024 | 9:27 AM PDT
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	DocuSigned by: Alicia Gibbs 49C42833345E483...	Date:	May-03-2024 | 9:41 AM PDT
Print Name:	Alicia Gibbs		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

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EXECUTIVE SUMMARY

Annually the Gas Planning department runs an analysis (load study) on Avista's gas distribution system to identify areas of the system with insufficient capacity to serve existing Firm customer loads on a design day. The design day is defined as the 30-year coldest average daily temperature of a weather region with 99% probability of happening. These deficient areas are given a risk ranking based on the severity and the number of customers impacted. The areas with the highest priority are selected for remediation and the project is assigned to Gas Engineering to evaluate options to provide sufficient capacity to meet firm gas demands on a design day. Typical projects completed under this Business Case may include upsizing existing gas mains, looping existing gas mains, and installing new, or upsizing existing regulator stations. Options are reviewed with Gas Planning, Gas Operations, and other interested parties. The pros and cons of each option are then reviewed with the Gas Engineering Manager and a preferred alternative is selected to proceed with a funding request. The business needs and potential solutions identified impact all gas customers in Avista's service territory. Spending per jurisdiction changes each year, as the intent is to complete the highest risk projects first, regardless of which State it is in.

The proposed annual budget is consistent with expenditures from past years to complete several of the highest priority projects each year. Individual reinforcement projects completed under this program can cost anywhere from approximately $10K, to upwards of $500K. Each year, Gas Engineering develops estimates for the highest priority projects. The projects that can be completed while keeping the total program spend at the budgeted amount are then identified and completed. Some years, not all high priority projects are able to be completed and have to carry over to the next year. There is currently a backlog of projects. Due to the number of remaining proposed reinforcements, and the continued customer demand in Avista's service territory, this is an ongoing program. The following table captures historical spend in this program since 2019:

Table 1: Historical Spend in ER 3000

Year	Spend
2019	$1,062,779
2020	$1,168,033
2021	$1,160,740
2022	$1,723,891
2023	$1,128,882

If these reinforcements are not completed, Avista's firm gas customers are at risk of a gas outage on a cold winter day. The number of customers impacted by each reinforcement is different; however, typically the highest priority reinforcements correlate to the highest number

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 359 of 535

DocuSign Envelope ID: 0FCEDD45-8E82-491D-93A2-32825B605887

of customers at risk of an outage. The estimated cost of an outage is $2,960 per customer[1]. This cost includes the cost for Avista to restore service and the potential economic impacts to the customer. The calculation assumes that restoration will be completed within 24 hours, which is Avista's restoration goal. On average, each high priority reinforcement area has the potential to lose 1,400 customers during an outage if the reinforcement is not completed. An outage response for 1,400 customers would cost approximately $4,144,000. Since peak gas load occurs on the coldest days, a system capacity related outage would most likely occur on a very cold day; therefore, customers who use natural gas as their primary heat source may also be at risk for life and/or property damage (example: frozen pipes). Other risks to customers include loss of revenue for commercial and industrial customers who rely on natural gas service for business. Ensuring our firm customers have adequate gas supply for all planned and unexpected weather conditions is part of being a prudent operator and is backed up in the work we do with our Integrated Resource Plan (IRP). This program is in direct support of that effort.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Jeff Webb*	*Initial draft of original business case*	*3/17/2017*
1.1	*Jeff Webb*		*4/06/2017*
2.0	*Jeff Webb*	*Revised for 2020 Oregon GRC Filing*	*2/17/2020*
2.1	*Tim Harding*	*Updated to the refreshed 2022 Business Case Template*	*8/31/2022*
2.2	*Shontelle Wilson/Rachael Anderson*	*Updated to the refreshed 2023 Business Case Template*	*4/10/2023*
2.3	*Rachael Anderson*	*Revised for 5-Year Capital Planning*	*4/19/2024*
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements*	*4/19/2024*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	**1,340,000**	**1,340,000**
2026	**1,380,000**	**1,380,000**
2027	**1,420,000**	**1,420,000**
2028	**1,465,000**	**1,465,000**
2029	**1,505,000**	**1,505,000**

[1] The Interruption Cost Estimate (ICE) Calculator was used to estimate the economic impacts to the customer at $116 per hour per customer. An estimated retoration cost of $176 per customer is based on the actual restoration costs incurred during the 2022 Crestline outage in Spokane. Therefore the total cost per customer is estimated to be $116 x 24 hours + $176 = $2,960.

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Project Life Span	***Ongoing***
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Rachael Anderson / Jeff Webb | Alicia Gibbs
Sponsor Organization/Department	B51 – Gas Engineering
Phase	Execution
Category	Program
Driver	Performance & Capacity

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

This annual program will identify and provide for necessary capacity reinforcements to the existing natural gas distribution system in WA, ID, and OR. Avista has an obligation to serve existing firm gas customers by providing adequate capacity on design day weather conditions. The design day is defined as the 30-year coldest average daily temperature of a weather region with 99% probability of happening. Periodic reinforcement of the system is required to reliably serve firm customers due to increased demand at existing service locations and new customers being added to the system. Execution of this program on an annual basis will ensure the continuation of reliable gas service that is of adequate pressure and capacity. If these reinforcements are not completed, Avista's firm customers are at risk of a gas outage on a cold winter day. The risks and impacts associated with this are discussed further in Section 1.3. Ensuring our firm customers have adequate gas supply for all planned and unexpected weather conditions is part of being a prudent operator and is backed up in the work we do with our Integrated Resource Plan (IRP). This program is in direct support of that effort.

1.2 Discuss the major drivers of the business case.

The major driver of this Business Case is Performance and Capacity. The intent of this program is to add capacity to the gas distribution system to ensure firm gas customers can receive an adequate supply of natural gas according to design day conditions. Without these reinforcements, customers will remain at risk of losing natural gas service when it is needed most, on the coldest winter days.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 361 of 535

DocuSign Envelope ID: 0FCEDD45-8E82-491D-93A2-32825B605887

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

There are currently areas of the gas systems that are at risk during extreme cold weather because the system capacity cannot meet peak demand. Currently, there are 34 identified distribution deficiencies across our entire system. This means, we are at risk of some level of customer outage in each of these areas at temperatures warmer than the design day standard. For each distribution area, one or more reinforcements may be needed to ensure all customers in the identified system can be served during a design day condtion. By upgrading these systems, we reduce the chance of cold weather outages. At a minimum, outages are an inconvenience to customers. They can, however, become a serious health and safety concern because they tend to happen during extremely cold weather. System outages that cause customers to be without heat during extreme cold weather must be avoided. If we fail to perform the proper reinforcement then the number of affected customers at risk of outages will increase. The number of customers impacted by each reinforcement is different, ttypically the highest priority reinforcements correlate to the highest number of customers at risk of an outage. On average, each high priority reinforcement area has the potential to lose 1,400 customers during an outage if the reinforcement is not completed. The estimated cost of an outage is $2,960 per customer[2]. This cost includes the cost for Avista to restore service and the potential economic impacts to the customer. The calculation assumes that restoration will be completed within 24 hours, which is Avista's restoration goal. An outage response for 1,400 customers would cost approximately $4,144,000.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

This proposed investment focuses highly on reliable service to customers. By reinforcing Avista's natural gas infrastructure, we will be able to provide customers with reliable energy and will be able to prevent our customers from having an interruption of service on very cold days when they need it the most. Ensuring our firm customers have adequate gas supply for all planned and unexpected weather conditions is part of being a prudent operator and is backed up in the work we do with our Integrated Resource Plan (IRP). This program is in direct support of that effort. Performing reinforcements keeps our customer's safety and health in mind by preventing unnecessary outages during below freezing temperatures.

[2] The Interruption Cost Estimate (ICE) Calculator was used to estimate the economic impacts to the customer at $116 per hour per customer. An estimated retoration cost of $176 per customer is based on the actual restoration costs incurred during the 2022 Crestline outage in Spokane. Therefore the total cost per customer is estimated to be $116 x 24 hours + $176 = $2,960.

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1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[3]

Annually the Gas Planning department runs an analysis (load study) on Avista's gas distribution system to identify areas of the system with insufficient capacity to serve existing firm customer loads on a design day. The design day is defined as the 30-year coldest average daily temperature of a weather region with 99% probability of happening. These deficient areas are given a risk ranking based on the severity and the number of customers impacted. On an annual basis, the Gas Planning group reviews system load studies and prioritizes the reinforcement projects. Currently, there are 34 identified distribution deficiencies across our entire system. This means, we are at risk of some level of customer outage in each of these areas at a temperature above the design day standard. For each distribution area, one or more reinforcements may be needed to ensure all customers in the identified system can be served during a design day condtion.The list of the above information can be found by Gas Engineering in N:\Gas Load Study\Gas_Planning_MASTER_PLAN.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The requested level of spending for this program allows some high priority projects to be completed every year. The number of reinforcements completed each year varies as reinforcements range in cost and scope. Individual reinforcement projects completed under this program can cost anywhere from approximately $10K, to upwards of $500K. Each year, Gas Engineering develops estimates for the highest priority projects. The projects that can be completed while keeping the total program spend at the budgeted amount are then identified and completed. Some years, not all high priority projects are able to be completed and have to carry over to the next year. All projects completed under this program involve installing new facilities in the gas distribution system to bring additional gas flow to the areas that Gas Planning has identified are at risk of gas outages during cold weather events. Typical projects completed under this Business Case may include upsizing existing gas mains, looping existing gas mains, and installing new, or upsizing existing regulator stations. When a reinforcement is done by looping a system, there is a secondary benefit of higher reliability to the area. Most of these projects will have a unique project number assigned to them, but the smaller scope, lower cost projects may be completed under the blanket project numbers set up for each district.

[3] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

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As the high priority reinforcements are completed, system deficiencies are reevaluated and taken off the list if the reinforcements have appropriately addressed the deficiency. Simultaneously, the list of new reinforcements continues to grow as system deficiencies are discovered due to customer demand changes. At a reduced funding level, project backlogs will increase and lead to a higher chance of a gas outage incidents. Each reinforcement that is completed reduces the risk of an outage event occurring. Risks associated with this are discussed more in Section 1.3.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[4]

Gas Planning uses load studies to predict system pressures during design day weather (extreme cold) conditions. These studies determine the likelihood of system outages, as well as how many customers are impacted. Annually, the Gas Planning group reviews system load studies and prioritizes the reinforcement projects. Currently, there are 34 identified distribution deficiencies across the entire system. This means, we are at risk of some level of customer outage in each of these areas at temperatures warmer than the design day standard. For each distribution area, one or more reinforcements may be needed to ensure all customers in the identified system can be served during a design day condtion. Gas Planning and Engineering then work together to develop recommendations that will reinforce the area and greatly reduce or eliminate the risk of an outage. Gas Planning is able to predict the benefit of any given reinforcement by modeling it in the load study before construction. Reinforcements are only recommended and completed after confirming that the proposed reinforcement reduces or eliminates the risk of an outage. Reinforcements are then ranked from high priority to low priority, based on the number of customers affected as well as the temperature at which we can expect an outage to occur. These recommendations are refreshed and reprioritized on an annual basis and given to Gas Engineering to complete.

Below is an example of a gas load study that identified a reinforcement is needed in order to support firm customer loads on a design day:

[4] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

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This is a pressure plot of an area. The red and purple pipes indicate the areas in the gas distribution system that we can expect customer outages will occur at design criteria temperatures due to low system pressures. Gas Planning is then able to simulate the benefits of the proposed reinforcement. The model will then show the reduced risk of an outage with the planned reinforcement in place. Here is an example of the same gas system at the same temperature with a proposed reinforcement in place:

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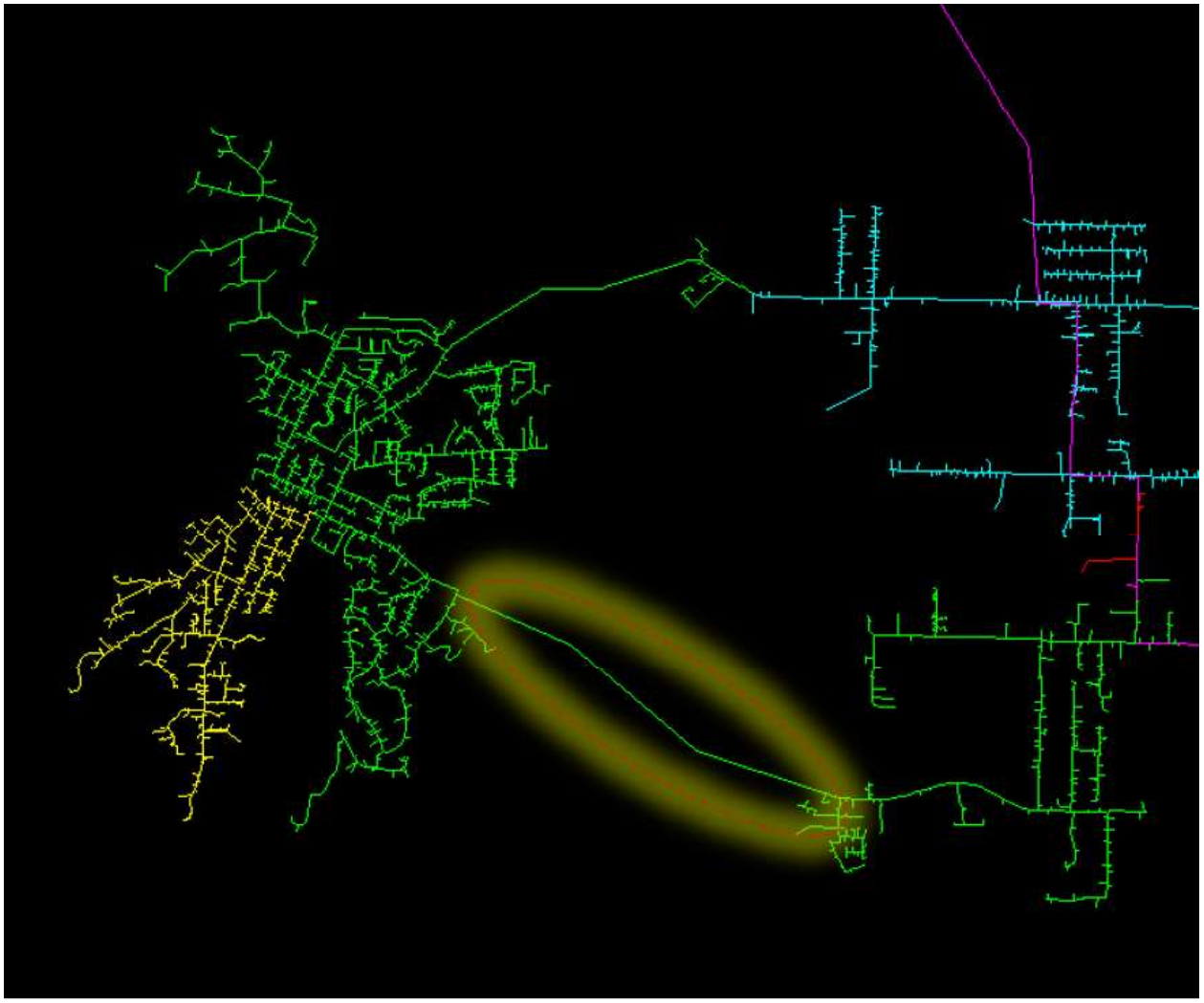

We can immediately see the reduced risk of customer outages with the new reinforcement in place (no red or purple pipes). All reinforcements are run through this analysis before they are given to Gas Engineering to design and complete.

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2.3 Summarize in the table, and describe below the DIRECT offsets[5] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$0	$0	$0	$0	$0
O&M	Cold Weather Action Plan	$22,800	$22,800	$22,800	$22,800	$22,800

During cold weather events, the system must be monitored by Avista personnel. This includes observing system pressures both in the field, as well as using remote monitoring equipment. When system deficiencies exist, but have not yet been completed due to competing projects that have a higher risk, field action plans are assembled and activated to avoid outages, and to minimize the impact of potential gas outages. See file *Offset Calculations ER 3000 Gas Reinforcement Program.xlsx* for assumptions and calculation details.

2.4 Summarize in the table, and describe below the INDIRECT offsets[6] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$0	$0	$0	$0	$0
O&M	Outage Response	$414,000	$828,000	$1,243,000	$1,657,000	$2,072,000

Completing this project will reduce the risk of customer outages due to system supply constraints. The costs shown in the table above are the estimated cost to restore a customer outage and the potential economic impacts to the customer. See file *Offset Calculations ER 3000 Gas Reinforcement Program.xlsx* for assumptions and calculation details.

[5] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[6] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

DocuSign Envelope ID: 0FCEDD45-8E82-491D-93A2-32825B605887

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1:

One alternative is to fund this program at $1,000,000, a lower level than what has been requested. This is not advised as Avista will get further behind on projects that are needing to be completed to avoid the risk of customer outages. The reduction in funding by $300,000 equates to anywhere from 1 to multiple high priority projects that are not able to be completed.There is already a backlog of projects and areas of the gas distribution that are at risk. Reducing the funding will increase the risk to our customers of being part of an outage during a cold weather event

Without a Reinforcement Program, Avista will not have sufficient capacity to meet our obligation to serve existing firm customer load on a design day scenario.

It is important to note that if service is lost during severe cold weather, gas service may not become available again for days until weather warms and customer demand decreases. Depending on the length of the outage, this can cause severe injury up to and including death to some customers. An outage response for an average of 1,400 customers would cost approximately $4,144,000.

Alternative 2:

An evaluation of non-pipe alternatives is considered against pipeline capacity reinforcements. Non-pipe alternatives will only be considered when the cost of an upgrade is at a level high enough where a non-pipe alternative may be cost-effective (i.e., greater than $500,000), can be accomplished prior to the time the upgrade is needed, and can lead to a great enough reduction of demand to defer or eliminate the need for the upgrade. Possible non-pipe alternatives include, but are not limited to, the following: uprating (raising) the existing pipeline pressure, energy efficiency efforts including encouraging customers to adopt more efficient appliances and equipment, and potentially electrification of natural gas appliances. A non-pipe alternative must address any capacity concerns at a lower cost versus the pipeline reinforcement to be considered a viable strategy.Thus far, a non-pipe alternative has never been able to replace the need for a pipeline capacity reinforcement.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Using computer-based load studies that are based on actual customer usage, Gas Planning identifies areas of concern that need reinforcement in order to reliably serve all firm customers during cold weather. Those projects are ranked by severity and the highest priority projects are sent to Gas Engineering to complete. Success can be estimated before the project is constructed by modeling the gas system with the proposed reinforcement in place. This analysis is done to ensure the proposed reinforcement remedies the area of concern. These projects are managed by the Gas Engineering group. Construction is completed by Gas Operations with company or

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contract resources. Gas Engineering monitors and ensures the reinforcements are completed during the year.

Success is also measured by the monitoring of distribution pressures during the cold winter months with electronic pressure recording devices. Annually, during the cold winter months, Gas Planning assigns electronic pressure recording devices to different parts of the distribution system. Looking at the historical data at these sites, we are able to verify improved pressures in parts of the distribution system after reinforcements are completed.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

This is an ongoing program with multiple projects completed between January and December of each year. Each project becomes used and useful once construction is completed, typically this is the same year the project starts.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The projects are managed by Gas Engineering and status updates are given to Gas Planning several times a year to ensure that the highest priority projects are being addressed first. The Business Case Owner manages the overall budget of the Business Case. At the beginning of the year, Gas Planning provides the updated reinforcement recommendation list. The reinforcements are assigned to the Gas Engineers to develop a cost estimate. Gas Engineering has an annual meeting to identify if all of the recommendations for the year fit within the approved budget. If not, lower priority reinforcements are put on hold until the following year. The Business Case Owner manages the budget closely throughout the year to ensure spending is in line with the approved yearly amount. If any changes to the budget for the year are needed, the Business Case Owner proposes a budget change and justification that must get approval from the Business Case Sponsor before it is brought before the Capital Planning Group. If additional funds are not approved, then the remaining work is reduced to remain within budget.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 369 of 535

DocuSign Envelope ID: 0FCEDD45-8E82-491D-93A2-32825B605887

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Gas Reinforcement Program, ER 3000* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Jeff Webb 5831FFAC45834CF...	Date:	May-03-2024 | 9:26 AM PDT
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	DocuSigned by: Alicia Gibbs 49C42855345E483...	Date:	May-03-2024 | 9:40 AM PDT
Print Name:	Alicia Gibbs		
Title:	Director Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

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EXECUTIVE SUMMARY

Nearly all Avista's pipeline systems are in public right-of-ways (R/W) that are governed by local jurisdictional franchise agreements. Locating Avista's gas facilities in R/W is beneficial to customers and is common practice for other utilities as well, such as electric, water, sewer, and communications. Local jurisdictions allow Avista to install facilities in this space with no upfront payment. In situations when local jurisdictional projects create a conflict, Avista is mandated under these agreements to relocate its facilities.

When conflicts are identified that may require relocating gas facilities, meetings with the appropriate entities take place in an attempt to design around the conflict. If relocation of the gas facilities is still required after meeting, then Avista must complete the work at our cost per the applicable franchise agreement. If the conflict cannot be designed around and the gas facility must remain in service, then there are no other alternatives than to relocate Avista's pipes.

It is very difficult to forecast year-to-year what the financial impacts in this category will be in each district and state as budgets change each year for the municipalities. Some road projects are more impactful than others to the buried gas facilities. The budgeted amounts for the next five years are based on average expenditures in this budget over the last several years. The yearly spend in this budget has ranged from $3.4 million to $7.7 million since 2019.The lower end of this range occurred in 2020 when many project were halted or delayed due to the COVID-19 Pandemic.

By completing the projects as requested, Avista meets the obligations under its franchise agreements, remains in good standing with the municipalities, and avoids financial penalties associated with project delays.

The work is generated by the various municipalities that Avista has franchise agreements with. Gas Operations manages this category of work in each district. The overall program budget is monitored by Gas Engineering closely throughout the year. Regular check-ins are conducted with Gas Operations to update the projected annual spend accordingly as new projects come up.

VERSION HISTORY

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 371 of 535

DocuSign Envelope ID: 0581ED12-F040-4FF8-A31E-211F297D4A21

Version	Author	Description	Date
1.0	*Jeff Webb*	*Initial draft of original business case*	*3/17/2017*
1.1	*Jeff Webb*	*Revised*	*4/17/2017*
2.0	*Jeff Webb*	*Revised for 2020 Oregon GRC Filing*	*2/17/2020*
3.0	*Jeff Webb*	*Revised for new BC format*	*8/30/2022*
3.1	*Shontelle McGrath*	*Updated to the refreshed 2023 Business case template*	*8/2/2023*
3.2	*Jeff Webb*	*Updated date for 2024*	*4/18/2024*
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements*	*4/24/2024*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	**5,500,000**	**5,500,000**
2026	**5,665,000**	**5,665,000**
2027	**5,834,950**	**5,834,950**
2028	**6,009,999**	**6,009,999**
2029	**6,190,298**	**6,190,298**

Project Life Span	***Ongoing***.
Requesting Organization/Department	B51 / Gas Engineering
Business Case Owner | Sponsor	Jeff Webb | Alicia Gibbs
Sponsor Organization/Department	B51 / Gas Engineering
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

The problems that are being addressed through this program are the physical conflicts between natural gas facilities and roadway projects or other utilities within R/W.

Virtually all Avista's pipelines are in R/W that are governed by local jurisdictional franchise agreements. Avista is mandated under these agreements to relocate our facilities, at our cost, when local jurisdictional projects necessitate. Many of

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these projects come to Avista without significant lead time by the local jurisdictions. It is often the case that meetings are called in the spring season to notify franchisees (natural gas, electric, cable, phone companies etc.) that they will need to relocate their facilities that year. This makes accurate long term budget forecasts challenging.

When conflicts are identified that may require relocating gas facilities, attempts are made to design around the conflict. If conflicts cannot be resolved, then relocation of gas facilities is required. Avista must then relocate the gas facility at its cost per the applicable franchise agreement. If the relocation project is of significant complexity, then Gas Engineering will take over the project to design and manage it through completion; otherwise, the local districts typically manage the project. The business needs and potential solutions identified impact all gas customers in Avista's service territory.

1.2 Discuss the major drivers of the business case.

The major driver of the business case is Mandatory and Compliance. Per the franchise agreements with local jurisdictions, Avista is required to resolve conflicts within R/W at Avista's cost.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The nature of this work is considered "work in request of others". If the conflicts are not resolved through design changes or relocation of the gas facilities, Avista would not comply with its franchise agreements and could be charged with delay of a project. This would not only be a financial burden on the company, but it would also greatly damage the working relationship between Avista and the municipality.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

The projects within this Business Case align with Avista's values of being Trustworthy and Collaborative. We are Trustworthy when we resolve conflicts between our pipeline facilities and local jurisdictional projects since that is what Avista agreed to in the franchise agreements. We are Collaborative when we work together with local jurisdictions to either design around the conflict or come up with a relocation plan that addresses the conflict.

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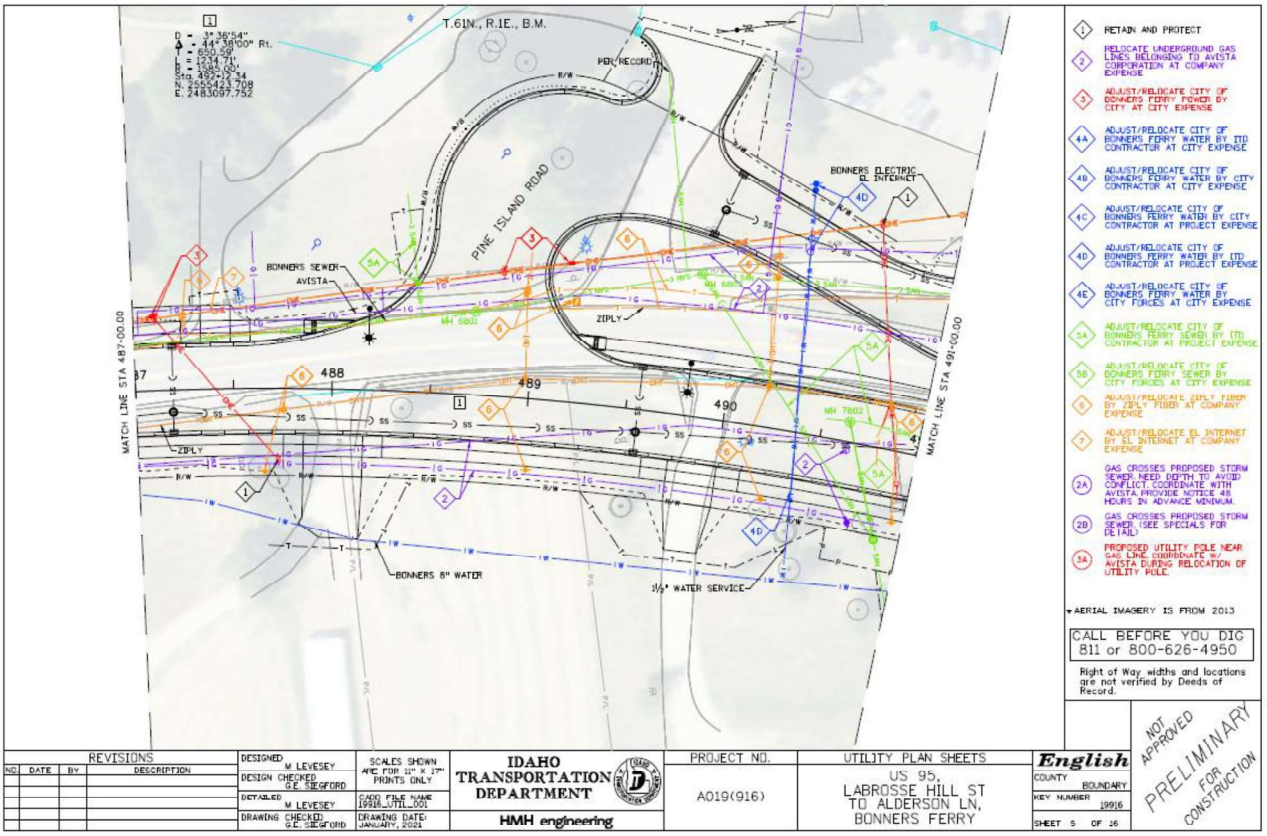
1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

Here is an example of a road move project that Avista worked on with the Idaho Transportation Department in Bonners Ferry. This is just one page of the project plans that involved relocating approximately 700 feet of 2" PE main and 1,200 feet of 4" steel main that were in conflict with the new roadway design.



This is just one example of the many road move projects that are completed under this Business Case. Avista receives project plans like these from the different municipalities to aid in project relocation designs. Oftentimes, Avista representatives meet with the different municipalities in advance of the project to assist in the relocation plan.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

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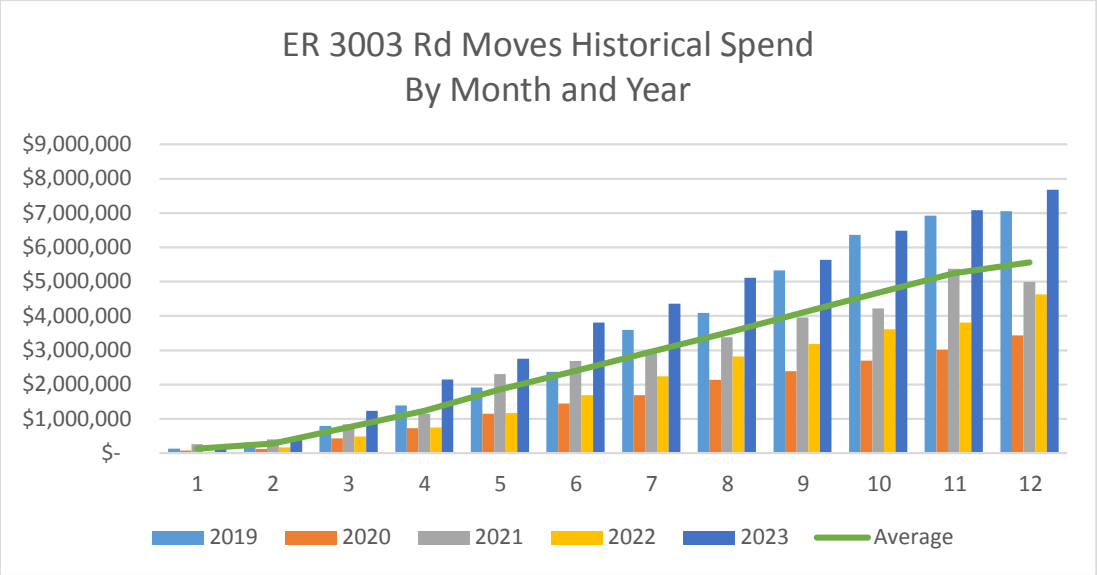
Budget forecasting is primarily based on historical spend. Below is a chart showing the actual monthly spend for the last five years and the large variation from year to year.



2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The projects within this program address and resolve conflicts between Avista's gas facilities and projects within local jurisdictions. Each project is unique. When a jurisdiction has a project where gas facilities are in conflict, efforts are made to design around the conflict. If this is not possible, Avista works with the jurisdiction to come up with a relocation plan to eliminate the conflict.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

By completing the projects as requested, Avista meets the obligations under its franchise agreements. A major risk associated with not completing the work under this Business Case is tarnishing Avista's good working relationships with the many

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

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municipalities in its service territory. Additionally, Avista would be at risk of financial penalties associated with project delays if gas facilities in conflict were not relocated. The work done under this Business Case allows Avista to avoid these risks.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no direct offsets or savings associated with this Business Case.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no indirect offsets or savings associated with this Business Case.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

If the conflict cannot be designed around by the municipality and the gas facilities must remain in service, then there are no alternatives for the resolution.

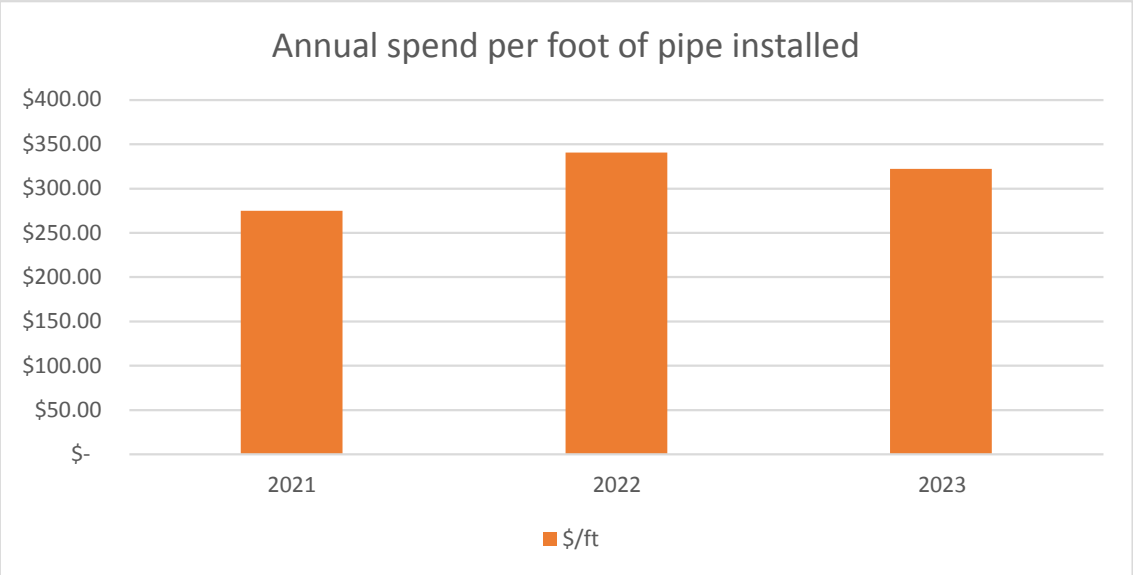
[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

DocuSign Envelope ID: 0581ED12-F040-4FF8-A31E-211F297D4A21

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Projects are either managed by Gas Engineering or local CPCs. Projects are monitored by the responsible party from project initiation through construction until the project is completed. Success can be measured by tracking completed projects and work orders under this Business Case. To help monitor changes in construction costs, annual cost per foot of gas pipe will start to be reported. See below for historical spend per foot of pipe.



2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Projects are typically started and completed within the same calendar year and are placed into service the same month they become used and useful.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Gas Engineering manages this Business Case. Many of the projects are handled by the local construction offices. For more complex relocation projects, Gas Engineering will manage the relocation project. Throughout the year, Gas

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Engineering conducts regular check-ins with the local construction offices to get updates on the road move projects for the year.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Business Case for ER3003 Replacement Street and Hwy Program and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Jeff Webb 5831FFAC45834CF...	Date:	May-02-2024 | 9:27 AM PDT
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	DocuSigned by: Alicia Gibbs 49C42855345E483...	Date:	May-03-2024 | 7:00 AM PDT
Print Name:	Alicia Gibbs		
Title:	Director Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

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EXECUTIVE SUMMARY

ER 3117 provides funding for additions and improvements to Avista's Gas Telemetry system. Active equipment includes a population of over 250 flow computers, electronic volume correctors, and electronic pressure monitors. The system provides safety related pressure monitoring and alarms at Gate Stations, Regulator Stations, Pipelines, Odorizers, and Transportation Customers. It also provides critical consumption/usage data for gas procurement, billing, EPA emissions, engineering analysis, capacity load studies, and system operations. Gas telemetry is critical for maintaining safe and reliable operation of our gas system, as well as compliance with Federal Codes Title 49 Part 192.741 and Part 192.635.

A lack of sufficient monitoring points on the system can create blind spots in our understanding of how the gas system is performing. These blind spots can decrease our ability to detect abnormal, non-compliant, or unsafe system operating conditions in real time. They can also create a data void, which makes it harder to analyze the system and justify new reinforcement projects to ensure gas reliability. Conversely, more monitoring points can provide Avista with more flexibility and confidence in deferring/delaying reinforcement projects.

Over the past year Avista has experienced two major system EOP events and one near-miss EOP event. During the 2023 Palouse Outage and 2024 MLK Gas & Power Supply EOPs, the telemetry system provided invaluable real-time gas system information to key stakeholders, decision-makers, and company executives. The near-miss event at Medford Gate Station was prevented from becoming an EOP largely because of Avista's telemetry system. If not for Avista's alarm and subsequent phone call to TC Energy, it's possible that TC Energy would not have responded in time to prevent a large-scale outage similar in size to the Palouse Outage.

Below is a summary of the estimated costs offsets for this Gas Telemetry program. Indirect O&M cost offsets pertain to avoiding manual pressure readings and monetary risks from regulatory fines, supplier fines, outages, and safety incidents.

ER 3117 Cost Offsets[1]	2025	2026	2027	2028	2029
Capital (Indirect)	$0	$0	$0	$0	$0
O&M (Indirect)	$209,325	$217,117	$224,910	$232,702	$240,494
Capital (Direct)	$0	$0	$0	$0	$0
O&M (Direct)	$0	$0	$0	$0	$0

Gas Engineering is proposing a 5-year budget of $100,000 per year plus inflation, which is consistent with historical annual spending for this scope of work. Proper funding is critical to ensuring that telemetry system equipment is replaced/upgraded as needed and new sites are installed as needed to monitor critical aspects of the system. Failure to fund or fully fund the program could prevent critical monitoring equipment from being replaced or installed at new sites, which negatively impact's Avista's risk with respect to safety, reliability, compliance, operations, and finances.

ER 3117 Budget Proposal	2025	2026	2027	2028	2029
Capital	$100,000	$103,000	$106,000	$109,000	$112,000

[1] Reference Sections 2.3 and 2.4 of the document for offset details

DocuSign Envelope ID: CAFB1AD4-8C1C-411C-BCB3-F90A5075DD01

VERSION HISTORY

Version	Author	Description	Date
1.0	*Jeff Webb*	*Initial draft of original business case*	*3/17/2017*
1.1	*Jeff Webb*		*4/07/2017*
2.0	*Dave Moeller*	*Revised for 2020 Oregon GRC Filing*	*2/17/2020*
2.1	*Dave Moeller*	*Updated to the refreshed 2020 Business Case Template*	*7/2/2022*
2.2	*Dave Moeller*	*Updated to the refreshed 2022 Business Case Template*	*7/15/2022*
2.3	*Mike Yang*	*Updated to the refreshed 2023 Business Case Template*	*4/17/2023*
2.3	*Mike Yang*	*Overall refresh / Revised to remove MiniAT/ERX program scope*	*5/3/2024*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	**100,000**	**100,000**
2026	**103,000**	**103,000**
2027	**106,000**	**106,000**
2028	**109,000**	**109,000**
2029	**112,000**	**112,000**

Project Life Span	***5 years***
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Mike Yang & Jeff Webb | Alicia Gibbs
Sponsor Organization/Department	B51- Gas Engineering
Phase	Execution
Category	Program
Driver	Performance & Capacity

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 380 of 535

DocuSign Envelope ID: CAFB1AD4-8C1C-411C-BCB3-F90A5075DD01

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

Ongoing funding for new gas telemetry equipment is required for situational awareness, safety, compliance, Transportation Customers, capacity analysis, and system improvements. Telemetry equipment includes flow computers, electronic volume correctors, and electronic pressure monitors installed at both permanent and temporary locations around the gas system. This equipment provides system performance, safety and compliance related pressure monitoring, and alarms throughout the gas system at Gate Stations, Regulator Stations, Pipelines, Odorizers, and Transportation Customers. It also provides critical consumption/usage data for gas procurement, billing, EPA emissions, engineering analysis, capacity load studies, and system operations. Avista's telemetry system currently consists of approximately 250 permanent device locations and 50 seasonally deployed device locations.

Code of Federal Regulations (CFR) Title 49 Part 192 has multiple requirements governing gas pipeline monitoring. CFR Title 49 Part 192.741 requires monitoring at regulator stations and CFR Title 49 Part 192.635 requires notification of potential rupture. Telemetry equipment installed and funded under this program are critical to staying in compliance with these code requirements.

Failure or malfunctioning telemetry equipment, or an inadequate number of monitoring points can impact Avista's ability to maintain efficiency, regulatory compliance, and reliability of the gas operations monitoring system. Lengthy outages due to failed or malfunctioning equipment increases the risk that Avista would not be able to detect abnormal, non-compliant, or unsafe system operating conditions (i.e., pressure and flow conditions) at key facilities or areas of the system that experience low pressures. Failed equipment also impacts Avista and the agents for Avista's transportation customer who rely on timely gas consumption data for accurate daily gas supply nominations to avoid contractual fines.

A lack of sufficient monitoring points on the system can create blind spots in our understanding of how the gas system is performing. These blind spots can decrease our ability to detect abnormal, non-compliant, or unsafe system operating conditions in real time. They can also create a data void, which makes it harder to analyze the system and justify new reinforcement projects to ensure gas reliability. Conversely, more monitoring points provides Avista with more flexibility and confidence in deferring/delaying reinforcement projects.

Over the past year Avista has experienced two major system Emergency Operating Plan (EOP) events and a near-miss EOP event. During the 2023 Palouse Outage and 2024 Gas & Power Supply EOPs, the telemetry system provided invaluable real-time gas system information to key stakeholders, decision-makers, and company executives. Without this information, critical awareness and operational decisions would have been severely hindered. Data provided by the gas telemetry system provided key information when responding to these events. The near-miss event at Medford City Gate was caused when TC Energy's gas facility shut down unexpectedly in the middle of the night. Avista's telemetry system eventually triggered a low-pressure alarm and Avista was able to contact TC Energy about getting the station back online. If not for Avista's alarm at this facility, it's possible that Avista would have experienced a large gas outage similar in size to the Palouse Outage.

DocuSign Envelope ID: CAFB1AD4-8C1C-411C-BCB3-F90A5075DD01

1.2 Discuss the major drivers of the business case.

The major drivers of this business case are "Performance & Capacity" and "Mandatory & Compliance". ER 3117 provides capital funding for additions, improvements, and replacements to the Gas Telemetry system. The system provides monitoring (including safety related alarms and history) of pressure, temperature, gas volumes, rupture detection, and gas flow rates at Gate Stations, Reg Stations, pipelines, odorizers, and for Transport Customers where applicable.

Continued investment in our Gas Telemetry System is a benefit to our customers since it allows us to continue operating our gas system safely, efficiently, and compliantly. It is also critical in providing accurate and timely billing data for our gas schedulers and customers.

Code of Federal Regulations (CFR) Title 49 Part 192.635 & 192.741 outline the requirements for gas pipeline monitoring. Telemetry equipment installed and funded under this program are critical to staying in compliance with these code requirements.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The requested funding is needed now to ensure there is capital funding necessary to keep Avista's gas telemetry system of over 300 devices operational, effective, and compliant. As mentioned previously, the inability to detect real-time conditions increases the risk associated with abnormal, non-compliant, or unsafe operating conditions. Inaccurate or untimely billing data can also result in fines, customer complaints, and/or regulatory scrutiny. Work required to keep the system operational includes both planned and unplanned work, so it is critical to have funding available every year for projects.

Deferring funding is not recommended, but it's possible that the monetary and operational risks mentioned above could be mitigated for a short period of time. There would still be elevated risk of existing sites going offline without the funding to replace them, but depending on the situation it may be possible to implement a temporary work-around solution until funding is restored. New sites needed for critical monitoring and/or compliance could also be delayed causing a similar increase in risk, but again there could be short-term work-around solutions. The short-term solutions would not provide the full benefits such as real-time data monitoring.

If funding is not approved, Avista runs the risk of falling out of compliance with federal codes and losing the ability to maintain remote monitoring capabilities at critical gas facilities. Failure to fund this program could create non-compliance situations and the inability to monitor critical infrastructure in real time. This would result in an elevated risk of regulatory fines, supplier fines, outages, and prolonged unsafe operating conditions. Fines could be up to $50,000/day from suppliers and up to $257,664/day from state regulatory commissions. System outages typically cost around $2,960 per customer outage.[2]

[2] Reference Section 2.4 for more detail on the gas outage cost of $2,960 per customer.

DocuSign Envelope ID: CAFB1AD4-8C1C-411C-BCB3-F90A5075DD01

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

Maintaining and improving upon the gas telemetry system has a direct impact on those customers who rely on having accurate, timely, and reliable billing data for their own internal processes and operations. More importantly having accurate, timely, and reliable information about gas system conditions throughout the service territory allows Avista to respond quickly to potentially unsafe or abnormal operating conditions that could have an impact on the safety of our customers and/or the public.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.

Gas Planning regularly performs an analysis of the gas system to predict future performance and identify areas of concern with respect to system capacity (i.e. low pressure areas). These locations require seasonal (i.e. temporary) and/or permanent telemetry devices to be installed so that the system can be monitored in real time to avoid outages. More details regarding this periodic analysis can be provided upon request.

In addition, the real-world data collected by the telemetry system is used as a baseline to ensure that the department's modeling program (Synergi) is an accurate depiction of the system. The real-world data is used to validate the model and identify areas of the model that need to be updated/revised.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Proposed 5-year funding for capital work to the gas telemetry system maintains our ability to replace existing failed/malfunctioning equipment and install gas monitoring equipment in new areas of the system as needed. The behavior and performance of the gas system is not static, so it is critical to maintain the flexibility to install new equipment as needed. New telemetry sites are typically determined by known gas stream quality issues that impact pressure regulation (e.g., dithiazine) or by the identification of low-pressure locations on the system using advanced modeling software (i.e., Synergi models). There are also new compliance related telemetry sites required when a gas system goes from having a single source of gas supply to having multiple supply sources (CFR Title 49 Part 192.741) or when rupture detection monitoring/notification is required (CFR Title 49 Part 192.635).

COST ESTIMATE BREAKDOWN: It is expected that this program will fund approximately 3 to 10 capital projects a year depending on project complexity and company need. Projects can range from the replacement of a reusable temporary portable pressure recorder (~$4,000 each) to a comprehensive gate station flow computer installation, which can include electrical work, power service, transmitters, buried conduit, site work, and a climate-controlled building (~$75,000 each). The

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median cost project is approximately $15,000 to $25,000 depending on the ability to use solar power or not. If solar is not an option, $25,000 includes the installation of a dedicated secondary power service or a microgenerator if grid power is not available.

The proposed budget of $100,000 per year plus inflation is based on historical spending data, which has been sufficient in the past to meet all telemetry system needs with respect to compliance and other telemetry system improvements.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[3]

In addition to the many qualitative benefits associated with improving safety, operational awareness of the gas system, customer service quality, and compliance, the work performed under this program will also provide indirect quantitative cost offsets. No direct costs offsets were identified with this program. Detailed explanations of these cost offsets can be found in Section 2.4, and below is a 5-year summary of these offsets compared to the proposed annual cost of the program.

ER 3117 Cost Offsets[4]	2025	2026	2027	2028	2029
Capital (Indirect)	$0	$0	$0	$0	$0
O&M (Indirect)	$209,325	$217,117	$224,910	$232,702	$240,494
Capital (Direct)	$0	$0	$0	$0	$0
O&M (Direct)	$0	$0	$0	$0	$0

ER 3117 Budget Proposal	2025	2026	2027	2028	2029
Capital	$100,000	$103,000	$106,000	$109,000	$112,000

2.3 Summarize in the table, and describe below the DIRECT offsets or savings (Capital and O&M) that result by undertaking this investment.

There are no direct offsets associated with this program.

2.4 Summarize in the table, and describe below the INDIRECT offsets (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
O&M	Manual Pressure Readings	$7,792	$15,584	$23,377	$31,169	$38,961
O&M	See Risk Matrix Below	$201,533	$201,533	$201,533	$201,533	$201,533

[3] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.
[4] Reference Sections 2.3 and 2.4 of the document for offset details

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 384 of 535

DocuSign Envelope ID: CAFB1AD4-8C1C-411C-BCB3-F90A5075DD01

Indirect offsets for O&M Manual Pressure Readings were determined by calculating the cost to send out operator qualified gas personnel to all critical monitoring points during a cold-weather event instead of using the telemetry system. Currently, the telemetry system allows us to remotely monitor and automatically alarm without human involvement. If the system is allowed to degrade by not replacing critical monitoring points, the company will be forced to send out personnel with pressure gauges to each of these critical locations during cold weather events. O&M expenses increase over time as more telemetry equipment fails/malfunctions without being replaced. Assumed 60 critical cold weather monitoring points, 3 devices fail per year (20-year life of devices), 10 days of monitoring per cold weather event, and one cold weather event every 3 years[5].

The risk matrix below represents a summary of the indirect cost offsets associated with the work performed under this business case budget. The probabilities associated with the risk increase over time if nothing is done to address existing obsolete or broken equipment, as well as the need for new monitoring sites as the gas system operating behavior continues to evolve. The budget proposed in this business case seeks to mitigate this risk matrix by providing a financially responsible plan to address these needs over a reasonable amount of time.

The cost of an outage was estimated at $2,960 per customer[6]. This cost includes the cost for Avista to restore service and the potential economic impacts to the customer. The calculation assumes that restoration will be completed within 24 hours, which is Avista's restoration goal. A severely damaged station may take longer than 24 hours to repair and bring back into service.

[5] Reference "Offset Calculations & Assumptions_ER 3117_2024.xlsx" document for details on indirect costs

[6] The Interruption Cost Estimate (ICE) Calculator was used to estimate the economic impacts to the customer at $116 per hour per customer. An estimated restoration cost of $176 per customer is based on the actual restoration costs incurred during the 2022 Crestline outage in Spokane. Therefore the total cost per customer is estimated to be $116 x 24 hours + $176 = $2,960.

DocuSign Envelope ID: CAFB1AD4-8C1C-411C-BCB3-F90A5075DD01

Gas Telemetry, ER 3117

Risk Probability Definitions:

Very High (VH)	Risk event expected to occur
High (H)	Risk event more likely to occur than not
Probable (P)	Risk event may or may not occur
Low (L)	Risk event less likely to occur than not
Very Low (VL)	Risk event not expected to occur

Risk Probability for Calculating Indirect Offsets:

75%
50%
25%
10%
1%

Risk Avoidance Over Time and the Cost of Doing Nothing:

#	Risk	Risk Over Time					Cost Estimate	Worst Case Cost Estimate
		1 Year	2 Years	5 Years	10 Years	15+ Years		
1	Regulatory Fines in response to a preventable incident	VL	VL	L	P	H	$257,664 per day per violation (Max) $2,576,627 Total (Max)	$ 2,576,627
2	Customer Outage	VL	L	P	H	VH	$2,960/outage (ex. ~ $1.5 million for 500 outages)	$ 1,500,000
3	Innaccurate billing	L	P	H	VH	VH	$50,000/day fine for Avista or Customer Agent	$ 350,000
4	Customer & Public Safety	VL	VL	L	P	H	$250,000 to $2 Million for Lost time, healthcare, lawsuits, system damage, etc.	$ 2,000,000

O&M Indirect Cost offsets over the next 5 years:

#	Risk	O&M Annual Indirect Offsets*					Total Cost per Risk Item
		2025	2026	2027	2028	2029	
1	Regulatory Fines	$ 51,533	$ 51,533	$ 51,533	$ 51,533	$ 51,533	$ 257,663
2	Customer Outage	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 375,000
3	Innaccurate billing	$ 35,000	$ 35,000	$ 35,000	$ 35,000	$ 35,000	$ 175,000
4	Customer & Public Safety	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 200,000
	TOTALS	$201,533	$201,533	$201,533	$201,533	$201,533	$ 1,007,663

*Took probability at 5 year mark, multiplied by worst case cost, and then divided by 5 for cost/year over 5 years

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 386 of 535

DocuSign Envelope ID: CAFB1AD4-8C1C-411C-BCB3-F90A5075DD01

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

See below for list of alternatives. None are recommended by Gas Engineering. The recommended funding of $100,000 is enough to complete critical work while also being a manageable workload for Avista's limited telemetry engineering and technical labor resources.

Alternative 1: Reduce 5-year program funding to $50,000/year

Reducing funding and replacing equipment at a slower rate increases the probability of failed equipment and the potential consequences associated with not being able to monitor the system and provide timely billing data to customers. This a reasonable alternative that could be absorbed over a short period of time (e.g. one year), but it's still not recommended. In addition to creating more risk, deferring projects can create future workload imbalances for Avista's limited Gas Telemetry resources.

Alternative 2: Defer all program funding for a year

Deferring all program funding to a future year creates more risk than alternative 1 and is not recommended for the reasons stated above. Long term this could be less disruptive than alternative 1 assuming full funding is restored the following year, but in the short term it is more risky and impactful than alternative 1 (Alternative 1 is reduced funding for all five years).

Alternative 3: Eliminate all 5-year funding (i.e. do nothing)

Eliminating all funding and doing nothing over the next five years is not a reasonable option and poses significant safety, operational, reliability, financial, regulatory, and public relations risk. There are also resource concerns with the potential of having severely imbalanced workloads in the future if all work has been put off for multiple years.

Option	2025 Capital Cost	Start	Complete
Recommended: Fund program at proposed budget of $100,000 / year	$100,000	January	December
Alternative 1: Reduce 5-year program funding to $50,000 / year	$50,000	January	December
Alternative 2: Defer all program funding for one year	$0	January	December
Alternative 3: Eliminate all 5-year funding	$0	January	December

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2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Tracking of program effectiveness will be accomplished using Gas Engineering's DNV Synergi models, compliance audits, monthly alarm reviews, telemetry meetings, and event/incident after-action reviews (e.g. EOPs, cold weather events, etc.). The Synergi model is used to proactively identify existing or future needs for telemetry with respect to system reliability and model validation. Internal and external audits help to ensure compliance with telemetry regulatory requirements. Monthly alarm reviews and telemetry meetings provide regular forums for subject matter experts to review safety and alarm related events on the system, which can bring awareness to monitoring gaps in the system. Event/incident after-action reviews provide real-world feedback on the performance of the telemetry system and whether there are any gaps in what is being monitored. All these qualitative and quantitative metrics provide feedback into the overall effectiveness of the program.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

It is expected that this budget will continue indefinitely since the gas telemetry system will continue to need new sites and replacement equipment as long as the gas system is operational. Existing telemetry devices have a range of vintages and performance, so there is continuous need to replace failed/malfunctioning equipment as well as obsolete/end-of-life equipment.

Field work completed under this budget occurs throughout the year as equipment is delivered and the projects are scheduled. As a result, multiple sites are expected to be installed every quarter under this program and are typically used and useful immediately upon installation.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Gas Engineering in consultation with other groups such as Gas Operations, Gas Control, Gas Supply, and Billing develops the planning, implementation, and performance of the telemetry system. Gas Engineering is responsible for identifying and prioritizing the work, getting approval via the Capital Project Request (CPR) procedure, and initiating changes via the Gas Management of Change (GMOC) process where applicable such as any instrumentation sending data to SCADA for use by Gas Control.

If any changes to the budget for the year are needed, the Business Case Owner proposes a budget change and justification that must get approval from the Business Case Sponsor before it is brought before the Capital Planning Group.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 388 of 535

DocuSign Envelope ID: CAFB1AD4-8C1C-411C-BCB3-F90A5075DD01

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed *ER 3117 Gas Telemetry* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Jeff Webb	Date:	May-21-2024 | 10:07 AM PDT
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	DocuSigned by: Alicia Gibbs	Date:	May-21-2024 | 2:54 PM PDT
Print Name:	Alicia Gibbs		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

DocuSign Envelope ID: B75BA67A-8C3F-4287-9A80-EC520F9E53EE

EXECUTIVE SUMMARY

Federal code CFR 49.192.467(F) requires that pipelines located near electric transmission systems must be protected from damage caused by faults on the transmission system. Avista has experienced safety issues, including fires at regulator stations and damaged equipment, due to electrical arcing caused by faults on adjacent electric power systems. Fault events of electric distribution or transmission systems can create momentary high voltage levels on nearby steel gas piping. This is due to either power system current arcing onto the pipe, or more typically, through electromagnetic induction. Sometimes gas systems experience 'steady-state' voltage. In these situations, there is an induced voltage on the pipe at all times that comes from nearby electric lines. These situations don't cause arcing, but the voltage level can be high enough to be a personnel safety concern, as well as a cause of pipeline corrosion.

The purpose of this program is to identify high pressure gas piping systems that are at risk of these conditions, identify gas systems that have high steady state voltage, and to then install mitigative measures to reduce the risk from these hazards. These efforts will protect the pipeline and equipment from being damaged, while also reducing employee exposure to touch voltage hazards. Common approaches to mitigation include the installation of grounding systems, gradient control mats, and other equipment that reduces the presence of dangerous voltage differentials on pipeline facilities.

This work is a direct effort to prioritize the safety of Avista's employees. Avista's customers and contactors also benefit from the improved safety of these systems as some of Avista's infrastructure is aboveground and therefore accessible to the general public.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Jeff Webb*	*Initial draft of original business case*	*12/17/2021*
1.2	*Tim Harding*	*Updated to the refreshed 2022 Business Case Template*	*9/01/2022*
1.3	*Shontelle Wilson*	*Updated to the refreshed 2023 Business Case Template*	*4/6/2023*
2.3	*Tim Harding*	*Updated to the refreshed 2023 Business Case Template*	*4/18/2023*
2.4	*Tim Harding*	*Updated for 2024 Business Case*	*4/15/24*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	*4/17/24*

DocuSign Envelope ID: B75BA67A-8C3F-4287-9A80-EC520F9E53EE

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	250,000	250,000
2026	250,000	250,000
2027	250,000	250,000
2028	250,000	250,000
2029	250,000	250,000

Project Life Span	***10 Year***
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Tim Harding / Jeff Webb | Alicia Gibbs
Sponsor Organization/Department	B51 – Gas Engineering
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

Buried steel natural gas pipes in close proximity to electric conductors can have high AC voltage present. The power lines induce this voltage on the pipe, either constantly, or during fault conditions. Industry standards, including AMPP Standard Practice SP0177 suggests that, for safety reasons, steady-state pipeline voltages should not exceed 15 volts. Systems experiencing voltages higher than this should be studied, and mitigation measures put in place to reduce system voltages.

Federal code CFR 49.192.467(F) requires that pipelines located near electric transmission systems must be protected from damage caused by faults on the electric transmission system. The mitigation schemes and equipment used to address fault voltage concerns often overlaps what is used to address steady-state voltage hazards. Fault incidents on nearby electric systems can lead to a significant voltage rise on the gas main – hundreds or thousands of volts. Gas systems are not designed to support these voltage levels, and because of this, electric arcing between components can occur. This arcing damages equipment, and can burn holes through gas-carrying components, leading to gas leaks and fires. Personnel working on these gas systems during a fault event can be exposed to fatal voltage levels.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 391 of 535

DocuSign Envelope ID: B75BA67A-8C3F-4287-9A80-EC520F9E53EE

Between 2017 and 2021, there were five electric fault incidents that caused arcing on gas facilities, resulting in blowing gas and fire. Each one of these incidents caused equipment damage and required emergency response from company personnel.

The constant presence of AC voltage on a pipeline can also lead to corrosion. AMPP Standard Practice SP21424 addresses this issue and gives guidance on testing, monitoring, and mitigation of this issue. AC corrosion can occur on pipelines with less than 15 volts, so systems without shock hazard risks may still have this issue. Because of this, AC corrosion risks must be monitored separately from the other two risks listed above.

1.2 Discuss the major drivers of the business case.

The primary driver for this business case is Mandatory & Compliance. This program addresses safety hazards and integrity concerns on high pressure steel gas mains. This benefits customers by reducing corrosion risks, as well as eliminating hazardous voltage levels on above-ground gas facilities – facilities that sometimes are accessible to the general public.

Based on Federal code CFR 49.192.467(F) "Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices." This business case supports this federal code requirement. Federal fines for not meeting code requirements are not prescribed but can range to a maximum daily fine of $257,664 per day and a maximum total of $2,675,627 per violation.

Fault events cause damage to the gas system and can also cause unsafe conditions when gas is released and is ignited. By mitigating areas that are prone to damage, the likelihood of these incidents occurring is reduced. The installation of mitigation equipment reduces O&M expenses. The two main reductions in these costs are due to fewer fault damage incidents that require emergency response, and the reduced need to follow special safety procedures when doing construction or maintenance on the system. The average cost savings per year in O&M is $7,200.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

There are multiple gas systems with known high-voltage hazards present. Between 2017 and 2021, there were five electric fault incidents that caused arcing on gas facilities, resulting in blowing gas and fire. Not mitigating these systems will result in the continued prevalence of electric fault incidents, as well as exposing employees to potentially hazardous steady-state pipeline voltages. Mitigation methods described in this program are a proven way to resolve these issues. This work must be done, and delaying the process puts system integrity and workers at an increased level of risk for each year of the delay.

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1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

This program aligns with Avista's organizational focus to maintain safe and reliable infrastructure to achieve optimum life-cycle performance, in a safe manner for our customers. As stated in the summary, equipment damage and fires have resulted in an unsafe environment. This program focuses on pipelines that may be damaged by nearby electric systems, or those that will expose employees and the general public to unsafe voltage levels.

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1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

As previously stated, five electric fault incidents have already occurred on Avista's gas system. The following image is of pipe damage that occurred from a fault incident that occurred on or around the date of 1/24/14.

Image 1. Pipe Damage from Fault Incident

The next image documents the ignition that occurred as a result a different fault incident in 2017.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

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Image 2. Ignition from Fault Incident

Similar photographic evidence documents the results from the other four fault incidents. To date, two studies have been performed by consulting engineering firms on the specific gas systems that have experienced multiple arcing incidents due to electric system faults. These studies have yielded reports and mitigation designs.

These studies use computer models to simulate the interaction between power lines and nearby buried steel pipelines. The computer models take into account the locations and characteristics of the power and gas systems, as well as the soil characteristics. The software simulates both steady-state conditions and fault events that occur on the electric system. It then determines the AC (Alternating Current) voltage levels that will be on the pipeline at these times.

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For the two studies conducted, the computer simulations showed worst-case pipeline voltages of 2,000 V_{AC} and 4,000 V_{AC} on the two different systems. Voltage levels of this magnitude can cause arcing at gas equipment and represent a fatal shock hazard.

The second part of each study involved putting together a mitigation design. High voltage hazards can be mitigated in different ways. There are three general schemes that are used to reduce these hazards:

1. Grounding – Steel gas pipes are coated to reduce corrosion. The better the coating on the pipe, the higher voltage the pipe will experience due to nearby power lines. By grounding the steel pipeline to the adjacent soil, the voltage rise on the pipeline is reduced. Gas systems have cathodic protection systems, which aren't compatible with a traditional grounding system. It's beyond the scope of this document to describe the details but note that special grounding designs are required.
2. Equipotential Mats – At above-ground gas facilities, such as regulator stations, personnel can come in contact with gas piping. If the piping is at a high voltage level, a hazard can exist when the piping is touched. The danger exists because there is a voltage difference between the pipe surface (hand contact) and the ground (foot contact). This voltage difference causes current to flow through the body, resulting in a shock. Equipotential mats are a metal grid that is placed 6-12" below ground in areas around above-ground gas pipes. The grid is connected to the pipe with wires. If the pipe voltage rises, the grid will rise to the same level. This eliminates the high voltage difference between the hands and feet, eliminating the shock hazard.
3. Insulation – Similar to the example above, this is another way to reduce shock hazards that can occur when contacting gas systems. In this case, 6-12" of high resistance gravel is added in areas around above-ground gas pipes. The resistance of the gravel is high enough that only a non-lethal current level would flow through the body if the gas pipe was touched.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The requested level of spending for this program allows the high priority projects on systems with known hazards to be completed. Outside consulting engineering firms have performed studies and helped identify which mitigation approach is appropriate for each known hazard area. As previously stated, mitigation approaches include: grounding, equipotential mats, and insulation. These projects are addressing serious system integrity and safety issues. A reduced level of funding will slow the installation of mitigation equipment, and delay resolving known system integrity and safety risks. For projects to be considered in this program, they must exhibit symptoms that would put them in violation of the Codes and Standards listed in Section 1.1 of this document. As projects are completed, these systems will become compliant with these requirements. As more systems are addressed, fewer will require mitigation and the program budget can be reduced.

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2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

Execution of this program ensures that Avista avoids the risk of federal fines resulting from noncompliance with Federal code CFR 49.192.467(F). Federal fines for not meeting code requirements are not prescribed but can range to a maximum daily fine of $257,664 per day and a maximum total of $2,675,627 per violation.

This program will also directly reduce O&M expenses related to extensive safety procedures currently required each time an employee works on a gas system that has potential voltage hazards, and the O&M labor that results when fault damage occurs. These are expanded on further in section 2.3, but average approximately $9,075 each year.

This business case is intended to address risk reduction and Avista's ability to maintain compliance in the states we operate within. The program is aimed at maintaining safe and reliable systems for our employees and our customers. Additional risk mitigation that is not currently quantified is the serious potential of Avista employee or customer contact with fatal voltage levels that may be present on the gas system.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	None	$0	$0	$0	$0	$0
O&M	Labor related to extra safety procedures	$5,200	$5,400	$5,600	$5,700	$5,900
O&M	Labor and materials to respond to fault damage events and make repairs.	$3,500	$3,600	$3,700	$3,800	$3,900

The installation of mitigation equipment reduced O&M expenses. The two main reductions in these costs are due to fewer fault damage incidents that require emergency

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

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response, and the reduced need to follow special safety procedures when doing construction or maintenance on the system.

When a fault event occurs that damages equipment, immediate response is needed by an Avista First Responder. There is then follow-up required by Gas Engineering to determine the cause of the incident.

In gas systems with known high voltage hazards, special safety procedures are required when contacting gas facilities that have not been mitigated. These safety procedures can include the use of rated rubber gloves, or the use of portable equipotential mats. These mats reduce touch voltage hazards and are similar to the gradient mats described in section 1.5. Setting up these mats is time consuming and once a facility has had permanent mitigation installed their use is no longer required. In addition, safety procedures require ongoing training for every employee working on the affected system.

2.4 Summarize in the table, and describe below the INDIRECT offsets (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$0	$0	$0	$0	$0
O&M	Labor and materials to repair system leaks caused by AC corrosion	$3,700	$3,800	$3,900	$4000	$4,200

The installation of mitigation systems reduces pipeline voltage. This decreases the chance of AC corrosion occurring, thereby reducing the chance of leaks from occurring on the pipe. High voltage hazards on pipelines create system integrity and safety risks. The costs associated with some of these risks can be hard to predict. Below are estimated cost ranges related to different risks.

Risk Probability Definitions:

Very High (VH)	Risk event expected to occur
High (H)	Risk event more likely to occur than not
Probable (P)	Risk event may or may not occur
Low (L)	Risk event less likely to occur than not
Very Low (VL)	Risk event not expected to occur

Risk Avoidance Over Time and the Cost of Doing Nothing:

#	Risk	Risk Over Time					Cost Estimate
		1 Year	2 Years	5 Years	10 Years	15+ Years	
1	Regulatory Fines	L	L	P	P	H	$257,664 per day per violation (Max)* $2,576,627 Total (Max)*
2	Pipeline Leak	L	P	P	H	H	$5,000 to $150,000 per site (site dependent)
3	Pipeline Failure & Outage	VL	L	L	H	H	$150,000 to $3,000,000 per site (site dependent)
4	Negative Reputation	L	L	P	H	H	Erosion of PUC and Public trust
5	Employee & Public Safety	H	H	H	VH	VH	Lost time, lawsuits, healthcare , etc. (varies)

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*Regulatory fines present a daily and overall maximum value per violation in accordance with 49 CFR Part 190.223. However, these values are not necessarily an accurate representation of how much Avista would be fined for any specific violation. The actual amount is likely to be much lower since Avista has an ongoing reputation and history of investing in programs related to safety and non-compliance issues. However, it is a bookend reminder from which to characterize the regulatory risk associated with chronic and/or egregious non-compliance, especially in the event of a pipeline safety incident (i.e. failure). Therefore, Avista must continue to demonstrate an ongoing commitment to compliance and pipeline safety to ensure favorable future outcomes with respect to regulatory penalties. (Actual penalty amount is at the discretion of the state or federal agency).

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1: Fund program at lower level

The current funding level per year is the minimum funding level required to address the highest priority mitigation projects. Any funding level below this amount means that high priority projects will not be addressed. Not mitigating the system will result in excessive prevalence of electric fault incidents. During these incidents, electric arcing can occur on gas facilities. This can, and has, lead to gas leaks and fires. Knowingly allowing dangerous incidents like this to continue is not acceptable and leads to increased risk to employee and customer safety.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

The completion of mitigation projects under this budget will have a positive impact on Gas Operations. Due to the current known safety issue, additional burdensome procedures are required when company personnel do construction and maintenance work on these systems. After the mitigation projects are complete, many of these additional safety procedures will no longer need to be required.

This program is being tracked and communicated through documentation updated by Gas Engineering in the SharePoint site. Identified projects as well as the status of these projects (complete, in progress, etc.) can be found on this document. Each completed project documents the success of this program in reducing the risk of a fault condition occurring, and/or of an individual coming into contact with potentially hazardous voltage levels.

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2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

This is designed as a 10-year program covering all three states. Projects that are performed under this budget can be both large and small. Smaller projects will typically transfer to plant monthly, while larger projects that take several months to complete will transfer to plant upon project completion. As completion rates occur, the timeline and forecasts will be updated accordingly.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

An engineer in the Gas Engineering group serves as the AC Mitigation Program Manager. The Program Manager oversees projects designs, construction, and the program budget. The Program Manager meets quarterly with representatives from Gas Engineering, Cathodic Protection, and Gas Compliance to review current and planned projects. Project are prioritized by the group. If any changes to the budget for the year are needed, the Program Manager proposes a budget change and justification that must get approval from the Business Case Sponsor before it is brought before the Capital Planning Group. If additional funds are not approved, then the remaining work is reduced to remain within budget.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Gas Transient Voltage Mitigation Program, ER 3010* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Jeff Webb 5831FFAC43834CF...	Date:	May-01-2024 | 4:43 PM PDT
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		
Signature:	DocuSigned by: Alicia Gibbs 49C428555345E489...	Date:	May-02-2024 | 8:04 AM PDT
Print Name:	Alicia Gibbs		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

EXECUTIVE SUMMARY

Avista co-owns a natural gas storage reservoir, Jackson Prairie (JP) Underground Natural Gas Storage Facility (JP). The JP natural gas storage facility is a critical component of Avista's overall natural gas supply strategy. Avista does not own any natural gas wells or supply facilities. The Company purchases all gas supply on behalf of its customers from multiple market trading hubs including AECO, Sumas, and Rocky Mountains. Avista has also secured adequate gas pipeline transport rights to ensure that all purchased gas can be reliably moved to serve customer load. In order to reduce the exposure to market prices, Avista also owns a third of the overall storage capacity at the JP gas storage facility in southwest Washington. Having gas storage allows Avista to inject gas when prices are lower and then withdraw gas during the winter peak use months when market prices are historically higher in order to keep customer rates affordable. All three owners share equally in the annual expense costs to operate the facility and the capital investments to improve operations, meet regulatory requirements and reduce future risks.

The three owners have contracted with PSE to operate the JP storage facility. The plant operations management creates an annual and five-year capital budget plan to ensure the storage facility is operated safely, reliably, and meets all federal and state regulatory requirements. Each owner has a representative that meets at least quarterly with the operating staff to review current operating performance, discuss current project spend and approve annual and five-year budget plans. The Director of Energy Supply represents Avista on the Owners Committee and approves all annual and five-year budgets after consulting with the Gas Supply department. The Manager of Gas Design is Avista's alternate representative on the Owners Committee and is also consulted on all budget decisions.

Without the JP gas storage facility, Avista customers would be completely exposed to market conditions that can be extremely volatile at times. The ability to inject gas into storage during lower priced time periods and withdrawal gas during high prices or peak load periods allows Avista to reduce customers' exposure and risks to real-time market prices and improve reliable service to customers. Avista's one third share of JP allows the utility to meet 100 percent of its customers' peak winter demand with the facility's stored reserves.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 401 of 535

VERSION HISTORY

Version	Author	Description	Date
1.0	*Scott Kinney*	*Annual Business Case Update*	*8/11/2023*
2.0	*Kevin Holland*	*2024 Business Case Update*	*9/27/2023*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements Steve Carrozzo*	*9/28/2023*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$2,397,000**	**$2,397,000**
2025	**$2,386,000**	**$2,386,000**
2026	**$2,386,000**	**$2.386,000**
2027	**$2,371,000**	**$2,371,000**
2028	**$2,368,000**	**$2,368,000**

Project Life Span	***5 Years***
Requesting Organization/Department	Natural Gas Energy Resources
Business Case Owner | Sponsor	Kevin Holland/Scott Kinney
Sponsor Organization/Department	Energy Resources
Phase	Execution
Category	Program
Driver	Performance & Capacity

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

This request is for the ongoing funding for the capital costs associated with the JP operations. Avista is a one-third owner of the facility. The three owners have contracted with PSE to operate the JP storage facility. The plant operations management creates an annual and five-year capital budget plan to ensure the storage facility is operated safely, reliably, and meets all federal and state regulatory requirements. Without the JP gas storage facility, Avista customers would be

completely exposed to market conditions that can be extremely volatile at times. The ability to inject gas into storage during lower priced time periods and withdrawal gas during high prices or peak load periods allows Avista to reduce customers' exposure and risks to real-time market prices and improve reliable service to customers. Avista's one third share of JP allows the utility to meet 100 percent of its customers' peak winter demand with the facility's stored reserves.

1.2 Discuss the major drivers of the business case.

The drivers for funding JP are Performance and Capacity. JP provides solutions for the following gas supply needs:

- Stored gas supply that enables Avista to reliably serve customers during peak load demand.
- Risk mitigation for shielding customers from extreme daily gas price volatility during cold weather or other events affecting the natural gas commodity market.
- A mechanism for purchasing gas at lower prices during off-peak periods for use during high-cost periods.

All commodity price benefits resulting from the utilization of JP are passed along to the customer through the annual PGA filings.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

JP is a functioning natural gas storage project that has critical ongoing capital funding requirements for ensuring continuous safe and reliable operation of the facility. Not funding JP at the requested levels increases a number of risks for plant operations including, but not limited to, non-compliance with Pipeline and Hazardous Materials Safety Administration's underground storage safety mandates, deliverability during peak demand periods, reduced physical plant security, reduced efficiency of plant output, or increased likelihood of component failure resulting in unplanned outages.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

JP is a critical integrated supply resource for our natural gas business. JP helps enable the delivery of natural gas energy safely, responsibly, and affordably to our customers. Without JP customers would be exposed to market price volatility risk and the need to acquire more pipeline transport capacity to the different gas supply regions.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 403 of 535

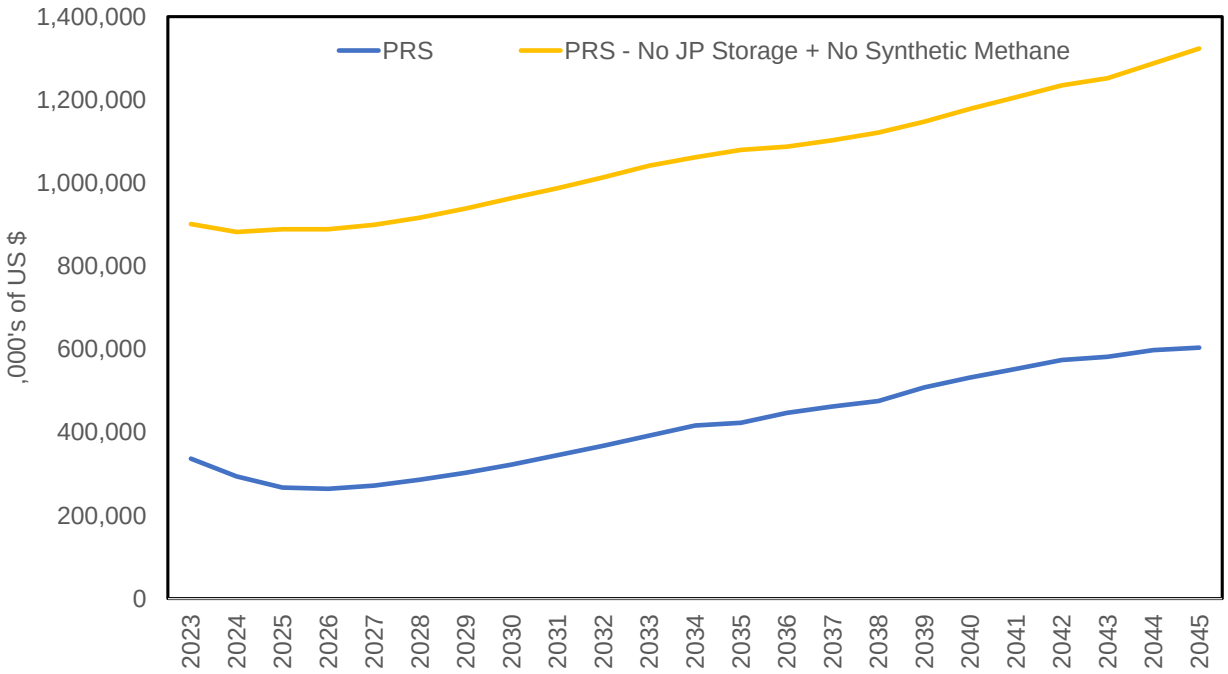
1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

The JP natural gas storage facility is a critical component of Avista's overall natural gas resources for peak day events as discussed in the Avista 2023 Natural Gas IRP. Without this resource and associated volumes, Avistas system is at risk of unserved demand during these peak day events where cold weather and risk to persons and property increase. Additionally, this facility is a least cost option and without it would likely lead to much greater costs for our customers. The 2023 Natural Gas IRP also shows that if JP were removed from the resource mix, and only currently viable technology was available to the system, load in Oregon and Washington is removed through electrification as the least cost option. Also, incremental RNG is purchased to supply peak day needs as the interstate pipeline capacity is maxed out during these cold events and additional capacity is not currently available for subscription on either major pipeline.

Scenario	NPV (2023-2042)
PRS from 2023 IRP (includes JP)	$5 B
PRS (removes Synthetic Methane and JP)	$11 B

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 404 of 535



2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The JP natural gas storage facility is a critical component of Avista's overall natural gas supply strategy to ensure reliable and affordable delivery of gas to meet customer needs. Avista does not own any natural gas wells or supply facilities. The Company purchases all gas supply on behalf of its customers from multiple market trading hubs including AECO, Sumas, and Rocky Mountains. Having gas storage allows Avista to inject gas when prices are lower and then withdraw gas during the winter peak use months when market prices are historically higher in order to keep customer rates affordable.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 405 of 535

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

The benefits of JP are outlined in detail in the 2023 Natural Gas IRP. The chart above shows the expected future demand, and available resources, including Jackson Prairie costs and demand with a least cost selection in the Preferred Resource Strategy (PRS) compared to the removal of JP as a resource choice. The ability to capture intrinsic values from summer to winter commodity prices paired with the on-demand ability to provide supply on peak days is apparent in the annual price differential. While extrinsic value can be operationally available depending on strategy, at this time extrinsic value is not specifically considered.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 406 of 535

2.5 DESCRIBE IN DETAIL THE ALTERNATIVES, INCLUDING PROPOSED COST FOR EACH ALTERNATIVE, THAT WERE CONSIDERED, AND WHY THOSE ALTERNATIVES DID NOT PROVIDE THE SAME BENEFIT AS THE CHOSEN SOLUTION. INCLUDE THOSE ADDITIONAL RISKS TO AVISTA THAT MAY OCCUR IF AN ALTERNATIVE IS SELECTED.

No cost-effective alternatives exist for replacing JP. Because JP is a unique solution that provides benefits/solutions for an array of supply needs, it would likely require multiple business solutions to replace the resource functionality provided by JP, none of which could fully duplicate the benefits of JP nor be cost competitive with JP.

Alternative 1:

N/A

Alternative 2:

N/A

Alternative 3:

N/A

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

The storage project is continually managed and monitored for optimal storage volume, injection and withdrawal performance, and other key operational metrics. An operations report is submitted to the JP Management Committee on a monthly basis. Additionally, the report provides a current and projected budget status.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

The annual capital spending for JP includes multiple capital improvement investments, which become used and useful at the end of each budget year.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 407 of 535

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Internal stakeholders include the Director of Energy Supply, Gas Supply and Gas Engineering. External stakeholders who directly interface with the business case include the two other ownership partners; PSE and Williams-NWP. Additionally, the Pacific Northwest (PNW) natural gas market and pipeline operation are directly affected by JP operations. JP provides critical supply delivery functionality to the PNW pipeline grid, especially during peak demand times.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Jackson Prairie Natural Gas Storage Facility and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Kevin Holland	Date:	Oct. 9, 2023
Print Name:	Kevin Holland		
Title:	Director of Energy Supply		
Role:	Business Case Owner		
Signature:	Scott Kinney	Date:	October 9, 2023
Print Name:	Scott Kinney		
Title:	Vice President of Energy Resources		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 408 of 535

Docusign Envelope ID: 825E3A90-F88A-407A-8DD3-5B461B3ADA81

EXECUTIVE SUMMARY

Avista defines these investments as "customer requests for new service connections, line extensions, transmission interconnections, or system reinforcements to serve a single large customer." We have often in the past referred to new service connects as "growth," as in growth in the number of customers, however, these investments are beyond the control of the Company, and as such they do not reflect a plan or strategy on the part of Avista. Responding quickly to these customer requests is a requirement of providing utility service. Typical projects include installing electric facilities in a new housing or commercial development, installing or replacing electric meters, or adding street or area lights per a request from an individual customer, a city, or county agency. As would be expected, fluctuation in the number of new customer connections is largely dependent on local economic conditions both in the housing and business sectors. New customers are served for electric in WA and ID and gas in WA, ID, and OR.

Both connects forecast and 12-month rolling Cost Per Service information are used to calculate costs directly related to providing service to customers. Electric and Gas devices are also included in this business case - Meters, Transformers, Gas Regulators, and ERTs (Encoder Receiver Transmitter). Many of these Meters, Transformers, and ERTs are used as replacements for Wood Pole Management, and Periodic Meter Changes, for example.

Growth Business Case Funds request:

ELEC & GAS	2025	2026	2027	2028	2029
Connects Forecast: Res & Comm	9,434	9,138	9,106	9,121	9,121
Extensions, Services	50,001,574	48,511,564	49,384,495	49,258,202	49,258,202
Lighting	2,471,078	2,471,078	2,471,078	2,471,078	2,471,078
Meters & Devices	12,678,791	13,291,389	13,641,025	14,306,324	15,046,589
Transformers & Network Protectors	20,750,000	21,750,000	23,850,000	26,160,000	28,701,000
Business Case Total	**85,901,442**	**86,024,030**	**89,346,598**	**92,195,604**	**95,476,869**

The 5 yr average annual spend for this business case has been around $89M. Requests for service are variable in number and in cost, sometimes requiring significant investment for system reinforcements such as gas regulator stations and electric distribution infrastructure. This funds request is based on ordinary expectation as supported by forecast and input from electric and gas operations engineers.

For 2025, there are updated impacts to Growth costs, see 2.2 for more detail.

VERSION HISTORY

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 409 of 535

Docusign Envelope ID: 825E3A90-F88A-407A-8DD3-5B461B3ADA81

Version	Author	Description	Date
1.0	*Joe Wright*	*Initial draft of original business case*	*5/02/24*
BCRT	*BCRT Team Memember – Joe Wright*	*Has been reviewed by BCRT and meets necessary requirements*	*5/02/24*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	**$85,901,442**	**$85,901,442**
2026	**$86,024,030**	**$87,087,040**
2027	**$89,346,598**	**$89,089,306**
2028	**$92,195,604**	**$92,321,897**
2029	**$95,476,869**	**$95,476,869**

Project Life Span	***5 years***
Requesting Organization/Department	Energy Delivery
Business Case Owner | Sponsor	Paul Good | Josh DiLuciano
Sponsor Organization/Department	Energy Delivery
Phase	Execution
Category	Mandatory
Driver	Customer Requested

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. **BUSINESS PROBLEM -** *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

The New Revenue – Growth Business Case is driven by tariff requirements that mandate obligation to serve new customer load when requested within our franchised area.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 410 of 535

Docusign Envelope ID: 825E3A90-F88A-407A-8DD3-5B461B3ADA81

1.2 Discuss the major drivers of the business case.

Customer Requested: The New Revenue – Growth Business Case serves as support of several focus areas in Avista. We seek to serve the interests of our customers, in a safe and responsible manner, while strengthening the financial performance of the utility. Our growth contributes to strong communities, ongoing value to our customers, and the device portion of the business case keeps our system safe and reliable.

All new customers on Avista's system are benefitted by this business case. In addition, all customers who have their metering or regulation changed, or who have transformers replaced, benefit from this business case.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Avista is required to serve appropriate new load, complying with our Certificate of Convenience and Necessity, and as part of our Obligation to Serve.

The New Revenue – Growth Business Case will provide funds for connecting new Electric and Gas customers in accordance with our filed tariffs in each state.

Our obligation to serve, mandates that we must extend service to new customers in our franchised service areas. We do not currently have an alternative to serving new customers. All projects are subject to our Line Extension Tariffs, filed with each State Utility Commission.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

This business case is about connecting customers to Avista's facilities. The work directly reflects our focus area for customers as well as our mission statement."We must hold our customer's interests at the forefront of all our decisions" and "We improve our customer's lives through innovative energy solutions."

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 411 of 535

Docusign Envelope ID: 825E3A90-F88A-407A-8DD3-5B461B3ADA81

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

N/A

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Providing service to customers upon request is mandated. As needed customer project coordinators (CPCs) and engineers review requests to determine solutions that best meet the needs of the customer and Avista. These extraordinary requests lend themselves to more visibility and oversight.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

Avista uses a rolling 12-month Cost Per New Service spreadsheet to measure ER1000, Electric New Revenue, and ER1001, Gas New Revenue spending. Device blankets are subject to demand for both new revenue and non-revenue installation and replacement.

Enclosed is a spreadsheet showing projected spend through 2029 with a breakout by Expenditure Request for the New Revenue – Growth Business Case. Connects forecast and 12 -month rolling Cost Per Service information are used. Electric and Gas devices are also included, such as Meters, Transformers, Gas Regulators, and ERTs (Encoder Receiver Transmitter). Many of the Meters, Transformers, and ERTs are used as replacements for

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.
[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Docusign Envelope ID: 825E3A90-F88A-407A-8DD3-5B461B3ADA81

Transformer Change Out Program, Wood Pole Management, and Periodic Meter Changes.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no identified direct savings associated with this business case. This business case supports the installation of equipment to support new customers.

There are no direct or indirect savings represented in the Growth business case. The Growth Business Case is driven by tariff requirements that mandate obligation to serve new customer load when requested within our franchised area. The business case also includes initial purchase of transformers, as well as electric and gas meters and devices which are on hand for immediate response for reliability and customer response reasons. The work utilizing this equipment is represented in various business cases.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no identified indirect savings associated with this business case. This business case supports the installation of equipment to support new customers.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Docusign Envelope ID: 825E3A90-F88A-407A-8DD3-5B461B3ADA81

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1:

In some instances, there may be alternative ways to serve a customer. Customer project coordinators and engineers determine the solution that best serves the customer while considering subsequent customers and Avista's infrastructure.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

We periodically review and update the line extension tariffs to ensure we are not creating excessive rate pressure in connecting new customers.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Work timeline is primarily driven by the request of the customer. The transfer to plant occurs monthly.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The Energy Delivery Director Team assumes the role of advisory group for the New Revenue – Growth Business Case, with quarterly reporting to the Board of Directors through the Financial Planning & Analysis department. The appropriate extension and service tariffs are designed and updated by the Avista Regulatory Affairs Department, in cooperation with Construction Services, and the Financial Planning & Analysis department. All Customer Project Coordinators are trained regularly, by Regulatory Affairs and Finance, on tariff application.

For the Electric and Gas New Revenue Expenditure Requests (ERs): Operations managers and directors receive monthly Cost of Service reports providing 12-month rolling average costs for the construction areas. This allows for review of trending of costs for decision-making regarding processes and resources.

For the Metering and Devices ERs: Monthly Capital ER and project results reports are distributed. These provide updated variance information facilitating oversight by the Electric Meter Shop and Gas Engineering department.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 414 of 535

Docusign Envelope ID: 825E3A90-F88A-407A-8DD3-5B461B3ADA81

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the New Revenue – Growth and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Signed by: Paul Good 8ADE2AA1AB5C4A9...	Date:	Aug-31-2024 | 3:40 PM PDT
Print Name:	Paul Good		
Title:	Director of Electric Operations		
Role:	Business Case Owner		
Signature:	Signed by: Josh DiLuciano A3C71874F6564DB...	Date:	Aug-30-2024 | 12:02 PM PDT
Print Name:	Josh DiLuciano		
Title:	VP Energy Delivery		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 415 of 535

DocuSign Envelope ID: 918EE9F0-FB94-48CF-B274-9A14F77F0E36

EXECUTIVE SUMMARY

The Capital Equipment Program (ER7005/7006) funds the essential tools required for Avista employees to perform work efficiently and safely. This equipment is necessary to construct, monitor, ensure system integrity, and properly repair and maintain the Avista systems (electric, gas, communications, fleet, facilities, and generation). This equipment needs to be fully functional and available for planned work as well as emergency outage repairs on our facilities and equipment. Capital tools are utilized in all service territories, and by all Crafts. Capital tools are required to execute and support work across all business units, and it is recommended to continually fund these tools at an annual level of $2.5M.

Capital tools benefit customers by reducing labor cost due to improved efficiency and improving quality of the work by advanced performance of the tools. Customers will also benefit from improved system reliability and reduced outage duration enabled by diagnostic tools. It is critical that capital tools are consistently and adequately funded year over year to maintain performance and ensure tool availability. The risk of not funding capital tools is reduced work performance, increased safety risk, reduced work quality, and increased outage time for customers.

DocuSign Envelope ID: 918EE9F0-FB94-48CF-B274-9A14F77F0E36

VERSION HISTORY

Version	Author	Description	Date
1.0	*Gary Shrope*	*Initial draft of original business case*	*4/28/2023*
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements*	

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	$2,500,000.00	
2026	$2,500,000.00	
2027	$2,500,000.00	
2028	$2,500,000.00	
2029	$2,500,000.00	

Project Life Span	***5 Years***
Requesting Organization/Department	Supply Chain
Business Case Owner | Sponsor	Cody Krogh | Kelly Magalsky
Sponsor Organization/Department	Supply Chain
Phase	Monitor/Control
Category	Program
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 417 of 535

DocuSign Envelope ID: 918EE9F0-FB94-48CF-B274-9A14F77F0E36

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Each year, the Capital Equipment Program has more requests for tools and equipment funding deficit prevents the purchase of all submitted requests. In addition, there is a trend of decreased funding for the capital tools. Over this same time period, the tool complement has been expanding by replacing manual tools with battery assist devices to increase safety and productivity. These additional tools are much more expensive. This requires more funding over time to support replacement costs, as well as ensure all areas of the company can take advantage of this technology. HIstorically the budget has not been fully funded resulting in reduced tool availability.

1.2 Discuss the major drivers of the business case.

The Capital Equipment Program (ER7005/7006) funds the essential tools required for Avista employees to perform work efficiently and safely. This equipment is necessary to construct, monitor, ensure system integrity, and properly repair and maintain the Avista systems (electric, gas, communications, fleet, facilities, and generation). Much of the capital equipment used in the utility industry is very specialized and may not be readily available due to long lead times. This equipment needs to be fully functional and available for planned work as well as emergency outage repairs on our facilities and equipment. Equipment failures contribute to injuries, slowdowns in work performance, and increased customer restoration time.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

This work is needed to ensure that our workers have safe and reliable tools that are necessary to complete their tasks, and also to ensure that if there are any tools that are broken, they can be replaced in a timely matter to keep projects/tasks on schedule. If this work is not approved/deferred the risks include breakage of equipment that is critical to daily operations/projects leading to longer lead times for repairs or project completion. Also, our employees need safe tools to ensure there are no injuries on the job. By having these updated through this program, we can increase our productivity by having tools that will allow us to complete our work efficiently on time and increase the safety of our employees.

DocuSign Envelope ID: 918EE9F0-FB94-48CF-B274-9A14F77F0E36

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization.

Capital equipment benefits customers by reducing labor cost due to improved efficiency and improving quality of the work by advanced performance of the tools. Customer will also benefit from improved system reliability and reduced outage duration enabled by diagnostic tools. It is critical that capital equipment is consistently funded year over year to maintain performance and ensure equipment/tool availability. The risk of not funding capital equipment is reduced work performance, increased safety risk, and reduced work quality.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

Attachment 1: Email by Tony Klutz describing the benefits of the Capital Equipment Program

Attachment 2: Scoring Criteria & Weighting

Attachment 3: Capital Equipment Committee Board Charter

Attachment 4: Capital Committee Notes

Attachment 5: Business Case Model / Offset Costs

For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

The safety project for ergonomic related battery assist tools was widely implemented in 2016. Since that time this number has increased to over 100 tools. This equipment has a 5-year warranty, so future failures for 5-year-old equipment will not be covered by the warranty. Replacements for these out of warranty tools will need to be budgeted for within the ER7006 budget each year, as per all additional "new" capital equipment.

2. PROPOSAL AND RECOMMENDED SOLUTION

- Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).

Option	Capital Cost	Start	Complete
[Recommended Solution] Alternative #1	$2.5 M	01/2025	*NA*
[Alternative #1] (Fully fund)	$2.5 M	01/2025	*NA*
[Alternative #2] (Partially fund based on priority)	varies	01/2025	12/2029
[Alternative #3] Rent equipment (0&M - $5,700,000)	O&M		

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

DocuSign Envelope ID: 918EE9F0-FB94-48CF-B274-9A14F77F0E36

2.1 Please summarize the proposed solution and how it helps to SOLVE THE BUSINESS PROBLEM IDENTIFIED ABOVE.

The proposed solution is to fully fund the capital equipment program. This ensures employees have the proper equipment available at all times to safely and efficiently perform their work. This will also improve system reliability and reduced outage duration for our customers.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

On average, the Capital Tool Program has more requests for tools and equipment than can be funded as shown below in Figure 1. The requests are prioritized, and tool selection is completed as described in Section 2.8. The funding deficit prevents the purchase of all submitted requests. In addition, there is a trend of decreased funding for the capital tools. Over this same time period, the tool complement has been expanding by replacing manual tools with battery assist devices to increase safety and productivity. Along with this, other more technical equipment is now being used such as Drones. These additional tools require more funding over time to support replacement costs.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

*** Not Apliccable to this Busines Case.

2.4 Summarize in the table, and describe below the INDIRECT offsets (Capital and O&M) that result by undertaking this investment.

Renting all equipment

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	Renting all Equipment	$	$	$	$	$
O&M	Renting all Equipment	$3,900,000	$5,700,000	$5,700,000	$5,700,000	$5,700,000

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

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Repair all equipment

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	Continually Repair all Equipment	($2,500,000)	$	$	$	$
O&M	Continually Repair all Equipment	$640,000	$640,000	$640,000	$640,000	$640,000

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1: Fund Program at Current Level (Recommended)

It is recommended that this Program be funded, annually, at its current level to ensure Avista has the proper capital equipment necessary to safely and efficiently perform all required work. This funding level is to cover inflation of current pricing, support increased tool complement as complement has increased in time, and support battery assist tools, drones, and other increasingly complex tools that have a higher cost. This funding also supports emergency replacement of tools due to mechanical failure, and unplanned tools needed to support changes in crew work structure. Due to the specialized nature of utility equipment, it is most efficient for Avista to equip employees with the necessary tools and equipment to safely perform timely emergency repairs, while using the same tools and equipment to perform ongoing scheduled work and maintenance. Furthermore, this specialized equipment is often only available directly from the manufacturer, and is not typically available as a rental.

By funding this Program, Avista ensures that employees have the proper equipment to safely and efficiently perform their work, while providing safe, reliable service to customers.

Option 1 will provide an approximate annual savings of $15M over Option 3 below, as shown in Attachment 5: Business Case Model / Offset Costs.

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Alternative 2: Partially Fund Program based on priority

This option is not the preferred approach over the long-term; however, it is exercised when necessary. Each year, when the requests for tools and equipment are submitted, cuts to the Capital Equipment Program are made by the business units to bring the projected cost of the list of equipment and tools into line with the budgeted amount. Further modification of the funding level for the Program is performed in concert with other business budget needs.

When the program budget needs to be reduced, reductions are first made to requests in the category of enhanced productivity, then replacement. Replacement is intended to replace aging units to achieve more predictable capital requirements and avoid replacement peaks caused by large-scale failures. Cutting into these requests over an extended period leads to reduced efficiency and may have safety impacts. This has caused excessive rollovers each year, which build up extensively when they are not able to be purchased within the current budget cycle. This leads to a buildup in capital equipment requests that cannot be adequately funded. For 2023 there were $1M of requests that were not able to be funded due to budget reduction.

Having the ability to test and incorporate equipment that falls within the enhanced productivity category helps support improved processes and leads to enhanced safety and longer equipment lifecycles.

Alternative 3: RENT EQUIPMENT

Renting of the capital equipment was considered as a possible alternative. Considering the total tools, only a small percentage are available to rent, while nearly all tools are needed on hand at all times for emergency locates and repairs. This leaves very few items that qualifiy as potential rental equipment (see Figure 3).

If equipment is rented, there is no guarantee of availability. Rental companies rent equipment on a first-come, first-served basis, making equipment scheduling for specific time sensitive jobs very difficult. Safety and compliance regulations are also affected when correct equipment is not available for rent.

Equipment failure is often a concern with rental equipment, as it is uncertain what condition rental equipment is in, or how it has previously been maintained. This can lead to safety issues for equipment operators when failures occur, as well as lost production time.

Depending on the timeline of the rental equipment, it would not be cost effective to rent long-term as the rental costs would exceed the base price of new equipment. An average rental price is $700 per month or $8400 per year which exceeds the cost of the tool purchase.

Training on rental equipment would also be required, if different than standardized Avista equipment. For example, Avista gas employees are only trained/qualified on specific equipment

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that has been standardized by Avista, which may or may not be what can be rented for specific jobs. This can contribute to added time necessary to qualify employees on the operation of the equipment, and safe operating procedures.

Due to the Department of Transportation (DOT) compliance, Avista is also required to maintain maintenance and calibration records for all gas equipment, along with operations guides for all on-site equipment. Avista would be out of compliance using various rental equipment as rental companies are not required to provide this documentation for their equipment to their customers.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

The Capital Tool Program has more requests for tools and equipment than can be funded as shown below in Figure 1. The requests are prioritized, and tool selection is completed as described in Section 2.2. The funding deficit prevents the purchase of all submitted requests. In addition, there has been a trend of decreased funding through 2020. The decreased budget has also impacted the requested funds as departments must be more judicious to align with budget. Over this same time period, the tool complement has been expanding by replacing manual tools with battery assist devices to increase safety and productivity. Along with this, other more technical equipment is now being used such as Drones. These additional tools require more funding over time to support replacement costs.

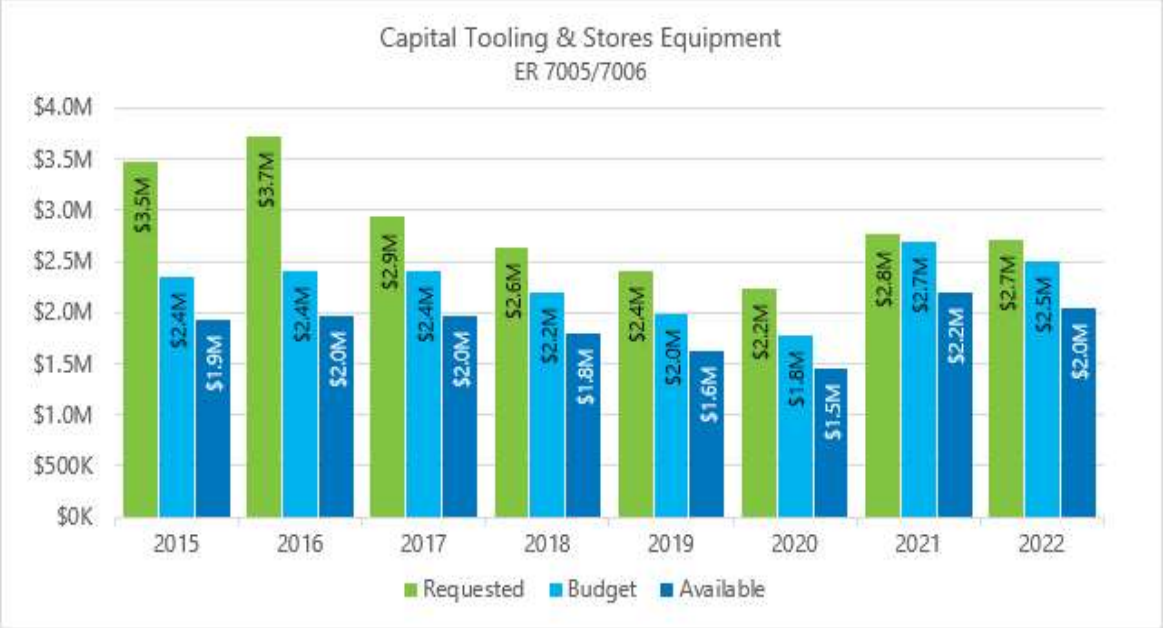

Figure 1

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The distribution of Capital Equipment funds by the Business Unit is shown below in Figure 2. The allocation is based on overall tool ranking and priority rather than a set allotment by department. As a result, there is variation year over year (as noted in the graph) ensuring that the most critical tools request by all departments are funded.

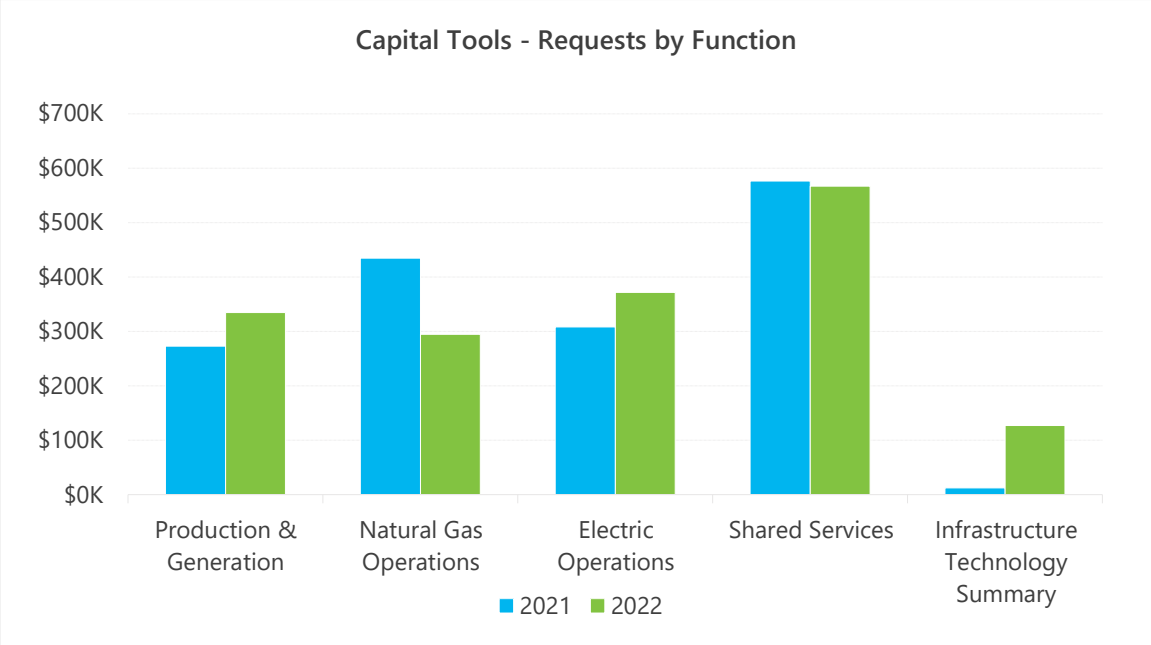

Figure 2

The 2022 capital tool breakdown by investment driver is represented below in Figure 3. The highest percent of spend (39.5%) was for tools related to Safety and Compliance. This category is also the highest-ranking investment driver. Spend in this area is related to changing industry compliance standards and tools identified to improve safety or ergonomics (improved body posture, reduced exertion of force, and reduction in frequency).

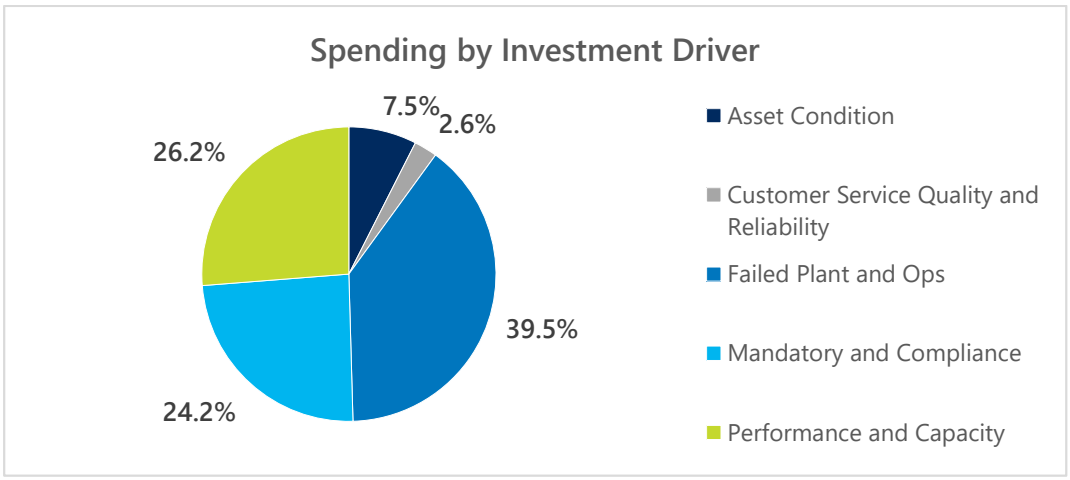

Figure 3

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 424 of 535

DocuSign Envelope ID: 918EE9F0-FB94-48CF-B274-9A14F77F0E36

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

An updated process outlined below was created in 2019, and is now fully implemented. The program is projected for five (5) years to account for equipment/tool life cycle and replacements. The planning and execution of the program is managed by the Supply Chain Department. Tools are received and delivered to internal customers and immediately become used and useful, this program has been ongoing for decades.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The Capital Equipment Committee (CEC) ensures that the investment successfully addresses all capital equipment requests to ensure each is warranted. The CEC also ensures that each request is prioritized based upon importance of need and equal allocation of funds for capital equipment requests.

An updated process was created in 2019 and was fully implemented in 2020. The process begins by requesting Business Unit Managers to upload their tool needs into a SharePoint site. As part of the tool submittal the Manager must complete several ranking criteria used to support the business need for the tool. These criteria are Priority, Current State, Investment Driver, Strategic Alignment, Stakeholder, and Demand Type. The Managers' requests are then routed to the respective Business Unit Directors for approval. For a detailed breakdown of the criteria see reference document "Scoring Criteria & Weighting" (see attachment 2).

The final list from each Business Unit is then reviewed by the CEC to ensure funding is distributed fairly and impartially across the company. The equipment request list is ranked per the scoring criteria ensuring all equipment is funded in order of ranking. This is required to prioritize spending as the total equipment requests exceed the allocated budget. Decision records and meeting notes are maintained on the SharePoint site once the CEC finalizes the list and purchasing is ready for execution.

2.8.1 Capital Equipment Steering Committee

The final requested tool list from each Business Unit is then reviewed by the Capital Equipment Committee (CEC) to ensure funding is distributed fairly and impartially across the company. The tool list is ranked from the scoring criteria to make certain the tools are funded in order of ranking. Ranking is required because the total tool requests exceed the allocated budget. Purchasing begins executing purchases starting with the highest priority scoring.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 425 of 535

DocuSign Envelope ID: 918EE9F0-FB94-48CF-B274-9A14F77F0E36

The governance process is documented in the Capital Equipment Committee Board Charter (See attachment 3). In summary it is guided by the following scoring criteria:

Priority, Current State, Investment Driver, Strategic Alignment, Stakeholder, Demand Type and Age of request. Each of these scoring criteria are weighted to help place the requests in order of high to low importance.

Those who provide oversight will be those who make up the Capital Equipment Committee Board (these members are nominated annually by Directors). These members will help to ensure that the funding for capital equipment is distributed fairly and impartially based on the needs of Avista.

The following are those members that make up the board composition:

Tool Keeper (Gas):	Voting Member
Tool Keeper (Elec):	Voting Member
Safety & Health Coordinator:	Voting Member
Electric Operations Manager:	Voting Member
Gas Operations Manager:	Voting Member
Generation & Production Manager:	Voting Member
Capital Planning Group Member:	Voting Member
Supply Chain Manager:	(Non) Voting Member
Capital Equipment Sourcing Professional:	(Non) Voting Member

DocuSign Envelope ID: 918EE9F0-FB94-48CF-B274-9A14F77F0E36

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Capital Equipment Program (ER7005/7006) and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Cody Krogh 72D171DBE3F04F8...	Date:	May-14-2024 | 9:21 AM PDT
Print Name:	Cody Krogh		
Title:	Manager Supply Chain		
Role:	Business Case Owner		

Signature:	DocuSigned by: Kelly Magalsky E7A0F731C49442B...	Date:	May-14-2024 | 9:42 AM PDT
Print Name:	Kelly Magalsky		
Title:	Director Shared Services		
Role:	Business Case Sponsor		

Signature:	DocuSigned by: Steve Carrozzo 5C2EBA48E6634F6...	Date:	May-14-2024 | 7:01 AM PDT
Print Name:	Steve Carrozzo		
Title:			
Role:	Steering/Advisory Committee Review		

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EXECUTIVE SUMMARY

For decades, several of Avista's most critical operations have been located on the 4th floor of Avista's General Office Building on the Mission Campus. This includes departments such as Transmission System Operations, Supervisory Control and Data Acquisition, Distribution Operations, Gas Control, Network Operations, Security Operations, and 24-hour Call Center Reps. Over time, as each of these departments experiences new growth due to ever-changing utility requirements and/or initiatives, capacity has been reached in their available square footage. Due to our current space constraints, we have handicapped our ability to manage storm events, narrowly meet government regulations, and created an inaccessible and ergonomically unfriendly working environment. These risks we run necessitate a need for a new space for our critical operations group.

Meanwhile, our Generation Control Center, which monitors the 5 dams along the Spokane River, is in a leased space at the Seehorn Building in downtown Spokane. The urban setting surrounding the control center has led to a heightened risk of criminality and unauthorized access for our Seehorn Building operations and employees. Located on the second floor of the commercial retail building, the control center only has one layer of defense in the form of a controlled access man door. Employees need to park a couple of blocks away from the building and their unsecured walk to the building is an employee security concern. Moving the Generation Control Center to a safe and secure Avista-owned space alongside the other critical operations group is imperative.

The recommended solution at this time is to relocate the GCC group to an Avista-owned facility and renovate the 4th floor of Mission. Relocating the GCC will allow for a purpose-built control center facility, with ample space for their current needs, reduce security risks, and remove us from a costly O&M lease. Renovating the 4th floor will allow for each group to expand and upgrade our technology to meet industry standards. A **rough-order-magnitude estimate of approximately** $8.5M spread over three years is estimated for design and construction. The other solutions evaluated by an Advisory Group, are also listed in this business case. Since this facility will support Avista functions in all service territories, the jurisdiction is slated to be Common Direct–Allocated All.

The three-year timeline will provide the opportunity to design and execute the recommended solution. With a project of this magnitude, many stakeholders and groups will be affected during the design phase in the first year of the project, with construction/execution occurring over the last two years. It is recommended to proceed with this business case as soon as possible to avoid any potential reliability risks that may occur in the future. The Facilities Capital Steering Committee approved the submission of this Business Case.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 428 of 535

DocuSign Envelope ID: 4315A7D0-2B60-48F5-AEF3-4E42B950730B

VERSION HISTORY

Version	Author	Description	Date
0.0	Vance Ruppert	Executive Summary Only	07/10/2020
1.0	Vance Ruppert	BCJN Update with 2021 Revisions	07/09/2021
2.0	Lindsay Miller	BCJN Update with 2022 Revisions	05/24/2022
2.1	Conor Craigen	BCJN Update	08/31/2022
3.0	Conor Craigne	Template + BCJN Update	04/14/2023
4.0	Conor Craigen	Template + Solution Update	04/12/2024
BCRT			*Steve Carrozzo 4/30/2024*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$516,500**	**$0**
2025	**$2,250,000**	**$0**
2026	**$2,250,000 + $3,500,000**	**$8,516,500**
2027	**$0**	**$0**
2028	**$0**	**$0**
2029	**$0**	**$0**

Project Life Span	***3 year***
Requesting Organization/Department	Facilities Management Group – H07
Business Case Owner | Sponsor	Eric Bowles | Kelly Magalsky
Sponsor Organization/Department	Shared Services
Phase	Planning
Category	Project
Driver	Performance & Capacity

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 429 of 535

DocuSign Envelope ID: 4315A7D0-2B60-48F5-AEF3-4E42B950730B

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

Avista's critical operations consist of Transmission System Operations (SO), Supervisory Control and Data Acquisition (SCADA), Distribution Operations (DO), Gas Control (GC), 24-Hr Customer Service Representatives (CSR), Network Operations Center (NOC), Security Operations, and Generation Control Center (GCC). Currently, the majority of these groups are located on the 4th floor of the General Office Building on the Mission Campus with the exception of the GCC. The Generation Control Group is located in downtown Spokane in a rented space in the Seehorn Building. Within these departments, there are staffing roles that are standard business hours, and roles that require 24-Hr shifts. The standard business hour support staff are critical to the department's functions and ideally, would be included in, or adjacent to, the secured space of the 24-hr operations staff, but this is not required.

There are several current problems that are meant to be addressed by this business case. The primary business problem is space limitations within each group. Compounding the issue is that departments have grown and plan to continue to grow. The 24-Hr shift jobs all have unique and specific tasks that require "operator style" workstations that are larger and more complex than the standard 6x9 (54 square feet) office cubicle. The modern operator workstation requires 600 square feet (SF) of total space. Due to this, and future growth, which will be expanded upon in this business case, their current allocated square footage cannot be reconfigured or remodeled to accommodate these future needs.

The SO control room was working comfortably in a space designed for a Transmission Operator Desk, Reliability Operator Desk, and Backup Operator Desk. In 2022 Avista entered the Energy Imbalance Market (EIM) which stuffed an EIM Operator desk into the middle of the SO control room. The once workable room has now become overcrowded and non-ADA accessible. The SO control room needs to be expanded and reconfigured to efficiently accommodate all four operator desks. This cannot be achieved in its current location as all space within the building has been utilized. Outside of the control room but still inside the physical security perimeter (PSP), all space for offices and cubicles is utilized. The SO department has one Training Coordinator responsible for about 2,000hrs/yr of training for the staff of 18. Similar-sized utility companies staff 2-3 Training Coordinators. The SO department also has only one Outage Coordinator responsible for both transmission and generation outages, and writing/rewriting roughly 2000 documents per year to support these outages. Like the Training Coordinator, similar-sized utility companies staff 2-3 Outage Coordinators. The EIM added additional work for the outage coordinator to update with a third-party system, PCI Energy Solutions. Inaccurate or missed entries could result in lost revenue or fines. The SO department would like to add a Training and Outage Coordinator, but the space constraints within the PSP space will not allow for such growth.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 430 of 535

DocuSign Envelope ID: 4315A7D0-2B60-48F5-AEF3-4E42B950730B

SCDA shares the same space within the PSP with the SO group. There are eight areas of expertise within the SCADA department. The SCADA team is only staffed with 8 engineers/techs supporting these eight areas. Similar-sized utility companies staff 16-20. The insufficiently staffed SCADA department runs a risk to grid reliability by not being able to quickly restore functionality in under 30 minutes. With a SCADA team staffed with knowledgeable and trained resources at insufficient levels, Avista SCADA resources cannot adequately support the timely update of SCADA infrastructure systems, placing grid cyber security at risk. In order for SCADA to get to a sufficient and sustainable support staff for the eight areas of expertise, they need to hire 11 engineers by 2028. These engineers should be located in the PSP alongside the areas they support. The current location will not allow for this growth.

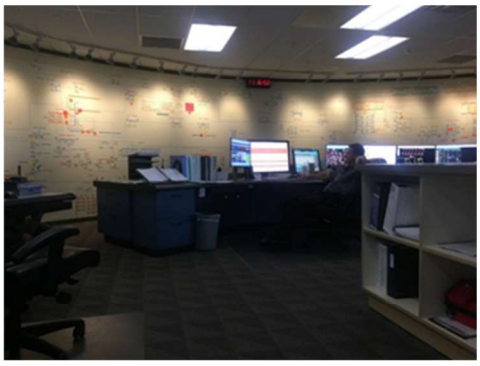
The DO dispatch space is a second PSP location that has become overcrowded not because of growth, but because half of their space was taken away in a space reconfiguration. A third of that space was taken over by the SCADA office area which currently sites west of the DO, and the remaining space was given to the CSRs to add two additional desks. In their reduced space the DO is not set up for proper storm response. They currently could not support a similar 2015 storm event if it were to happen today. In 2015 the DO could staff 6 dispatch operators and 6 assistants. Today they can staff 6 dispatch operators and 2 assistants. During an event, solo operators run the risk of losing a crew's locations in the field by not being able to keep them current in the system. When a crew is discovered "lost", work stops and all crews in the field must return to the campus and regroup. This could result in a lost day of work and an extended outage. A lost day in a recent 2021 Windstorm event cost the company $5M. A worst-case scenario could happen if a line is energized that an undiscovered "lost" crew is working on. The fatality of a lineman could cost the company millions plus the incalculable toll on their family, friends, and colleagues. The current space constraints would put the DO group in a difficult situation if they ever lost their outage management tool (OMT) program, which does not have a backup system. They would need to resort to 21 3'x4' printed maps of Avista's distribution system. There is no table or desk space to view plans in the DO area. The DO is in the process of updating its OMT program to the new Advanced Distribution Management System (ADMS). This new system will require new employees to manage the system in an area with no room for expansion. The current forecast for new employees required for the ADMS system sits at 15 (SCADA (6), DO (4), ET (3), GC (2)), all being required to sit in the PSP with the possible exception of ET.

The GC group is in the PSP area alongside the DO group. Governed by the Pipeline and Hazardous Materials Safety Administration (PHMSA), they have a long list of requirements regarding fatigue, environmental setting, and ergonomic factors that need to be met. Even in their cramped quarters next to the distractions of the DO dispatch group they are loosely compliant with all PHMSA regulations. A separate dedicated space would allow the GC to better comply with these PHMSA regulations. The GC group needs to add another Mobile Dispatch System Administrator desk to support the upcoming expansion of digital workflow anticipated with the ADMS. This will be difficult to achieve in a space with no room to expand.

DocuSign Envelope ID: 4315A7D0-2B60-48F5-AEF3-4E42B950730B

The second business problem being addressed is technology limitations and upgrades. The existing SO control room was constructed in the 1950s. Several upgrades have been made over time, but the Map Board Display Control System is from the 70s and requires a lot of manual labor to maintain and update. It takes three staff members to update the map board. An operator has to manually scrape off the tap of the old diagram, fill in the many light node holes, retape the new diagram, and drill in new node light holes. Behind the map board, a tech engineer has to physically rewire the new system, while SCADA updates their system. This labor-intensive process can take up to 5+ days to complete. The SO group runs the risk of making a switching mistake during this update process because an area of the system is depicted three times during the transition; the old diagram, a temporary paper plan drawing depicting the new diagram posted on the map board, and the newly tapped diagram. A single point in the system could be tagged three times during this process. If the system gets mistagged, a switching mistake could be made which would lead to damaged equipment and a customer outage. Replacing a damaged transformer ranges from $5M-10M.. Outages could also lead to daily fines in certain service areas.

The parts for the old 70s map board are also becoming obsolete. The magnetic tiles that comprise the face of the map board are no longer available. The SO has 10 spare tiles remaining.



The positioning of the map board is also an issue as it sits low in relation to the workstations. This results in poor sight lines for the operators to see critical information. The 9' ceiling height is the highest elevation the building will allow. Current control room map walls today are using central LED video display systems displaying critical information, at elevations of 15', providing situational awareness from any point in the room.

Another issue is that a single operator desk commonly requires 12+ dedicated network drops to run all the systems required. It is becoming increasingly difficult to expand desk space and expensive to retrofit the technology to enhance these systems. Many operator desks require 8 to 12 computer monitors, which limits views to their shared department displays. These limited and confined workspaces inhibit operator interactions, create ergonomic issues, and hinder technology.

A third business problem is operation safety and security. The GCC group is located in the rented Seehorn building in downtown Spokane. Having a critical operations control center in a public building surrounded by urban development increases the security risk of our operations and our employees.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 432 of 535

DocuSign Envelope ID: 4315A7D0-2B60-48F5-AEF3-4E42B950730B

1.2 Discuss the major drivers of the business case.

The major driver of this business case is Performance & Capacity, with aspects of Service Quality & Reliability and Asset Conditions. Avista's critical operations need to be at the forefront of performance and reliability, especially during an outage, emergency, or customer event. It is imperative that these critical functions remain operational and maximize effectiveness for the benefit of all our customers. Due to our current space constraints, we have handicapped our ability to manage storm events, narrowly meet government regulations, and created an ergonomically unfriendly working environment. The outdated conditions of all these departments to meet the growing needs and requirements of the system become another minor driver of this business case.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

With the business problems described above, our critical operation groups are asked to carry a heavy burden. We are currently not accommodating their needs well, let alone their future need for growth. A new space specifically designed for their operations is needed. This new space would improve our ability to manage major events, better meet government regulations, and provide reliable support to our current/increasing systems. We currently run the risk of delaying power outages, fines from untimely grid restorations, lagging behind cyber security threats, not being able to meet government regulations, and physical harm to our employees. The longer the business case is not implemented, the greater the risk that Avista will be forced to implement a solution that would be reactive, and not proactive. Any reactive solution would probably have a higher capital expense than the alternatives in the business case, and might even carry significant O&M expenses (i.e. rented space/building).

DocuSign Envelope ID: 4315A7D0-2B60-48F5-AEF3-4E42B950730B

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

The major reason to perform this project is to align with Avista's strategic vision of customer performance and reliability. It is also beneficial to new initiatives such as the Energy Imbalance Market, who will be primarily housed within this new Critical Operations Facility.

A secondary reason, if a new facility solution is selected, is to recoup office space at the Mission Campus to aid in the net employee growth that Avista has seen throughout the last 10 years. Bringing Avista employees together in person provides a collaborative environment to grow and work together. This might also provide relief from having to maintain other Avista sites no longer needed or lease off-site office space in the years to come.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

- R.E. Lamb, Inc.'s 2023 Control Room Site Evaluation Final Report. Available upon request (Facilities/ Conor Craigen).

Avista hired Robert E. Lamb, Inc. to perform a study on our critical operations groups, available existing buildings, and provided a report on their study. R.E. Lamb is a full-service planning, design, and construction firm for industrial, manufacturing, utility, and transportation clients. They have completed over 500 high-reliability utility control center projects in the United States. R.E. Lamb's team interviewed our critical operations group listed above gathering information on their operations, needs, and future growth. Their team toured five existing locations; Mission Main Office 4th floor, Service Building, Ross Park, Spokane Valley Call Center, and the Downtown Project Center. They looked into existing conditions, space layout, infrastructure, and security. Arising out of R.E. Lamb's final report, we learned our critical operations group's space needs, which existing locations are feasible, rough order magnitude budget estimates, and how we compare with industry standards.

R.E. Lambs considered all the requests from the GCC, SO, SCADA, DO, GC, CSR, NOC, and Security groups and created a space program. Their results suggested a new greenfield critical operations facility meeting current industry standards would need to be 64,402 SF. The critical operations spaces totaled 24,356 SF (GCC, SO, SCADA, DO, GC, & CSR). The current footprint of these groups is around 14,500 SF. This space program is a good benchmark for space planning but will be refined to better meet our needs. Lamb estimated this new greenfield building would cost $55M+. The estimate did not include any land purchase or site work.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

DocuSign Envelope ID: 4315A7D0-2B60-48F5-AEF3-4E42B950730B

Based on the space program we know that the Mission 4th Floor and Spokane Valley Call Center do not offer enough square footage for all our critical operations groups to expand or sufficiently upgrade technology. Ross Park and The Downtown Network Project Centers locations in regard to the general public raised too many security threats to be considered a good location for our critical operations. The 1st Floor of the Service Building was considered manageable, but it would require space compromise, business disruptions, and accepted risks as compared to a purpose-built greenfield option.

We took this knowledge and investigated three locations here on our main Mission Campus, as well as a new offsite greenfield building. The onsite options are as follows; renovate the east half of the Service Building's 1st floor, add a 2nd story to the east half of the Service Building, and build a new greenfield building in the center of campus between the parking garage, auditorium, and Service Building or at the location of the Warehouse yard.

- Wolfe Architectural Groups 2023 Critical Operations Facility Mission Campus Conceptual Design and MACC Estimating Group Commercial Building Shell Cost Study Estimate. Available upon request (Facilities / Conor Craigne).

A code study was performed and it was determined that a new building could be placed in the center of our campus. Multiple new building renderings were created and generic commercial building estimates were developed.

- 24-Hour Operations Facility - Major Requirements Matrix – July 2020 Update of a July 2018 document. Available upon request (Facilities / Conor Craigen).

- 2005 study of possible control center for 24-Hour operations, "Avista Utilities Facility Planning Study". Available upon request (Facilities / Conor Craigen).

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 435 of 535

DocuSign Envelope ID: 4315A7D0-2B60-48F5-AEF3-4E42B950730B

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The current proposed solution is divided into two plans. In place of a new facility housing and expanding all our critical operations groups, the focus will be moving the GCC to an Avista-owned space and renovating the Mission 4th Floor to improve the critical operations groups space.

Part 1

The north annex building of the Downtown Project Center has sat vacant since acquired by Avista. It offers ample room, 5,125 SF, for the GCC group which operates is 3,400 SF. The building would require a major renovation to function as a control center. The building would need to be gutted to the studs to allow for a proper layout. The electrical and HVAC systems would need to be completely redone to bring them up to code and capacity. The perimeter security fencing would need to be modified due to the fact the east side of the building sits outside the secured perimeter. The fiber line and all IT components would need to be introduced to the building. This renovation option will allow for optimal layout and security, and most importantly remove Avista from an undesirably leased space. The initial high-level cost estimate for the project is $4,987,500 broken out into $516,500 for design and $4,471,000 for construction. Facilities is requesting design dollars in 2024 so that construction may begin in 2025. It should be noted that Avista needs to give a two-year notice to the Seehorn landlord to break the lease.

Part 2

Mission 4th Floor houses the remainder of our critical operations groups. We propose to completely renovate the 4th floor to create more space for each group and bring their technology up to date. For this to work we would need to relocate 80 non-critical operations employees off the 4th floor. Facilities request to retain the $3,500,000 allocated for this work to commence in 2026.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 436 of 535

DocuSign Envelope ID: 4315A7D0-2B60-48F5-AEF3-4E42B950730B

Proposed	Capital Cost	Start	Complete
GCC DTPC North Annex Relocation	$4,987,500	2024	2026
Mission 4th Floor Renovation	$3,500,000	2026	2026
Total	$8,487,500	2024	2026

Notes:

1. See Appendix A for GCC North Annex estimate breakdown of proposed capital costs shown in the table above.
2. Since there is no path forward, these values are considered a Class 4 estimate as per the Cost Estimate Classification Matrix by the Association for Advancement of Cost Estimating (AACE). See Appendix B for further information and a copy of the AACE Matrix. A Class 4 cost estimate is considered to have only 1% to 15% of the project definition completed, with an expected accuracy range 30% below to 50% higher of the capital cost shown.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

There are no additional analyses or metrics at this time.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	N/A	$	$	$	$	$
O&M	Seehorn Lease	$175,000	$175,000	$175,000	$175,000+	$175,000+

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 437 of 535

DocuSign Envelope ID: 4315A7D0-2B60-48F5-AEF3-4E42B950730B

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	N/A	$	$	$	$	$
O&M	N/A	$	$	$	$	$

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

See Appendix C for cost estimate breakdowns of Alternative 1- 3's capital costs shown in the tables below.

Since there is no path forward, these $59M-$23M values are considered a Class 4 estimate as per the Cost Estimate Classification Matrix by the Association for Advancement of Cost Estimating (AACE). See Appendix B for further information and a copy of the AACE Matrix. A Class 4 cost estimate is considered to have only 1% to 15% of the project definition completed, with an expected accuracy range 30% below to 50% higher of the capital cost shown.

Alternative 1:

Alternative	Capital Cost	Start	Complete
Option 1: Greenfield facility on new property.	$59.9M	2025	2028

Option 1 considers a new 45,000 SF building, on a newly acquired 40-acre piece of land estimated at $15.6M. The most expensive option but all groups could be accommodated, all security risks could be eliminated, and there would be no disruptions to other Avista operations.

Alternative 2:

Alternative	Capital Cost	Start	Complete
Option 2: Service Building 2nd floor east side addition.	$30.9M	2025	2028

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

DocuSign Envelope ID: 4315A7D0-2B60-48F5-AEF3-4E42B950730B

Option 2 considers a 30,000 SF 2nd Floor addition to the Service Building. All critical operations groups would be accommodated, security risks would be limited, and existing Mechanical/Electrical/Plumbing (MEP) infrastructure is already in place, but operations inside the Service Building would be greatly affected. Employees would temporarily need to be relocated or work from home during construction.

Alternative 3:

Alternative	Capital Cost	Start	Complete
Option 3: Service Building 1st floor east side remodel.	$23.8M	2025	2028

Option 3 considers a 20,500 SF remodel of the Service Building 1st Floor. All critical operations groups would be included, but not at the ideal capacity, and there would be little room for future growth. Security risks would be limited, and existing MEP infrastructure is already in place. Hundreds of employees utilizing this space would need to be relocated, and Avista currently does not have enough office space to accommodate a relocation this size.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

At this time, the only measure that can be used is to design solutions that provide room for growth, expands technology requirements, and adheres to safety and security best practices. Some of these solutions would include items such as:

1) Materials/ Storage: Provide spaces that meet the needs of the Stores team and Operations
2) Environmental/ Compliance: Ensure that the building and site meet Avista's environmental standards
3) Employee/ Customer Impacts: Room for employee or operations growth
4) Operational Efficiency: Ensure that the operational needs of employees are being met
5) Asset Condition: Provide systems and materials that meet Avista standards

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

This business case is considered a project, as it is not intended to be an ongoing project beyond 2027. The major milestones and timeline of the project are estimated to be the following:

Complete Design Drawings: 2025

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 439 of 535

DocuSign Envelope ID: 4315A7D0-2B60-48F5-AEF3-4E42B950730B

Note: Based on the technology selected and the operator station complexity of the control room designs, completion for the overall design drawings could extend out at least a year.

Bidding/permits complete, General Contractor (GC) selection: 2025

GC begin construction: 2025-26

GC completed construction, and receive Certificate of Occupancy: 2027

Install Furniture, Fixtures, and Equipment: 2027

Testing of all systems: 2027

Move into the new facility: 2027

Note: Based on the technology selected and the operator station complexity of the control room, completion of the control room IT/ET/SCADA systems and FF&E could extend out at least a year.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

A. The Facilities Steering Committee (SteerCo) shall consist of the following: Kelly Magalsky, Alicia Gibbs, Alexis Alexander, David Howell, Paul Good, Jeremy Gall, Mike Magruder, Vern Malensky, and Bruce Howard.

B. Advisory Groups that assisted in shaping this Business Case consisted of the following stakeholders:

- Facilities: Eric Bowles, Conor Craigen, and Annie Lundy
- Kelly Magalsky, Director of Shared Services
- Mike Magruder, Director of Transmission Ops & System Plan
- Alexis Alexander, Director of IT and Security
- Alicia Gibbs, Director of Natural Gas
- Clay Storey, Director of Security
- Jennifer Esch, Director of Customer Service
- Chuck Benson, Chief Systems Operator
- Reuben Arts, Manager of Distribution Operations
- Craig Figart, Manager SCADA/EMS
- Tim Mair, Manager of Gas Control and Service Dispatch
- Nicola Hostetler, Manager of Operations Support and Gas Control
- Ryan Bean, Manager Spokane River Hydro
- Mike Mecham, Manager Plant Ops Thermal
- Andrea Pike, Manager of Customer Service

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 440 of 535

DocuSign Envelope ID: 4315A7D0-2B60-48F5-AEF3-4E42B950730B

C. The project shall use certain Project Management Professional (PMP) guidelines and procedures during the course of this project.

A Project Execution Plan, consisting of the documents below, will be drafted and approved by the SteerCo described in Section 2.8 (A).

- Project Charter, Change Management Plan, Communication Management Plan, Cost Management Plan, Procurement Management Plan, Project Team Management Plan, Risk Management Plan and Risk Register, Schedule Management Plan, Scope Management Plan, and Project Execution Approval Form.

Each month, the project manager will provide the following information either at the scheduled SteerCo meeting, or via email.

- Approved Yearly Budget, Accrued Yearly to Date, Year Estimate at Complete, Year Variance at Complete, Approved Lifetime Budget, Accrued Life to Date, Lifetime Project Estimate at Complete, and Lifetime Project Variance at Complete.

Each month, the SteerCo will make decisions on cost, scope, or budget items as required by the Project Execution Plan. The project manager reserves the right to present items not outlined in the Project Execution Plan if he/she determines its importance is relevant to SteerCo input.

D. The final decisions regarding these items, especially certain change requests as required by the Project Execution Plan, will be presented to, and voted upon by the SteerCo. The decisions will be documented in a monthly meeting minutes of the SteerCo for documentation and oversight.

It will be the Project Manager's role to monitor the scope, budget, and schedule and present the results to the SteerCo, regardless if they are within tolerances, or not.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 441 of 535

DocuSign Envelope ID: 4315A7D0-2B60-48F5-AEF3-4E42B950730B

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Central 24 HR Operations Facility business case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Eric Bowles 4ACC7[illegible]	Date:	May-02-2024 | 9:58 AM PDT
Print Name:	Eric Bowles		
Title:	Corp. Facilities Manager		
Role:	Business Case Owner		

Signature:	DocuSigned by: Kelly Magalsky E7A0F[illegible]	Date:	May-03-2024 | 3:18 PM PDT
Print Name:	Kelly Magalsky		
Title:	Director of Shared Services		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 442 of 535

DocuSign Envelope ID: 4315A7D0-2B60-48F5-AEF3-4E42B950730B

Central 24 HR Operations Facility

Appendix A - Critical Operations Facility Level 4 Estimate

New Greenfield on Mission Campus[6]

Scope	Cost
Site and Building Construction[3] (**40,500 SF**)	$17,875,000.00
Well water MEP[1]	$222,040.00
SCADA & GCC Data Room[2]	$1,800,000.00
Backup Power	$2,500,000.00
FF&E[1]	$2,250,000.00
Tax (9 %)	$2,218,233.60
Control Room Design[5]	$150,000.00
Building Design[1]	$1,248,975.00
ET[1]	$2,775,500.00
Avista Labor[1]	$455,182.00
Benefits[1]	$414,104.60
Overhead / Contingency / AFUDC (10%)[1]	$3,190,903.52
Warehouse Relocation Project	$2,000,000.00
Total	**$37,099,938.72**

New Greenfield on New Property

Scope	Cost
Site and Building Construction[3] (**45,000 SF**)	$20,627,000.00
Well water MEP[1]	$222,040.00
Corp. Data Center, SCADA & GCC Data Room[2]	$5,400,000.00
Backup Power	$2,500,000.00
FF&E[1]	$2,250,000.00
Tax (9 %)	$2,789,913.60
Property[4] (40 acres)	$15,600,000.00
Control Room Design[5]	$150,000.00
Building Design[1]	$1,248,975.00
ET[1]	$2,775,500.00
Avista Labor[1]	$455,182.00
Benefits[1]	$414,104.60
Overhead / Contingency / AFUDC (10%)[1]	$5,443,271.52
Total	**$59,875,986.72**

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 443 of 535

DocuSign Envelope ID: 4315A7D0-2B60-48F5-AEF3-4E42B950730B

Central 24 HR Operations Facility

Service Building 2nd Floor East Side Addition

Scope	Cost
Building Construction[3] (**30,000 SF**)	$12,614,000.00
Existing Building Structural Retrofit	$675,000.00
Well water MEP[1]	$222,040.00
SCADA & GCC Data Room[2]	$1,800,000.00
Backup Power	$2,500,000.00
FF&E[1]	$2,250,000.00
Tax (9 %)	$1,805,493.60
Control Room Design[5]	$150,000.00
Building Design[1]	$1,248,975.00
ET[1]	$2,775,500.00
Avista Labor[1]	$455,182.00
Benefits[1]	$414,104.60
Temp relo workers[1]	$1,110,200.00
Overhead / Contingency / AFUDC (10%)[1]	$2,802,049.52
Total	**$30,822,544.72**

Service Building 1st Floor East Side Remodel

Scope	Cost
Building Construction[3] (**20,500 SF**)	$7,394,000.00
Well water MEP[1]	$222,040.00
SCADA & GCC Data Room[2]	$1,800,000.00
Backup Power	$2,500,000.00
FF&E[1]	$2,250,000.00
Tax (9 %)	$1,274,943.60
Control Room Design[5]	$150,000.00
Building Design[1]	$1,248,975.00
ET[1]	$2,775,500.00
Avista Labor[1]	$455,182.00
Benefits[1]	$414,104.60
Temp relo workers[1]	$1,110,200.00
Overhead / Contingency / AFUDC (10%)[1]	$2,159,494.52
Total	**$23,754,439.72**

1. 2021 Business Case Estimate +Inflation
2. R.E. Lamb, Inc Estimate
3. MACC Estimating Group Estimate
4. Avista Real Estate ROM Estimate: $130k-650k/acre, used $390k/acre
5. Mauell Corporation ROM Estimate: $50k/Control Room
6. Located on north half of warehouse yard.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 444 of 535

DocuSign Envelope ID: 4315A7D0-2B60-48F5-AEF3-4E42B950730B

Appendix B – Cost Estimate Classification Matrix per the Association for Advancement of Cost Estimating (AACE)

	Primary Characteristic	*Secondary Characteristic*			
ESTIMATE CLASS	**LEVEL OF PROJECT DEFINITION** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]	**PREPARATION EFFORT** Typical degree of effort relative to least cost index of 1 [b]
Class 5	0% to 2%	Concept Screening	Capacity Factored, Parametric Models, Judgment, or Analogy	L: -20% to -50% H: +30% to +100%	1
Class 4	1% to 15%	Study or Feasibility	Equipment Factored or Parametric Models	L: -15% to -30% H: +20% to +50%	2 to 4
Class 3	10% to 40%	Budget, Authorization, or Control	Semi-Detailed Unit Costs with Assembly Level Line Items	L: -10% to -20% H: +10% to +30%	3 to 10
Class 2	30% to 70%	Control or Bid/ Tender	Detailed Unit Cost with Forced Detailed Take-Off	L: -5% to -15% H: +5% to +20%	4 to 20
Class 1	50% to 100%	Check Estimate or Bid/Tender	Detailed Unit Cost with Detailed Take-Off	L: -3% to -10% H: +3% to +15%	5 to 100

Notes: [a] The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

[b] If the range index value of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%. Estimate preparation effort is highly dependent upon the size of the project and the quality of estimating data and tools.

DocuSign Envelope ID: 4315A7D0-2B60-48F5-AEF3-4E42B950730B

Central 24 HR Operations Facility

Appendix C - Downtown Project Center North Annex Building Remodel Level 4 Estimate

Basment Floor	3,120	sf
Main Floor	3,216	sf
Total	**6,336**	**sf**

2023 $	Selective Building Demo	$	5.00	/sf	$	31,680.00	MACC Estimating Group pricing (typ)
	Exterior Enclosure	$	40.00	/sf	$	253,440.00	Reduced from $60 to $40
	Interior Construction	$	17.00	/sf	$	107,712.00	
	Stairs	$	2.00	/sf	$	12,672.00	
	Intertior Finishes	$	31.00	/sf	$	196,416.00	
	Conveying System	$	5.00	/sf	$	31,680.00	
	Plumbing	$	19.00	/sf	$	120,384.00	
	HVAC	$	50.00	/sf	$	316,800.00	
	Fire Protection	$	6.00	/sf	$	38,016.00	
	Electrical	$	80.00	/sf	$	506,880.00	Bumped $60 to $80
	Equipment	$	1.00	/sf	$	6,336.00	
	Furnishings	$	20.00	/sf	$	126,720.00	Bumped $10 to $20
	Site Improvements	$	10.00	/sf	$	63,360.00	
	Site Mechancial	$	10.00	/sf	$	63,360.00	
	Site Electrical	$	10.00	/sf	$	63,360.00	
	General Requirments	$	20.00	/sf	$	126,720.00	
	Building Subtotal				$	2,065,536.00	
	2025 $ Compounded Rate		18.31%		$	2,443,735.64	$ 385.69 /sf
	Bond & Insurance		1.50%		$	36,656.03	
	OH&P		8%		$	195,498.85	
	GC Construction Subtotal				$	2,675,890.53	
	Avista		10%		$	267,589.05	Historical data %
	Avista ET				$	927,476.00	ET provided estimate
	Project Subtotal				$	3,870,955.58	
	Contingency		5%		$	193,547.78	
	Project Total				$	4,064,503.36	
	ROM Bump		10%		$	406,450.34	
	CPG Build $ Request				$	4,470,953.70	$ 705.64 /sf
	Arcitectual & Engineering Design		4%		$	178,838.15	Historical data %
	Avista		3%		$	134,128.61	Historical data %
	ET				$	203,300.00	ET provided estimate
	CPG Design $ Request				$	516,266.76	$ 81.48 /sf
	Design+Build $				$	4,987,220.45	$ 787.12 /sf

EXECUTIVE SUMMARY

The Fleet Vehicle Refresh Capital Plan is the annual and ongoing plan to replace a portion of Avista's fleet to ensure the highest level of reliability and the lowest total cost of ownership. The annual cost of vehicles is split into two types: direct operating, and indirect costs. Direct costs include fuel and maintenance, while indirect costs include common ownership expense. Avista's replacement model is based on a proven fleet management concept: there are predictable increasing maintenance costs and decreasing ownership costs as vehicles age. The point at which those two lines intersect gives Avista a window of opportunity in which we will achieve the lowest total cost for a given unit. Replacing units within that window allows us to provide a high level of reliability (95% availability currently) while at the same time providing a steady and predictable capital spend, and level of work for our technicians.

Maintaining a high reliability percentage is essential when we experience an EOP event. Over the last several years we have experienced multiple large EOP events that have tested the reliability of our fleet. During these events, our fleet experienced very few breakdowns even though our units were being used around the clock in some of the most severe conditions. This strategy also gives us the advantage of liquidating units while they still have a reasonable amount of value in the secondary market. These funds help supplement our planned spend, minimizing the need for additional funds requests as market prices fluctuate. We have been navigating inflationary pressures like every other line of business with little sign of significant future relief. In a meeting with our largest supplier, they shared that amongst the most common commodities they use in the manufacturing of our vehicles they have seen increases from the low end of 17% to upwards of 60% in the last three years (see Figure 1 Below). However, these are not the largest price pressures we face over the next five years. As Oregon and Washington adopt the **California Air Resource Board (CARB)** Omnibus and Advanced Clean Truck (ACT) rules to move to zero emissions, vehicles we will face greater economic impacts.

Additionally, in 2027, EPA's Green House Gas Emission Standards for Heavy Duty and Medium Duty Vehicles Phase 3 will become effective and impact a majority of the vehicles we operate. This mandate will have stringent GHG targets in all jurisdictions in which we operate. While these mandates do not dictate what percentage of electric vehicles we purchase, they do mandate what percentage of new unit's OEMs register in these states. EPAs rules do contain ZEV guidance that will need to be fully resolved before implementation.

Our greatest concerns are in the medium duty segment of trucks ranging from 14,000 GVWR to 20,000 GVWR. What makes this of greatest concern is that we do not have clear answers from our largest supplier (Ford), on how they will meet these requirements. Unfortunately, the other competitors in this market are not indicating they are in any better position. This puts us at risk of seeing significant increases in chassis cost over the next 5 years. As you will see in more detail later in this document a lack of funding will always create a cascading effect both in capital expenses but more significantly in O&M expenses. We are engaged in conversations with OEM's and desire to be a part of the solution that not only fulfills our obligations to the laws of our states but to ensure we are doing what is right for our planet, and the communities we serve. With your support we have successfully kept our fleet on an environmentally responsible path, and our desire is to continue that into the future.

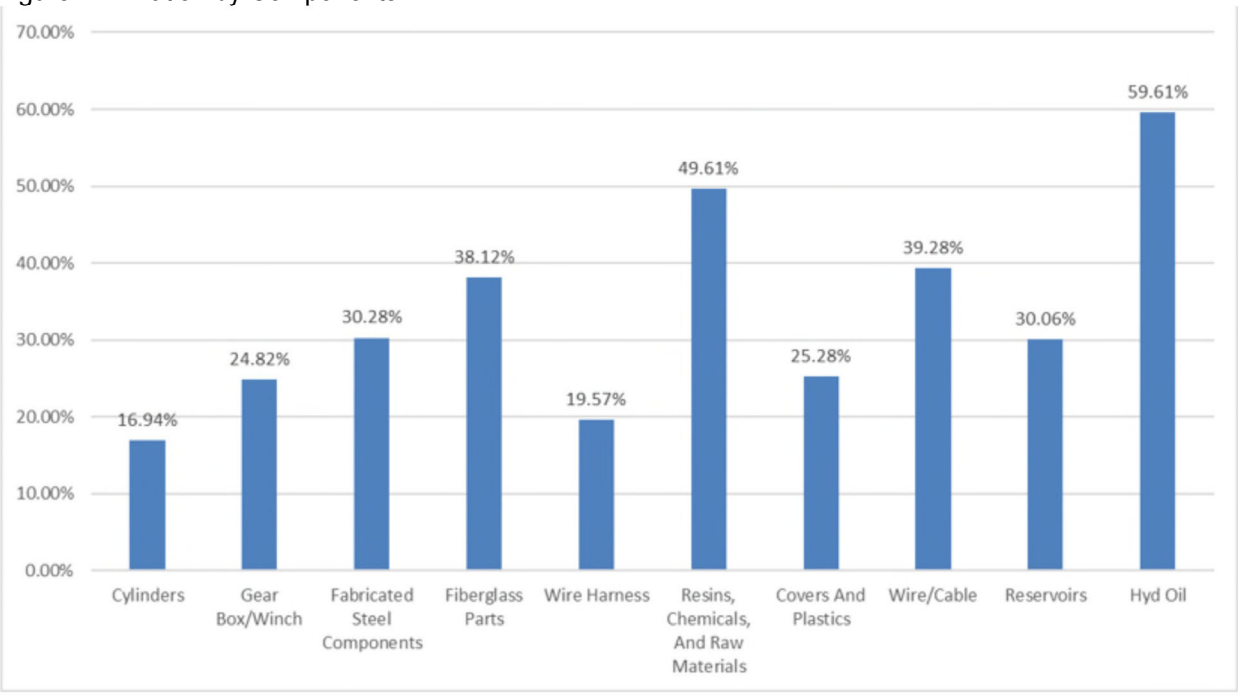
Avista has worked with Utilimarc, a utility focused data analytics company that provides benchmarks with a proven record working with utility fleets in the US. The model inputs the initial price, actual maintenance & repair costs, depreciation expense and salvage value to establish each class of vehicle's replacement cycle.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 447 of 535

The recommended solution is to replace 50-70 units per year with an escalating spend over the next five-years for a total cost of $47.5M. The investment in Avista's fleet, over the past decade, means that we have an exceptionally reliable fleet that meets the service level expectations of our internal customers. Our equipment must function reliably in the most extreme situations. Our trucks can be in 120+ degree heat at the bottom of Hells Canyon or 0-degree snowstorms in Sandpoint. Trucks that are running allow crews to work an outage and reenergize/repressurize the system.

By spending a level amount of capital every year, we can maintain a constant average fleet age which produces a known quantity of work in our shop, and it prevents us from having clusters of trucks that are the same age, creating budget strain in the later years of a unit's lifecycle. The investments made have meant that we are able to provide an extremely functional, reliable, and safe tool for our crews. Continued investment is critical in ensuring we provide the safest equipment for our operators, as well as decreasing the environmental impact of our fleet. The capital program has allowed us to maximize our value while minimizing our total cost. Failing to fund this program will create a growing cost of repair expense, including the potential need for additions to staff complement, and a decreasing level of reliability/availability.

Figure 1: Inflation by Components



VERSION HISTORY

Version	Author	Description	Date
1.0	*Potter*	*Initial draft of original business case*	*5-1-24*
2.0	*Potter*	*Final Copy*	*5/3/2024*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	SMC 5/3/2024

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 448 of 535

GENERAL 2025-2029

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	**$7,132,040**	**$7,132,040**
2026	**$8,822,402**	**$8,822,402**
2027	**$9,484,558**	**$9,484,558**
2028	**$10,496,342**	**$10,496,342**
2029	**$11,545,976**	**$11,545,976**

Project Life Span	***5 year***
Requesting Organization/Department	K51
Business Case Owner | Sponsor	Greg Loew | Kelly Magalsky
Sponsor Organization/Department	Energy Delivery
Phase	Execution
Category	Program
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

Trucks and equipment do not age well. Fleet vehicles experience a duty cycle that most vehicle owners would not imagine, having only experience with a personal car or truck. Avista's fleet of vehicles operate in conditions that are often extreme: excessive heat and cold, dusty, and muddy environments are common in our service territory. These vehicles also endure employees constantly ingressing, and egressing, while the engines experience high idle time or high loads.

These factors all contribute to the wear and tear on our vehicles and can create substantial demand for repair workorders. This kind of duty cycle over the life of a truck will add up to an increasing amount of repair work and a lower reliability factor as vehicles age. Our program allows us to optimize our vehicle life so that we extract the right amount of useful value from our vehicles and replace them before they experience a rapid rise in the amount of repair expenses they incur. The program we have built affords us the ability to plan our labor and maximize our internal mechanic resources while having a fleet of vehicles that are available for any job, planned or unplanned operational response.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 449 of 535

1.2 Discuss the major drivers of the business case.

The Fleet Equipment Capital Refresh Program is driven by Asset Condition. This program benefits both our internal and external customers.

Internal customers: Our drivers have safe and reliable trucks because of the investment in our fleet. Our fleet of trucks are ready for work over 95% of the time. In the field our trucks experience fewer breakdowns per one hundred hours of operations and are in the first quartile when compared to peer utility fleets. Our fleet of vehicles includes advanced safety features, modern efficient engines and operational tools that make tasks more efficient. We work extremely hard with input from our internal customers to make sure we are producing units that give them the vehicles they need to in turn serve our external customers safely, efficiently, and reliably.

External customers: Our customers benefit from our Fleet Replacement Program Additionally, new vehicles have the cleanest burning engines and advanced safety features that protect the environment and drivers on the road. A highly reliable fleet ensures that our customers will not experience a delay in getting their energy restored; we are ready and able to get to them in any location necessary.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The investment in vehicles for Avista's fleet is not an option. Our crews do not get to their jobsites, near or far, in any way but in an Avista owned piece of equipment. Vehicles will break down and reach their end of life and their life can be prolonged by making expensive and time-consuming repairs. The availability of the company's fleet and its field reliability will suffer if there is not an investment of capital. Additionally, the company will see a steady rising cost in maintenance both in labor and material dollars. The deferral of investment will also cause spikes of increased capital needs in future years as the team tries to shore failed assets and work to bring the average fleet age in line with industry best practices.

If we do not invest our dollars into the capital replacement plan, we will end up spending those dollars on costly repairs. Repair costs are much higher, and less predictable making it more difficult to forecast. In the worst case we could see a 12,000-hour delta between available labor and the labor required to complete the increased repair demand created by the replacement deferral in the coming decade. That difference would likely be met with increased utilization of vendor labor at a significantly higher cost over internal labor, or the need for additional employee complement. In 2032 that would add an additional $660,000 per year to the clearing account which would be born through significant equipment cost burdens

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 450 of 535

			2023 Goal(s)	Status	3-5 Year Focus
Perform	a.	Affordably operate and maintain safe, clean, reliable generation and energy delivery infrastructure	Meet or Exceed 2022-23 Biennium energy efficiency savings goals for Washington	⇨	Meet regulatory and Integrated Resource Plan (IRP) goals for energy efficiency savings
			Replace aging outage management & distribution management system (ADMS)	⇨	Achieve electric reliability and improve outage management system
			Achieve reliability metric goals	⇨	
			Develop substation security roadmap and identify initial improvements to be made at our most critical substations	⇨	Mature physical security program and emergency response system
			Achieve emergency gas response goals	⇨	
	b.	Achieve stated financial objectives	File Oregon & Idaho General Rate Cases and secure outcomes to meet objectives for financial performance and affordability	⇨	Achieve Authorized Return
			Complete joint use system audit to identify and realize additional revenue opportunities	⇨	
			Achieve Cost per Customer metric to meet cost management and affordability goals	⇨	
			Achieve earnings goals to meet objectives for financial performance	⇨	
			Remodel electric and gas hedging & optimization programs to reduce risk and better capture forward value of market positions	⇨	

4

The Fleet Vehicle Refresh Capital Program (FVRCP) can play a role in the "Perform" goal of achieving Cost per Customer to meet cost management and affordability goals. This can be achieved through steady capital spend which in turn allows us to maintain predictable O&M cost year over year. Having a reliable fleet also allows the hard-working men and women in the field to efficiently perform their work in a timely manner.

			2023 Goal(s)	Status	3-5 Year Focus
Invent	a.	Foster and apply an innovation culture to benefit employees, customers, communities and shareholders	Implement Robotic/Business Process Automation to drive operational excellence	⇨	Adopt new proven technologies to drive operational excellence
			Hold two Startup Avista events and innovation training opportunities	⇨	Launch one or more regulated or non-regulated new businesses as a result of internal innovation activities
	b.	Create the utility of the future with our stakeholders, optimizing for cost, carbon and reliability	Avista Innovation Lab hosting platform, capital efficiency and regional energy ecosystem	⇨	Move the concepts of the bi-directional grid from the lab and demonstration into the operation of the electric grid.
			Implement carbon trading policies and practices in support of clean energy goals and regulations	⇨	Deliver on the clean energy milestones developed during 2022, including achievement of a carbon-neutral supply of electricity by the end of 2027
			Prepare infrastructure for low-carbon fuels, including new work practices	⇨	

The FVRCP also can help support the "Invent" goal of creating the utility of the future by optimizing for cost, carbon, and reliability. With a large fleet of vehicles on the road across four states it is critical to ensure we are not negatively affecting the environmental impact on our communities. While we have many outside entities putting pressure to meet environmental impact goals around how we generate electricity and deliver natural gas, we also have many vehicles emission milestones quickly approaching. Fully funding our capital investment will help propel us down the path proactively.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

1.5.1 Please reference and summarize any studies that support the problem

Supplemental information is available from Utilimarc.com

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Lifecycle Summary

This table shows the lifecycle recommendations for Avista's top vehicle classes. These classes represent around 75% of Avista's annual fleet spend.

Class	Average Mileage	Purchase Price	Calculated Lifecycle	Lifecycle Used
Pickup - Class 2a	8,789	$56,000	14	14
Pickup - Class 2b**	8,512	$60,000	13	14
Pickup - Class 3**	13,256	$100,068	10	9
Dump Truck - Class 7**	5,005	$142,750	12	15
Dump Truck - Class 8**	5,536	$241,328	12	15
Service Truck - Class 3*	13,693	$130,000	13	11
Service Truck - Class 5**	8,464	$175,000	15	14
Service Truck Class 6+**	7,583	$221,706	15	15
Stake Truck**	6,291	$165,000	20	16
Bucket Truck - Class 5*	15,100	$200,000	8	9
Bucket Truck - Class 7**	9,345	$231,423	11	12
Bucket Truck - Class 8**	4,929	$349,372	17	18
Digger Derrick - Class 8**	4,565	$400,000	15	18

* Mix of company and industry maintenance data ** Industry maintenance data

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 452 of 535

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

Option	Capital Cost	Start	Complete
Requested Adjustment (no adds to complement funded)	*$47.5M*	*01 2025*	*12 2029*
Current Allocated Funding	*$28.1M*	*01 2025*	*12 2029*
Lease	*$M*	*01 2025*	*12 2029*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Avista's Vehicle Replacement Model (VRM) uses fleet data to develop company specific replacement criteria for each vehicle class in fleet. This analysis is unique to the behavior and characteristics of the Avista fleet. The inputs for the Utilimarc VRM include:

- Company specific trending parts and labor cost for each vehicle class
- Company specific purchase price for each vehicle class
- Company specific annual usage patterns (mileage) for each vehicle class
- Company specific loaded productive labor rate and mechanic productivity
- Vehicles are identified as candidates for replacement when over their recommended replacement age or replacement life to date mileage, whichever occurs first.

A vehicle is identified as a candidate for replacement when it reaches its replacement range for age or lifetime mileage. Replacing within these ranges ensures operating within 1% of the lowest total ownership cost of the vehicle over its lifetime. This can be seen in the chart below with the green 5-year window. A standard regression model is used in this analysis. There are certain units such as first responder/local rep units that may reach the upper limits of the mileage triggers well before the desired age. In this situation we attempt to move these units into a spare role that will allow us to get the full life expectancy out of the vehicle. Conversely if we have units that see lower than expected use, we can extend its years of service granted maintenance and repairs remain steady.

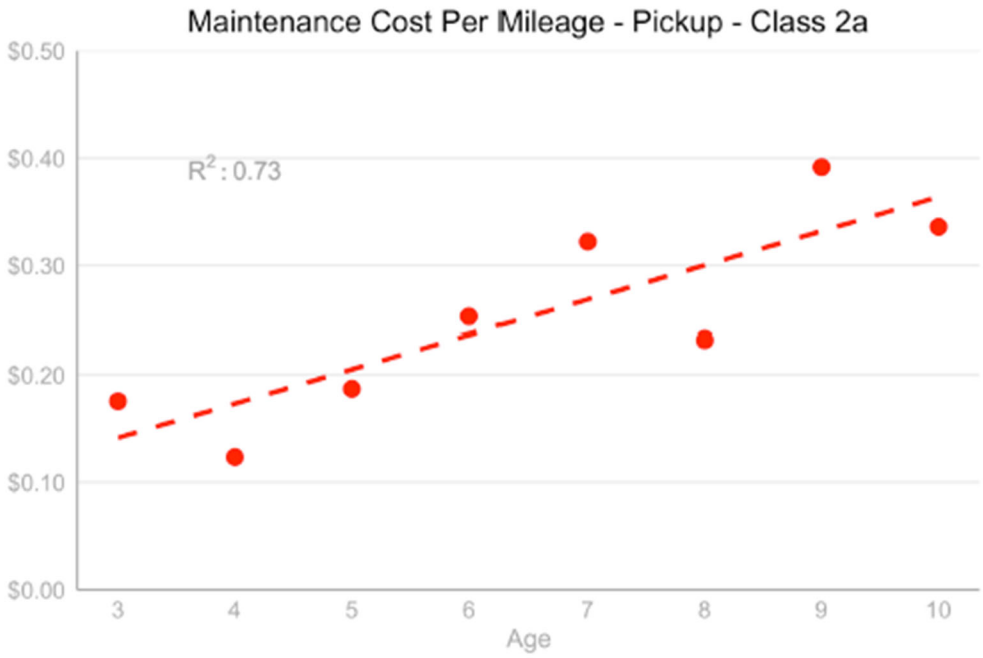
Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 453 of 535

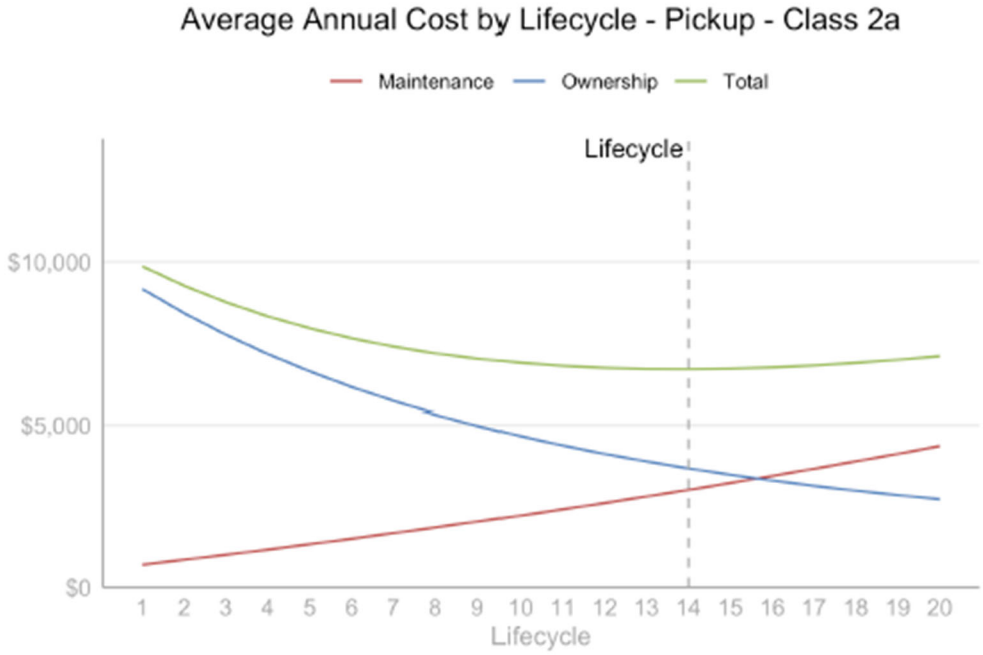
Pickup - Class 2a

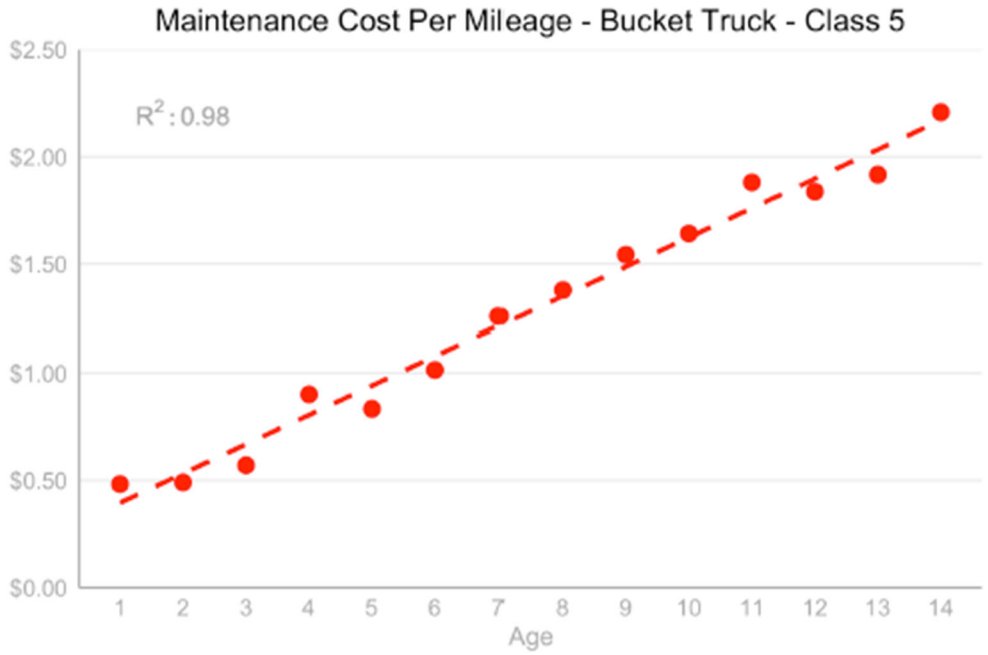
	Value
Lifecycle	14
Purchase Price	$56,000
Average Salvage at Sale	$3,480
Market Depreciation Rate	18%
Inflation Rate	2%
Average Annual Mileage	8,789

Lifecycle	Maintenance	Ownership	Total	Deviation
1	$697.32	$9,161.60	$9,858.92	47.48%
2	$849.57	$8,412.18	$9,261.75	38.55%
3	$1,005.79	$7,744.50	$8,750.29	30.9%
4	$1,166.07	$7,148.52	$8,314.59	24.38%
5	$1,330.49	$6,615.54	$7,946.03	18.87%
6	$1,499.15	$6,137.97	$7,637.12	14.25%
7	$1,672.14	$5,709.19	$7,381.34	10.42%
8	$1,849.57	$5,323.47	$7,173.04	7.3%
9	$2,031.52	$4,975.78	$7,007.30	4.82%
10	$2,218.10	$4,661.73	$6,879.83	2.92%
11	$2,409.41	$4,377.48	$6,786.89	1.53%
12	$2,605.55	$4,119.68	$6,725.23	0.61%
13	$2,806.64	$3,885.39	$6,692.02	0.11%
14	$3,012.78	$3,672.01	$6,684.79	0%
15	$3,224.08	$3,477.29	$6,701.37	0.25%
16	$3,440.66	$3,299.23	$6,739.89	0.82%
17	$3,662.63	$3,136.07	$6,798.70	1.7%
18	$3,890.11	$2,986.27	$6,876.38	2.87%
19	$4,123.23	$2,848.44	$6,971.67	4.29%
20	$4,362.10	$2,721.40	$7,083.50	5.96%

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 454 of 535


Maintenance Cost Per Mileage - Pickup - Class 2a
$0.50
$0.40
$0.30
$0.20
$0.10
$0.00
R^2: 0.73
3
4
5
6
7
8
9
10
Age


Average Annual Cost by Lifecycle - Pickup - Class 2a
Maintenance
Ownership
Total
Lifecycle
$10,000
$5,000
$0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
Lifecycle



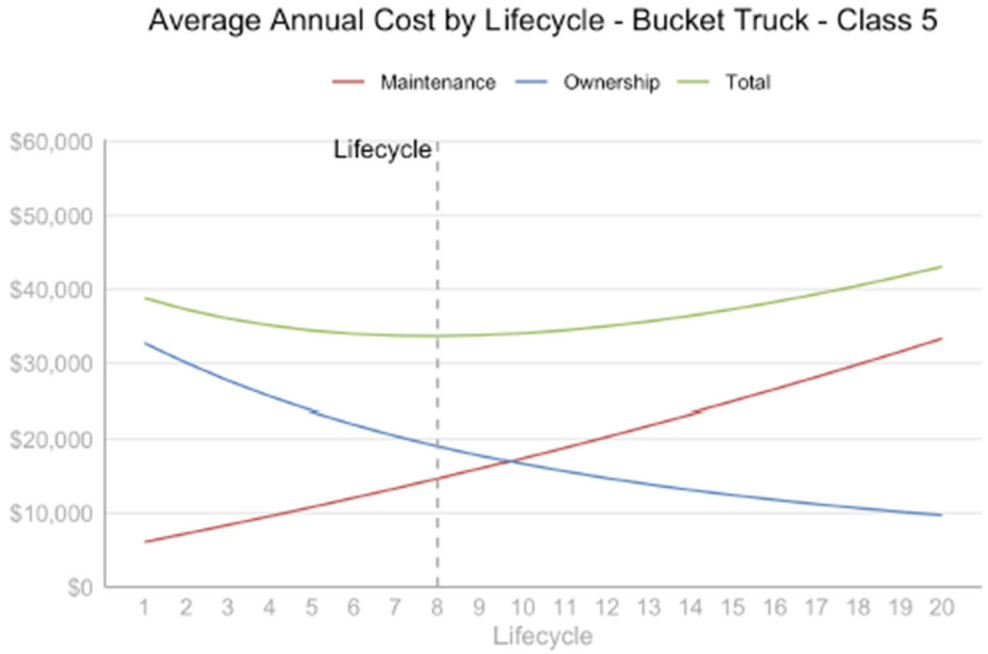


Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 456 of 535

2.2

Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

The capital in this case is an escalating amount to that reflects past capital allocation shortfalls (where we prioritized investment in high expense & high required reliability over other lower priority equipment), new regulatory requirements (driving higher purchase prices) and inflation driven increases. The investment of capital in this case will provide a consistent replacement plan which enables our continuing investment to ensure levelized (normalizing for increasing costs) to ensure predictable parts, labor costs, vehicle downtime, and technician requirements across the majority of our fleet.

Annual labor savings by maintaining the capital plan and having a predictable labor requirement.

Year	2024	2025	2026	2027	2028
Annual Capital Allocated	$5,594,822.00	$5,615,086.00	$5,612,261.00	$5,618,098.00	$5,615,389.00
Average Age	11.57	11.84	12.18	12.54	12.93
Labor Hours	45,772	46,723	47,640	48,656	49,581
Annual Capital Adjustment Request	$5,594,822.00	$7,132,040.00	$8,822,402.00	$9,484,558.00	$10,496,342.00
Average Age	11.57	11.72	11.87	11.96	12.08
Labor Hours	45,722	46,118	45,667	45,200	44,580
Labor Dollars Delta*	$4,230.00	$51,183.00	$166,915.80	$292,377.60	$423,084.60
Avoided Crew Downtime					

Our 2021 analysis showed that demand repair work orders would increase over time when not controlling the total overall average age of fleet. A percentage of demand repair orders has some impact on the users of the trucks. On average for this exercise, we assume each work order creates 2 minutes of crew downtime when repairs are completed internally.

Labor impact	2024	2025	2026	2027	2028
FTE increase	0	0.49	1.63	2.92	4.31
Increase FTE Cost*	$0.00	$66,037.98	$226,267.67	$417,498.55	$634,726.48
Outsourced Labor Cost**	$3,750.00	$45,375.00	$147,975.00	$259,200.00	$375,075.00
Outsource Crew DT cost***	$0.00	$184,169.89	$187,795.56	$191,790.83	$195,451.70

* Assuming 1 FTE O&M impact cost is $130,746 per year with a 3% annual increase
** Assuming average outsourced labor rate at $150 per hour in 2023 with 50% going to O&M
***Assuming 2023 Hourly 4-person crew labor rate is $397

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 457 of 535

[Offsets to projects will be more strongly scrutinized in general rate cases going forward *(ref. WUTC Docket No. U-190531 Policy Statement)*, therefore it is critical that these impacts are thought through to support rate recovery.]

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

2.4 Summarize in the table, and describe below the INDIRECT offsets (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M	Estimated repair hour as measured in labor hours	$32,994	$113,047	$208,589	$317,120	$378,925*

*2029 hours estimated using trendline data from 2023 estimates as Avista did not subscribe to a Vehicle Replacement Model in 2024

By funding the additional capital request, we can have a significant impact on the O&M budget over the next 5 years. The data indicates that if we maintain the current spending level of $5.6M per year, we will see an increase in the average age of the Avista Fleet. This has a cascading effect on the number of labor hours and work orders needed to maintain the health of the fleet to minimize crew downtime and safety. Additionally, as we see an increase in the number of hours needed to complete the repairs and maintenance, we have

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

two options for sourcing additional capacity. Outsource is one way we can supplement this; however, this will significantly increase the length and cost of downtime for our crews. This option also requires us to spend valuable time inspecting every repair when it comes back from a vendor as well as increasing the risk of damage or theft from units being off-site. The second and most effective option would be to increase our department complement to accommodate for the increased workload. While this does come with a slightly higher cost, it minimizes our risk significantly in ways that are difficult to quantify. Our desire is to maintain the average age of the fleet and thus continue to maintain our current staffing level.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1:

Reduce investment approximately 25% ($11.9M). By investing below the optimum scenario, we will be able to continue to address the highest cost per mile vehicle classes (five of which account for 55% of the total annual operating spend) and those vehicles that are critical response units. We will still face the risk of increased costs, downtime, and inadequate technician capacity. However, the amount may be mitigated by focusing on the highest cost and most critical assets. Additionally, we risk the potential that additional funding would need to be allocated in one or two years to get “caught up.” This will create clusters of additional work for the team purchasing and preparing units for service and will increase parts and maintenance costs.

Alternative 2:

Fund the program at 50% ($23.7M). This route would create an even larger cluster that will need to be addressed by future capital spending that could exceed the recommended spend by as much as 50%. One of the biggest challenges we will face in this scenario is the effect it will have on our shop workload. As previously stated, this scenario will create a 12,000 hour or a 33% delta between the amount of labor available and what is required to complete all demand driven repairs and associated maintenance. With a predictable number of units coming in, we can better plan our team’s schedule. This also allows us to maintain level staffing needs year over year.

Alternative 3:

The third scenario would be transitioning to a leasing model. Multiple utility fleets lease their vehicles. This on the surface has the potential to free up capital for other uses. The risk in this option is that you are trading a capital cost for an operating cost. The depreciation that was realized on the P&L statement is now an O&M cost that must be absorbed. Those costs include a leasing company’s return on equity. This would require huge change management with help from the operations management team, as our vehicles are highly customized to ensure they can do their work in the most efficient and expedient manner.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

The fleet capital plan is driven by a statistical analysis that is based on our financial and operating outcomes. This analysis is reviewed by the Fleet Manager, Specialist, and Analyst by utilizing the data from our analytics partner Utilimarc. The analysis can also be confirmed by monitoring average age as well as tracking work order count and maintenance spend using our fleet management system Asset Works.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

The Fleet Vehicle Refresh is a capital plan. Each vehicle or piece of equipment purchased gets a jurisdiction code, specific project number, and a FERC specific task code. We begin purchasing the next years equipment during the summer of the prior year. Right now, we are taking delivery of equipment that had purchase orders cut last August. The lead time for our most expensive mounted hydraulic equipment is averaging between 350-450 days. We transfer each individual unit to plant when in becomes used and useful, which is typically 30-90 days after receipt and invoicing.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Each individual vehicle purchase is approved in two parts: 1) The Fleet Manager approves the CPR request, and the Shared Services Director is notified. 2) The requisition process is approved at multiple levels based on its value, from the Fleet Manager and as high as the CEO.

Department and district managers are involved in the order process by confirming which vehicles are to be replaced and by helping to ensure any requests that specific operators or crews may have. Managers, operators/drivers sign off on a VLC form which is maintained for every class and build of vehicle.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Fleet Vehicle Refresh Capital Program and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 460 of 535

Signature:	Gregory Loew	Date:	5/3/2023
Print Name:	Greg Loew		
Title:	Fleet Manager		
Role:	Business Case Owner		

Signature:	Kelly Magalsky	Date:	
Print Name:	Kelly Magalsky		
Title:	Director Shared Services		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 461 of 535

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Palouse Service Center

EXECUTIVE SUMMARY

The existing Pullman Service Center facility was constructed in 1959. Due to its age, many of the buildings on the site are past their useful life and in need of considerable capital investment. The current site is located on a long narrow 5-acre parcel boxed between SR71 to the South and a large hill to the North. As the property is so narrow, it has been difficult to efficiently utilize the space for current operational needs and materials inventory as well as plan for any projected growth. There is no adjacent property available for purchase to extend the campus, and the adjacent properties would be difficult to utilize. The existing site and building have environmental, safety and code concerns, many that do not have an effective resolution. These include stormwater management issues, safe pedestrian pathways and ADA access and restroom requirements.

This project would impact both Gas and Electric customers in both Washington and Idaho. We expect our preferred solution, to cost $23M.

The proposed solution is to relocate the Pullman Service Center to the new location and sell the existing building. The building will be located on a new property more in line with our current 10-acre, square of rectangular yard standard. This new site allows the Service Center, the pole yard, and the warehouse together. This option would allow us a better layout of the materials yard, establish a more efficient vehicle flow pattern, and give us flexibility for future growth. With new energy codes and insulation values, a new building would result in a lower cost per square foot to heat and cool, estimated at 15%. The space will be designed to meet the needs of today's employees and would meet all current code requirements.

This project would benefit external customers in that the new Service Center can improve efficiencies. Having all materials, supplies and staff in one location allows for improved use of resources and response times. Employees benefit from improved communication during outages and ability to perform their tasks safely and effectively. The Pullman building and the site have many critical systems that need replacement, including HVAC, plumbing and roof systems. Avista will need to address the materials yard shortage by purchasing additional property in the coming years, to meet this space need. The Pullman building and site have many worn buildings and assets in dire need of replacement, as many of capital projects have been put on hold until the future state of the site is known.

The Facilities Capital Steering Committee approved submission of this Business Case.

VERSION HISTORY

Version	Author	Description	Date
1.0	*L. Miller*	*Initial draft on New Template*	*4/8/2024*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	*Steve Carrozzo 4/30/2024*

PLANNED SPEND FOR PARTIAL FUNDING

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 462 of 535

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The CPG partially funded this program in 2024 and 2025 below is the planned project spend for those years. The 2024 projects are currently in planning. This partial funding will be spent across the two locations in the program to provide them with needed improvements to maintain functionality at the current locations.

YEAR	LOCATION	PROJECT	ESTIMATED SPEND	PLANNED TTP
2024	Pullman	Roof Replacement	$200,000	11/2024
2024	Pullman	Asphalt	$200,000	11/2024
2024	Pullman	Oil Water Separator/ Wash Bay	$150,000	11/2024
2024	Pullman	Temp. Storage Yard	$200,000	11/2025
TOTAL ALLOCATION			**$750,000**	
2025	Pullman	Storage Buildings/ Canopy	$250,000	11/2025
2025	Pullman	Asphalt Phase 2	$200,000	11/2025
2025	Pullman	Interior Improvements Phase 2	$125,000	11/2025
2025	Pullman	HVAC and Lighting Upgrades	$175,000	11/2025
TOTAL PLANNED ALLOCATION			**$750,000**	

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GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$750,000**	**$750,000**
2025	**$750,000**	**$750,000**
2026		
2027		
2028		
2029		

Project Life Span	***5 years***
Requesting Organization/Department	Facilities
Business Case Owner | Sponsor	Eric Bowles | Kelly Magalsky
Sponsor Organization/Department	Facilities
Phase	Planning
Category	Program
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

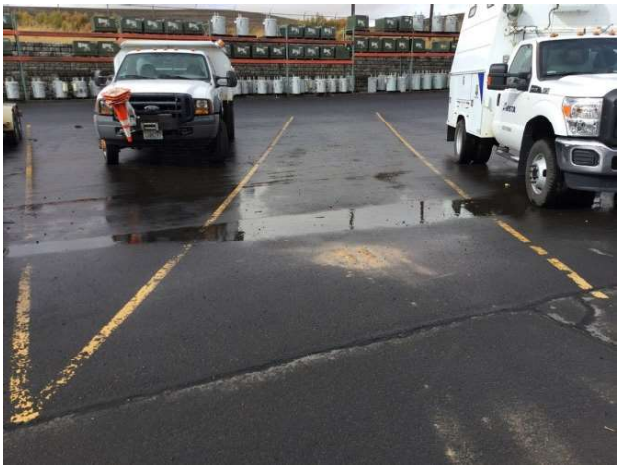
The Pullman service center facility was constructed in 1959, with various upgrades, remodels, and additions since then. Some of the upgrades included the construction of an addition to the West side of the service center in 1979, the construction of a storage canopy and meter shop area, offices, a parking canopy, and an office addition to the East side of the building in 2009.

Building Condition

The Pullman Service Center had a Building Condition Assessment completed by a third party in 2017. In that survey, items were identified that needed immediate replacement or repair totaling $217,000. Another $1,400,000 in repairs and replacements have been identified today that would need to be completed in the next 5 years, including replacing the basic building systems such as electrical, domestic water piping, the plumbing and septic system and the entire service yard asphalt and drainage.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 464 of 535

DocuSign Envelope ID: 16B1CEA3-9B44-404E-BDD9-880D3754A87D



Some of the immediate repair and replace items identified:

All the roll up doors need to be replaced at the site. Many are damaged and beyond repair. They are part of the original construction and are not insulated and do not meet today's standards with the proper safeties and automation.

The built-up roof requires a lot of maintenance and has several cracks and flashing that need repair. There are blisters that are past repair and standing water observed throughout by the third-party assessor.

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In the interior, there are needs for flooring replacements, furniture changes and ceiling grid improvements. In the exterior there is concrete block repair, unit heater repair and painting throughout the entire Service Center.

There are no existing fire safety systems at the Pullman location. This is considered a critical failure and would need to be rectified immediately if we do not move forward with a new building. Installation of a fire suppression system would include extensive ceiling work, lighting changes and additional plumbing. At a minimum adding a monitored fire notification system may be required at an O&M expense.

Materials/ Storage

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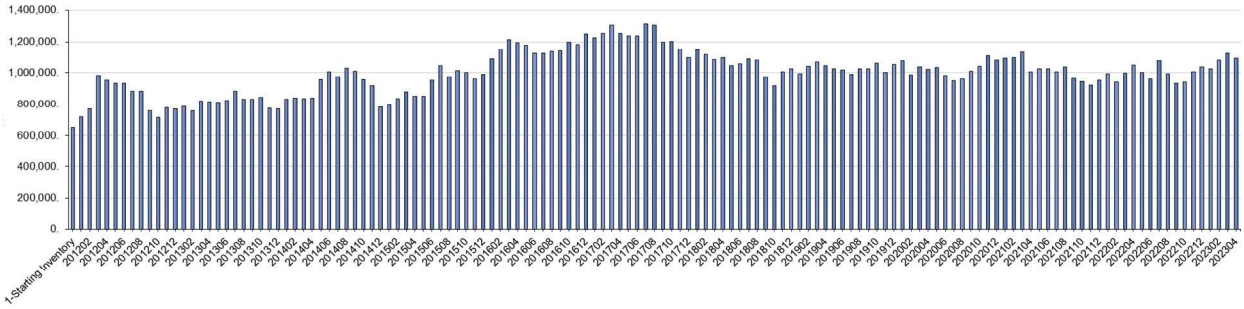
The existing Pullman Service Center is too small and unable to sustain the inventory needed. The Palouse area has historically had a high level of inventory compared to other Service Centers with territories of a similar size. The local warehouseman has struggled for years to make use of the existing land. We have used all the existing storage space available, and soon there will be additional smart grid inventory which will overwhelm the storage yard. We are unable to purchase any additional land adjacent to the existing property to expand. There is a hillside to the north and east of the property, but it would not be useable because it would require extensive excavation to bring it down to the existing property grade. To the west, the land is part of the highway drainage system, so we are unable to purchase that land.

Historical Warehouse Inventory- Pullman:



The layout of the yard requires the whole property to be fenced. During business hours, when gates must be left open to provide safe access from the highway, the public can enter our property where all our equipment and material is stored. This is a security issue because some doors into the office are unlocked during business hours (for ease for employees) and sometimes bay doors are left open – which people could enter at any time. There is not enough space to provide a separate fenced warehouse storage yard.

The workload in the Palouse District is growing each year. Pullman is a large portion of that growth. Over the last two years Pullman has grown by 2.3%. The Palouse construction office services nearly 41,000 natural gas and electric customers (3rd largest District in the company by customer count.) Palouse District also has one of the largest service territories, around some 5,000 square miles of area. The workload in the region is expected to continue to increase with the load growth we are seeing.

The storage/warehouse room is out of space. It is also very inconvenient because the building is in the middle of the property and the East end of the property gets smaller and smaller. Delivery vehicles have a very hard time because there is not a good spot for them to be able to turn around safely. These limitations and the odd configuration create inefficiencies for warehouse staff and crews. It also creates confusion around inventory,

Environmental/ Compliance

This site has environmental concerns and needs to have a review of the water runoff plain and upgrades will need to be made. One concern is the public highway runoff, which the state has made some changes to, but we need to look at its impact on maintenance on our site. The vehicle wash bay also needs to be properly mitigated, which is not currently happening. To manage the wash bay properly an oil water separator system would need to be installed, estimated at $200K.

The existing building has minor code compliance and security issues. There are many ADA issues, such as non-compliant restrooms and building access, and much of the construction does not comply with current code. The site layout prevents the yard from being secured during the day as the building is centrally located. This layout causes customer and visitor traffic to cross a portion of the storage yard. This also leaves the site open for access by outside folks to all areas of the storage yard, warehouse, and fleet area. The interior of the main building needs an update and possibly a large reconstruction or renovation. The layout is no longer conducive to today's business needs. Avista has added a number of onsite FTE's increasing the need for office space. Most of these added FTE's

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are Construction Project Coordinators working on the growth in the Palouse area. Many of the building systems are antiquated and have reached the end of their useful life.

Employee/ Customer Impact

Currently there are 41 employees that work out of the Pullman office, including 3 local reps that have their own location along with visiting/working out of Pullman office occasionally. The office is currently full with respect to being able to "house" employees in the current Service Center as there are only 18 workspaces available, and the Pullman employees do not typically work hybrid and are all in the office day to day. There are plans to add an employee to either the Pullman/Clarkston office, but we may have to put them in Clarkston because of the lack of room for the employee in Pullman. Though the employee would like to be in the Pullman office. We also currently don't have room for summer students and must pair them up with a local rep desk when they work out of the office. There are no spare desks for anyone visiting the office to use.

There are 30 legal parking spaces at the current Service Center. With 41 employees we currently have there is not enough customer/employee parking available. There is parking that occurs outside of the permitted parking, along drive paths and in front of storage materials. When local reps, serviceman and others are in attendance of safety meetings or other meetings, the vehicles are parked all over the property due to lack of parking space. This poses safety concerns and limits the ability to maneuver through the yard. This also creates a safety concern for pedestrians as they walk from their vehicles to the building, crossing operations vehicle traffic.

Operational Efficiency/ Safety

Traffic must enter and exit from the Service Center straight onto/ from a 55mph highway. This is problematic for hauling poles, trailers and equipment which is done daily. This is a safety concern in the winter as well and crossing traffic can be dangerous. While we have made improvements to the entrance to help mitigate this issue it is still problematic. The current mitigation is the use a driveway installed by the highway to the West of the property on adjacent land not owned by Avista.

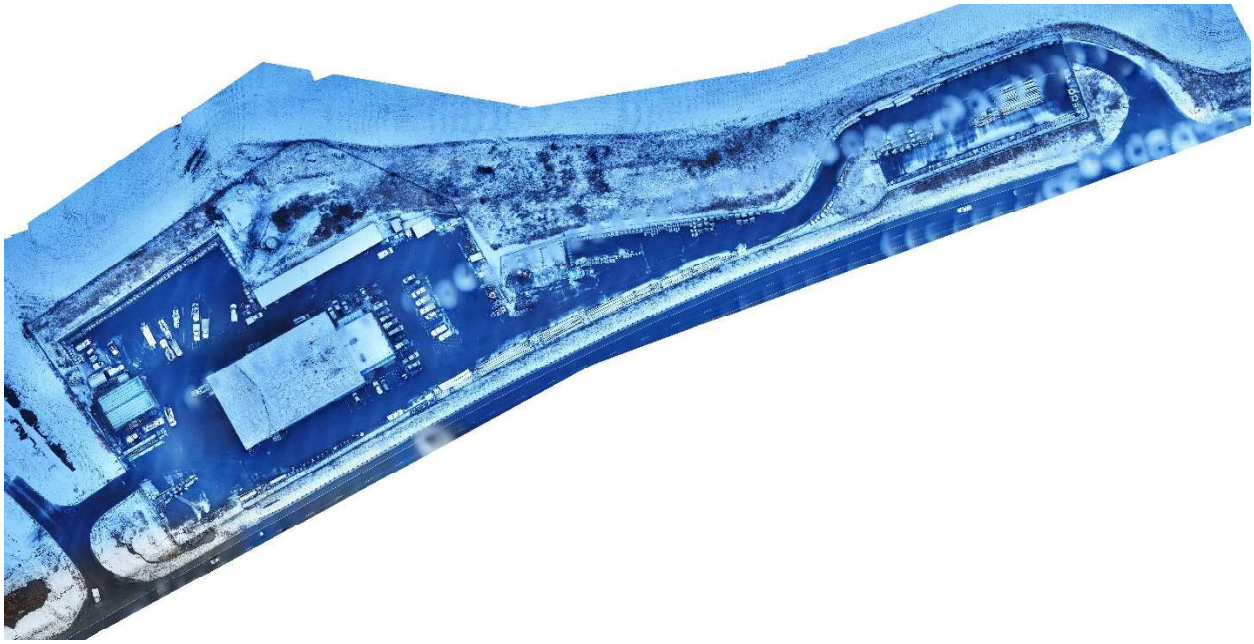
There isn't enough room to park company vehicles in covered areas. We currently park 6 vehicles indoors out of all the vehicles in Pullman yard. The remainder of the vehicles and trailers are parked throughout the service yard. Many of the company vehicles that are parked inside are parked with few inches to spare between the dock and the roll up door. The bays are not large enough due to larger equipment purchased for today's needs. This provides limited movability around the trucks and requires that the employees driving must basically back up into the dock, leaving no room behind the vehicle and the line dock.

Previous Pullman Service Center Aerial

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 468 of 535

DocuSign Envelope ID: 16B1CEA3-9B44-404E-BDD9-880D3754A87D

Current Pullman Service Center Aerial- Revised Highway entrance



1.2 Discuss the major drivers of the business case.

The major driver of this business case is Asset Condition, Safety and Performance and Capacity.

The Pullman building and site have many worn buildings and assets in dire need of replacement, as many of capital projects have been put on hold until the future state of the site is known. This is causing the current Asset Condition to fall well below acceptable. The lack of investment in these assets has resulted in safety concerns throughout the building and site. Examples of safety items include risk of slips, trips, and falls and snow/ ice shedding from roofs. The Pullman Service Center has been considered for replacement since 2018.

This project would benefit external customers in that the new Service Center can improve efficiencies. Having all materials, supplies and staff in one location that is efficiently laid out allows for improved use of resources and response times. Internal Customers benefit from improved communication during outages and ability to perform their tasks safely and effectively with the necessary tools and facilities. The current situation in Pullman is such that Avista will need to address the materials yard shortage by purchasing additional property in the coming years, to meet this space need.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

A large investment is needed for the Pullman Service Center due to its condition. The Pullman Service Center had a Building Condition Assessment completed by a third party in 2017. In that survey, items were identified that needed replacement or repair under Operations and Maintenance totaling $217,000 over the next 5 years. Another $1,400,000 in repairs and replacements have been identified as of today that would need to be completed under Capital Spend in the next 5 years, including replacing the basic building systems such as electrical, domestic water piping, the plumbing and septic system and the entire service yard asphalt and drainage. Facilities estimates that an interior remodel including ADA upgrades to restrooms and relocation/ remodel of office and shop space to accommodate business changes would total

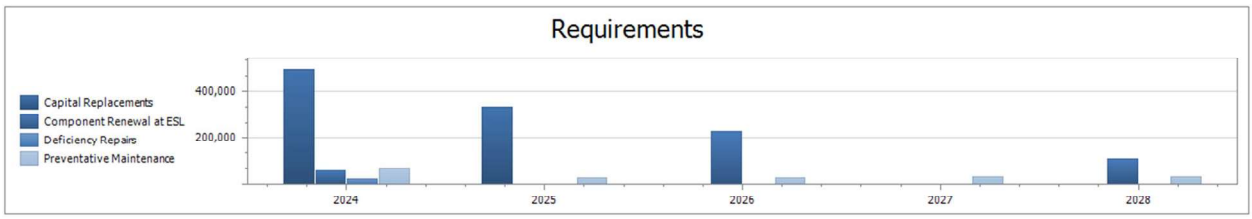
Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 469 of 535

DocuSign Envelope ID: 16B1CEA3-9B44-404E-BDD9-880D3754A87D

another $3,000,000 over the next 5 years. These costs would be invested into a building that does not meet the needs of the business. Facilities has delayed spend at this location since 2018 due to the active request to fund this work.

As the site itself is insufficient for the needs of the business an alternative solution needs to be looked at. Differing this work may result in capital investments to be made to an existing location that has large safety and condition issues. Regardless of improvements made the site is unable to accommodate appropriate vehicle storage canopies, materials storage (both yard and warehouse), office and meeting space needs and the safety impact of the highway remains.

Asset Condition Requirements:



Year

Account	2024	2025	2026	2027	2028	Grand Total
Capital Replacements	$493,428	$332,241	$0	$0	$0	$825,669
Component Renewal at ESL	$59,699	$0	$228,063	$114	$109,531	$397,406
Deficiency Repairs	$24,433	$0	$0	$0	$0	$24,433
Preventative Maintenance	$68,319	$28,301	$29,150	$30,024	$30,925	$186,718
Grand Total	$645,879	$360,542	$257,213	$30,138	$140,455	$1,434,227
Active Assets	7	7	7	7	7	
Total Replacement Value	$7,612,327	$7,840,697	$8,075,918	$8,318,195	$8,567,741	

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

The major reason to perform this project is to align with Avista's Focus Areas of Our Customer and Our People. Being able to provide service to our customers safely and efficiently is a cornerstone of Avista and the facilities our crews report to is a vital piece of this service effort. Having facilities and storage yards that meet the needs of both electric and gas operations benefits both Our People and Our Customers.

This project also aligns with our value of Innovation and our Mission of innovative energy solutions. Innovation is change and having an openness to improve products, processes, and services. Whether it is from incorporating new ideas into already established systems, or completely transforming how something is done, innovation is the key to solving the challenges Facilities is faced with today. Facilities has worked to include innovation into each of the projects we complete with a focus on energy and operational efficiency. Providing savings to both the company and customers by reducing company utility bills. Operationally, layouts of service yards and buildings will be evaluated to create the most efficient pathways and access. Saving employee time and increasing safety.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 470 of 535

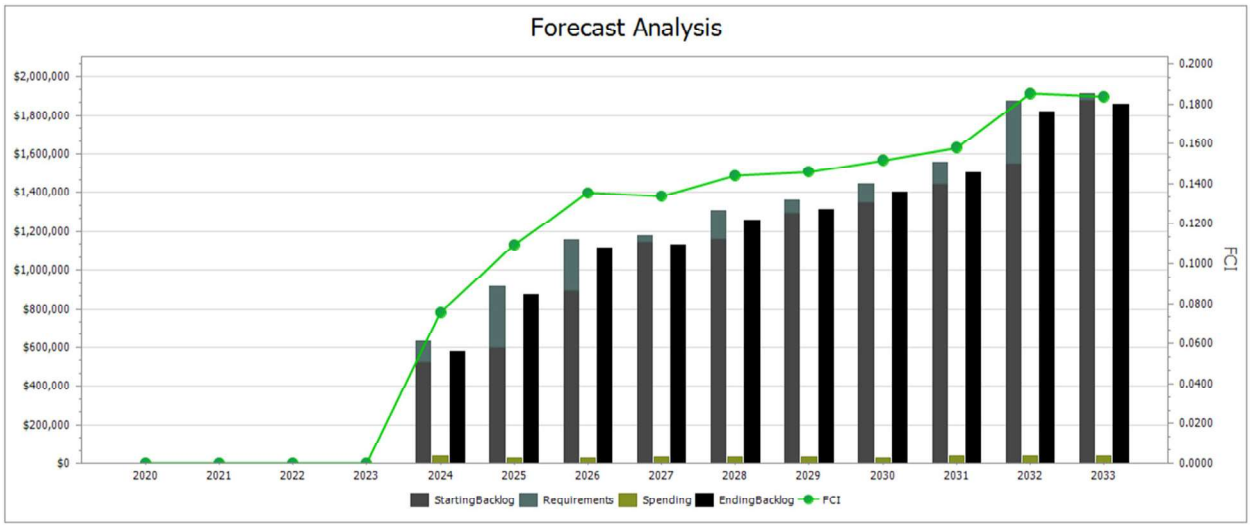
DocuSign Envelope ID: 16B1CEA3-9B44-404E-BDD9-880D3754A87D

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

The Asset Condition Study and Asset Condition Report for the Pullman Service Center were used to help determine the best option to resolve the various business problems. These reports help to understand the Asset Condition needs of the existing structure and the cost impacts to those improvements. The Facilities 10-year plan Matrix was also used to compare the Avista owned assets to determine which locations require new locations, remodels, or upgrades.

Pullman 10- Year Forecast of Backlog and Requirements:

*Based on typical yearly spend in Pullman, does not include any of the planed $1.5M spend



[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 471 of 535

DocuSign Envelope ID: 16B1CEA3-9B44-404E-BDD9-880D3754A87D

Starting Backlog: $523,118

ID	Grouping	Category	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Grand Total
1	Backlog (Start of Year)	Capital	$0	$0	$0	$0	$498,685	$581,498	$879,365	$1,128,188	$1,146,179	$1,276,008	$1,331,517	$1,426,155	$1,530,761	$1,855,613	
		O&M	$0	$0	$0	$0	$24,433	$16,469	$16,963	$17,472	$17,996	$18,536	$19,092	$19,665	$20,255	$20,863	
	Backlog (Start of Year) Total		$0	$0	$0	$0	$523,118	$597,967	$896,328	$1,145,660	$1,164,175	$1,294,544	$1,350,609	$1,445,820	$1,551,016	$1,876,475	
2	Requirements	Capital	$0	$0	$0	$0	$78,829	$286,594	$228,063	$114	$109,531	$31,399	$64,089	$77,547	$287,830	$0	$1,163,994
		O&M	$0	$0	$0	$0	$27,476	$28,301	$29,150	$30,024	$30,925	$31,853	$32,808	$33,792	$34,806	$35,850	$314,985
	Requirements Total		$0	$0	$0	$0	$106,305	$314,895	$257,213	$30,138	$140,455	$63,251	$96,897	$111,339	$322,637	$35,850	$1,478,980
3	Backlog + Requirements		$0	$0	$0	$0	$629,423	$912,861	$1,153,541	$1,175,798	$1,304,630	$1,357,796	$1,447,506	$1,557,159	$1,873,653	$1,912,325	
4	Budget	Capital	$0	$0	$0	$0	$15,000	$15,450	$15,914	$16,391	$16,883	$17,389	$17,911	$18,448	$19,002	$19,572	$171,958
		O&M	$0	$0	$0	$0	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$250,000
	Budget Total		$0	$0	$0	$0	$40,000	$40,450	$40,914	$41,391	$41,883	$42,389	$42,911	$43,448	$44,002	$44,572	$421,958
5	Spending	Capital	$0	$0	$0	$0	$13,954	$14,339	$12,393	$15,507	$16,866	$16,538	$10,989	$17,526	$17,026	$16,726	$151,863
		O&M	$0	$0	$0	$0	$22,694	$14,678	$15,119	$15,572	$16,039	$16,520	$17,016	$17,526	$18,052	$18,594	$171,811
	Spending Total		$0	$0	$0	$0	$36,648	$29,017	$27,511	$31,079	$32,906	$33,058	$28,005	$35,052	$35,078	$35,320	$323,674
6	Variance (Budget minus Spending)	Capital	$0	$0	$0	$0	$1,046	$1,111	$3,520	$883	$16	$851	$6,921	$922	$1,975	$2,845	$20,091
		O&M	$0	$0	$0	$0	$2,306	$10,322	$9,881	$9,428	$8,961	$8,480	$7,984	$7,474	$6,948	$6,406	$78,189
	Variance (Budget minus Spending) Total		$0	$0	$0	$0	$3,352	$11,433	$13,402	$10,311	$8,976	$9,331	$14,905	$8,396	$8,923	$9,251	$98,280
7	Backlog (End of Year)	Capital	$0	$0	$0	$0	$564,561	$853,753	$1,095,329	$1,112,795	$1,238,843	$1,292,735	$1,384,617	$1,486,176	$1,801,566	$1,838,886	
		O&M	$0	$0	$0	$0	$15,989	$16,469	$16,963	$17,472	$17,996	$18,536	$19,092	$19,665	$20,255	$20,863	
	Backlog (End of Year) Total		$0	$0	$0	$0	$580,550	$870,222	$1,112,292	$1,130,267	$1,256,839	$1,311,271	$1,403,709	$1,505,841	$1,821,820	$1,859,749	
8	Unfunded Preventative Maintenance		$0	$0	$0	$0	$13,226	$13,622	$14,031	$14,452	$14,886	$15,332	$15,792	$16,266	$16,754	$17,256	$151,617
9	FCI		0.0000	0.0000	0.0000	0.0000	0.0757	0.1094	0.1354	0.1336	0.1441	0.1459	0.1516	0.1578	0.1851	0.1835	
10	Total Replacement Value		$0	$0	$0	$0	$7,840,697	$8,075,918	$8,318,195	$8,567,741	$8,824,773	$9,089,516	$9,362,202	$9,643,068	$9,932,360	$10,230,331	
11	Spending as % of TRV		0.00 %	0.00 %	0.00 %	0.00 %	0.47 %	0.36 %	0.33 %	0.36 %	0.37 %	0.36 %	0.30 %	0.36 %	0.35 %	0.35 %	

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Short Term Alternative Solution- Provide Funding for Specific improvements at the Current Pullman Service Center- $1.5M

Provide the Pullman Service Center with a temporary solution while we work towards the recommended long-term solution. Providing $1.5M over two years will allow for improvements to the parking lot and storage yard. Repair of the roof and improvements to the canopy. Construction of a new temporary storage yard off Airport Road will provide an alternative pole storage yard.

Asset Condition Projects: $925,000

Repair of the roof, to improve safety and eliminate roof leaks. Replacement of the asphalt, to reduce pooling water and ice and provide safer access for the forklift. Add a wash pad and oil water separator, to wash vehicles without impacting the site.

Operational Request Projects: $575,000

Construction of a new temporary storage yard, potentially off Airport Road at the site of a new substation. Interior improvements to provide additional needed off space and upgrades to create efficiency. Lighting and HVAC upgrades due to failing systems.

Providing these improvements will allow the Pullman Service Center team to work more efficiently over the next 10 years. While this does not solve for all the Business Problems, including much of the asset condition issues it does provide solutions for many of them.

DocuSign Envelope ID: 16B1CEA3-9B44-404E-BDD9-880D3754A87D

Recommended Solution- New Pullman Service Center

The proposed solution to the business problems identified above is to build a new Service Center. The new Service Center will be located on a new property where we could locate the Service Center, the pole yard and warehouse, fleet location and radio tower. The radio tower is a critical part of the communications system with crews, both daily and during an outage, and will need to be included in the relocation. This option would allow us to find a property large enough allowing future growth. This new Service Center would meet the requirements outlined in the Business Problem stated above. Providing the needed warehouse and storage, office space and include the necessary environmental requirements and safety protocols.

A property has been identified in Moscow ID and is currently being reviewed for feasibility with Real Estate but is not confirmed for funding. The property is 7.5 miles from our current location and centered within the Palouse service territory.

The new Service Center, regardless of location, will include environmentally protected transformer storage areas and adequate storm water protection, including oil water separators for the entire facility. This is the new environmental standard for design for Avista, meeting legal requirements as well. The new facility will centralize all of Pullman crew functions into one location, saving windshield time each day for crews who currently travel to various substation properties for materials if needed.

The new Service Center would be designed to meet the needs of today's employees and would meet current code requirements. These needs include both men's and women's ADA restrooms and showers, workspace for all necessary employees, meeting space for both Move Safe and EOP's, workout equipment and warehousing. All the building systems would be designed to today's technology and are planned to be more efficient than the existing location due to technology improvements and reduction of energy costs per square foot.

The current building will be sold to offset some of the cost of building new.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

There is currently an identified backlog of $523K in Asset Condition work needed at the Pullman Service Center. In 2017 Terricon identified $110K in work on their initial assessment. This list is growing every year as our building ages and new items are identified that need replacement. At the current funding level this backlog of capital work will continue to grow. The backlog is growing faster than our current funding model can accommodate. Making the investment into the existing structure will not solve the remaining problems of limited space, safety and environmental.

Environmental Compliance has rated the Sandpoint Service Center as a 3. Placing at the top of our list for locations needing environmental mitigation.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 473 of 535

DocuSign Envelope ID: 16B1CEA3-9B44-404E-BDD9-880D3754A87D

Pullman

Element	Score	Reason
Surface Water	1	Adjacent wetland and Paradise Creek
Floodplain	0	
Historic District	0	
Adjacent Use	1	Ag and steep slopes
Zoning	0	
Total	2	

2.3 Summarize in the table and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	-	$	$	$	$	$
O&M	Utility savings/ Sale of Building	$	$	$	$0	$

*Building sale not valid in partial funding solution

Direct (Based on Revised Solution):

- None

2.4 Summarize in the table and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	-	$	$	$	$	$
O&M	Business Operations Improve	$	$155,905	$155,905	$155,905	$155,905

Indirect (Based on Partial Funding):

- Extended/ improved storage yards or storage facilities: Improved business operations and time efficiencies for crews. An example of this would be added storage racking resulting in easier material access, yard consolidation.
  - 15 emp x 0.25 hr./day x 260 workdays x $85/hr. avg loaded rate= **$82,975**
- Efficiencies created through improved storage, more efficient workspaces and expanded workspaces as required for growth.
  - 22 emp x 0.15 hr./day x 260 workdays x $85/hr. avg loaded rate= **$72,930**

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

DocuSign Envelope ID: 16B1CEA3-9B44-404E-BDD9-880D3754A87D

2.5 Describe in detail the alternatives, including proposed cost for each alternative, which were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1: PULLMAN RENOVATION/ STORAGE YARD LAND

O&M: $217,000 **CAPITAL: $9,900,000**

To avoid constructing a new Pullman service center, Avista would need to continue upgrading the existing Service Center building. This would include several hundred thousand dollars' worth of upgrades and improvements. Purchasing additional adjacent properties and expanding the service center is not an option. Hills and grading difficulties will cost hundreds of thousands of dollars any time we were to increase the yard by even a little bit.

- Required replacement or repair under Operations and Maintenance totaling $217,000 over the next 5 years.
- Another $1,400,000 in repairs and replacements were identified that would need to be completed under Capital Spend over the next 5 years.
- A $3,000,000 renovation to the existing structures would be required to complete and interior remodel including ADA upgrades to restrooms and relocation/ remodel of office and shop space to accommodate business changes.

We would need to purchase land in another area of town and create an additional storage yard and possibly additional structures to accommodate larger trucks. This would require that crews drive to and from this new storage yard/ secondary location several times a day. Impacting response times and reducing productivity.

- A land purchase to accommodate a storage yard would need to be made. The land would need to be a minimum of 5 acers. Based on property estimates in the Palouse are: $500,000.
- Development on land and vehicle storage barn. $5,000,000

Alternative 2: MAINTAIN CURRENT LOCATION

O&M: $217,000 **CAPITAL: $4,400,000**

Choosing to maintain the current location would greatly impact the Operations and Maintenance budget for the Pullman facility. The existing building condition would require that some large Capital investment be made to create a useable and safe location for employees to work. The building would require an extensive renovation to try to accommodate the current employees and materials.

The current land is not sufficient for the needs of the Pullman Service Team. Materials would need to be stored at other locations including Clarkston and Spokane greatly impacting response times.

- Required replacement or repair under Operations and Maintenance totaling $217,000 over the next 5 years.
- Another $1,400,000 in repairs and replacements were identified that would need to be completed under Capital Spend over the next 5 years.

A $3,000,000 renovation to the existing structures would be required to complete and interior remodel including ADA upgrades to restrooms and relocation/ remodel of office and shop space to accommodate business changes.

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2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Confirm the scoping documentation and approved design to the final constructed solution that provides room for growth, expands technology requirements, and adheres to safety and security best practices. Some of these solutions would include items such as:

1) Materials/ Storage: Provide warehouse space that meet the needs of the Stores team and Operations. Reduction in trips back to Spokane or other storage yards for materials (currently not tracked).
2) Environmental/ Compliance: Ensure that the building and site meets with Avista's environmental standards. Currently not meeting the base standards for storm water runoff.
3) Employee/ Customer Impacts: Room for employee or operations growth
4) Operational Efficiency: Ensure that operational needs of employees are being met, increase of productivity and reduced windshield time for crews.

Asset Condition: Provide systems and materials that meet with Avista standards and current building codes and requirements.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Plan if fully Funded:

The property purchase would be completed in 2024. Design will begin in early 2026 with construction to follow in 2026 and 2027. Currently, as of April 2023, we expect to Transfer to Plant by December of 2027.

Partial Funding Plan:

The CPG partially funded this program in 2024 and 2025 below is the planned project spend for those years. This partial funding will be spent across the two locations in the program to provide them with needed improvements to maintain functionality at the current locations.

YEAR	LOCATION	PROJECT	ESTIMATED SPEND	PLANNED TTP
2024	Pullman	Roof Replacement	$200,000	11/2024
2024	Pullman	Asphalt	$200,000	11/2024
2024	Pullman	Oil Water Separator/ Wash Bay	$150,000	11/2024
2024	Pullman	Temp. Storage Yard	$200,000	11/2025
TOTAL ALLOCATION			**$750,000**	
2025	Pullman	Storage Buildings/ Canopy	$250,000	11/2025
2025	Pullman	Asphalt Phase 2	$200,000	11/2025
2025	Pullman	Interior Improvements Phase 2	$125,000	11/2025
2025	Pullman	HVAC and Lighting Upgrades	$175,000	11/2025
TOTAL PLANNED ALLOCATION			**$750,000**	

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2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Facilities Capital Steering Committee

Once the project list is assembled, the finalized list of projects is approved by the Capital Facilities Steering Committee. This Committee of Directors is responsible for approving the submission of Business Cases to the Capital Planning Group and approval of projects and any changes within this program.

In the past this has most often been:

- Director of Shared Services
- Director of Environmental Affairs
- Director of Financial Planning and Analysis
- Director of Generation, Production, Substation Support
- Director of IT and Security
- Director of Natural Gas

The project shall use certain Project Management Professional (PMP) guidelines and procedures during the course of this project.

A Project Execution Plan, consisting of the documents below, will be drafted and approved by the SteerCo described in Section 3.1 (A).

- Project Charter, Change Management Plan, Communication Management Plan, Cost Management Plan, Procurement Management Plan, Project Team Management Plan, Risk Management Plan and Risk Register, Schedule Management Plan, Scope Management Plan, and Project Execution Approval Form.

Each month, the project manager will provide the following information either at the scheduled SteerCo meeting, or via email.

- Approved Yearly Budget, Accrued Yearly to Date, Year Estimate at Complete, Year Variance at Complete, Approved Lifetime Budget, Accrued Life to Date, Lifetime Project Estimate at Complete, and Lifetime Project Variance at Complete.

Each month, the SteerCo will make decisions on cost, scope, or budget items as required by the Project Execution Plan. The project manager reserves the right to present items not outlined in the Project Execution Plan if he/she determines its importance is relevant to SteerCo input.

The final decisions regarding these items, especially certain change requests as required by the Project Execution Plan, will be presented to, and voted upon by the SteerCo. The decisions will be documented in a monthly meeting minute of the SteerCo for documentation and oversight.

It will be the Project Manager's role to monitor the scope, budget, and schedule and present the results to the SteerCo, regardless of they are within tolerances, or not.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 477 of 535

DocuSign Envelope ID: 16B1CEA3-9B44-404E-BDD9-880D3754A87D

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Palouse Business Case* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Eric Bowles 4ACC724B187E64C2...	Date:	May-01-2024 | 12:40 PM PDT
Print Name:	Eric Bowles		
Title:	Corporate Facilities Manager		
Role:	Business Case Owner		

Signature:	DocuSigned by: Kelly Magalsky E7A0F731C49442B...	Date:	May-01-2024 | 3:25 PM PDT
Print Name:	Kelly Magalsky		
Title:	Director-Shared Services		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 478 of 535

EXECUTIVE SUMMARY

Avista owns and maintains electric transmission, distribution, and natural gas facilities which cross public lands managed by a variety of state, federal and local agencies, as well as entities who own extensive tracts, such as railroads. Traditionally, we have secured long-term rights-of-way permits for these facilities, but have been required to renew them through an annual billing process. The cost of renewing these permits continues to increase each year, ranging from 3% to 10% annually, depending on the agency/entity, thereby increasing annual O&M expenses to the company and our customers. This business case proposal is to secure long-term agreements with lump-sum payments to reduce overall expenses related to labor of tracking, researching, and processing these annual permits. In some cases, we have been able to negotiate a lower annualized cost over the term of the permit by paying a lump sum up front. In either case, we reduce costs to the company and our customers. Making long-term lump sum payments allows us to capitalize these costs, as the permit is a long-term asset.

A final determination was made by project accounting that all right of way permits may be capitalized since they are in the retirement catalog. The permit must be for a term of at least one year.

Without capital funding, we will continue to incur increasing annual permitting fees and related internal costs as an O&M expense. These costs affect all customers, electric and gas, in the entire Avista service territory.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Ted Hermann*	*Initial draft of original business case*	*8/30/23*
2.0	*Ted Hermann*	*Information moved to new 2025-2029 template*	*4/29/24*
BCRT	*Heide Evans*	*Has been reviewed by BCRT and meets necessary requirements*	*4/29/24*

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 479 of 535

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2025	**$250,000**	**$250,000**
2026	**$250,000**	**$250,000**
2027	**$250,000**	**$250,000**
2028	**$250,000**	**$250,000**
2029	**$250,000**	**$250,000**

Project Life Span	***Annually***
Requesting Organization/Department	V08 / Real Estate
Business Case Owner | Sponsor	Ted Hermann / Bruce Howard
Sponsor Organization/Department	A04 / Environmental Affairs
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. **BUSINESS PROBLEM -** *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

Avista owns and maintains electric transmission, distribution, and natural gas facilities which cross public lands managed by a variety of state, federal and local agencies, as well as entities who own extensive tracts, such as railroads. As these rights of way permits renew, we've been paying annually increasing fees, leading to increased O&M expenses associated with both the permit costs and the labor to process them.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 480 of 535

1.2 Discuss the major drivers of the business case.

Performance & Capacity, and Failed Plant & Operations. In order to legally construct, maintain and upgrade our facilities on agency owned lands, we must acquire and renew rights of way permits. While we would continue doing this work without this business case, the main benefits to the customer are being able to negotiate lower fixed permit costs through lump sum payments, as well as securing long term permits which will allow us to maintain reliability in our infrastructure. In addition, we will reduce our labor costs for managing these permits. We also reduce the risk of annual permits not being renewed or being modified unilaterally.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Right of way permitting on agency-owned lands is an ongoing and necessary scope of work. We will continue doing this work without an approved capital business case. This business case is based on our potential of saving the company and our customers money over the long term by capitalizing permit fees and negotiating lower costs through long term, lump sum payments.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

Our proposed investment is aligned with Avista's mission of delivering reliable power to our customers at the most affordable price we can deliver. Right-of-Way Use Permits are required for Avista to construct, maintain, and upgrade electric infrastructure. Without these rights of way, we cannot meet our objectives.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 481 of 535

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

Row Labels	Sum of Transaction Amount
2020	126,396.32
2021	202,717.87
2022	265,548.90
2023	383,587.04

Based on historic data, the program cost is approximately $250k annually.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

We propose that through this business case, we will work with agencies to negotiate lump sum payments for our rights of way permits, thereby securing long-term, and lower fixed costs associated with acquiring and renewing these permits.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.
[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 482 of 535

This business case was developed utilizing a historical analysis of expenses related to labor and other administrative costs in completing previous Right-of-Way Use Permits.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

direct costs of acquiring legal rights to maintain and/or extend rights-of-way (ROW) for Avista's electric transmission/distribution and gas infrastructure on public lands. Public land entities typically provide rights-of-way via permits, and our goal is to acquire these at the lowest cost and for the longest term possible.

Absent such permits, Avista would be required to re-route linear projects around public lands. Such re-routing would result in significant additional direct costs. These would include additional materials and construction costs for longer distances, increased ROW acquisition costs, and increased internal labor for design, planning, permitting and project management. The range of such costs is too uncertain to quantify but would be in the millions of dollars. By not maintaining ROW permit approvals, Avista would risk legal action, fines and ultimately, eviction from public lands.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M		$	$	$	$	$

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

While there are no quantifiable indirect savings, were Avista unable to acquire permits for public land ROW, we would be forced to seek alternative routes. In addition to the direct additional costs, there would be indirect costs, such as increased line losses due to increased distances, increased AFUDC, time delays, etc.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

There are no alternatives to renewing Right-of-Way Use Permits.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Once the highway audit is complete Real Estate will have a complete understanding of what portions of highway have Avista facilities that are not permitted. We can use this audit to track permit application submittals and approvals as we progress through the list. This list is currently maintained in Excel. A regular audit should be scheduled every 2 years to verify checks and balances are accurate and facilities are maintained in an approved status.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

This is a program, and the work is completed throughout the year based on when agency permits are received. They will become used and useful once the fully executed permit is in place.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

This program will be monitored by the Real Estate Manager, Sr. Director of Environmental Affairs, and Department Financial & Budget Specialist. We will evaluate the annual costs and savings to ensure the program is on track.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 484 of 535

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Right-of-Way Use Permits* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Ted Hermann	Date:	April 30th, 2024
Print Name:	Ted Hermann		
Title:	Manager Real Estate		
Role:	Business Case Owner		

Signature:	Bruce F. Howard	Date:	April 30, 2024
Print Name:	Bruce Howard		
Title:	Sr Dir Environmental Affirs		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 485 of 535

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EXECUTIVE SUMMARY

The existing Sandpoint Service Center facility was acquired in 1995 with an original construction date estimated at 1957. The existing storage yard is becoming too small for ever-growing inventory, which has almost tripled in the last 10 years. The unique voltage in the Sandpoint area, different than the rest of the company, requires the local storekeeper to have more material than yards of a similar size because Spokane cannot be utilized for backup. The property is too small for our needs, and we are unable to purchase any additional land adjacent to the existing property. We are currently looking for additional off-site storage to help accommodate the needs of the Service Center. The property to the North, which Avista owns, is wetlands and currently the drainage from this property runs through our yard creating stormwater issues.

The Sandpoint substation, currently adjacent to the Service Center, needs a rebuild in the next 15 years. The current plan is to locate the new substation on the land currently occupied by the Sandpoint Service Center. When building substations, it is least expensive for Avista to build a new station (with all the modern equipment and to current standards) on a parcel right next door the old station. That allows us to keep the old station energized and serving load while we build. Then we cut the load over to the new station with very little (or no) impact to our customers. The farther we are from the old yard the harder the cut over is and the more interruption our customers will see. This requires the Service Center be relocated prior to the design phase of that substation.

The proposed solution to the business problems identified above was to relocate the Sandpoint Service Center where we will locate the office, line dock, pole yard and the warehouse. The building will be located at an already purchased parcel North of Sandpoint. This option would allow for future growth. Due to unavailable funding the solution was proposed to provide a minimal amount of funding to make improvements to the Sandpoint Service Center at its current location. Improving the asphalt, storage areas and repairing building systems such as roofs, electrical and HVAC will provide the Sandpoint team with a few improvements while we work towards the preferred solution of a new Service Center in the next 10 years. A new storage yard located on another property to the North is also included in this option to provide additional storage. These improvements will cost $1.5M over two years.

This project would impact both Gas and Electric customers in both Washington and Idaho and this project would benefit external customers in that the Service Center improvements can improve efficiencies. Having all materials, supplies and staff in a safe location allows for better use of resources and response times. Employees benefit from improved communication during outages and ability to perform their tasks safely and effectively. The Sandpoint building and the site have many critical systems that need replacement, including electrical, HVAC, plumbing and roof systems. Many of these projects have been put on hold as there are functional issues in Sandpoint that the location is unable to accommodate, such as trucks being unable to park at the line dock due to current vehicle size and the inability to house a future Gas crew.

The Facilities Capital Steering Committee approved submission of this Business Case.

VERSION HISTORY

Version	Author	Description	Date
1.0	*L. Miller*	*Initial draft on New Template*	*4/4/2024*
2.0	*L. Miller*	*2nd Draft for BCRT Review*	*04/26/2024*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	*Steve Carrozzo 4/30/2024*

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 486 of 535

DocuSign Envelope ID: DD7B2E08-519E-43D4-A38F-44D5BE1CF5BB

PLANNED SPEND FOR PARTIAL FUNDING

The CPG partially funded this program in 2024 and 2025, below is the planned project spend for those years. Many of the 2024 projects are in the planning process and will transfer to plant before the end of 2024. This partial funding will be spent to provide the Sandpoint Service Center with needed improvements to maintain functionality at the current location until a new Service Center can be designed and built. It is expected that these improvements will allow the Service Center to maintain functionality for the next 5-10 years at which point designing and relocating the Service Center will be required.

YEAR	LOCATION	PROJECT	ESTIMATED SPEND	PLANNED TTP
2024	Sandpoint	Partial Roof Replacement	$150,000	11/2024
2024	Sandpoint	Asphalt Phase 1	$100,000	11/2024
2024	Sandpoint	Warehouse Design	$60,000	11/2024
2024	Sandpoint	Exterior Lighting Upgrades	$20,000	9/2024
2024	Sandpoint	Furniture/ Chair Upgrades	$120,000	11/2024
2024	Sandpoint	Pole Storage Yard	$200,000	11/2024
2024	Sandpoint	Warehouse Construction Start	$100,000	11/2025
TOTAL ALLOCATION			**$750,000**	
2025	Sandpoint	Warehouse Construction	$500,000	11/2025
2025	Sandpoint	Asphalt Phase 2	$100,000	11/2025
2025	Sandpoint	Interior Improvements	$120,000	11/2025
2025	Sandpoint	HVAC and Lighting Upgrades	$30,000	11/2025
TOTAL PLANNED ALLOCATION			**$750,000**	

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$750,000**	**$650,000**
2025	**$750,000**	**$850,000**
2026		
2027		
2028		
2029		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 487 of 535

DocuSign Envelope ID: DD7B2E08-519E-43D4-A38F-44D5BE1CF5BB

Project Life Span	***5 years***
Requesting Organization/Department	Facilities
Business Case Owner | Sponsor	Eric Bowles | Kelly Magalsky
Sponsor Organization/Department	Facilities
Phase	Planning
Category	Program
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

BUSINESS PROBLEM - THIS SECTION MUST PROVIDE THE OVERALL BUSINESS CASE INFORMATION CONVEYING THE BENEFIT TO THE CUSTOMER, WHAT THE PROJECT WILL DO AND CURRENT PROBLEM STATEMENT.

1.1 What is the current or potential problem that is being addressed?

The site has many issues and concerns that are forcing us to make an investment in the site or a new location. The Sandpoint Service Center facility was acquired in 1995 for $181,483. We are unsure of the original construction date but estimate it in 1957. Since that time, Avista has invested $514,423 in capital improvements to the facility. Major maintenance upgrades include a new roof and an asphalt overlay in the service yard. The issues and concerns are as follows:

Building Condition

The Sandpoint Service Center building had a Building Condition Assessment completed by a third party in 2017. In that survey, items were identified that needed immediate replacement or repair totaling $150,000. The current backlog and requirements, as of today, total $912,000 in repairs and replacements. There is additional work identified that would need to be completed in the next 5 years bringing the backlog and requirements to $1,193,000. The estimates are for like for like replacements and make no operational building or site improvements. The Inventory Condition Report was completed to review the existing condition of the structure as well.

There are specific items that need to be replaced per the third-party survey we had completed in 2017. Items like the emergency generator, electrical panels, unit heaters and bollards. There is also extensive repair needed to the existing CMU walls. There is widespread asphalt damage and requires complete replacement throughout the Service Center.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 488 of 535

DocuSign Envelope ID: DD7B2E08-519E-43D4-A38F-44D5BE1CF5BB

Sandpoint Service Center

There are a large number of small items that need to be repaired and replaced in the next 5 years. The flooring needs to be replaced, lighting needs to be upgraded, the entire building inside and out needs paint, and the roof hatch needs to be replaced. The plywood roof decking needs to be replaced in areas and the HVAC system and window units need to be upgraded.

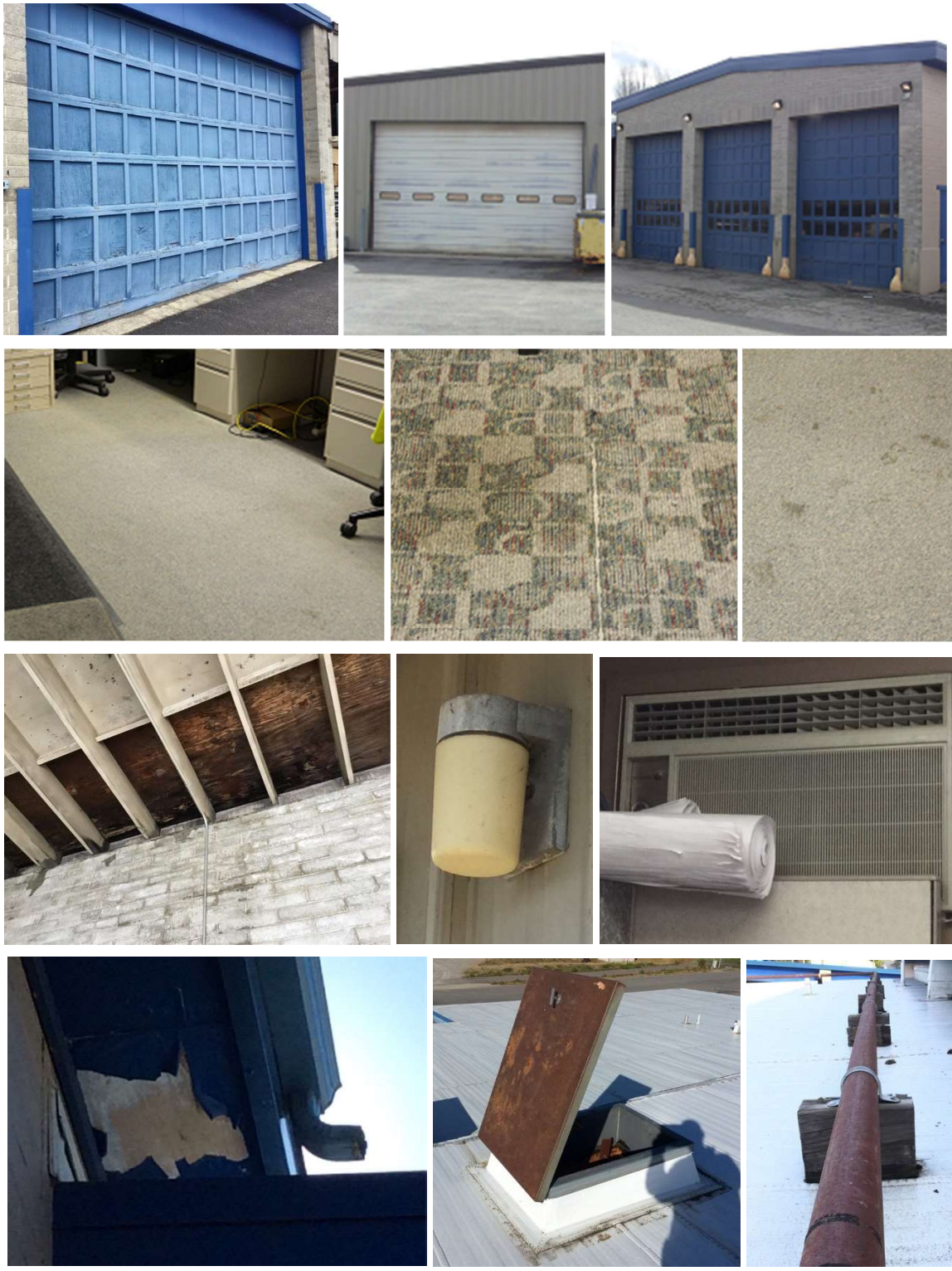
All the roll up doors need to be replaced at the site. Many are damaged and beyond repair. They are part of the original construction and are not insulated and do not meet today's standards. The site has extensive damage to the concrete sidewalks and paving and needs replacement. The fencing requires extensive work and has a lot of damage from the snowplows and winter weather.

Most of this work would be capital investments that would need to be written off once the building is demolished to accommodate the Sandpoint Substation in the next 15 years. A small portion, about 5%, of this identified work is O&M, including paint and fence repair.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 489 of 535

DocuSign Envelope ID: DD7B2E08-519E-43D4-A38F-44D5BE1CF5BB

Sandpoint Service Center



Current Sandpoint Service Center:

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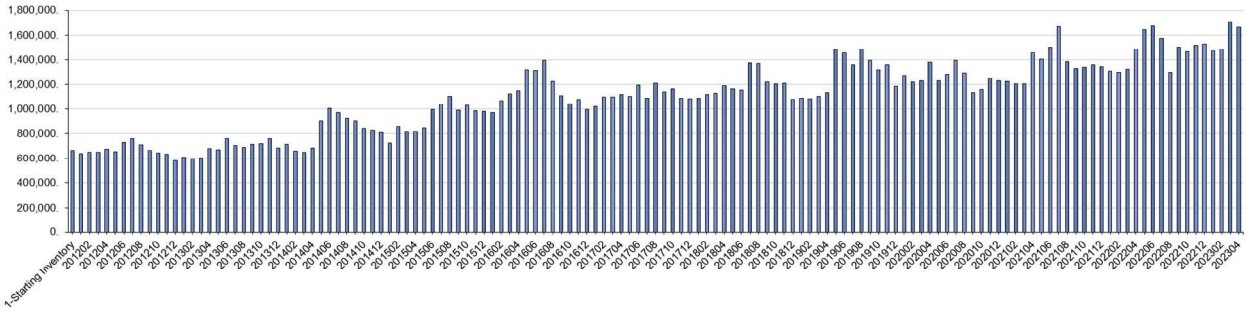
Materials/ Storage

The existing storage yard is becoming too small for ever-growing inventory, which has almost tripled in the last 10 years. Due to the unique voltage only in the Sandpoint area, the local storekeeper must keep more material than other yards as Spokane cannot be utilized for backup. Facilities has everything it can to capitalize on the existing storage space available. However, the property is too small to meet the needs of our customers and there is an inability to purchase any additional adjacent land.

A further issues and risk to the storage yards is the creek that runs through our yard yearly floods. We are currently looking for additional off-site storage to help accommodate the needs of the Service Center.

Historical Warehouse Inventory- Sandpoint:



Every spring a creek expands and runs through the back of the Sandpoint yard resulting in the crews working in 18” of water to load poles.

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Environmental/ Compliance

Many of the building systems are antiquated and have reached the end of their useful life. We expect some of these systems to fail in the next 5 years. If the systems fail, we will need to replace them to allow for continued use of the structure. As the building will be demolished to accommodate the Sandpoint substation in the next 15 years investing in these systems could result in a large write off at that time.

This site has environmental concerns and needs to have a review of the water runoff plain and upgrades will need to be made. One concern is the public highway runoff, which the state has made some changes to, but facilities and environmental need to look at its impact on maintenance on the site. The vehicle wash bay also needs to be properly mitigated, which is not currently happening. Facilities estimates that installing a proper drainage and oil/ water separator system would cost approximately $250k.

The existing building has minor code compliance and security issues. These include no ADA access or restrooms and no access control system or automatic gates. The interior of the main building needs an update and possibly a large reconstruction or renovation. The layout is no longer conducive to today's business needs. The office space is limited preventing current staff from having dedicated seating. There are many ADA issues and much of the construction does not comply with current code requirements.

Employee/ Customer Impact

There are currently 22 employees working out of the Sandpoint Service Center. In addition, there are contract crews from NPL that work out of that office and leave their equipment in the yard. We do not have enough parking for the current employee/ contractor count. One of the employee's trucks had $3,500 worth of damage due to ice unloading while parked in an undesirable area because we had no room with 24" of snow that forces us out of most areas. Employees also experience icy walking conditions throughout the exterior of the service center. The roof of the dock area leaks creating icy patches that must be continually de-iced and sanded. It is very hard to shovel and plow safely due to the paving in Sandpoint.

The weather during the winter months in Sandpoint is much worse than in the Spokane area. Sandpoint averages 59 inches of snow per year and employees spend a great deal of time shoveling snow off their equipment and materials to function in the winter because it is not under cover. One of the canopies on site collapsed a few years ago due to snow load, the structure was unsafe, built very poorly. The remaining structure is very narrow, preventing vehicles from being able to utilize the cover.

The interior of the main building is in need of an update and possibly a large reconstruction or

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renovation. The layout is no longer conducive to today's business needs. There is no meeting room for employee meetings or for community use. Employees use the breakroom when meetings are required and impact the use of that space. There is no room for exercise equipment to help assist our employees with fitness.

Operational Efficiency/ Safety

Emergency exit lighting and smoke detection systems are missing from the building. This is a critical failure and would need to be rectified if a new building is not built. The existing building has minor code compliance and security issues. These include no ADA access or restrooms and no access control system or automatic gates.

There isn't enough room to park company vehicles in covered areas. Avista has purchased larger and larger vehicles over the last 15 years which has caused a systemic issue with vehicle size line dock parking. The line docks were designed for the vehicles at that time which no longer safely fit. Many of the company vehicles that are parked inside are parked with few inches to spare between the dock and the roll up door. The bays are not large enough due to larger equipment purchased for today's needs. This provides limited movability around the trucks and requires that the employees driving must back up into the dock.

The mechanic's bay has taken over a bay in the truck barn to accommodate the need to repair vehicles. This has moved another vehicle out into the weather. There is also no means of washing the vehicles and the mag chloride (road de-ice/ salt) is creating an incredible amount of down time on our fleet due to the corrosiveness over time.

1.2 Discuss the major drivers of the business case.

The major drivers of this business case are Asset Condition and Safety.

The Sandpoint building and site have many worn buildings and assets in dire need of replacement, as many of capital projects have been put on hold until the future state of the site is known (see section 1.1). The upcoming Sandpoint Substation has caused a hold to be placed on any improvements to this site as the plan is to demolish the building. This is causing the current Asset Condition to fall well below acceptable. The lack of investment in these assets has resulted in safety concerns throughout the building and site. Examples of safety items include risk of slips, trips, and falls and snow/ ice shedding from roofs. The Sandpoint Service Center has been considered for replacement since 2018.

This project would benefit external customers in that the new Service Center can improve efficiencies. Having all materials, supplies and staff in one location allows for improved use of resources and response times. Employees benefit from improved communication during outages and ability to perform their tasks safely and effectively. The current situation in Sandpoint is such that Avista will need to address the materials yard shortage by purchasing additional property in the coming years, to meet this space need.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The funds being requested are to enable the Sandpoint Service Center to meet its customer needs both internally and externally until a replacement facility is constructed at a later, unspecified date. The Sandpoint Service Center had a Building Condition Assessment completed by a third party in 2017 that identified immediate replacement or repair needs totaling $150,000. There is also a current backlog totaling $912,000 in repairs and replacements. Other work identified needing to be completed in the next 5 years brings amounts to approximately $1,193,000. and includes replacing the basic building systems s; the septic system; and the entire service yard asphalt and drainage.

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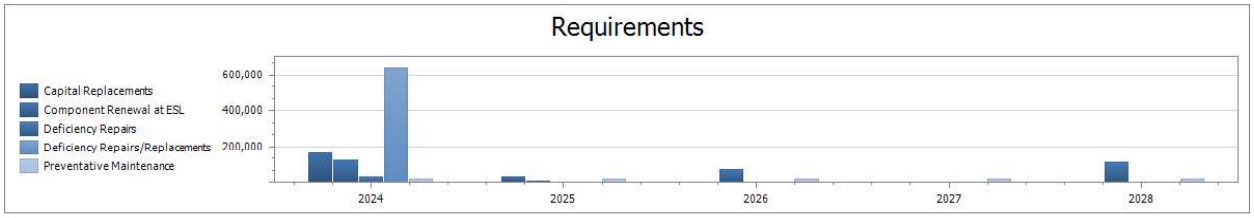
The upcoming Sandpoint Substation has caused a hold to be placed on any improvements to this site as the plan is to demolish the building. However, this caused the current Asset Condition to fall well below acceptable. The lack of investment in these assets has resulted in safety concerns throughout the building and site.

Asset Condition Requirements:



Year

Account	2024	2025	2026	2027	2028	Grand Total
Capital Replacements	$163,881	$28,025	$0	$0	$0	$191,905
Component Renewal at ESL	$120,100	$8,589	$67,358	$0	$110,488	$306,535
Deficiency Repairs	$27,226	$0	$0	$0	$0	$27,226
Deficiency Repairs/Replacements	$638,763	$0	$0	$0	$0	$638,763
Preventative Maintenance	$14,794	$15,238	$15,695	$16,166	$16,651	$78,545
Grand Total	$964,765	$51,852	$83,054	$16,166	$127,139	$1,242,976
Active Assets	5	5	5	5	5	
Total Replacement Value	$6,661,417	$6,861,260	$7,067,098	$7,279,111	$7,497,484	

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

The major reason to perform this project is to align with Avista's Focus Areas of Our Customer and Our People. Being able to better facilitate in providing service to our external customers safely and efficiently is a cornerstone of Avista and the facilities our crews report to is a vital piece of this service effort. These requested improvements will enable the Sandpoint Service Center to meet its customers' needs up until a new facility is constructed.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 494 of 535

DocuSign Envelope ID: DD7B2E08-519E-43D4-A38F-44D5BE1CF5BB

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

The Asset Condition Study and Asset Condition Report for the Sandpoint Service Center were used to help determine the best option to resolve the various business problems. These reports help to understand the Asset Condition needs of the existing structure and the cost impacts to those improvements.

The Facilities Building Matrix was used to compare the Avista owned assets to each other. This helped to determine which locations require new buildings to be constructed, remodels needed, or upgrades to existing structures. This matrix prioritized the locations based on current location and site suitability, condition rating, current utilization, site risk and environmental risk.

Site	Built	Current Age	Size	Location Suitability		Design / Site Suitability		Condition Rating		Site Utilization		Identified Site Risk		Environmental Risk		Notes	Site Scoring	Recommended Course of Action
Pullman	1959	61	Lrg	Fair	2	Poor	5	Fair	3	Over Capacity	5	Med	3	Med	2	Busy Highway access, site drainage issues	20	Sell and Relocate Facility
Sandpoint	1957	63	Med	Fair	2	Poor	4	Fair	3	Over Capacity	4	High	4	High	3	Located in residential area / Spring drainage flooding	20	Sell and Relocate Facility
Davenport	1966	54	Med	Poor	4	Poor	4	Fair	2	Over Capacity	4	Med	3	High	3	Low Structural bracing can be hit by vehicles/ transformer storage by river / Offsite pole yard floods	20	Sell and Relocate Facility
Grangeville	1933	87	Med	Fair	2	Poor	4	Fair	3	Over Capacity	4	High	4	High	3	Truck parking access, safety issue	20	Sell and Relocate Facility
Chewelah	1985	35	Sm	Fair	2	Poor	4	Poor	5	Fair	3	Med	3	High	3	Access off 395,River floods property each Spring	20	Sell and Relocate or Merge with Colville or DP?
Othello	1974	46	Med	Fair	2	Poor	4	Fair	3	Over Capacity	4	Med	3	Med	2	Sloped / winter yard hazard / drainage	18	Sell and Relocate Facility
Ritzville	1955	65	Sm	Fair	2	Poor	4	Poor	5	Fair	3	Med	2	Low	1	Roof and Retaining Wall Issues	17	Renovate existing building or build new on existing site
Spokane Valley Call Center	1979	41	XLrg	Fair	3	Fair	3	Good	1	Over Capacity	4	High	5	Low	1	Security issues and difficult access off high speed highway	17	Maintain and Operate or Sell and Merge with Corp
St Maries	1974	46	Med	Fair	3	Fair	3	Fair	3	Fair	3	Med	3	Med	2	Steep slope, winter slide danger / storage yard on 100 year flood plain	17	Maintain and Operate Office/ Relocate storage yard
CDA	1994	26	XLrg	Good	1	Fair	3	Fair	2	Over Capacity/ Expandable	4	Med	2	Med	2	Create Campus Plan / Property owned and available for campus expansion	14	Major Yard Refresh / Expansion
Clarkston	1975	45	Lrg	Good	1	Fair	3	Fair	3	Over Capacity/ Expandable	4	Low	1	Low	1	Create Campus Plan / Property owned and available for campus expansion	13	Major Yard Refresh / Expansion
Jack Stewart Training	1993	27	XLrg	Good	1	Fair	2	Poor	4	Over Capacity/ Expandable	4	Low	1	Low	0	Trailers in poor condition / Remediated spill site / Corp Fiber ring	12	Site Refresh
Orofino	1970	50	Sm	Fair	2	Fair	2	Fair	2	Adequate	2	Low	1	Low	1	Local Rep Office	10	Maintain and Operate
Colfax	1990	30	Sm	Good	1	Fair	2	Fair	3	Expandable	1	Low	1	Med	2	Local Rep Office, can develop yard for future expansion	10	Maintain and Operate
Lewiston Call Center	1976	44	XLrg	Good	1	Good	1	Fair	2	Fair	3	Med	3	Low	0	Downtown Area Security Risk	10	Maintain and Operate
Medford	1994	26	Lrg	Good	1	Fair	2	Fair	2	Over Capacity/ Expandable	4	Low	1	Low	0	Yard is nearing Capacity	10	Maintain and Operate
Tekoa	1971	49	Sm	Good	1	Fair	2	Fair	2	Adequate	2	Low	1	Med	2	New Roof in 2014	10	Maintain and Operate
Kellogg	1960	60	Med	Good	1	Good	1	Fair	2	Adequate	2	Med	2	Med	2	Strong Community presence with benefit being downtown	10	Maintain and Operate
Grants Pass	1960	60	Sm	Good	1	Fair	2	Fair	2	Adequate	2	Low	1	Low	1	Small site adaquate for need	9	Maintain and Operate

The Inventory Condition Report is a report the Paragon Asset Management System provides that can be used to assess the condition of all the building assets found at the Sandpoint Service Center.

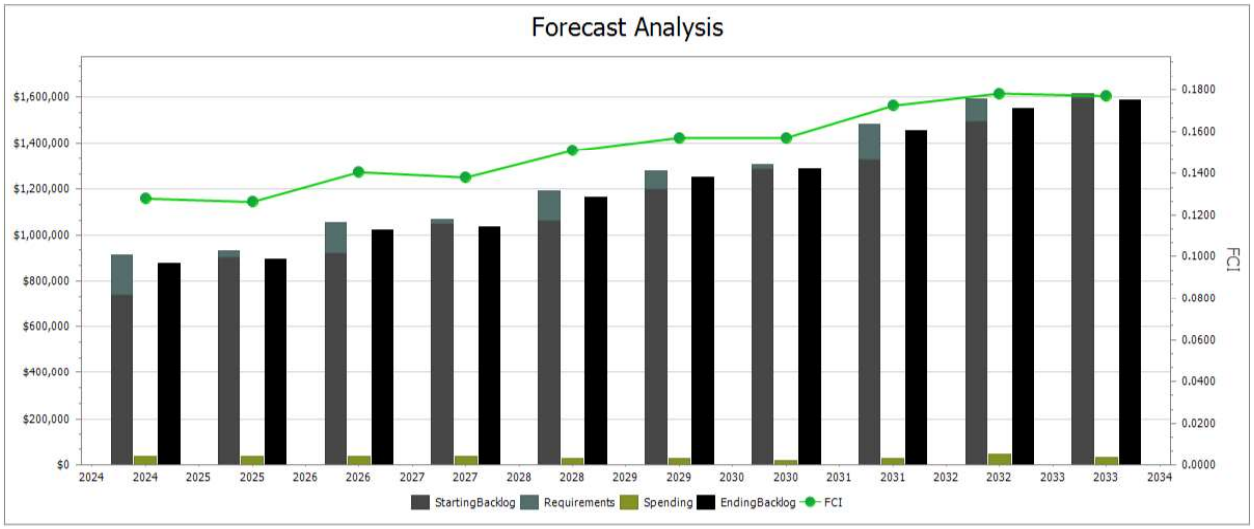
[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 495 of 535

DocuSign Envelope ID: DD7B2E08-519E-43D4-A38F-44D5BE1CF5BB

10- Year Forecast of Backlog and Requirements:

*Based on typical yearly spend in Sandpoint, does not include any of the planed $1.5M spend



Starting Backlog: $742,589

			Year										
ID	Grouping	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Grand Total
1	Backlog (Start of Year)	Capital	$721,319	$886,012	$904,820	$1,037,629	$1,050,088	$1,184,101	$1,270,543	$1,308,659	$1,479,354	$1,576,079	
		O&M	$21,269	$18,821	$14,946	$15,394	$15,856	$16,331	$16,821	$17,326	$17,846	$18,381	
	Backlog (Start of Year) Total		$742,589	$904,833	$919,766	$1,053,022	$1,065,944	$1,200,433	$1,287,364	$1,325,985	$1,497,199	$1,594,460	
2	Requirements	Capital	$155,137	$8,589	$123,234	$0	$110,488	$61,101	$0	$136,868	$75,417	$0	$670,835
		O&M	$14,794	$15,238	$15,695	$16,166	$16,651	$17,151	$17,665	$18,195	$18,741	$19,303	$169,601
	Requirements Total		$169,931	$23,827	$138,929	$16,166	$127,139	$78,252	$17,665	$155,063	$94,158	$19,303	$840,436
3	Backlog + Requirements		$912,520	$928,660	$1,058,695	$1,069,189	$1,193,083	$1,278,685	$1,305,029	$1,481,048	$1,591,358	$1,613,763	
4	Budget	Capital	$20,000	$20,600	$21,218	$21,855	$22,510	$23,185	$23,881	$24,597	$25,335	$26,095	$229,277
		O&M	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$200,000
	Budget Total		$40,000	$40,600	$41,218	$41,855	$42,510	$43,185	$43,881	$44,597	$45,335	$46,095	$429,277
5	Spending	Capital	$16,516	$16,134	$20,648	$18,126	$10,963	$11,666	$0	$9,261	$24,924	$11,207	$139,445
		O&M	$17,791	$19,549	$15,695	$16,166	$16,651	$17,151	$17,665	$18,195	$18,741	$19,303	$176,908
	Spending Total		$34,307	$35,683	$36,344	$34,292	$27,614	$28,817	$17,665	$27,457	$43,665	$30,510	$316,353
6	Variance (Budget minus Spending)	Capital	$3,484	$4,466	$570	$3,728	$11,547	$11,519	$23,881	$15,336	$411	$14,888	$89,830
		O&M	$2,209	$451	$4,305	$3,834	$3,349	$2,849	$2,335	$1,805	$1,259	$697	$23,092
	Variance (Budget minus Spending) Total		$5,693	$4,917	$4,874	$7,562	$14,896	$14,368	$26,216	$17,140	$1,670	$15,585	$112,922
7	Backlog (End of Year)	Capital	$860,205	$878,466	$1,007,406	$1,019,503	$1,149,613	$1,233,536	$1,270,543	$1,436,266	$1,530,173	$1,564,872	
		O&M	$18,273	$14,510	$14,946	$15,394	$15,856	$16,331	$16,821	$17,326	$17,846	$18,381	
	Backlog (End of Year) Total		$878,478	$892,977	$1,022,352	$1,034,897	$1,165,469	$1,249,868	$1,287,364	$1,453,592	$1,548,019	$1,583,253	
9	FCI		0.1280	0.1264	0.1405	0.1380	0.1509	0.1571	0.1571	0.1723	0.1781	0.1769	
10	Total Replacement Value		$6,861,260	$7,067,098	$7,279,111	$7,497,484	$7,722,408	$7,954,081	$8,192,703	$8,438,484	$8,691,639	$8,952,388	
11	Spending as % of TRV		0.50 %	0.50 %	0.50 %	0.46 %	0.36 %	0.36 %	0.22 %	0.33 %	0.50 %	0.34 %	

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2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

SHORT TERM ALTERNATIVE SOLUTION- PROVIDE FUNDING FOR SPECIFIC IMPROVEMENTS AT THE CURRENT SANDPOINT SERVICE CENTER- $1.5M

Provide the Sandpoint Service Center with a temporary solution while we work towards the recommended long-term solution. Providing $1.5M over two years will allow for improvements to the parking lot and storage yard as well as many operations needs of the business. This $1.5M allocation will be spend across both Asset Condition and Operation capital projects. In an effort to ensure the best functionality for the Sandpoint team over the next 5-10 years the allocation will be as follows:

Asset Condition Projects: $520,000

Repair of the canopy and roof, to improve safety and eliminate roof leaks. Replacement of the asphalt and added asphalt in the storage yard, to reduce pooling water and ice and provide safer access for the forklift. Lighting and HVAC upgrades due to failing systems.

Operational Request Projects: $980,000

Construction of a new temporary storage yard off Bronx Road, at the future Service Center site. Construction of a new warehouse pole building, to improve safety for the storekeeper and access to materials. Renovation of the existing warehouse to provide a meeting room and additional office space for staff.

Providing these improvements will allow the Sandpoint Service Center team to work more efficiently over the next 10 years. While this does not solve for all of the Business Problems, including much of the asset condition issues it does provide solutions for many of them.

RECOMMENDED LONG TERM SOLUTION- NEW SANDPOINT SERVICE CENTER- $18M

In the next 10 years we need to prepare the area for the next 50 years of service, we are asking to invest in a new building. We propose constructing a new line dock facility and covered storage buildings for materials inventory, expensive equipment, provide modernized offices, meeting rooms, and mini warehouse. The facility will be fully fenced, and card reader access gates installed. The HVAC systems will be modernized, which will provide energy savings.

The proposed solution to the business problems identified above is to build a new Service Center. Avista currently owns a vacant property where we would locate the new Service Center, the pole yard and warehouse. This option would allow us to develop the existing property using any remaining acreage for future growth.

The new Service Center will include environmentally protected transformer storage areas and adequate storm water protection. This will include oil/water separators for the entire facility, allowing for greater warehouse flexibility for transformers. This is the environmental standard for design for Avista and meets the legal requirements as well. The new facility will centralize all of Sandpoint crew functions into one location.

The new Service Center would be designed to meet the needs of today's employees and would meet current code requirements. These needs include both men's and women's ADA restrooms and showers, workspace for all necessary employees, meeting space for both Move Safe and EOP's, workout equipment and warehousing. All the building systems would be

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designed to today's technology and are planned to be more efficient than the existing location due to technology improvements.

This new substation project, at this location, is already being discussed and currently is on the 15-year plan according to the Engineering Round Table.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

There is currently an identified backlog of $742K in Asset Condition work needed at the Sandpoint Service Center. In 2017 Terricon identified $150K in work on their initial assessment. This list is growing every year as our building ages and new items are identified that need replacement. At the current funding level this backlog of capital work will continue to grow. The backlog is growing faster than our current funding model can accommodate. Making the investment into the existing structure will not solve the remaining problems of limited space, safety and environmental.

Environmental Compliance has rated the Sandpoint Service Center as a 3.

Sandpoint

Element	Score	Reason
Surface Water	0	
Floodplain	0	
Historic District	0	
Adjacent Use	1	Heavy MF residential in vicinity, not ideal
Zoning	1	Zoned Res. MF, CUP required, not ideal
Total	3	

2.3 Summarize in the table and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	None	$0	$0	$0	$0	$
O&M	Energy savings	$0	$0	$0	$0	$0

Direct (Based on Revised Solution):

- None

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

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2.4 Summarize in the table and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	Use of existing land	$0	$0	$0	$0	$0
O&M	Business Operations Improve	$0	$0	$0	$0	$0

Indirect (Based on Revised Solution Funding):

- None

2.5 Describe in detail the alternatives, including proposed cost for each alternative, which were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1: SANDPOINT RENOVATION/ STORAGE YARD LAND

O&M: $95,000 CAPITAL: $8,193,000

To avoid constructing a new Sandpoint Service Center, Avista would need to continue upgrading the existing Service Center building. This would include several hundred thousand dollars' worth of upgrades and improvements. Purchasing adjacent properties and expanding the Service Center would be very costly due to the cost of land in the adjacent Sandpoint area and the risk of building an already identified wetland.

Items were identified that needed replacement or repair under Operations and Maintenance totaling $95,000 over the next 5 years. Another $1,193,000 in repairs and replacements were identified that would need to be completed under capital spend in the next 5 years, including replacing the basic building systems such as electrical, domestic water piping, the plumbing and the entire service yard asphalt and drainage, including management of the stormwater and wetlands.

Facilities estimates that an interior remodel including ADA upgrades to restrooms and relocation/ remodel of office and shop space to accommodate business changes would total another $2,000,000 over the next 5 years.

We would need to create an additional storage yard at an already purchased property outside of town and possibly additional structures to accommodate larger trucks. This would require that crews drive to and from this new storage yard/ secondary location several times a day. Impacting response times and reducing productivity. The estimate for this land development and vehicle storage barn is $5,000,000.

Alternative 2: MAINTAIN CURRENT LOCATION

O&M: $95,000 CAPITAL: $3,193,000

Choosing to maintain the current location would greatly impact the Operations and Maintenance budget for the Sandpoint facility. The existing building condition would require that some large Capital investment be made to create a useable and safe location for employees to work. The

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

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building would require an extensive renovation to try to accommodate the current employees and materials.

The current land is not sufficient for the needs of the Sandpoint Service Center team. Materials would need to be stored at other locations including Clarkston and Spokane greatly impacting response times and customer restoration as materials would not be on hand.

Items were identified that needed replacement or repair under Operations and Maintenance totaling $95,000 over the next 5 years. Another $1,193,000 in repairs and replacements were identified that would need to be completed under capital spend in the next 5 years, including replacing the basic building systems such as electrical, domestic water piping, the plumbing and the entire service yard asphalt and drainage, including management of the stormwater and wetlands.

Facilities estimates that an interior remodel including ADA upgrades to restrooms and relocation/ remodel of office and shop space to accommodate business changes would total another $2,000,000 over the next 5 years.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Confirm the scoping documentation and approved design to the final constructed solution that provides room for growth, expands technology requirements, and adheres to safety and security best practices. Some of these solutions would include items such as:

1) Materials/ Storage: Provide warehouse space that meet the needs of the Stores team and Operations. Reduction in trips back to Spokane or other storage yards for materials (currently not tracked).
2) Environmental/ Compliance: Ensure that the building and site meets with Avista's environmental standards. Currently not meeting the base standards for storm water runoff.
3) Employee/ Customer Impacts: Room for employee or operations growth
4) Operational Efficiency: Ensure that operational needs of employees are being met, increase of productivity and reduced windshield time for crews.

Asset Condition: Provide systems and materials that meet with Avista standards and current building codes and requirements.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

The CPG partially funded this program in 2024 and 2025, below is the planned project spend for those years. This partial funding will be spent to provide the Sandpoint Service Center with needed improvements to maintain functionality at the current location until a new Service Center can be designed and built. It is expected that these improvements will allow the Service Center to maintain functionality for the next 5-10 years at which point designing and relocating the Service Center will be required.

YEAR	LOCATION	PROJECT	ESTIMATED SPEND	PLANNED TTP
2024	Sandpoint	Partial Roof Replacement	$150,000	11/2024
2024	Sandpoint	Asphalt Phase 1	$100,000	11/2024

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2024	Sandpoint	Warehouse Design	$60,000	11/2024
2024	Sandpoint	Exterior Lighting Upgrades	$20,000	9/2024
2024	Sandpoint	Furniture/ Chair Upgrades	$120,000	11/2024
2024	Sandpoint	Pole Storage Yard	$200,000	11/2024
2024	Sandpoint	Warehouse Construction Start	$100,000	11/2025
TOTAL ALLOCATION			**$750,000**	
2025	Sandpoint	Warehouse Construction	$500,000	11/2025
2025	Sandpoint	Asphalt Phase 2	$100,000	11/2025
2025	Sandpoint	Interior Improvements	$120,000	11/2025
2025	Sandpoint	HVAC and Lighting Upgrades	$30,000	11/2025
TOTAL PLANNED ALLOCATION			**$750,000**	

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Facilities Capital Steering Committee

Once the project list is assembled, the finalized list of projects is approved by the Capital Facilities Steering Committee. This Committee of Directors is responsible for approving the submission of Business Cases to the Capital Planning Group and approval of projects and any changes within this program.

In the past this has most often been:

- Director of Shared Services
- Director of Environmental Affairs
- Director of Financial Planning and Analysis
- Director of Generation, Production, Substation Support
- Director of IT and Security
- Director of Natural Gas

The project shall use certain Project Management Professional (PMP) guidelines and procedures during this project.

A Project Execution Plan, consisting of the documents below, will be drafted and approved by the SteerCo described in Section 3.1 (A).

- Project Charter, Change Management Plan, Communication Management Plan, Cost Management Plan, Procurement Management Plan, Project Team Management Plan, Risk Management Plan and Risk Register, Schedule Management Plan, Scope Management Plan, and Project Execution Approval Form.

Each month, the project manager will provide the following information either at the scheduled SteerCo meeting, or via email.

- Approved Yearly Budget, Accrued Yearly to Date, Year Estimate at Complete, Year Variance at Complete, Approved Lifetime Budget, Accrued Life to Date, Lifetime Project Estimate at Complete, and Lifetime Project Variance at Complete.

Each month, the SteerCo will make decisions on cost, scope, or budget items as required by the Project Execution Plan. The project manager reserves the right to present items not outlined in the Project Execution Plan if he/she determines its importance is relevant to SteerCo input.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 501 of 535

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The final decisions regarding these items, especially certain change requests as required by the Project Execution Plan, will be presented to, and voted upon by the SteerCo. The decisions will be documented in the monthly meeting minutes of the SteerCo for documentation and oversight.

It will be the Project Manager's role to monitor the scope, budget, and schedule and present the results to the SteerCo, regardless of they are within tolerances, or not.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 502 of 535

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3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the ***<Sandpoint Service Center>*** and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Eric Bowles 4ACC724D18764C2...	Date:	May-01-2024 | 12:44 PM PDT
Print Name:	Eric Bowles		
Title:	Corporate Facilities Manager		
Role:	Business Case Owner		

Signature:	DocuSigned by: Kelly Magalsky E7A0F731C49442B...	Date:	May-01-2024 | 3:28 PM PDT
Print Name:	Kelly Magalsky		
Title:	Director-Shared Services		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 503 of 535

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EXECUTIVE SUMMARY

This program is responsible for the capital maintenance, site improvement, and furniture budgets at over 75 Avista offices, Service Centers, storage buildings, and pole structures (1.2M total square feet) companywide. This program is intended to systematically address lifecycle asset replacements (examples: roofing, asphalt, electrical, plumbing), lifecycle furniture replacements new furniture additions (to support growth), and business additions or site improvements. These can include requests for productivity or business-related needs (examples: storage yard reconfigures, office space changes and improvemens and additions due to changes in the business.

Facilities apportions approximately 50% ($2,625,000 for 2025) to Asset Condition work that is identified using Paragon Asset Condition software, 30% ($1,575,000 for 2025) is set aside for Manager Requested projects, and 20% ($1,050,000 for 2025) is kept aside for unexpected capital needs and furniture replacements. There is currently $15.8M in Asset Condition backlog and requirements identified using the Paragon Asset Condition software. A funding of $5.25M in 2025, and an additional 3% for inflation in remaining years will provide Facilities with the ability to keep a level backlog for the next 5 years. Underfunding this program will increase the backlog of work creating a bow wave in the coming years as Avista's aging assets continue to need improvements.

This program supports Avista's entire Service Territory and all service codes and jurisdictions. Performing adequate Asset Management allows the Company to preserve and fully utilize its properties while reducing expensive repairs in the long term. It also ensures a safe environment for people and equipment. Damaged or poorly maintained facilities can create very real safety risks and associated liability for employees, customers, and contractors. For internal stakeholders such as employees and management, well- maintained assets ensure safe and efficient working envoronments. This leads to improved employee morale and productivity as equipment and facilties function optimally and reliably. When assets like machinery, buildings, and systems are in top condition, external customers benefit from consistent, high- quality service.

The Facilities Capital Steering Committee approved submission of this Business Case.

VERSION HISTORY

Version	Author	Description	Date
1.0	*L. Miller*	*Initial draft on Revised Template*	*4/8/2024*
2.0	*L. Miller*	*Revised draft*	*4/26/2024*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	*Steve Carrozzo 4/29/2024*

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 504 of 535

DocuSign Envelope ID: 65DED319-C3D8-490E-AF6E-B6BE5E65C859

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$5,200,000	$5,000,000
2025	$5,250,000	$5,000,000
2026	$5,410,000	$5,200,000
2027	$5,700,000	$5,500,000
2028	$5,900,000	$5,700,000
2029	$6,195,000	$6,000,000

Project Life Span	***1 year***
Requesting Organization/Department	Facilities
Business Case Owner | Sponsor	Eric Bowles | Kelly Magalsky
Sponsor Organization/Department	Shared Services
Phase	Planning
Category	Program
Driver	Performance & Capacity

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

Many of the Service Centers in Avista's territory were built in the 1950s and 60s and are starting to show signs of severe aging. Almost half of Avista's assets were built before 1980. Most of the building systems, such as electrical and mechanical, are past their recommended life based on recognized industry standards defined by Building Owners and Managers Association (BOMA), and International Facility Management Association (IFMA) and are requiring renovation or replacement. Many of the original campus layouts and buildings at our Service Centers are no longer functional due to changes in vehicle size, materials storage needs, and operational flow. These sites and structures were designed for the requirements of the business at the time and over the years those needs have grown and transformed. These changes have caused the necessity for project funding to address changing business and site requirements.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 505 of 535

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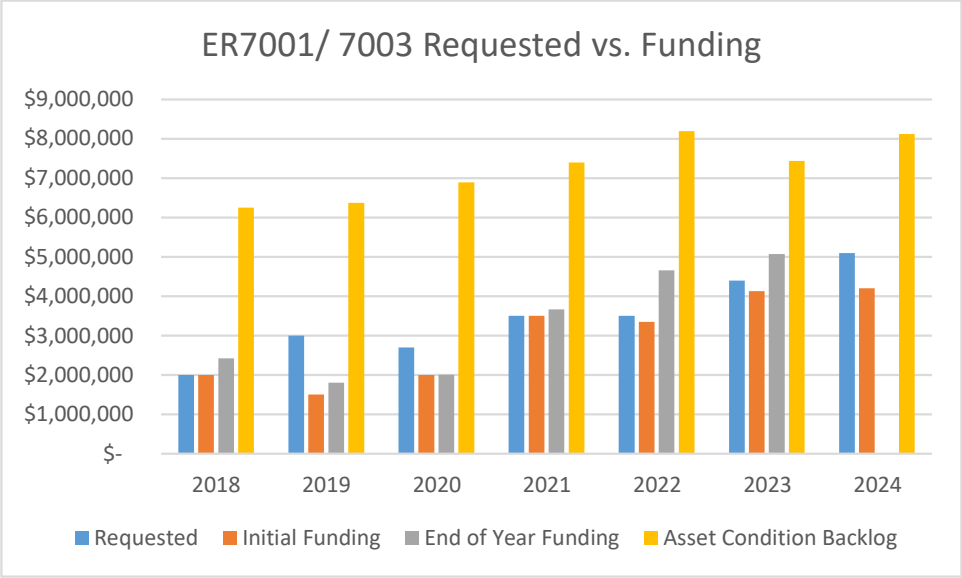
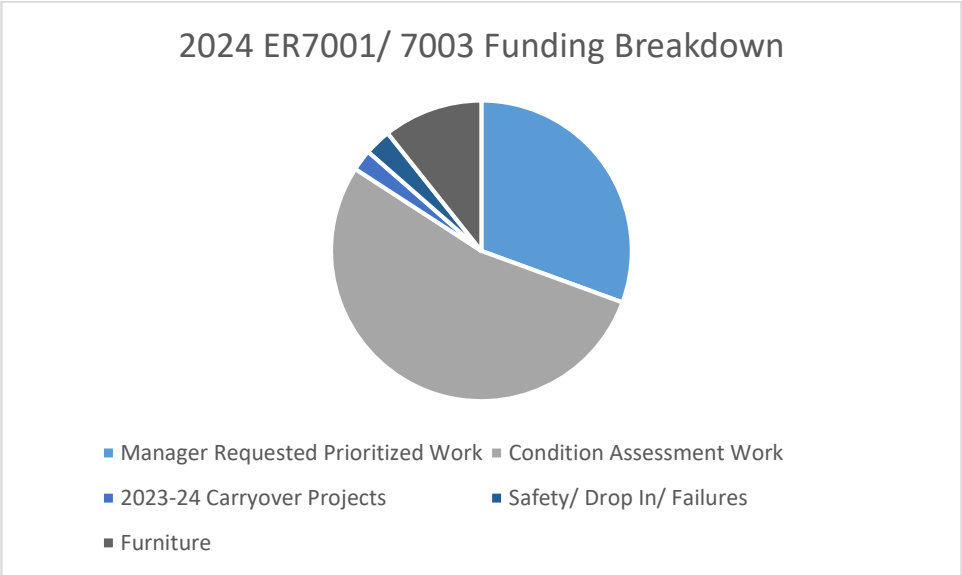


*The Asset Condition drop in 2023 is due to funding some larger Asset Condition projects.

This backlog is continuing to grow due to the average age of our infrastructure. As projects are address the backlog is adjusted and those projects are removed. Larger projects can impact the backlog, as noted in 2023.

Funding backlog

There is an identified backlog and requirements totaling over $15.8M (as of April 2024) in Asset Condition work needed across the system of assets Facilities manages. In 2017 Terricon identified $6M in work on their initial assessment. This list is growing every year as our buildings age and new items are identified that need replacement. The backlog is growing faster than our current funding model can accommodate.



Capital Lifecycle Asset Replacements ER 7001

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ER7001/ 7003 Structures and Improvements

This portion of the Structures and Improvements Program is based on the results of the Facilities Condition Assessment Survey. This survey considers the condition and lifecycle of each Facilities asset. Assets are graded and those requiring replacement within the next 10 years will be estimated and scheduled for replacement at an appropriate year during the 10-year time frame of the survey. These identified projects are prioritized within the Paragon Asset Management system. This process takes into consideration risk, safety and impact to the business. Buildings as a whole are assigned a Facilities Condition Index (FCI) as part of the survey to help compare future capital needs and drive the decision of continued capital expenditures vs. possible replacement.

Examples (asphalt and structural issues):

Furniture Replacement or Additions: ER 7003

The Furniture portion of the program is for new furniture solutions as well as replacements of existing assets based on industry standard lifecycles, condition, and availability of parts. The furniture program is also meant to support new furniture additions required as part of approved remodel and reconfiguration projects. The hybrid work environment is impacting this program as we work toward solutioning ergonomic needs of employees working outside of the typical office environment.

This evolving process is also impacting how the existing office space is utilized and designed to support work. This results in Facilities examination of how spaces are being utilized and can be better optimized for performance and experience. As technology and work styles transform, the workspace for impacted employees needs to be modified to support the business needs. These modifications can include furniture reconfigures, replacements and upgrades and can also include large scope renovations.

The lifecycle of commercial office furniture is typically 10-15 years and portions of our furniture assets across the business needs to be replaced every year in an ongoing replacement process. Facilities estimates that the majority of our panel systems furniture, approximately 70%, is well past

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this lifecycle. The average 6' x 9' fully ergonomic workstation, the Avista standard size, is $10K to replace. The furniture additions and replacements portion of the program is typically funded at $400K per year.

Examples:

Business Additions or Site Improvements: ER 7001

This portion of the program is intended to support site improvement requests and productivity or business-related needs. Project requests are made by Managers throughout Avista, including both operations and office staff. These requests are submitted in June of the previous year. The list of requests is then vetted for validity and business need by director-level management. Approved projects are prioritized vs. capital asset replacement priorities and assigned per available capital funding. Projects that are tied to compliance, safety, or productivity will be given funding preference. This portion of the program is typically funded at 30% of the overall funding for the Business Case.

Example (security fencing and gate, weld shop crane):

A robust operations and maintenance program is required to help further extend the lifecycle of our Facilities assets and help to lessen capital replacement needs. Conversely, limited O&M maintenance programs will result in shorter than standard asset lifecycles, and ultimately increased Capital spending. Existing O&M funding has required a shift to maintaining only the most critical systems, thus more aesthetic problems such as dirty carpets and windows are "selectively neglected." This reduction in scope reduces the expected life of assets and

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increases long term maintenance costs. As the condition of our Facilities improve, capital asset replacements should lessen in future years of the program. This is again dependent on sufficient O&M maintenance budgets and workforce.

1.2 Discuss the major drivers of the business case.

The major driver of this business case is Asset Condition. Facilities apportions approximately 50% to Asset Condition work that is identified using Paragon Asset Condition software (Terracon), 30% is set aside for Manager Requested projects, and 20% is kept aside for unexpected capital needs and furniture replacements. A proactive Asset Management program prevents the occurrence of asset failures or breakdowns. This also allows the company to spread these investments across time and plan for this work, rather than responding to critical failures after the fact that can impact business operations.

Customers benefit from this project by Facilities providing safe, usable buildings through which our Operations teams provide electricity and gas to our customers.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

As previously stated, there is an Asset Condition backlog and requirements identified totaling over $15.8M. This list is growing every year as our buildings age and new items are identified that need replacement. Deferring this work will cause a large bow wave of Capital investment in future years. Providing a level investment over the next 10 years will allow us to prevent equipment failures and the need for a large unplanned capital investment.

10-year Forecast- 75% Funding:

YEAR	REQUESTED SPEND AMOUNT ($)	75% OF REQUESTED SPEND AMOUNT($)
2024	$5,200,000	$3,900,000
2025	$5,250,000	$3,937,500
2026	$5,410,000	$4,057,500
2027	$5,700,000	$4,275,000
2028	$5,900,000	$4,425,000
2029	$6,195,000	$4,646,250

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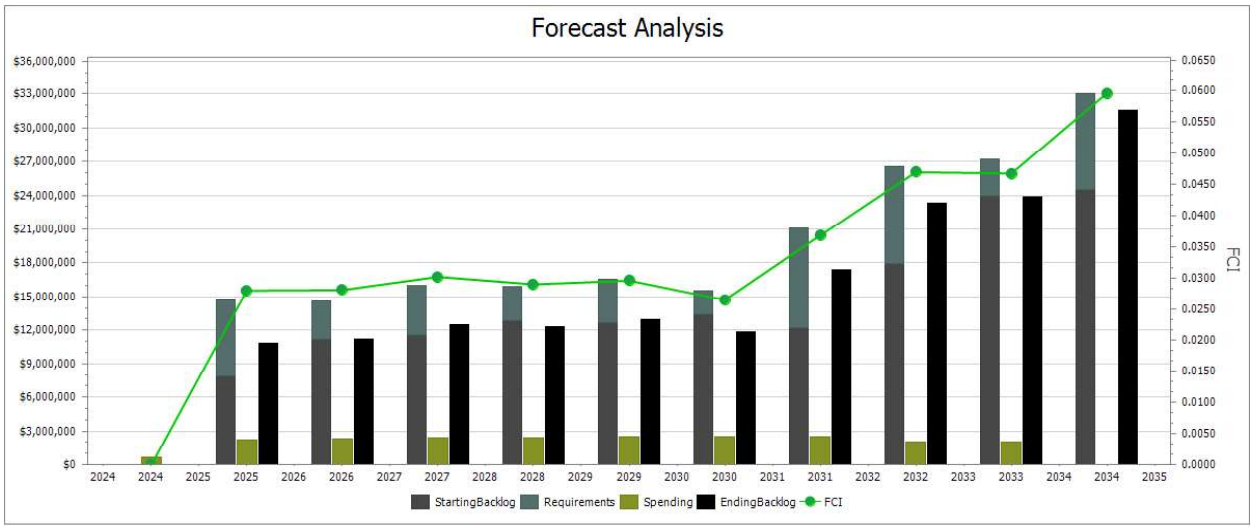

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

The major reason to perform the projects within this program is to align with Avista's Focus Areas of Our Customer and Our People. Being able to provide service to our customers safely and efficiently is a cornerstone of Avista and the facilities our crews report to is a vital piece of this service effort. Having facilities and storage yards that meet the needs of both electric and gas operations benefits both Our People and Our Customers.

This program also aligns with our value of Innovation and our Mission of innovative energy solutions. Innovation is change and having an openness to improve products, processes, and services. Whether it is from incorporating new ideas into already established systems, or completely transforming how something is done, innovation is the key to solving the challenges Facilities is faced with today. An example of this effort is how Facilities has used part of the existing building cooling system at our main campus to create a Data Canter cooling system that currently uses no mechanical cooling to operate. Providing savings to both the company and customers by reducing company utility bills.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

The Asset Condition Study and Asset Condition Report for all Avista's Assets is used to help determine the best options to resolve the various Asset Condition needs. It is used to help determine the best projects to fund in any given year. Projects are prioritized by the Paragon Asset Condition program using metrics such as risk, impact, and ROI. This prioritized list is then used to create the Asset Condition project list for the coming year.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

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Example of Paragon Work Package List:

Package ID	Work Package Name	Hierarchy	Asset	Average Impact Score	Estimated ROI	Average Priority Rating	# Work Items	Budget Category	Budget Account	Current Cost with Burden
2017 (Count=171)										
B20-93854	CMU repairs.	Avista Corp • Tekoa Facility	11501 Tekoa Facility	10.00	78.1	5.00	1	O&M	Deficiency Repairs	$453.81
G20-93764	Replace concrete curb throughout	Avista Corp • Coeur d'Alene Service Center	116 Site-Coeur d'Alene Service Center	10.00	1.4	3.00	1	Capital	Capital Replacements	$3,970.84
G20-93760	Replace concrete retaining wall.	Avista Corp • Ritzville Facility	113 Site-Ritzville Facility	10.00	-0.8	6.00	0	Capital	Capital Replacements	$0.00
B10-93908	Replace plywood decking	Avista Corp • Sandpoint Service Center	12602 Sandpoint Truck Canopy	8.50	0.3	3.00	1	Capital	Capital Replacements	$5,529.69
B20-93853	Repaint building exterior	Avista Corp • Ritzville Facility	11301 Ritzville Facility	8.50	-0.4	3.00	1	Capital	Capital Replacements	$3,063.22
B30-93814	B30 - Deficiency Repairs	Avista Corp • Chewelah Facility	10301 Chewelah Facility	8.50	221.9	3.00	2	O&M	Deficiency Repairs	$245.05
B10-93799	Demolish CMU enclosure and coal shoot.	Avista Corp • Main Campus	10105 Main Campus Ross Park Building	8.50	-0.3	5.00	1	O&M	Deficiency Repairs	$124,798.07
B30-93786	Perform repairs to the existing BUR roof system	Avista Corp • Main Campus	10101 General Office Building	8.50	3.8	6.00	1	O&M	Deficiency Repairs	$11,345.28
G20-93766	Full depth replacement of asphalt pavement	Avista Corp • Grangeville Facility	118 Site-Grangeville Facility	8.50	0.5	3.00	1	Capital	Capital Replacements	$63,306.66
G20-93755	Remove and replace short stone wall along north side of property	Avista Corp • Davenport Service Center	108 Site-Davenport Service Center	8.50	0.5	2.00	1	Capital	Capital Replacements	$907.62
G20-93762	G20 - Deficiency Repairs	Avista Corp • Spokane Valley Call Center	114 Site-Spokane Valley Call Center	8.25	61.1	2.50	2	O&M	Deficiency Repairs	$1,134.53
B20-93831	Brick wall repairs.	Avista Corp • Colfax Facility	10602 Colfax Storage Building	8.00	2.5	5.00	1	O&M	Deficiency Repairs	$11,345.28
D50-93792	Remove abandoned transformer	Avista Corp • Main Campus	10105 Main Campus Ross Park Building	8.00	-1.0	3.00	1	O&M	Deficiency Repairs	$2,269.06
G20-93761	G20 - Deficiency Repairs	Avista Corp • Ritzville Facility	113 Site-Ritzville Facility	7.50	-0.9	3.00	2	Capital	Capital Replacements	$111,183.73
C20-93795	C20 - Deficiency Repairs	Avista Corp • Main Campus	10105 Main Campus Ross Park Building	7.00	-0.5	5.00	2	O&M	Deficiency Repairs	$13,614.34
B30-93889	B30 - Deficiency Repairs	Avista Corp • Orofino Facility	12201 Orofino Facility	6.50	25.6	5.00	2	O&M	Deficiency Repairs	$2,178.31
B10-93851	Repaint galvanized canopy supports	Avista Corp • Ritzville Facility	11301 Ritzville Facility	6.50	12.1	2.00	1	O&M	Deficiency Repairs	$2,722.87
C20-93838	Repaint interior stair in warehouse	Avista Corp • Davenport Service Center	10801 Davenport Service Center	6.50	14.2	2.00	1	O&M	Deficiency Repairs	$147.49
D10-93791	Remove abandoned crane.	Avista Corp • Main Campus	10105 Main Campus Ross Park Building	6.50	-1.0	3.00	1	O&M	Deficiency Repairs	$22,690.56
G20-93777	Re-stripe traffic markings	Avista Corp • LaGrande Service Center	129 Site-LaGrande Service Center	6.50	0.6	2.00	1	O&M	Deficiency Repairs	$283.63
G20-93751	G20 - Deficiency Repairs	Avista Corp • Colville Service Center	105 Site-Colville Service Center	6.50	11.2	2.33	3	O&M	Deficiency Repairs	$3,085.93
G20-93765	G20 - Deficiency Repairs	Avista Corp • Coeur d'Alene Service Center	116 Site-Coeur d'Alene Service Center	6.08	30.1	3.33	6	O&M	Deficiency Repairs	$24,986.84

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Fund Program at full amount of $5.2M for 2025 and then fully therafter

Funding the Structures and Improvements Program and the full proposed amount allows Facilities to address capital asset replacements and business needs. Safety, compliance, and productivity requests are rated highest and given priority first. Many of these replacements can create safety risk if not addressed (sidewalks, structural repairs). Not systematically addressing maintenance needs could ultimately result in complete replacement of the buildings at some point.
Exmple priority list based on safety, compliamce and risk:

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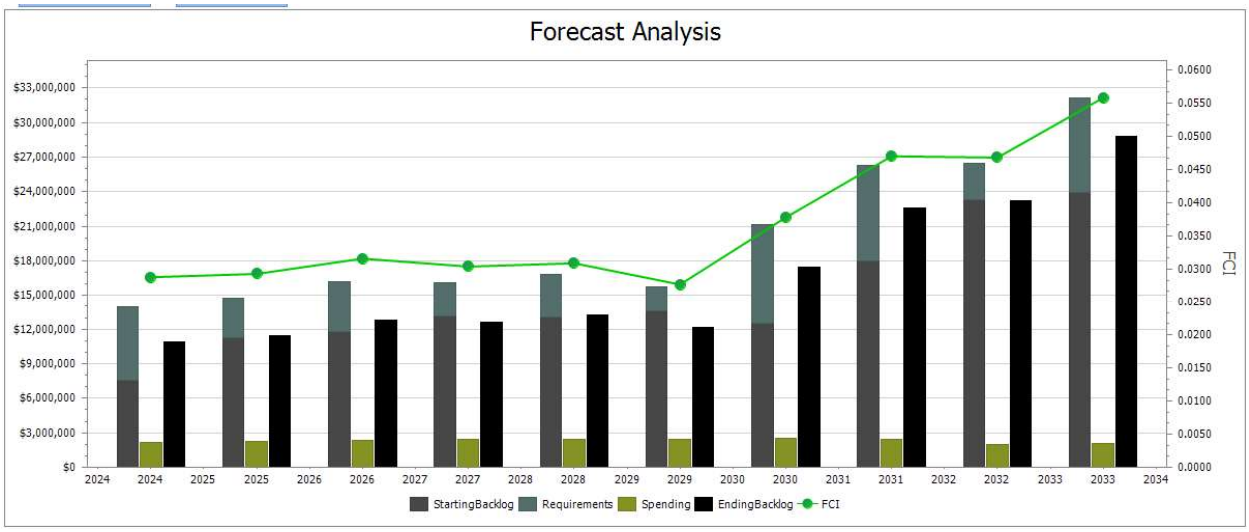
Package ID	Work Package Name	Hierarchy	Asset	Average Impact Score	Estimated ROI	Average Priority Rating
B30-93786	Perform repairs to the existing BUR roof system	Avista Corp • Main Campus	10101 General Office Building	8.50	3.8	6.00
G20-93760	Replace concrete retaining wall.	Avista Corp • Ritzville Facility	113 Site-Ritzville Facility	10.00	-0.8	6.00
B10-102860	Replace/ repair wood trusses	Avista Corp • Sandpoint Service Center	12602 Sandpoint Truck Canopy	4.00	-0.7	5.00
B10-102859	Replace Columns assess structural	Avista Corp • Sandpoint Service Center	12602 Sandpoint Truck Canopy	6.00	-0.1	5.00
C30-101247	Carpet Replacement	Avista Corp • Pullman Service Center	11201 Pullman Service Center	6.50	0.3	5.00
D50-101242	Replace aged switchgear	Avista Corp • Main Campus	10101 General Office Building	6.00	-1.0	5.00
G20-101240	Replace Asphalt	Avista Corp • Sandpoint Service Center	126 Site-Sandpoint Service Center	4.50	1.6	5.00
G20-101238	Replace Entry Stairs	Avista Corp • Pullman Service Center	112 Site-Pullman Service Center	2.50	-0.8	5.00
D30-97245	Replace with listed welding fume collector	Avista Corp • Beacon	10204 Beacon GPSS Metal Shop	9.50	-0.5	5.00
G20-97243	Replace Damaged Section of asphalt	Avista Corp • Orofino Facility	122 Site-Orofino Facility	8.50	-0.4	5.00
D20-93917	Cleaning, preventive maintenance and testing of emergency eye wash	Avista Corp • Medford Service Center	13001 Medford Service Center	6.00	0.1	5.00
B20-93895	Exterior wall repairs.	Avista Corp • St. Maries Service Center	12401 St. Maries Service Center	2.50	10.4	5.00
A10-93894	Structural evaluation.	Avista Corp • St. Maries Service Center	12401 St. Maries Service Center	6.00	4.6	5.00

At the current funding level this backlog of capital work will continue to grow. The backlog is growing faster than our current funding model can accommodate. It is the goal of this program to maintain a level backlog that projects are selected from using Terracon's risk assessment and the impact the item has on the Company's ability to perform its work, making the highest priority projects readily apparent.

10-year Forecast- Fully Funded:



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			Year										
ID	Grouping	Account	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Grand Total
1	Backlog (Start of Year)	Capital Replacements	$5,386,268	$5,116,549	$5,034,971	$4,707,423	$4,285,929	$3,835,521	$3,353,927	$2,840,724	$2,389,651	$2,461,341	
		Component Renewal at ESL	$26,994	$3,968,047	$4,647,484	$6,420,912	$6,723,134	$7,828,481	$7,142,207	$13,100,689	$18,812,431	$19,278,699	
		Deficiency Repairs	$1,457,303	$1,398,128	$1,337,130	$1,274,357	$1,209,620	$1,142,975	$1,129,474	$1,163,358	$1,198,259	$1,234,207	
		Deficiency Repairs/Replacements	$704,008	$725,129	$746,883	$769,289	$792,368	$816,139	$840,623	$865,842	$891,817	$918,571	
	Backlog (Start of Year) Total		$7,574,574	$11,207,852	$11,766,468	$13,171,980	$13,011,050	$13,623,116	$12,466,231	$17,970,613	$23,292,159	$23,892,818	
2	Requirements	Capital Replacements	$81,161	$295,192	$69,457	$0	$0	$0	$0	$0	$0	$0	$445,810
		Component Renewal at ESL	$5,197,283	$2,089,050	$3,180,229	$1,726,464	$2,551,426	$844,593	$7,351,816	$6,954,965	$1,767,178	$6,819,974	$38,482,978
		Preventative Maintenance	$1,100,812	$1,133,837	$1,167,852	$1,202,887	$1,238,974	$1,276,143	$1,314,428	$1,353,860	$1,394,476	$1,436,311	$12,619,581
	Requirements Total		$6,379,256	$3,518,079	$4,417,538	$2,929,351	$3,790,400	$2,120,736	$8,666,243	$8,308,825	$3,161,655	$8,256,284	$51,548,369
3	Backlog + Requirements		$13,953,830	$14,725,931	$16,184,007	$16,101,332	$16,801,451	$15,743,852	$21,132,475	$26,279,438	$26,453,813	$32,149,103	
4	Budget	Capital Replacements	$500,000	$515,000	$530,450	$546,365	$562,755	$579,635	$597,025	$614,935	$633,385	$652,385	$5,731,935
		Component Renewal at ESL	$1,500,000	$1,545,000	$1,591,350	$1,639,095	$1,688,265	$1,738,905	$1,791,075	$1,844,805	$1,900,155	$1,957,155	$17,195,805
		Deficiency Repairs	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$1,000,000
		Preventative Maintenance	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$1,000,000
	Budget Total		$2,200,000	$2,260,000	$2,321,800	$2,385,460	$2,451,020	$2,518,540	$2,588,100	$2,659,740	$2,733,540	$2,809,540	$24,927,740
5	Spending	Capital Replacements	$499,906	$514,821	$530,128	$546,327	$562,122	$579,281	$595,943	$520,674	$0	$0	$4,349,201
		Component Renewal at ESL	$1,499,698	$1,544,976	$1,591,280	$1,638,735	$1,688,242	$1,738,891	$1,791,072	$1,844,709	$1,900,127	$1,957,051	$17,194,783
		Deficiency Repairs	$99,898	$99,943	$99,891	$99,969	$99,935	$46,399	$0	$0	$0	$0	$546,034
		Preventative Maintenance	$99,999	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$99,999	$100,000	$100,000	$999,998
	Spending Total		$2,199,501	$2,259,740	$2,321,299	$2,385,030	$2,450,299	$2,464,571	$2,487,015	$2,465,382	$2,000,127	$2,057,051	$23,090,016
6	Variance (Budget minus Spending)	Capital Replacements	$94	$179	$322	$38	$633	$354	$1,082	$94,261	$633,385	$652,385	$1,382,734
		Component Renewal at ESL	$302	$24	$70	$360	$23	$14	$3	$96	$28	$104	$1,022
		Deficiency Repairs	$102	$57	$109	$31	$65	$53,601	$100,000	$100,000	$100,000	$100,000	$453,966
		Preventative Maintenance	$1	$0	$0	$0	$0	$0	$0	$1	$0	$0	$2
	Variance (Budget minus Spending) Total		$499	$260	$501	$430	$721	$53,969	$101,085	$194,358	$733,413	$752,489	$1,837,724
7	Backlog (End of Year)	Capital Replacements	$4,967,523	$4,888,322	$4,570,313	$4,161,096	$3,723,807	$3,256,239	$2,757,984	$2,320,050	$2,389,651	$2,461,341	
		Component Renewal at ESL	$3,052,473	$4,512,121	$6,233,095	$6,527,315	$7,600,467	$6,934,102	$12,719,116	$10,264,496	$10,717,104	$24,141,621	
		Deficiency Repairs	$1,357,406	$1,298,185	$1,237,239	$1,174,388	$1,109,685	$1,096,577	$1,129,474	$1,163,358	$1,198,259	$1,234,207	
		Deficiency Repairs/Replacements	$704,008	$725,129	$746,883	$769,289	$792,368	$816,139	$840,623	$865,842	$891,817	$918,571	
	Backlog (End of Year) Total		$10,881,410	$11,423,756	$12,788,330	$12,632,088	$13,226,326	$12,103,137	$17,447,197	$22,613,746	$23,196,911	$28,755,741	
8	Unfunded Preventative Maintenance	Preventative Maintenance	$1,000,813	$1,033,837	$1,067,852	$1,102,888	$1,138,974	$1,176,143	$1,214,428	$1,253,861	$1,294,476	$1,336,311	$11,619,583
9	FCI		0.0288	0.0293	0.0316	0.0304	0.0309	0.0277	0.0378	0.0470	0.0468	0.0558	
10	Total Replacement Value		$413,189,935	$425,585,633	$438,353,202	$451,503,798	$465,048,912	$479,000,379	$493,370,390	$508,171,502	$523,416,647	$539,119,146	
11	Spending as % of TRV		0.53%	0.53%	0.53%	0.53%	0.53%	0.51%	0.50%	0.49%	0.38%	0.38%	

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

Base known projects over the next 10 years- including backlog:

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

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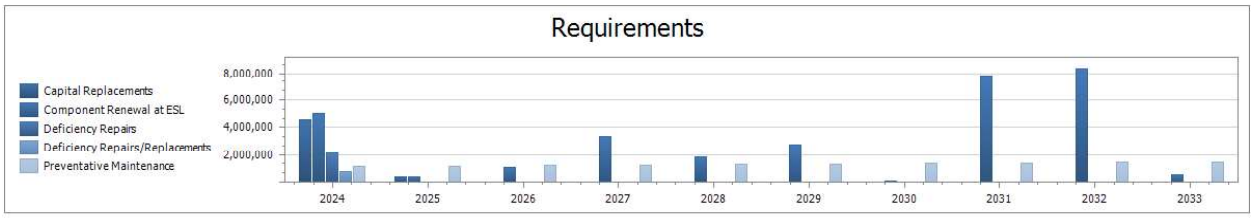
ER7001/ 7003 Structures and Improvements



Account	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Grand Total
Capital Replacements	$4,593,070	$360,266	$0	$0	$0	$0	$0	$0	$0	$0	$4,953,336
Component Renewal at ESL	$5,038,133	$386,887	$1,063,903	$3,320,802	$1,823,829	$2,703,262	$78,743	$7,816,348	$8,358,659	$527,377	$31,117,943
Deficiency Repairs	$2,116,355	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,116,355
Deficiency Repairs/Replacements	$746,925	$0	$0	$0	$0	$0	$0	$0	$0	$0	$746,925
Preventative Maintenance	$1,174,680	$1,167,852	$1,202,887	$1,238,974	$1,276,143	$1,314,428	$1,353,860	$1,394,476	$1,436,311	$1,479,400	$13,039,011
Grand Total	$13,669,163	$1,915,004	$2,266,791	$4,559,777	$3,099,972	$4,017,689	$1,432,603	$9,210,824	$9,794,969	$2,006,777	$51,973,570
Active Assets	117	117	117	117	117	117	117	117	117	117	
Total Replacement Value	$413,189,933	$425,585,631	$438,353,199	$451,503,795	$465,048,909	$479,000,377	$493,370,388	$508,171,500	$523,416,644	$539,119,144	

Facilities 10 Year plan Matrix:

Site	Built	Current Age	Size	Location Suitability		Design / Site Suitability		Condition Rating		Site Utilization		Identified Site Risk		Environmental Risk		Notes	Site Scoring	Recommended Course of Action
Pullman	1959	61	Lrg	Fair	2	Poor	5	Fair	3	Over Capacity	5	Med	3	Med	2	Busy Highway access, site drainage issues	20	Sell and Relocate Facility
Sandpoint	1957	63	Med	Fair	2	Poor	4	Fair	3	Over Capacity	4	High	4	High	3	Located in residential area / Spring drainage flooding	20	Sell and Relocate Facility
Davenport	1966	54	Med	Poor	4	Poor	4	Fair	2	Over Capacity	4	Med	3	High	3	Low Structural bracing can be hit by vehicles/ transformer storage by river / Offsite pole yard floods	20	Sell and Relocate Facility
Grangeville	1933	87	Med	Fair	2	Poor	4	Fair	3	Over Capacity	4	High	4	High	3	Truck parking access, safety issue	20	Sell and Relocate Facility
Chewelah	1985	35	Sm	Fair	2	Poor	4	Poor	5	Fair	3	Med	3	High	3	Access off 395,River floods property each Spring	20	Sell and Relocate or Merge with Colville or DP?
Othello	1974	46	Med	Fair	2	Poor	4	Fair	3	Over Capacity	4	Med	3	Med	2	Sloped / winter yard hazard / drainage	18	Sell and Relocate Facility
Ritzville	1955	65	Sm	Fair	2	Poor	4	Poor	5	Fair	3	Med	2	Low	1	Roof and Retaining Wall Issues	17	Renovate existing building or build new on existing site
Spokane Valley Call Center	1979	41	XLrg	Fair	3	Fair	3	Good	1	Over Capacity	4	High	5	Low	1	Security issues and difficult access off high speed highway	17	Maintain and Operate or Sell and Merge with Corp
St Maries	1974	46	Med	Fair	3	Fair	3	Fair	3	Fair	3	Med	3	Med	2	Steep slope, winter slide danger / storage yard on 100 year flood plain	17	Maintain and Operate Office/ Relocate storage yard
CDA	1994	26	XLrg	Good	1	Fair	3	Fair	2	Over Capacity/ Expandable	4	Med	2	Med	2	Create Campus Plan / Property owned and available for campus expansion	14	Major Yard Refresh / Expansion
Clarkston	1975	45	Lrg	Good	1	Fair	3	Fair	3	Over Capacity/ Expandable	4	Low	1	Low	1	Create Campus Plan / Property owned and available for campus expansion	13	Major Yard Refresh / Expansion
Jack Stewart Training	1993	27	XLrg	Good	1	Fair	2	Poor	4	Over Capacity/ Expandable	4	Low	1	Low	0	Trailers in poor condition / Remediated spill site / Corp Fiber ring	12	Site Refresh
Orofino	1970	50	Sm	Fair	2	Fair	2	Fair	2	Adequate	2	Low	1	Low	1	Local Rep Office	10	Maintain and Operate
Colfax	1990	30	Sm	Good	1	Fair	2	Fair	3	Expandable	1	Low	1	Med	2	Local Rep Office, can develop yard for future expansion	10	Maintain and Operate
Lewiston Call Center	1976	44	XLrg	Good	1	Good	1	Fair	2	Fair	3	Med	3	Low	0	Downtown Area Security Risk	10	Maintain and Operate
Medford	1994	26	Lrg	Good	1	Fair	2	Fair	2	Over Capacity/ Expandable	4	Low	1	Low	0	Yard is nearing Capacity	10	Maintain and Operate
Tekoa	1971	49	Sm	Good	1	Fair	2	Fair	2	Adequate	2	Low	1	Med	2	New Roof in 2014	10	Maintain and Operate
Kellogg	1960	60	Med	Good	1	Good	1	Fair	2	Adequate	2	Med	2	Med	2	Strong Community presence with benefit being downtown	10	Maintain and Operate
Grants Pass	1960	60	Sm	Good	1	Fair	2	Fair	2	Adequate	2	Low	1	Low	1	Small site adequate for need	9	Maintain and Operate
Roseburg	2004	16	Med	Good	1	Fair	2	Fair	2	Adequate	2	Low	1	Low	0	Small site adequate for need	8	Maintain and Operate

Example of projects in Asset Condition System:

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 514 of 535

DocuSign Envelope ID: 65DED319-C3D8-490E-AF6E-B6BE5E65C859

Package ID	Work Package Name	Hierarchy	Asset	Average Impact Score	Estimated ROI	Average Priority Rating
B30-93786	Perform repairs to the existing BUR roof system	Avista Corp • Main Campus	10101 General Office Building	8.50	3.8	6.00
G20-93760	Replace concrete retaining wall.	Avista Corp • Ritzville Facility	113 Site-Ritzville Facility	10.00	-0.8	6.00
B10-102860	Replace/ repair wood trusses	Avista Corp • Sandpoint Service Center	12602 Sandpoint Truck Canopy	4.00	-0.7	5.00
B10-102859	Replace Columns assess structural	Avista Corp • Sandpoint Service Center	12602 Sandpoint Truck Canopy	6.00	-0.1	5.00
C30-101247	Carpet Replacement	Avista Corp • Pullman Service Center	11201 Pullman Service Center	6.50	0.3	5.00
D50-101242	Replace aged switchgear	Avista Corp • Main Campus	10101 General Office Building	6.00	-1.0	5.00
G20-101240	Replace Asphalt	Avista Corp • Sandpoint Service Center	126 Site-Sandpoint Service Center	4.50	1.6	5.00
G20-101238	Replace Entry Stairs	Avista Corp • Pullman Service Center	112 Site-Pullman Service Center	2.50	-0.8	5.00
D30-97245	Replace with listed welding fume collector	Avista Corp • Beacon	10204 Beacon GPSS Metal Shop	9.50	-0.5	5.00
G20-97243	Replace Damaged Section of asphalt	Avista Corp • Orofino Facility	122 Site-Orofino Facility	8.50	-0.4	5.00
D20-93917	Cleaning, preventive maintenance and testing of emergency eye wash	Avista Corp • Medford Service Center	13001 Medford Service Center	6.00	0.1	5.00
B20-93895	Exterior wall repairs.	Avista Corp • St. Maries Service Center	12401 St. Maries Service Center	2.50	10.4	5.00
A10-93894	Structural evaluation.	Avista Corp • St. Maries Service Center	12401 St. Maries Service Center	6.00	4.6	5.00
B30-93889	B30 - Deficiency Repairs	Avista Corp • Orofino Facility	12201 Orofino Facility	6.50	25.6	5.00
B20-93854	CMU repairs.	Avista Corp • Tekoa Facility	11501 Tekoa Facility	10.00	78.1	5.00
D50-93846	Replace electrical panel	Avista Corp • Pullman Service Center	11202 Pullman Service Center Canopy	4.00	-0.5	5.00
B30-93842	BUR replacement.	Avista Corp • Pullman Service Center	11201 Pullman Service Center	2.50	0.2	5.00

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital	Scope Reduction: Planned Work	$20,600	$21,220	$21,860	$22,510	$
O&M	Estimated Energy Savings + 3%	$11,330	$11,670	$12,020	$12,380	$

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2025	2026	2027	2028	2029
Capital		$	$	$	$	$
O&M	Operational Efficiencies +3%	$301,746	$310,799	$320,123	$	$

This program is intended to systematically address the following needs:
Lifecycle asset replacements (examples: roofing, asphalt, electrical, plumbing)
Examples of saving by performing planned replacements vs delayed:

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

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- Estimated 3-5 projects a year: HVAC, Plumbing and Electrical systems: Possibility of a failure resulting in emergent site visits of crew members and non- scheduled replacements resulting in office downtime and broader employee impacts.
    - Examples of these failures can include unplanned electrical fire damaging electrical infrastructure often resulting in an extended outage; central plant HVAC failures, with widespread building or campus HVAC losses; unplanned roof leaks affecting workspace.
    - For the electrical risk calculation, Avista is assuming that this possible electrical or HVAC risk could be conservatively assumed to be anywhere from $100,000 to $1,000,000 per incident. Examples of this risk would be excessive arc flash risk, breakers not operating as expected due to age, connection resistance between buses and various connections causing excessive temperature. Loss of main circulating pump motor, large compressor failures.
    - Avista has taken the average of these ranges presented above ($550,000) and divided it over the 30-year accounting depreciation rate of this investment. Lastly, a conservative estimate of likely occurrence of this risk would be approximately 10%, so that is multiplied by the yearly figure.
        - $550,000 / 30 years x 10% = $1,833.33 yearly
    - Reduction in energy usage due to more efficient equipment, estimated at 1% year over year.
        - $1.1M yearly energy costs x 1% = $11,000 yearly
    - Reduction of risk to employee productivity from an unplanned failure (average number across all sites):
        - 25 emp x 4 hr. per failure x $85/hr. avg loaded rate= $8,500
        - $8,500 per project x 5 projects = $42,500
- Estimated 1-2 projects a year: Roofing: Possibility of a failure resulting in emergent site visits of crew members and non- scheduled replacements resulting on office downtime.
    - Reduction of unplanned leaks resulting in additional sub roof damage requiring an increased scope of work. A proactive asset-based replacement vs. run to failure ensures a minimal scope of work.
        - Additional scope average project cost increase of = $10,000
        - $10,000 per project x 2 projects = $20,000
- Estimated 1-2 projects a year: Asphalt and sidewalks: Possibility of a failure resulting is emergent site visits of crew members and non- scheduled replacements resulting on office downtime.
    - Reduction in safety issues related to cracking, heaving and slips, trips, and falls. This data under investigation and will be included in future reporting.
- All projects:
    - Planned replacements can result in savings due to competitive bidding. Unplanned failures are often unbid, time sensitive contracts
    - Reduction of risk related to damage to equipment and buildings

Business additions or site improvements (examples: adding a welding bay, vehicle storage canopy, expanding an asphalt yard. Can sometimes include property purchases to support site expansions.)

- Examples of savings:
    - Estimated 2-3 projects a year: Extended/ improved storage yards or storage facilities: Improved business operations and time efficiencies for crews. An example of this would be added storage racking resulting in easier material access, yard consolidation.
        - 5 emp x 0.25 hr./day x 260 workdays x $85/hr. avg loaded rate= $27,625
        - $27,625 per project x 3 projects = **$82,875**
    - Estimated 1-2 projects a year: General improvements: Efficiencies created through improved storage, more efficient workspaces and expanded workspaces as required for growth.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 516 of 535

DocuSign Envelope ID: 65DED319-C3D8-490E-AF6E-B6BE5E65C859

- 25 emp x 0.15 hr./day x 260 workdays x $85/hr. avg loaded rate= $82,875
- $82,875 per project x 2 projects = **$165,750**

Lifecycle furniture replacements and new furniture additions (to support growth)

- No savings to report

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1: Partially Fund Program based on priority

This option would decrease the capital program and increase existing O&M budgets to prolong structures' lifecycles beyond rated life and reduce capital needs. This option is not the preferred approach due to he Avista business model. Capital investments can be limited with a corresponding increase in O&M dollars. As building systems continue to decline O&M burden will increase.
The reduction of the program would result in larger project being differed due to lack of funding. These projects are considered to have a high impact on the business and failue could result in an O&M impact. If these items were to fail a request to the CPG would be required at that time.

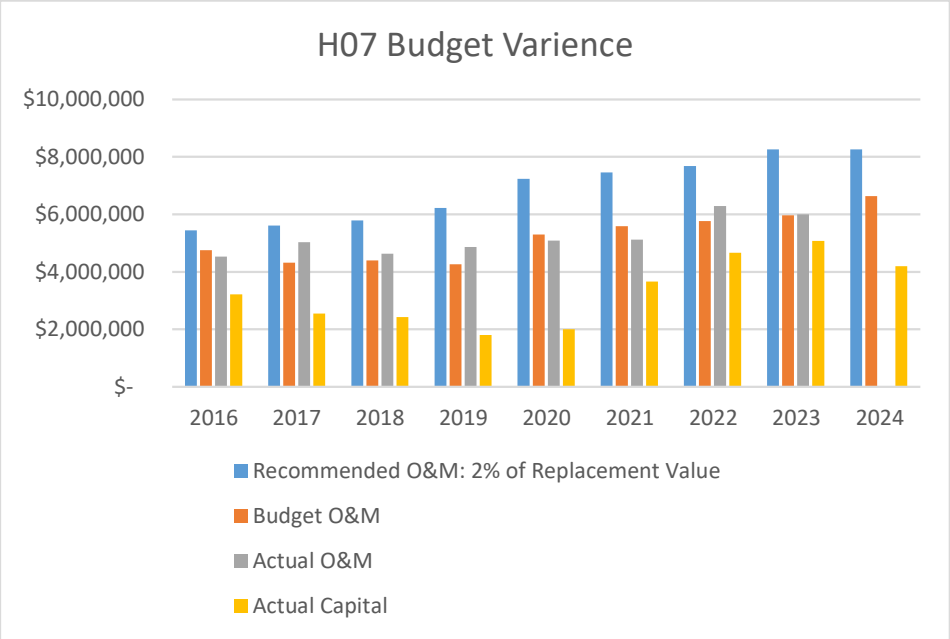
Potential differed projects with reduced in funding over the next 5 years:

Project	Cost Estimate
Mission Site Design: Sidewalk upgrades/ de-ice, pond, landscaping end of life	$1M
Irrigation Water Line Replacement	$600K
Cafe Elevator Replacement	$500K
Extend Generator Service to the Service Building	$400K
Service Building Switchgear and Transformer Replacement	$2M
Replace Elevator Motors @ Mian Building	$700K
Main Building Roof Replacement	$375K
Service Building Freight Elevator Replacement	$500K

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 517 of 535

DocuSign Envelope ID: 65DED319-C3D8-490E-AF6E-B6BE5E65C859

ER7001/ 7003 Structures and Improvements



The estimated replacement value of Avista's assets when the Terricon survey was taken in 2017 was approximately $242 million, with estimated operations and maintenance requirements based on the Terracon report of $8,800,640 *per year*, which equals 3.64% of the current replacement value of the assets. Today the replacement value of Avista's facility assets is $413,190,000. The graph above clearly demonstrates that the amount spent by Avista (the green bars) typically does not reach the minimum level of O&M expenditures (the blue bars) standard in the building industry for basic sustenance of facilities. This level of underfunding would need to be addressed if the choice is made to underfund this program. If capital replacements are unable to be funded, additional O&M work would be required to keep systems functioning.

Business site improvement requests are intended to address changing business needs. These projects are usually linked to an enhanced productivity outcome. Having the ability to incorporate structures and equipment that fall within the improvement and business needs category can help support improved processes and lead to enhanced safety and longer lifecycles. When the budget needs to be reduced, reductions are first made to requests in this category.
Replacement is intended to replace aging units to achieve more predictable capital requirements and avoid replacement peaks caused by large-scale failures. Cutting into these requests over an extended period could lead to reduced efficiency and have safety impacts.

Funding this business case at less then $4M will require a reallocation of the dollars, reducing the funding for Manager Requested Projects.

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 518 of 535

DocuSign Envelope ID: 65DED319-C3D8-490E-AF6E-B6BE5E65C859

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

The first metric that would be used to demonstrate the investment was successful would be a leveling out of the Asset Condition Backlog. While a reduction in the backlog would be ideal, due to funding limitations, a flattening of the curve would constitute success.

Beyond this, the only measure that can be used is to design solutions that provides room for growth, expands technology requirements, and adheres to safety and security best practices. Some of these solutions would include items such as:

1) Materials/ Storage: Provide spaces that meet the needs of the Stores team and Operations
    a. Estimated 1-2 projects a year: General improvements: Efficiencies created through improved storage, more efficient workspaces and expanded workspaces as required for growth.
2) Estimated 1-2 projects a year: Extended/ improved storage yards or storage facilities: Improved business operations and time efficiencies for crews. An example of this would be added storage racking resulting in easier material access, yard consolidation.
3) Environmental/ Compliance: Ensure that the building and site meets with Avista's environmental standards
4) Employee/ Customer Impacts: Room for employee or operations growth
5) Operational Efficiency: Ensure that operational needs of employees are being met
6) Asset Condition: Provide systems and materials that meet with Avista standards
    a. Estimated 1-2 projects a year: Roofing: Possibility of a failure resulting in emergent site visits of crew members and non- scheduled replacements resulting on office downtime.
        i. Reduction of unplanned leaks resulting in additional sub roof damage requiring an increased scope of work. A proactive asset-based replacement vs. run to failure ensures a minimal scope of work.
    b. Estimated 1-2 projects a year: Asphalt and sidewalks: Possibility of a failure resulting is emergent site visits of crew members and non- scheduled replacements resulting on office downtime.

Reduction in safety issues related to cracking, heaving and slips, trips, and falls. This data under investigation and will be included in future reporting.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Most projects in the Facilities Structures and Improvements program begin work in the 2nd or 3rd quarter of each year and will usually transfer to plant before the end of the year. Some of the larger projects, or projects with extensive design, can carry over to the following year.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

ER7001 Facilities Structures and Improvements is a 5-year program created to address the capital lifecycle asset replacements and business/site improvements at all Avista's regional sites and offices. Asset lifecycle replacements are compiled by Facilities and are based on an asset condition report and industry recognized lifecycles. Site improvement projects are approved based on productivity and/or business need.

Asset Lifecycle Replacement Projects

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 519 of 535

DocuSign Envelope ID: 65DED319-C3D8-490E-AF6E-B6BE5E65C859

In 2017 and 2022 Avista hired Terracon Consultants to perform a condition assessment on 76 Avista-owned facilities and 35 real estate sites at 34 different locations, comprising approximately 1,186,000 square feet. These facilities were constructed between 1903 and 2019. Terracon estimated the value of this infrastructure at approximately $365 Million.

The Terracon study was highly detailed and in depth. They examined every characteristic of each facility from a variety of perspectives. External structures from asphalt in the parking lot to roof condition, fences, curbs, work, and storage areas were examined to ascertain and score condition and to identify issues and note concerns. Internal aspects such as walls, carpets, and furniture condition were evaluated.

They surveyed building systems including plumbing, heating, and cooling, electrical, lighting, air quality, drainage, and security. They also looked at safety aspects from both the customer and employee perspective. Then each item in the facility was rated based upon its condition and assigned a budget category of O&M Preventative Maintenance, O&M Deficiency Repairs, Capital Replacement, and Capital Renewal/In-Kind Replacement. Terracon's list is sorted by relative risk and the impact the item has on the Company's ability to perform its work, making the highest priority projects readily apparent. Of the 363 "at risk" items Terracon identified, nearly 60% had a risk rating higher than 5 (on a 1 to 10 scale) and 20% were identified as having an actual impact on operations. This rating is what is used to identify the highest risk replacements needed and the project list is created using this information.

Site Improvement Projects

These types of requested facilities projects undergo a multi-level internal review process. It begins with the related manager who either identifies the capital need themselves or is notified of an issue that needs to be resolved by an employee. If the manager believes the project is in the best interests of his group and the Company, the proposal is submitted to that manager's director. If the director also sees the value of the request, it is submitted to a group known as the Facilities Capital Request Board.

This Board meets every fall to review the requested projects for the upcoming year. Managers from each major business area send a representative (the employee chosen usually changes every year). In addition, there is a requirement of at least one person from Operations, Environmental Affairs, Materials Management, and Facilities. This broad mixture of perspectives is designed to provide a neutral and "outside" perspective while having access to the expertise and experience of the directly related and impacted business entities.

By the time the Board receives the list of requests, it has already been vetted twice within its related department. The requests are prioritized based on the Capital Request form that was filled out and approved. At the Board level, each request is reviewed for required criteria such as risk, safety, environmental impact, and compliance. Thus, this process is designed to ensure that multiple stakeholder participation provides a thorough and robust analysis of all facility needs and alternatives across the Company.

Facilities Capital Steering Committee

Once the project list is assembled, the finalized list of projects is approved by the Capital Facilities Steering Committee. This Committee of Directors is responsible for approving the submission of Business Cases to the Capital Planning Group and approval of projects and any changes within this program.

In the past this has most often been:

- Director of Shared Services
- Director of Environmental Affairs

DocuSign Envelope ID: 65DED319-C3D8-490E-AF6E-B6BE5E65C859

- Director of Financial Planning and Analysis
- Director of Generation, Production, Substation Support
- Director of IT and Security
- Director of Natural Gas

The project shall use certain Project Management Professional (PMP) guidelines and procedures during this project.

A Project Execution Plan, consisting of the documents below, will be drafted and approved by the SteerCo described in Section 3.1 (A).

- Project Charter, Change Management Plan, Communication Management Plan, Cost Management Plan, Procurement Management Plan, Project Team Management Plan, Risk Management Plan and Risk Register, Schedule Management Plan, Scope Management Plan, and Project Execution Approval Form.

Each month, the project manager will provide the following information either at the scheduled SteerCo meeting, or via email.

- Approved Yearly Budget, Accrued Yearly to Date, Year Estimate at Complete, Year Variance at Complete, Approved Lifetime Budget, Accrued Life to Date, Lifetime Project Estimate at Complete, and Lifetime Project Variance at Complete.

Each month, the SteerCo will make decisions on cost, scope, or budget items as required by the Project Execution Plan. The project manager reserves the right to present items not outlined in the Project Execution Plan if he/she determines its importance is relevant to SteerCo input.

Decision Making, Prioritization and Change Requests:

- The final decisions regarding these items, especially certain change requests as required by the Project Execution Plan, will be presented to, and voted upon by the SteerCo. The decisions will be documented in a monthly meeting minutes of the SteerCo for documentation and oversight.
- It will be the Project Manager's role to monitor the scope, budget, and schedule and present the results to the SteerCo, regardless of if they are within tolerances, or not.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Structures and Improvements* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Eric Bowles 4ACC724D18764C2...	Date:	May-03-2024 | 10:56 AM PDT
Print Name:	Eric Bowles		
Title:	Corporate Facilities Manager		
Role:	Business Case Owner		
Signature:	DocuSigned by: Kelly Magalsky E7A0E731C49442B...	Date:	May-03-2024 | 2:52 PM PDT

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 521 of 535

DocuSign Envelope ID: 65DED319-C3D8-490E-AF6E-B6BE5E65C859

Print Name:	Kelly Magalsky		
Title:	Director-Shared Services		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 522 of 535

DocuSign Envelope ID: BDF05058-842B-4637-B226-3006525C1ADB

EXECUTIVE SUMMARY

Fleet operations across the US and within the utility industry are implementing telematics solutions to solve complex business problems. The Advisory Group has identified five ways that vehicles on the road impact Avista. The first represents the first generation of telematics and is focused on utility owned trucks. The next four have the potential to positively or negatively impact our business but they are vehicles not owned by the Avista. It could be the contractor working for Avista in a contractor owned truck, a contractor in their personal vehicle, Avista's employee's doing business on behalf of the utility in their personal vehicle and crews responding to mutual aid in our service territory. Telematics has been implemented on the Avista's fleet since 2012. The first generation of telematics was implemented to streamline and track the inspections of trucks and mounted equipment. The digitization of inspections has been very successful and has improved the tracking of federally required inspections and the administration of those records as required by the same authorities.

In February 2022 our current provider has notified us that the 3G network that nearly 500 devices connect to would sunset. This network shut down forces us to invest capital in an upgrade. Additionally, customer requirements and our strategy to put the customer at the center of every decision necessitate the need for us to leverage vehicle location data on a modern and timely platform. Finally, best in class utilities are using telematics to provide both coaching to drivers and collecting leading indicators on decisions a fleet of drivers are making. The Advisory Group's recommendation is to replace Zonar telematics with a modern cloud platform system. Both platforms address latency issues and integrate more info sources than ever before. The final estimated cost for this is upgrade $2,387,500 spread over three years. An upgraded system will integrate location data with the CX platform to give our customers accurate response info, safer roads for all and lower overall costs by streamlining our operations with data. We began this investment in 2021 with the 2022 shutdown of the AT&T 3G network. In doing nothing we will lose our ability to complete a critical compliance function by being unable to complete our daily vehicle inspections. Additionally, we fail to meet our customers where they expect us to be in today's digitally connected economy.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Greg Loew	Initial draft of original business case	6/19/2019	
1.0	Greg Loew	Updated business case	7/21/2020	
2.0	Greg Loew	Updated business case	9/1/2022	Includes change to program

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 523 of 535

DocuSign Envelope ID: BDF05058-842B-4637-B226-3006525C1ADB

GENERAL INFORMATION

Requested Spend Amount	$2,185,250
Requested Spend Time Period	*4 years.*
Requesting Organization/Department	Fleet K51
Business Case Owner | Sponsor	Greg Loew | Alicia Gibbs
Sponsor Organization/Department	Energy Delivery
Phase	Execution
Category	Program
Driver	Asset Condition

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 524 of 535

DocuSign Envelope ID: BDF05058-842B-4637-B226-3006525C1ADB

1. BUSINESS PROBLEM

Advances in technology, customer requirements and safety are driving the need to invest capital in our connected vehicle systems. Implementing the next generation of telematics in vehicles on the road operating on behalf of Avista have the opportunity to delight our customers, reduce our liability exposure and improve operational safety.

Technological Changes: Telematics works by connecting the vehicle to the cellular data network. Currently, most telematics connectivity use third generation networks (3G) provided by the major carriers. In February 2022 this network will no longer be supported and many carriers are already preventing new 3G devices on their networks. To ensure current functionality we will need to equip our vehicles to connect to the fourth and fifth generation networks (LTE and 5G respectively). We also know that connected worker solutions are proliferating across our workforce. This has driven numerous data connections inside and outside of the vehicle. Telematics technology has advanced to allow the consolidation of connections. Leading telematics providers have embraced a platform perspective. They have acknowledged that original equipment manufacturers are controlling some of the data flow from the vehicle or like Caterpillar it is just build in to the equipment computer. This migration to a platform is beneficial for Avista as we advance solutions for the fully digitized worker of the coming decade.

Customer Requirements: Our customers are being influenced by Amazon and Google and other leading customer experience companies. They expect timely and relevant communications from everyone they do business with. The utility is not exempt from these expectations. Next generation telematics is an enabling technology for a fully integrated and digital field work process. The connected vehicle and worker, integrated with the mobile work management system and customer experience platform will provide greater visibility about where our field personnel are and when they will arrive. The information will be available to employees and to customers, improving our ability to provide firm estimates of when we will be there to complete the work. The platform will also improve emergency response times through improved routing and real time location services. Finally, providing more crew location information to our dispatchers will allowing us to dispatch the crew closet to the work saving valuable time and resources.

Safety: The impact of telematics on the overall safety to a fleet of vehicles is under estimated. Telematics allows the capture of data around all facets of the drive cycle. More importantly, telematics is to several leading indicator safety metrics. Next generation telematics integrations will allow us to see items as specific as seat belt usage, the engagement of reverse or how close we backed up to an object. Telematics also has the ability to coach drivers in real time and or provide them a summary of their performance on a pre-determined interval. Finally, the next generation systems will provide metrics on the co-location of supervisors to the crews which has been proven to be a major predictor in crew safety performance

Additionally, as the Advisory Group has engaged internal stakeholders we have created a required functionality list. Based on current published Zonar capabilities the following issues with Zonar were identified:

Issue	Impact on Capability

DocuSign Envelope ID: BDF05058-842B-4637-B226-3006525C1ADB

Dynamic Reporting	Provides inconsistent data points
Server based system	5-8 minute lag in actual unit status
Only support Android operating system	Avista has standardized on iOS
No vehicle as a hotspot capability	Multiple connections and expense
Driver coaching	Requires dedicated tablet
Workflow management	No integrations or partnerships
Behavior metrics	No metrics outside of speed to posted
Auxiliary system data capture	No 3rd party device integration
Point designed solution	No platform capabilities at this time
No manufacture API integration	Requires us to always us an ancillary device

Telematics 2025 will initially provide a platform for compliance. We can and will continue to measure inspections completions and other safety related functions. We will use this platform to capture, track and communicate this information to users and leaders. A feedback loop to the driver on their driving performance will be a key feature of this initiative. Over time the advanced telemetry data from this system will help us shrink the gap between actual behaviors and expected behaviors.

The Driver Safety team that was stood up in 2017 identified a dozen key actions to improve our vehicle incident rate. These recommendations where based on the analysis of multiple best in class companies and the programs/practices they had in place to achieve such results. Every program we looked at had some sort of driver performance feedback mechanism.

1.1 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

Asset Condition

Telematics 2025 is also an enabling platform for Customer Experience advancements and Business Intelligence. We could measure improvements in customer satisfaction, reduced maintenance costs, and lower overall cost per customer being driven by fleet related activities.

1.2 Identify why this work is needed now and what risks there are if not approved or is deferred

The 3G network that Zonar currently operates on will cease operations in February of 2022. Our DOT/FMCSA compliance with CFR49 and the inspections required before and after operation are digitally managed. Not doing anything will force our commercial vehicle operators to complete inspections by pen and paper and creates a document management challenge because we must keep them for 12 months before disposing of them. Failure to do so opens the company to additional liability.

DocuSign Envelope ID: BDF05058-842B-4637-B226-3006525C1ADB

1.3 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

4. **Direct Savings** - Description of Estimated Direct Savings Resulting from this Business Case (please describe and quantify any hard cost savings Avista's customers will gain due to the work under this project. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other):

By implementing vehicle telemetry as a part of this project and the subsequent data analytics that is part of the program we will experience direct savings in the following areas:

Maintenance—Current maintenance practices are based on time. This practice means we over service a portion of the fleet while at the same time underservicing high use vehicles. The process to manage the underservicing is problem therefore a manual process that currently has no automation and relies on staff knowledge/awareness. By integrating real time usage data into the Fleet Management Information System (FMIS) we can base maintenance on actual use and potential diagnostic codes to perform maintenance only when approaching the threshold or codes indicate an issue.

Vehicle Maintenance Cost Per Mile*	$ 0.85	Miles Driven Per Year*	8344	**Potential Annual Savings**
		Maintenance Reduction	2.0%	$ 106,386.00

Allocation:
O&M—$42,555
Capital—$63,831
Based on current clearing account O&M vs. Capital split

Quantified direct savings:

2022	2023	Lifetime
$0	$106,386	$212,772

5. **Indirect Savings** - Description of Estimated Indirect Savings and/or Productivity Gains Resulting from this Project (please describe and quantify any indirect cost savings or productivity gains Avista's customers will gain from this project). For example, deploying this capital investment reduces the future need to hire

DocuSign Envelope ID: BDF05058-842B-4637-B226-3006525C1ADB

X number of employees. For a new substation or transmission line, are there efficiencies to be gained from less line losses. Or, if we don't do this project now, if may cost more in the future (cost avoidance).

Telematics 2025 has the following indirect savings areas

Utilization—Vehicle use each day can be tracked and the validation of equipment needs can be verified. The company's primary focus in the first two years will be pickup trucks. Based on utilization data and subsequent analysis in the first two years, based on peer utility results, it is estimated that Avista can reduce the number of light duty trucks by 7-8 units. That reduction in count results in a two year total of $330,000 (based on 2020 class average spend) is vehicles that will not need to be replaced. Additionally, the company estimates that it can reduce is light and heavy trailers by 1% or 11 total units for an additional $201,000 in capital savings These reductions may not be realized immediately but over the class average life span we will see this reduction. This initiative will begin in 2022 and run through 2024. It will require approximately 6 months of data for validity. This reduction also results in a total life-time operating cost savings on maintenance of $440,310 in 2020 dollars. This is based on the light duty fleet operating cost of $4,516 including major costs such as fuel, maintenance, repairs and licensing over the 13 year life of a pickup truck and finally multiplying that across our estimated reduction.

Light Duty Pickup Reduction Summary Estimate

Average Vehicle Purchase Price*	$ 44,000	Fleet Reduction	0.5%	**Potential Annual Savings**
Realization Period (Years)	2	Vehicle Reduction	3.8	$ 165,000.00

Light and Heavy Trailers Reduction Summary Estimate

Average Non-Vehicle Purchase Price*	$ 18,295	Fleet Reduction	1.00%	**Potential Annual Savings**
Realization Period (Years)	2	Non-Vehicle Reduction	5.5	$ 100,622.50

Allocation*:
O&M—$176,124
Capital—$795,186
Based on current clearing account O&M vs. Capital split

Reduced Total Mileage—Avista's fleet travels more than 7.5 million miles annually. By reducing our total mileage driven .25% we can save $44,000 per year. The focus of this is route optimization, commuter miles and dispatch efficiency.

Vehicle Operating Cost (With Fuel) Per Mile*	$ 2.84	Mileage Reduction	0.25%	**Potential Annual Savings**
		Miles Driven Per Year*	8344	$ 44,431.80

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 528 of 535

DocuSign Envelope ID: BDF05058-842B-4637-B226-3006525C1ADB

Allocation:
O&M—$17,773
Capital—$26,658
Based on current clearing account O&M vs. Capital split

Customer Service
The three year average for complaint calls related to vehicles and the potential whereabouts of people doing work on behalf of Avista totals 55 call hours per year using customer complaint records and an average call duration of 6.5 minutes.

Calls per year	Average call duration (min)	CSR cost per minute *assuming $52/hr loaded	Potential Annual Savings
55	6.5	$.87	$310

Allocation:
O&M—$310

Safety & Risk Reduction
The use of telematics allows us to identify risky driving behavior.

Average Accident Cost	$ 1,788	Preventable Accident Reduction	1.00%	**Potential Annual Savings**
		Number of Preventable Accidents	30	$ 536.40

2020 Vehicle accident rate per million miles driven	Average annual corporate miles driven	Catastrophic accident settlement / verdict	Catastrophic accident frequency
5.8	7,500,000	$7,500,000	8.5 years
Average recordable accidents per year	Average # of accidents per 8.5yr period	Potential risk exposure	Total annual risk cost
43.5	370	1/370	$20,270

Allocation:
O&M—$20,484
Capital—$321
Based on current clearing account O&M vs. Capital split

Maintenance
Under maintenance, on diesel engines with high idle times, has the potential to cost the company $111,702 annually. By basing maintenance scheduling on real time use age data both hours and miles we have the potential to save engine repair or replacement costs.

2020 engines replaced due to excessive idle and hours exceeding manufactures recommended maintenance interval	Average cost per engine parts & labor	Potential annual savings
5	$18,617	$93,085

Allocation:
O&M—$37,234
Capital—$55,851
Based on current clearing account O&M vs. Capital split

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 529 of 535

DocuSign Envelope ID: BDF05058-842B-4637-B226-3006525C1ADB

Compliance

DOT inspection administration

Average admin cost per hour loaded	Total number of commercial vehicles	Man hours per vehicle per year	Avoided labor cost
$40	489	1	$19,560

Allocation:
O&M—$19,560
Capital—$0

Quantified indirect savings:

2022	2023	Lifetime
$238,477	$443,815	$1,907,277

Calculation details

	2022	2023
Light Duty Pickup Reduction Summary Estimate	$ 82,500.00	$ 165,000.00
Light and Heavy Trailers Reduction Summary Estimate		$ 100,622.50
Reduced Total Mileage	$ 22,215.90	$ 44,431.80
Customer Service	$ 310.00	$ 310.00
Safety and Risk Reduction	$ 20,806.40	$ 20,806.40
Maintenance	$ 93,085.00	$ 93,085.00
Compliance	$ 19,560.00	$ 19,560.00
Total	**$ 238,477**	**$ 443,815**

1.4 Supplemental Information

1.4.1 Please reference and summarize any studies that support the problem

See the Driver Safety Team report out February 2018 by Greg Loew and Tony Klutz

1.4.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

The current network for Zonar will ceased operation in 2022. As noted in section 1.1 several functions were noted as missing for future anticipated business processes.

2. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Full telematics program implementation	$2,185,250M	01 2021	12 2026
Partial funding telematics program	$1,208,250	01 2021	12 2026

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 530 of 535

DocuSign Envelope ID: BDF05058-842B-4637-B226-3006525C1ADB

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Telematics Capabilities				
Problem Statement	Identify a telematics solution that provides safety and compliance data on vehicles doing work on behalf of Avista and enables or supports solutions connected to the digital worker of the future.			
Required Functionality	**Details**	**Alternatives**	**Priority**	**Focus Area**
Electronic Inspections	The completion and documentation of DOT required inspections plus pre-flight inspections	Paper		Compliance
Regulatory Mileage Reporting	Multiple federal and state agencies require exact mileage to be reported per state	N/A		Compliance
Diagnostic Alerting and Reporting	The ability for the truck to push diagnostic trouble codes to Fleet	N/A		Fleet
AssetWorks Integration	Pushing mileage to database to act as system of record eliminating the need for the vehicle ledge	N/A		Fleet
iOS Compatible	Must work on iOS devices	N/A		IT
Driver Behavior Scoring and Coaching	Feed back mechanism to help drivers know how they are driving	In cab or daily summary		Safety
4G and 5G capable	3G network is at end of life	N/A		IT
Customer facing info	Customer know who the worker is that will be serving them and visibility into when they will be t	N/A		Customer Service
Utilization	Reporting and mechanisms for understanding under utilized equipment	N/A		Fleet
Idle Reduction	Knowing what it productive idle and non-productive idle	N/A		Fleet
ECM data/Vehicle Performance	Real-time performance data to build dynamic maintenance response	Maintain current system of time base		Fleet
Integration for Distribution Dispatch	Showing vehicle assets to distribution dispatchers to improve dispatch capabilities	N/A		IT
Work Flow Management	Match personnel and resources to work requiring completion (work management) (maybe a tie to	N/A		Operations
Driver Identification	Knowing who is driving every single truck every time it moves	Assumptions based on inspection		Safety
Behavior Metrics	Data analysis info to understand trends and habits	N/A		Safety
Accident Reconstruction	Capability to record some amount of data that can be analyzed after minor crashes	Uses air bag computer after major crashes		Safety
Integration of mulitple telemetry data systems	Trailers and other AVA assets can use different location systems.	Put everything one syste		Fleet
Auxiliary System Data Capture	Capability to capture data from other systems installed on the truck (back up sensors, seatbelt usa	N/A		Safety
GPS location for non motorized units	Find the lost trailer	N/A		Fleet
Vehicle Hotspot	Vehicle based data connection point	Current system with rugged laptops		IT
Smart Phone App	App that could be installed on contractors phone to know where they are at in our system (think gas survey)	N/A		IT
Productivity	Expedited routing	N/A		Operations
Co-Location	Where are supervisors (GFs, managers) in relations to crews	N/A		Safety
Mobile Device Use Reporting	Utilizing mobile device app integrated with telematics to know if the phone is used while vehicle is in motion	App deployed with MDM solution		Safety
Satellite Connectivity	For use in remote wilderness areas	N/A		Safety
Vehicle Pooling	Dynamic assignment of available vehicle to worker requiring vehicle	One vehicle for each worker		Fleet
Driver Cameras	Forward and rear facing in cab cameras	Forward facing camera only		Safety

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

Telematics 2025 will be implemented over a six year period beginning in 2021 in order to meet 3G obsolescence. In year one our commercial fleet will be functional and on

DocuSign Envelope ID: BDF05058-842B-4637-B226-3006525C1ADB

the new systems. In years two and three we will bring our light duty vehicles fully on to the platform plus trailers and complete integrations to systems like Assetworks, Intelex and Oracle.

On an ongoing basis the operational costs for telematics flow to the Fleet Clearing Account. From there a portion of the costs go to capital and some to O&M depending on the class of vehicle. Vehicle rates for light duty trucks and trailers will see a small impact from this technology.

[Offsets to projects will be more strongly scrutinized in general rate cases going forward *(ref. WUTC Docket No. U-190531 Policy Statement)*, therefore it is critical that these impacts are thought through in order to support rate recovery.]

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Telematics 2025 will continue to be used by Fleet and Distribution Ops. The CX project will use the data stream from this system as described in section 1.1. Vehicle electrification efforts have the potential to tap into the platform.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Upgrade existing system. Preserve current functionality with technology that does not meet current or future business needs across the enterprise.

Partial install on only the on-road portion of our fleet (excludes trailers)

Partial install of new system on commercial motor vehicles only. Preserves current functionality does not integrate or capture almost a third of all Avista owned vehicles. Many safety and operational benefits would not be met.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer.

$808K	Q1-2023 Product orders and TTP EOFY 22 work	Q2-2023 Product installs	Q3-2023 Vehicle installs TTPs as districts or orgs completed	Q4-2023 Project planning and remaining TTP
$400K	Q1-2024 Planning and SOW	Q2-2024 Development	Q3-2024 Development	Q4-2024 Development
$200K	Q1-2025 Implementation	Q2-2025 TTP 2024 work	Q3-2025	Q4-2025
$200K	Q1-2026 Planning and SOW	Q2-2026 Integrations, installs and final TTP	Q3-2026	Q4-2026

DocuSign Envelope ID: BDF05058-842B-4637-B226-3006525C1ADB

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Enhancing the telematics in the fleet vehicles directly aligns with the four focus areas; customers, people, perform and invent.

Customers are better served by providing a platform that enables notifications and awareness of crew arrival times. Avista **Employees** are better served through interactive coaching and feedback on their driving behavior. **Performance** is better served through the enhanced integrations that are enabled and the information that can be shared across multiple systems. **Invention** is served by recognizing that the expectations of customer service has changed, and that technology is required, not only in our back office but in the front-line vehicles that serve as the initial touchpoint for many customer interactions.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

The majority of Telematics 2025 scope is the replacement of a system that will no longer operate after February 2025. As outlined in section 1.1 our next generation telematics will enable additional functions and help streamline analog processes. Project management and business case owner will continue to review the scope of the project for material changes.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Stakeholder Name	Department
Andrea Pike	Customer Service
Reuben Arts	Distribution Dispatch
Amy Parsons	Finance
Paul Good	Gas Ops
Alexis Alexander	GPSS
Mike Littrel	Enterprise Technology
Jon Thompson	Enterprise Technology

2.8.2 Identify any related Business Cases

Exhibit No. 10
Case Nos. AVU-E-25-01/AVU-G-25-01
J. DiLuciano, Avista
Schedule 3, Page 533 of 535

DocuSign Envelope ID: BDF05058-842B-4637-B226-3006525C1ADB

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

This project reports in with the executive advisory committee comprised of:

Heather Rosentrater	Jason Thackston	Jim Kensok

Alicia Gibbs	Jeremy Gall	Kermit Olson
Jim Corder	Liz Fredrickson	

3.2 Provide and discuss the governance processes and people that will provide oversight

Specific project updates will be provided and key decisions will be confirmed by the group from the program owner.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The project manager and the business case owner will be responsible for monitoring and recording priority changes and material change requests.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *<Business Case Name>* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: DocuSigned by: Greg Loew E32CB80399F242F... Date: Sep-09-2022 | 8:42 AM PDT

Print Name: Greg Loew

Title: Fleet Manager

Role: Business Case Owner

DocuSign Envelope ID: BDF05058-842B-4637-B226-3006525C1ADB

Signature:	DocuSigned by: Alicia Gibbs 49C42855345E483...	Date:	Sep-08-2022 | 1:16 PM PDT
Print Name:	Alicia Gibbs		
Title:	Alicia Gibbs		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		