Exh. JDD-2

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET UE-240006

DOCKET UG-240007

DIRECT TESTIMONY OF

JOSHUA D. DILUCIANO

REPRESENTING AVISTA CORPORATION

Proforma Capital Additions for 07.2023 - 12.2023 and 2024 by Plant Category
DiLuciano

WA GRC Plant Category	Project #	Business Case	07.2023-12.2023 TTP (System)	2024 TTP (System)	Exh. JDD-2 Page #
Large or Distinct Projects	1	Jackson Prairie Natural Gas Storage Facility	$ 1,748,191	$ 2,397,000	3
	2	Local Reps Office Program	$ -	$ 248,981	11
	3	Metro 115kV Substation	$ -	$ 6,000,000	27
	4	Oil Storage Improvements	$ 2,330,000	$ 169,614	46
	5	Palouse Service Center	$ -	$ 746,533	59
	6	Strategic Initiatives - South Landing (Catalyst) - Clean Energy Fund 3	$ 2,997,928	$ -	76
	7	Strategic Initiatives - UIASSIT	$ 149,960	$ -	80
Large or Distinct Projects Total			$ 7,226,080	$ 9,562,128	
Mandatory & Compliance	8	Colstrip Transmission	$ 133,074	$ 650,119	88
	9	Elec Relocation and Replacement Program	$ 3,869,387	$ 7,000,011	95
	10	Gas Above Grade Pipe Remediation Program	$ 339,000	$ 650,004	103
	11	Gas Cathodic Protection Program	$ 788,471	$ 665,000	114
	12	Gas Facility Replacement Program (GFRP) Aldyl A Pipe Replacement	$ 16,423,658	$ 27,187,249	123
		Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System			136
		Study of Aldyl A Pipe Leaks 2022 Update			171
	13	Gas Isolated Steel Replacement Program	$ 1,368,102	$ 2,000,000	182
	14	Gas Overbuilt Pipe Replacement Program	$ 325,731	$ 412,000	195
	15	Gas PMC Program	$ 272,468	$ 3,200,000	200
	16	Gas Replacement Street and Highway Program	$ 2,696,316	$ 3,718,000	209
	17	Gas Transient Voltage Mitigation Program	$ 674,445	$ 500,001	216
	18	Generation Interconnection	$ 108,535	$ -	227
	19	Joint Use	$ 3,203,666	$ 3,999,996	235
	20	Saddle Mountain 230/115kV Station (New) Integration Project Phase 2	$ 2,984	$ 716,783	244
	21	Transmission Construction - Compliance	$ 2,138,505	$ 500,000	253
	22	Transmission NERC Low-Risk Priority Lines Mitigation	$ 2,366,517	$ 1,133,452	261
	23	Westside 230/115kV Station Brownfield Rebuild Project	$ -	$ 4,717,625	269
	24	WSDOT Control Zone Mitigation	$ 580,562	$ 999,998	276
Mandatory & Compliance Total			$ 35,291,423	$ 58,050,238	
Programs	25	Capital Equipment Program	$ 2,179,307	$ 2,074,003	288
	26	Distribution Grid Modernization	$ 1,055,048	$ 987,476	296
	27	Distribution Minor Rebuild	$ 6,779,574	$ 12,999,990	308
	28	Distribution System Enhancements	$ 6,106,491	$ 10,162,656	318
	29	Downtown Network - Asset Condition	$ 1,245,324	$ 2,000,000	333
	30	Downtown Network - Performance & Capacity	$ 2,736,210	$ 1,200,021	349
	31	Electric Storm	$ 6,935,274	$ 4,975,634	361
	32	Fleet Services Capital Plan	$ 3,891,975	$ 6,850,000	369
	33	Gas ERT Replacement Program	$ 302,676	$ 225,000	384
	34	Gas Non-Revenue Program	$ 3,685,505	$ 9,682,000	396
	35	Gas Regulator Station Replacement Program	$ 685,386	$ 1,069,995	409
	36	Gas Reinforcement Program	$ 468,738	$ 1,577,830	421
	37	Gas Telemetry Program	$ 184,132	$ 100,000	433
	38	LED Change-Out Program	$ 162,877	$ 200,003	445
	39	Meter Minor Blanket	$ 152,207	$ 250,001	456
	40	New Revenue - Growth	$ 61,695,518	$ 78,505,094	462
	41	SCADA - SOO and BuCC	$ 1,086,767	$ 700,000	472
	42	Structures and Improvements/Furniture	$ 4,056,748	$ 5,348,646	483
	43	Substation - Asset Condition	$ 17,853,298	$ 25,772,370	503
	44	Substation - Performance and Capacity	$ 3,760,226	$ 8,621,160	518
	45	Transmission - Minor Rebuild	$ 3,674,974	$ 3,343,420	529
	46	Transmission - Performance & Capacity	$ -	$ 100,000	536
	47	Transmission Critical Crossing Reinforcement	$ -	$ 1,000,000	545
	48	Transmission Major Rebuild - Asset Condition	$ 6,558,470	$ 8,250,000	553
	49	Wood Pole Management	$ 7,659,818	$ 13,000,004	564
Programs Total			$ 142,916,541	$ 198,995,303	
Misc. accrual reversals, corrections or additional TTP			$ 25,739	$ 7,442	
Grand Total			**$ 185,459,783**	**$ 266,615,111**	

[1] Includes system profroma capital for the period July 1, 2023 through December 31, 2023.
[2] Totals exclude Idaho and Oregon direct business cases from revenue requirement in this case.

Provisional Capital Additions for 2025-2026 by Plant Category
DiLuciano

WA GRC Plant Category	Project #	Business Case	2025 TTP (System)	2026 TTP (System)	Exh. JDD-2 Page #
Large or Distinct Projects	50	Central 24 HR Operations Facility	$ -	$ 3,499,757	577
	1	Jackson Prairie Natural Gas Storage Facility	$ 2,386,000	$ 2,386,000	3
	2	Local Reps Office Program	$ 248,983	$ -	11
	3	Metro 115kV Substation	$ 3,200,004	$ 38,700,000	27
	5	Palouse Service Center	$ 750,011	$ -	59
	51	West Plains New 230kV Substation	$ -	$ 3,950,000	594
Large or Distinct Projects Total			$ 6,584,998	$ 48,535,757	
Mandatory & Compliance	8	Colstrip Transmission	$ 569,999	$ 99,997	88
	9	Elec Relocation and Replacement Program	$ 7,000,013	$ 7,000,005	95
	10	Gas Above Grade Pipe Remediation Program	$ 650,004	$ 650,004	103
	11	Gas Cathodic Protection Program	$ 665,000	$ 665,000	114
	12	Gas Facility Replacement Program (GFRP) Aldyl A Pipe Replacement	$ 27,999,995	$ 29,999,998	123
		Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System			136
		Study of Aldyl A Pipe Leaks 2022 Update			171
	13	Gas Isolated Steel Replacement Program	$ 2,000,000	$ 2,000,000	182
	15	Gas PMC Program	$ 3,200,000	$ 3,000,000	200
	16	Gas Replacement Street and Highway Program	$ 3,830,000	$ 3,945,000	209
	18	Generation Interconnection	$ 38,006	$ 554,008	227
	19	Joint Use	$ 3,999,996	$ 3,000,000	235
	21	Transmission Construction - Compliance	$ 500,000	$ 250,000	253
	24	WSDOT Control Zone Mitigation	$ 999,998	$ 2,000,002	276
Mandatory & Compliance Total			$ 51,453,011	$ 53,164,014	
Programs	25	Capital Equipment Program	$ 2,079,010	$ 2,085,001	288
	26	Distribution Grid Modernization	$ 979,842	$ 911,763	296
	27	Distribution Minor Rebuild	$ 12,999,991	$ 12,204,154	308
	28	Distribution System Enhancements	$ 7,499,982	$ 9,999,987	318
	29	Downtown Network - Asset Condition	$ 2,000,000	$ 2,000,000	333
	30	Downtown Network - Performance & Capacity	$ 1,200,022	$ 1,200,753	349
	31	Electric Storm	$ 5,000,005	$ 5,000,008	361
	32	Fleet Services Capital Plan	$ 5,748,784	$ 7,092,857	369
	33	Gas ERT Replacement Program	$ 235,000	$ 245,000	384
	34	Gas Non-Revenue Program	$ 9,972,000	$ 10,272,000	396
	35	Gas Regulator Station Replacement Program	$ 1,069,995	$ 1,069,995	409
	36	Gas Reinforcement Program	$ 1,000,000	$ 1,000,000	421
	37	Gas Telemetry Program	$ 100,000	$ 100,000	433
	38	LED Change-Out Program	$ 199,999	$ 199,999	445
	39	Meter Minor Blanket	$ 250,001	$ 250,001	456
	40	New Revenue - Growth	$ 73,745,609	$ 75,985,327	462
	41	SCADA - SOO and BuCC	$ 700,000	$ 701,014	472
	42	Structures and Improvements/Furniture	$ 4,238,511	$ 4,399,224	483
	43	Substation - Asset Condition	$ 44,265,853	$ 34,666,286	503
	44	Substation - Performance and Capacity	$ 7,399,007	$ 1,350,006	518
	45	Transmission - Minor Rebuild	$ 3,343,420	$ 3,343,419	529
	46	Transmission - Performance & Capacity	$ 1,400,000	$ 500,000	536
	47	Transmission Critical Crossing Reinforcement	$ 1,000,000	$ 2,000,000	545
	48	Transmission Major Rebuild - Asset Condition	$ 9,040,634	$ 10,000,000	553
	49	Wood Pole Management	$ 9,999,994	$ 9,999,994	564
Programs Total			$ 205,467,659	$ 196,576,788	
Grand Total			**$ 263,505,668**	**$ 298,276,559**	

[1] Includes system profroma capital for the period July 1, 2023 through December 31, 2023.
[2] Totals exclude Idaho and Oregon direct business cases from revenue requirement in this case.

<Project Name>ckson Prairie Natural Gas Storage Facility

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.

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]

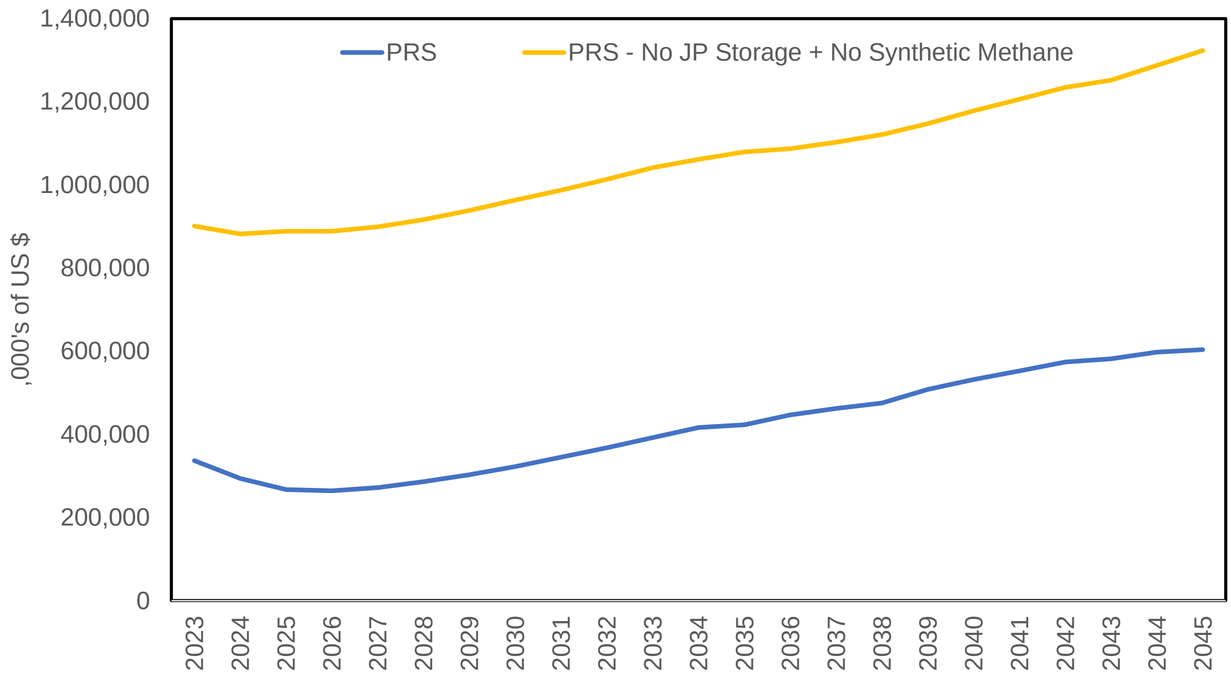
JP is a critical integrated supply resource for our natural gas business. JP helps enable the delivery of natural gas energy safely, responsibly, and affordably to our customers. Without JP customers would be exposed to market price volatility risk and the need to acquire more pipeline transport capacity to the different gas supply regions.

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.



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.

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 offsets4 (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.

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.

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		

Local Reps Office Program

EXECUTIVE SUMMARY

The existing Ritzville and Chewelah Local Reps offices were previously used as temporary storage buildings for materials and equipment. Over the years these locations have evolved into more permanent usage by both Gas and Electric employees. These locations now have two permanent employees each. Crews from outlying areas use both locations as meeting points for work in nearby rural areas, this has increase storage requirements at both locations. Over the years customer meeting have been discouraged at these sites but many walk ins still occur.

While the properties are large enough to accommodate the needs of the business the locations and quality of the buildings themselves needs to be addressed. The Ritzville building is single-story, concrete and wood framed structure constructed as a gas station in 1955 and is currently being used primarily for office needs, warehousing and materials storage, meeting with customers and rendezvousing with Avista crews coming from other areas to do larger work. The site was leased for many years and purchased in 2016 with the intention of renovation the building. The Chewelah building was never designed to be occupied on a continuous basis. The space is not insulated and is a simple pole building. The restrooms and doorways do not meet today's ADA requirements. Both sites need extensive renovations totaling more than $1M over the next 10- years. Replacing these buildings on the existing property with a new standard Local Rep Office building will reduce design costs and proved crews with the needed office space, materials and vehicle storage and landing space during an outage.

This project would impact both Gas and Electric customers in Washington. We expect our preferred solution to cost $2M. $1M in 2024 and $1M in 2028. The spacing is to accommodate other Capital Requests and workload within Facilities.

Both the Ritzville and Chewelah locations require extensive updates to the existing structures. As these buildings were not designed for Avista's needs, we propose replacing these buildings with a new construction building on the existing sites rather than investing in structures that do not meet the requirements. The standard design will be used at both locations and fulfills the requirements for local reps use and the needs of crews during large projects and outages. 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%.

This project would benefit external customers in that the new Local Reps Offices can improve efficiencies. Having all materials, supplies and staff in one location allows for improved use of resources and response times. This also improves our ability to stage crews for improvements to both Gas and Electric systems. Employees benefit from improved communication during outages and ability to perform their tasks safely and effectively. The Ritzville and Chewelah buildings and the sites have many critical systems that need replacement, including HVAC, plumbing and roof systems. There are many worn 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 of original business case*	*4/27/2023*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements Steve Carrozzo*	*05/11/2023*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$1,000,000**	**$1,000,000**
2025		
2026		
2027		
2028	**$1,250,000**	**$1,250,000**

Project Life Span	*6 years*
Requesting Organization/Department	Facilities
Business Case Owner | Sponsor	Eric Bowles | Kelly Magalsky
Sponsor Organization/Department	Shared Services
Phase	Initiation
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?

Ritzville Local Reps Office:

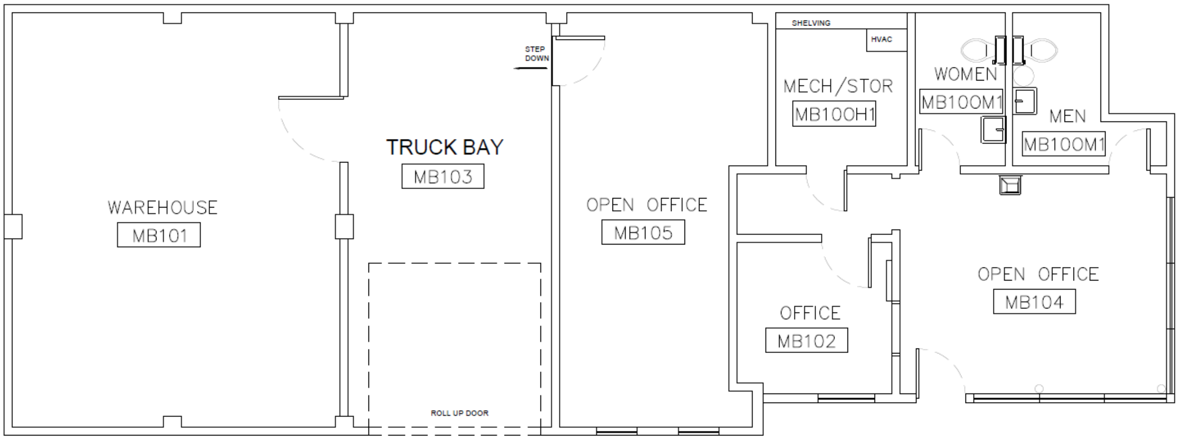
The Ritzville local rep's office has two permanent employees, a gas local rep and an electric local rep. These employees work out of this location. The current building is single-story, concrete and wood framed structure constructed in 1955 and is currently being used primarily for office needs, warehousing and materials storage, meeting with customers and rendezvousing with Avista crews coming from other areas to do larger work. The exterior walls are painted CMU construction and pre-finished corrugated metal panels. This structure was originally a gas station and is not designed for Avista's current needs.

This location has become a staging point for crews doing work in the nearby rural areas. Having materials delivered to this location limits drive time for crews having to return to Spokane for materials. The current building configurations prevents crews from being able to have meetings indoors during inclement weather.

The truck bay is too small for any of Avista's vehicles and currently stores the forklift used in the storage yard. The office space is disjointed and not efficient. There is no space for crews to meet when on site. The warehouse is on a different level and requires a step to get to, limiting what can be stored in that space as everything must be hand carried. The restrooms and doorways do not meet today's ADA requirements and there is no shower provided for crews, as has become our standard.

The current structure also has many assets condition issues. There is currently identified Backlog of asset condition work totaling $333K. This constitutes of a complete replacement of the roof, exterior, windows and doors, interior ceilings, and walls, electrical and all domestic water piping. Current Ritzville Floor Plan:

Local Reps Office Program



Chewelah Local Reps Office:

The Chewelah local rep's office has two permanent employees, both electric local reps. These employees work out of this construction office full time. This location is necessary to meet the response times of the nearby mountain area during an outage. This building is a single-story wood-framed structure built in 1985. The exterior walls consist of a combination of metal panels. The high-sloped roof areas are covered with corrugated metal panels applied over wood roof decking. This building was designed and built as a temporary storage structure and was never intended to be heated or occupied full time. The Colville River runs to the East of the property and during Spring season the river will flood the East end of the yard almost up to the building. Building up the property and location the builder to the West end of the lot will prevent this flooding going forward and increase environmental protections to the river.

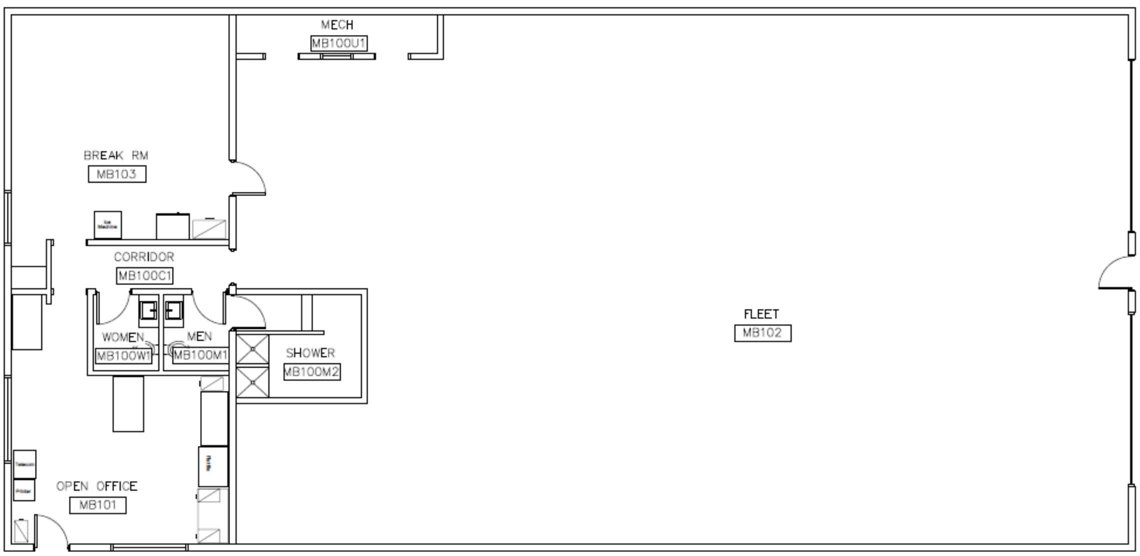
This location has become a staging point for crews doing work in the nearby rural areas. Having materials delivered to this location limits drive time for crews having to return to Colville, Deer Park, or Spokane for materials.

The Chewelah building was never designed to be occupied on a continuous basis. The space is not insulated and is a simple pole building. The restrooms and doorways do not meet today's ADA requirements. Renovating the building to convert it to a permanent office/ shop structure would take extensive work, estimated at $750K.

The building is currently located about fifty yards from the high water of the creek to the East. This creek has flooded to almost reach the man door during heavy rain/ snow seasons. Ideally this building would be located to the front of the property and the property would be built up to prevent flooding in the future.

The current structure also has many assets condition issues. There is currently identified Backlog of asset condition work totaling $374K. This is expected to balloon to $830K. This constitutes of a complete replacement of the roof, exterior, windows and doors, interior ceilings, and walls, electrical and all domestic water piping.

Current Chewelah Floor Plan:



1.2 Discuss the major drivers of the business case.

The major drivers of this business case are Asset Condition and Safety.

The Ritzville and Chewelah buildings and assets are in dire need of replacement, as many 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.

These locations are critical to Avista maintaining appropriate response times to rural areas. The Local Reps that work out of these locations play a critical part in Avista's Customer Experience. Providing local contacts that can quickly respond to issues, repairs and outages as needed. Both locations are required to meet the requirements of response times to the surrounding rural areas.

This project would benefit external customers in that the new Local Reps Offices 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 local reps' offices become a meeting point during outages and these buildings are critical to our service in these remote areas.

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.

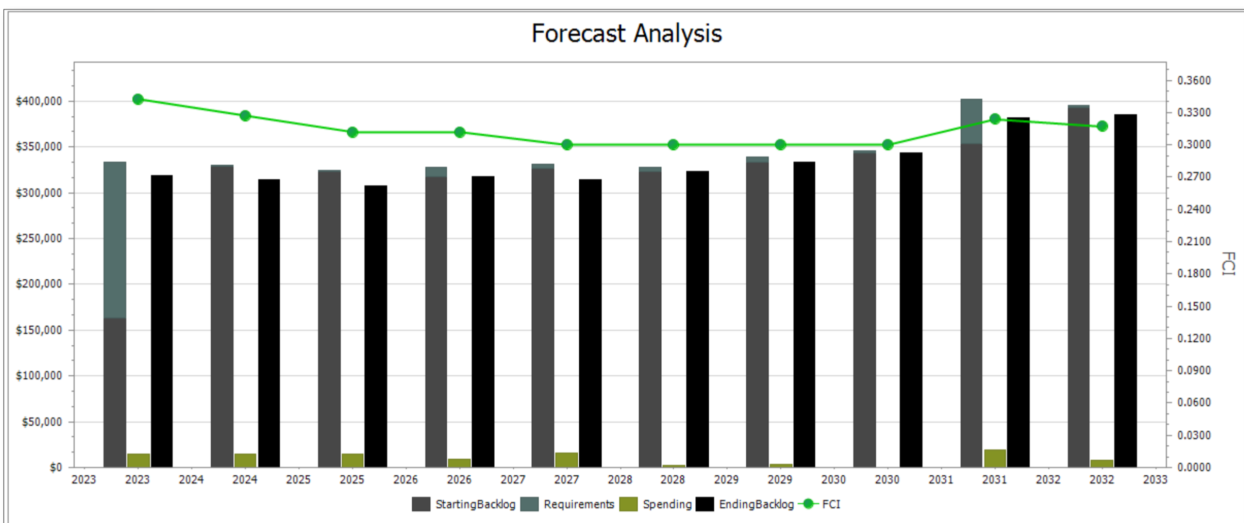
The Ritzville and Chewelah local reps' offices have assets that are in dire need of replacement, as many of the capital projects have been put on hold until the future state of the site is known. This includes, window and door replacements, lighting upgrades, plumbing improvements and HVAC replacements at both locations. 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 buildings and sites. Facilities must either move forward with the relocation/ rebuild of these building or invest in the existing structures to maintain functionality.

These improved buildings and sites will increase efficiency of both the office and warehouse spaces. Current building and site limitations prevent material from being stored in an easy to access manner due to disorganization and limited space. This will also resolve existing environmental concerns regarding the Colville River at the Chewelah location.

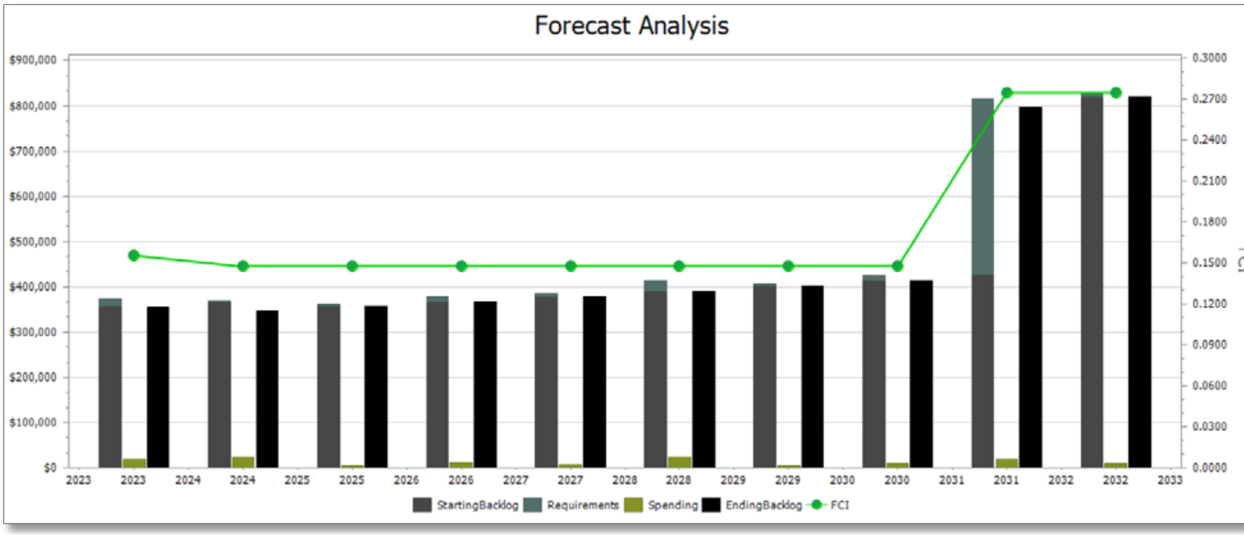
Ritzville has $333K worth of identified work that it needs today, the building requires a complete overhaul from interior to exterior as every building system is either in failure or is expected to fail in the next 5 years.

Chewelah has $375K worth of identified work that it needs today, the building requires building systems that it does not have currently. Systems like, insulation and appropriate HVAC for an occupied building. In 10 years, Chewelah is expected to need a total of $830K in Asset Condition work.

Ritzville 10- Year Asset Condition Forecast:



Chewelah 10- Year Asset Condition Forecast:



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. Having facilities and storage yards in one location that meet the needs of both electric and gas operations benefits employees through ease of access and efficiency.

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 innovative 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.

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 are pictures of the existing Ritzville and Chewelah locations. As shown these buildings are in dire need of upgrades, both interior and exterior.

Ritzville Pictures:

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

Local Reps Office Program

Warehouse:

Storage/HVAC:

Garage:

Open Office:

Office:

Restroom:

Restroom:

Front Office:

Local Reps Office Program

Chewelah Pictures:

Exterior:

Exterior:

Restoom:

Shop Interior:

Shop Interior:

Office Interior:

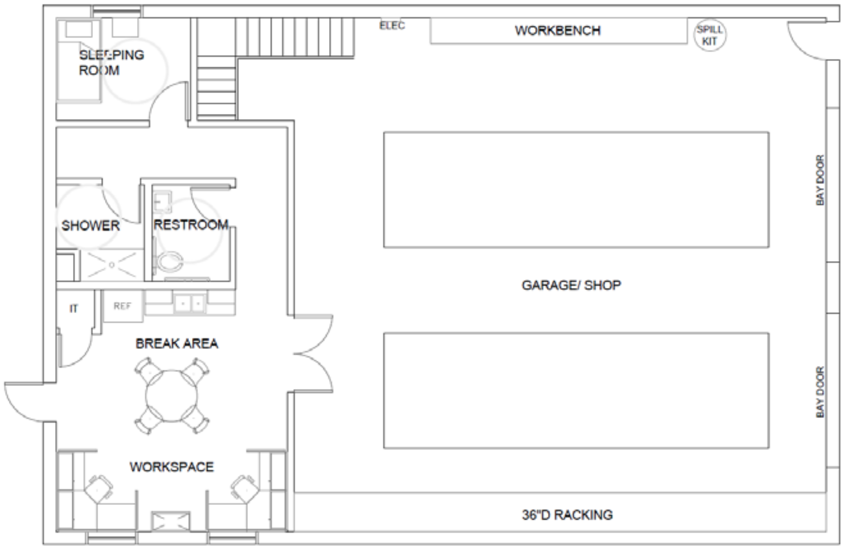
2. ROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

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

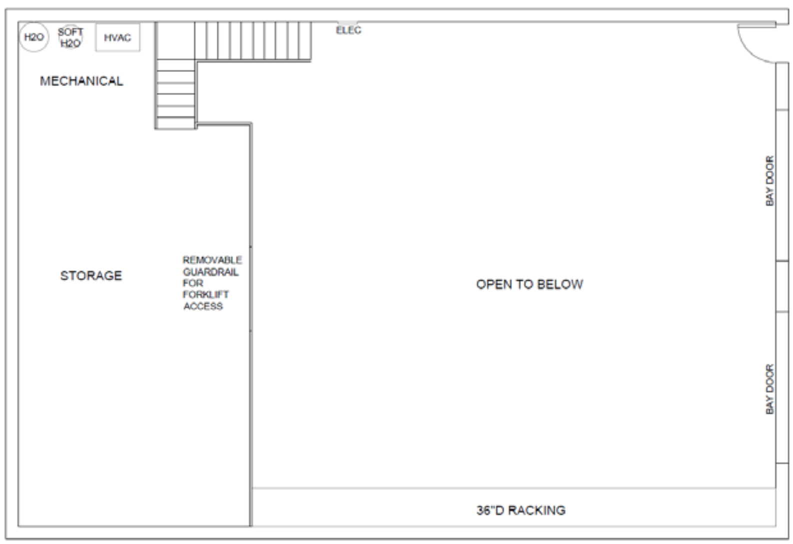
Both the Ritzville and Chewelah locations require extensive updates to the existing structures. As these buildings were not designed for Avista's needs we propose replacing these buildings with a new construction building on the existing sites rather than investing in structures that do not meet the requirements. The standard design, shown below, will be used at both locations and fulfills the requirements for the local reps use and the needs of crews during large projects and outages.
These locations are critical to Avista maintaining appropriate response times to rural areas. The Local Reps that work out of these locations play a critical part in Avista's Customer Experience. Providing local contacts that can quickly respond to issues, repairs and outages as needed. Both locations are required to meet the requirements of response times to the surrounding rural areas. Land in the Ritzville and Chewelah areas has increased in value and these properties are already owned by Avista. We propose demoing the existing buildings and rebuilding on the existing sites. In Ritzville this will require minimal site improvements including asphalt, fencing and gates. In Chewelah this will require more extensive sitework including building up to prevent flooding in the future, asphalt fencing and gates.

We propose a newly constructed standard building to be completed in Ritzville in 2024 and Chewelah to follow in 2028.

First Floor Proposed Plan:



Second Floor Proposed Plan:



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]

Ritzville has $333K worth of identified work that it needs today, the building requires a complete overhaul from interior to exterior as every building system is either in failure or is expected to fail in the next 5 years.

Chewelah has $375K worth of identified work that it needs today, the building requires building systems that it does not have currently. Systems like, insulation and appropriate HVAC for an occupied building. In 10 years, Chewelah is expected to need a total of $830K in Asset Condition work.

Both locations continue to have roof leaks, plumbing outages, door repairs and various other small tasks that require constant upkeep. The Local Reps on site have become their own “Building Serviceperson,” working to maintain minimal operation of their equipment between trips by the Facilities crew.

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		$	$	$	$	$

Direct: None Identified

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	2024	2025	2026	2027	2028
Capital	-	$	$	$	$	$
O&M	Business Operations Improve	$	$22,100	$22,100	$22,100	$22,100

Indirect:

- 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.
    - 2 emp x 0.25 hr./day x 260 workdays x $85/hr. avg loaded rate= **$11,050**
- Efficiencies created through improved storage, more efficient workspaces and expanded workspaces as required for growth.

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[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.

- 2 emp x 0.15 hr./day x 260 workdays x $85/hr. avg loaded rate= **$11,050**

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: Interior Remodel of Existing Buildings

Ritzville: $333,000 Chewelah: $830,000

Ritzville has $333K worth of identified work that it needs today, the building requires a complete overhaul from interior to exterior as every building system is either in failure or is expected to fail in the next 5 years. This alternative would fund the remodel of the existing structure only and does not include any improvements to the operation of the site.

Chewelah has $375K worth of identified work that it needs today, the building requires building systems that it does not have currently. Systems like, insulation and appropriate HVAC for an occupied building. In 10 years, Chewelah is expected to need a total of $830K in Asset Condition work. This alternative would fund the remodel of the existing structure only and does not include any improvements to the operation of the site.

Doing these improvements to the existing structures will increase the life of the building but due to their age it will continue to require large capital investments to the building systems as they age beyond useful life.

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
5) 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.

Design will begin in 2023 with construction in Ritzville to follow in 2024. Currently, as of April 2023, we expect Ritzville to Transfer to Plant by December of 2024. Construction of Chewelah will be done in 2028, as of April 2023, we expect Chewelah to Transfer to Plant by December of 2028.

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.

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 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.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Local Reps Office 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: Eric Bowles Date: 5/12/2023
Print Name:
Title:
Role: Business Case Owner

Signature: Kelly Magalsky Date: 5/12/2023
Print Name: Kelly Magalsky
Title: Director Shared Services
Role: Business Case Sponsor

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

Metro 115 kV Substation

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 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 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. The design enables a longer station lifespan where individual pieces of equipment can be safely serviced and upgraded without prohibitive site/outage constraints. 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 impacted 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 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.

The Metro rebuild project was scoped in 2020 and a Project Charter was initiated and approved in 2021. This effort included analysis and assessments of operational risks and challenges, mitigation options and 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.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Karen Kusel/ Crystal Holmes*	*Final Draft of Business Case*	*3/1/2023*
BCRT	*Steve Carrozzo.*	*Has been reviewed by BCRT and meets necessary requirements* DS SC	May-09-2023 | 3:08 PM PD

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2023	$13,255,000	$0
2024	$19,500,000	$6,000,000 (CIRCUIT BREAKERS/WALL CONSTRUCTION)
2025	$14,100,000	$3,200,000 (AUTO TRANSFORMERS RECEIVED)
2026	$11,800,000	$55,800,000 (SUBSTATION CONSTRUCTION COMPLEX)
2027	$6,500,000	$6,000,000 (COMMUNICATION/SECURITY COMPLETE)
2028	$3,500,000	$2,000,000 (FINAL CHARGES)

Note: $4.5M has been funded for this project out of Substation Rebuilds Business Case for the period of 2020 to 2022. This brings the estimated total cost of the project to $73,000,000.

Project Life Span	*5 Years*
Requesting Organization/Department	Substation Engineering/M08
Business Case Owner | Sponsor	Glenn Madden | 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?

There are several Transmission, Distribution, and Substation issues at the current Metro 115kV Substation that are detailed below:

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).
    - 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 a ~100' long "tunnel" that contains many types of cable including the 115 kV 3HT-PST Third & Hatch-Post St line racked in an open configuration 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.

  - 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 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

- <u>Racking Breakers for Feeder Outages</u>
  - 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.

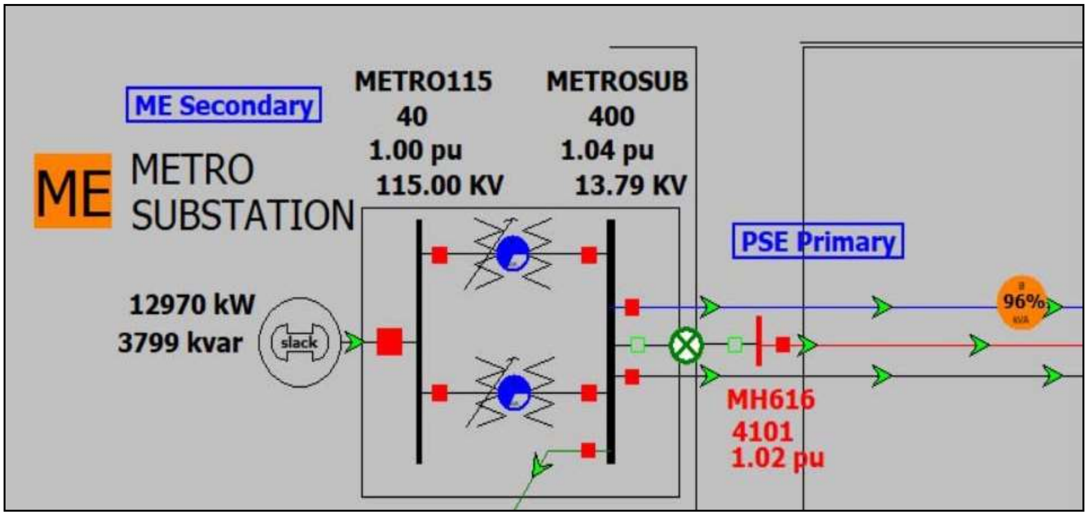
    Remote racking is available at Post Street, but not at Metro. Instead, the older switchgear is either jacked into place using a portable jacking motor, or in some cases, ratcheted horizontally into the energized 13 kV bus, manually. In order to do either requires a cableman to be physically inside the 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.

- <u>Three Metro East Feeder Exits Need Upgraded for Thermal Reasons</u>
  - 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.

Metro 115 kV Substation



- 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 outage would continue as no options to backfeed primary exist within the Downtown Network.

- <u>Lower South Hill Radial Feeder Reliability</u>
  - 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

- <u>Transformer/Low Side Fault Clearing</u>
  - 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 transformer

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.

  - 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.

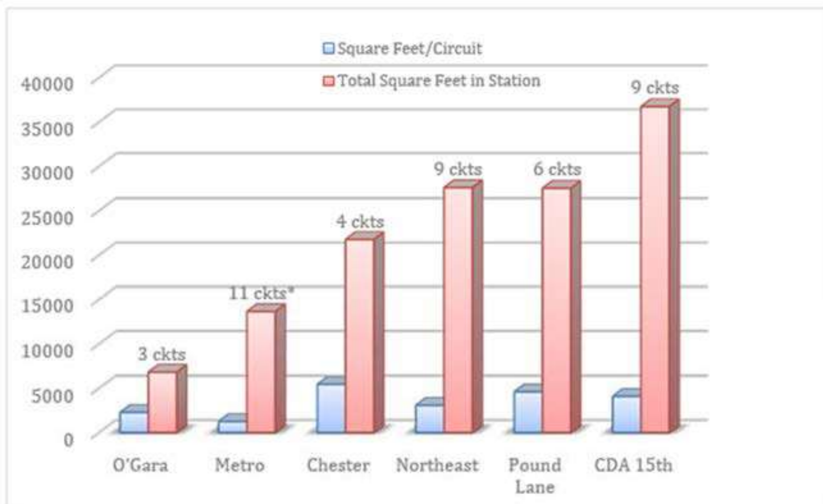
- Batteries at the Existing Station are Undersized
  - Issue: Batteries at the existing Metro are undersized given both the importance of the station (transmission breakers, six feeders of urban load) and the amount of equipment in the station. The station's batteries are presently sized at 100 amp-hours (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 (refer to Section 3.2).

- 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).



*Metro's circuit (ckt) count does not take into account the 3HT-PST line, which transitions to underground within the existing Metro site.

  - 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.

  - 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.

- <u>The "Pigeon Problem"</u>
  - 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.

- <u>115 kV PT Issues</u>
  - 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 PT's 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.

- <u>Recent LTC Issues Found</u>
  - 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.

- <u>Avista Does Not Carry Spare LTC or Throat-connected Transformers</u>
  - Issue: The repair on Transformer #2 LTC brought up the concern about not having a spare transformer with an LTC.

  - 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 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.
- 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.

[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. 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 are 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. It 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
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.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$0	$0	$0	$0	$0
O&M		$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.

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	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

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 arch 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.

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.

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.

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
- 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 scheduled 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	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2023	$16,200,000	$0
2024	$21,340,000	$6,000,000 (CIRCUIT BREAKERS/WALL CONSTRUCTION)
2025	$14,010,000	$3,200,000 (AUTO TRANSFORMERS RECEIVED)
2026	$9,790,000	$55,800,000 (SUBSTATION CONSTRUCTION COMPLEX)
2027	$5,160,000	$6,000,000 (COMMUNICATION/SECURITY COMPLETE)
2028	$2,000,000	$2,000,000 (FINAL CHARGES)

This project initiated 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.

Glenn Madden – Business Case Owner/Manager, Engineering Substations

Brian Vandenburg – Manager, Engineering Projects

Brian Chain – Sr. Engineer, Downtown Network

Aaron Henson – Principal Engineer – Substation - Civil

Brian Parsons – Sr. Engineer, Substation - Civil/Structural

Patrick Henderson – Sr. Engineer, Substation Engineering - Electrical

Bryan Hyde – Sr. Engineer, Transmission Engineering

Tim Figart – Principal Engineer - Electric Distribution Design

Crystal Holmes – Project Manager, Electrical Engineering 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.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the ***Metro 115kV Substation*** and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designate d representatives.

Signature:	DocuSigned by: Glenn J Madden	Date:	May-11-2023 | 11:32 AM PDT
Print Name:	Glenn Madden		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		
Signature:	DocuSigned by: Vern Malensky	Date:	May-09-2023 | 1:50 PM PDT
Print Name:	Vern Malensky		
Title:	Director, Electrical Engineering		
Role:	Business Case Sponsor		
Signature:	DocuSigned by: Brian Vandenburg	Date:	May-09-2023 | 1:51 PM PDT
Print Name:	Brian Vandenburg		
Title:	Manager, Engineering Projects		
Role:	Steering/Advisory Committee Review		

Oil Storage Improvements

EXECUTIVE SUMMARY

In the 1990s, an underground vault was built at the Mission Campus to house several tanks intended to hold new oil, used but viable oil, and scrap oil, all related to substation maintenance and electrical distribution operations. This system connected the electric shop and the scrap oil recovery areas through a series of manifolds and pumps to segregate the new and used oils. Several incidents, including one holiday weekend overfill incident in 2010, brought to light the disadvantage of using an underground system, as problems could go undetected. This risk was further highlighted during a 2019 pipeline spill and subsequent investigation/excavation and cleanup.

In 2014, two new above-ground scrap oil storage tanks were built as part of the Waste & Asset Recovery (WAR) Building. This allowed for the two scrap tanks in the underground vault to be decommissioned, but the remaining four underground tanks, and associated underground piping, remain in use. This system still poses risks of undetected leaks. In addition, access to the underground system becomes more problematic as we redevelop the campus. The vault space itself limits use of the area. Finally, the vault has been subject to intrusion by water, and maintenance costs to ensure the vault provides proper containment are increasing.

The recommended solution will build two additional new oil tanks by the WAR Building, with several smaller "day" containers for the Electric Shop, allowing the underground vault to be permanently removed, eliminating environmental risk.

The recommended solution is estimated to cost $1.5 million (as of May 2022). There will be two rate jurisdictions for this project. For the actual oil tanks and dispensing equipment, since they will only be used for Substation Support, the costs will be filed under Electric Only – WA & ID. All other associated site improvements, since they could be used by any business unit at the Mission Campus, will be filed with the rate jurisdiction of Common Direct – Allocated All. The major customer benefit would be the reduction in future O&M maintenance, and costs of clean up of environmental events. Customers will also benefit with an enhanced oil storage process that will provide Avista employees with reduced overall environmental risk, time efficiencies and generally faster response times within substation maintenance. It is recommended to proceed with this business case as soon as possible to avoid any additional environmental risk and inefficiencies utilizing the existing system. The Facilities Capital Steering Committee approved submission of this Business Case.

VERSION HISTORY

Version	Author	Description	Date	Notes
0.0	Vance Ruppert	Initial draft to be approved by Sponsors	7/6/2020	
1.0	Vance Ruppert	Final Draft, Sponsor edits incorporated	7/10/2020	
1.1	Vance Ruppert	BCJN update Capital Planning	7/9/2021	
2.0	Lindsay Miller	Executive Summary Update	5/24/2022	
2.1	Conor Craigen	BCJN update	08/31/2022	

GENERAL INFORMATION

Requested Spend Amount	$1,500,000
Requested Spend Time Period	2 years
Requesting Organization/Department	Shared Services (Facilities)
Business Case Owner | Sponsor	BC Owner: Eric Bowles Sponsors: Bruce Howard, Alexis Alexander, and Alicia Gibbs
Sponsor Organization/Department	Environmental / GPSS / Shared Services
Phase	Initiation
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

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

In the 1990s, an underground vault was built at the Mission Campus which housed several tanks that were intended to hold new oil, used but viable oil, and scrap transformer oil, all related to substation maintenance and electrical distribution operations. Over time, there have been several incidents of an environmental regulatory nature that began to question the ongoing practicality of retaining this asset.

A. The prime event occurred in September 2019, when an Electric Shop Electrician discovered a pipe rupture into the containment vault after operating the system for approximately 30 minutes. The pipe connects the vault and the Electric Shop (a substation maintenance shop) within the Service Building (one of several standalone buildings on the Mission Campus). The leak released an estimated two hundred gallons of oil, and required excavation to a depth of 15 feet deep and approximately 31 cubic yards of soil. The system is currently curtailed to direct pumping operations from the containment building, which is cumbersome to Avista personnel. On June 17, 2020 Avista received a letter from the Washington Department of Ecology's Toxic Cleanup Program stating that "no further action" is required in the cleanup effort.

B. Another incident occurred in 2010, when an oil transfer occurred on a Friday with electric shop personnel and a contractor. The wrong tank was selected to fill, the oil overflowed out of the tank and oil was allowed to float on the floor for over three days as it was a holiday weekend. It is unknown if the oil significantly penetrated the concrete floor, but some concrete may have been contaminated. Designation and disposal will occur under this business case.

C. O&M dewatering - The roof to the underground vault is an asphalted lid that doubles as a drive path for Avista vehicles. However, water seeps down into the vault through cracks and porous surfaces. This problem has accelerated through the years and requires a hazardous waste technician to pump out the water, and screen it for oil/PCB contamination before disposing of it. This occurs 5-10 times per year.

D. The oil storage vault is a "stranded asset" as multiple stakeholders claim use of the resource, without a single stakeholder that "owns" the asset for O&M checks or maintenance. O&M checks are currently performed by Hazardous Waste Technicians and Security contractors to ensure that oil isn't present in the containment on a weekly basis.

1.2 Discuss the major drivers of the business case and the benefits to the customer

The major driver for this Business Case is "Asset Condition," due to its containment failures and environmental risks as outlined in Section 1.1. The major customer benefit would be the offset of any future O&M maintenance or clean up of environmental events. Customers will also benefit with an enhanced oil storage process that will provide Avista employees with time efficiencies and generally faster response times within substation maintenance.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

With the past failures as outlined above, it is Avista's belief that a major environmental event with the underground vault is a matter of when, not if. Avista cannot predict when that event would occur, be it months or years. However, in general, the longer this Business Case is not implemented, the greater the chance the risk could occur without the problem being fixed.

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.

At this time, the only measure that can be used is to design an oil storage system that takes lessons learned from the underground vault and uses them to mitigate risks. Some measures include a system that will:

1) be easily viewable by multiple employees on a daily basis to check for leaks

2) not use any underground tanks or piping

3) use oil containment best practices such as: active electronic monitoring, modern pumping equipment, reinforced single or double-walled tanks, weathertight roofing, purpose-built concrete containment with impermeable coating.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

2010 CH2M Hill Assessment of Underground Storage Tanks for Avista. Available on request (Facilities / Vance Ruppert).

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.

Pictures of the underground pipe oil leak as described in Section 1.1 (A) above are available on request (Facilities / Conor Craigen).

Pictures of the oil tank overflow as described in Section 1.1 (B) above are available on request (Facilities /Conor Craigen).

Pictures of the annual water roof leaks as described in Section 1.1 (C) above are available on request (Facilities /Conor Craigen).

Option	Capital Cost	Start	Complete
Recommended Option: Build new above ground tanks, demolish underground vault and tanks	*$1.5M (see note 1 below)*	*07/2022*	*11/2023*
Alternate #1: Build a new GPSS Maintenance Shop at Mission or off-site, with a new tank(s) arrangement.	*$15M - $25M (?)*	*2022 (?)*	*2024 (?)*

Notes:

1) See Appendix A for further cost estimate breakdowns of the Recommended Option's $1.5M Capital Cost as shown in the table above.

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The main intent of this project is to avoid significant environmental risks as described in Section 1.1 Any risks that actually occur carry with it significant O&M costs as well. For instance, the underground pipe oil leak as described in Section 1.1(A) had a remediation cost of approximately $100,000.

If (and when) a major environmental risk were to occur with the underground vault, such as a burst oil tank and vault containment failure, a remediation cost of the soil below the vault would probably start at $200,000, and would potentially reach multiples of that amount if the contamination reached groundwater. Avista would be subject to environmental enforcement, penalties, and significant reputational harm.

Avista Facilities employee time to contend with the other issues in Section 1.1 can range from a few hours to several days. A conservative estimation of an average Avista Facilities maintenance employee labor rates, which includes hour rates, overhead, and benefits, is at least $60 an hour. If an average estimate of each event requires 2 employees for 4 hours, 1 time a month, then yearly O&M savings could be assumed to be $5,760.

In addition, the Avista senior hazardous waste technician ($75 per hour) spends at least two and a half hours per event (with 5-10 events every year) to dewater the vault as described in Section 1.1 (C). The 10 event estimate would calculate to a yearly O&M savings of approximately $1,875, plus disposal costs of approximately $1000. Should cross contamination of water occur, costs would increase by orders of magnitude.

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). Include any known or estimated reductions to O&M as a result of this investment.

The requested capital cost amount of $1.5M will be used for tank procurement and construction.

The project will provide the following new equipment and processes:

Two new 10,000 gallon tanks, one for new oil, and one for used but viable oil. They shall be installed near the existing tanks at the Waste & Asset Recovery Building (WAR Bldg). The tanks shall be above ground, surrounded by a concrete spill containment. They will also require a covered roof/canopy, and may also require metal siding to prevent snow/rain accumulation in the containment.

A smaller racked oil storage containers will be purchased for the Electric Shop for day use.

The new oil tank will be filled as needed by our oil supply vendor. The used but viable oil tank will be filled by our Electric Shop (ES), a department within Avista's Generation Production Substation Support (GPSS) business unit.

A 500 gallon portable storage tote to be filled with new oil from the tank mentioned above. It will be filled as required by the ES, but it is expected to be no more than 2-3 times a year.

A 300 gallon portable storage tote to be filled with used but viable oiland to transport scrap oil to the tank mentioned above. It will be used as required by the ES, but it is expected to be no more than 2-3 times a year.

A storage area (concrete slab or asphalted) will be provided for 20 empty 55 gallon drum barrels for new or used oil as required by the ES.

A second storage area (concrete slab or asphalted), with a covered roof/canopy, will be provided for 12 full 55 gallon drum barrels for new oil as required by the ES. It may also require metal siding to prevent snow/rain accumulation in the storage area.

The ES will forklift the totes to and from the WAR Building. Due to the storm water containment systems and oil water separators that have been installed on the Mission

Campus over the past decades, the risk of any major oil spill events from forklift traffic is extremely low.

The new oil tank will also provide oil to an approx. 3000 gallon Isuzu tanker truck or an 8000 gallon tanker trailer Avista owns and stores at our Beacon Substation. Both pieces of equipment will be used as needed for large substation equipment work at both the Mission Campus ES, and in the field / at any particular substation.

Demolish the existing underground vault. Remove only 6 feet or so top-down, with existing slab and footings to remain. Holes will be bored in to the abandoned slab, and the remaining area filled in with structural fill. The removed underground vault will be replaced with a new asphalt parking lot, approximately the same footprint, for GPSS use.

Siding and slider doors will be added to the (2) existing tanks at the WAR Bldg. due to snow/rain/ice accumulation inside its concrete containment the past few years.

In addition to the O&M savings for Avista employees as described in Section 2.1, it can be conservatively estimated that this new process will save at least 30 minutes for two ES employees at least once a week. The yearly O&M savings, using a $75 ES employee rate, can be assumed to be $3,900.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Current processes, metrics, & data:

1) Currently, the underground vault has four tanks that can be used by the Electric Shop (ES). There are (2) 10,000 gallon tanks to hold oil, and (2) 5000 gallon tanks subdivided into (4) 2500 gallon compartments that hold new or used but viable oil. The (2) 5000 gallon tanks can be used as queuing tanks from either of the 10,000 gallon tanks.
2) The 5000 gallon tanks were previously accessed by the ES through direct underground plumbing coming from the vault directly into the ES. The controls for switching between all the tanks, and also the (4) 2500 gallon subdivided tanks, are in the vault.
3) Inside of the ES, 55 gallon drums/totes (usually around four total) were being filled using the direct plumbed line. This practice recently ended however, due to the discovery of the leak in the underground piping as described in Section 1.1 (A). Now that the underground plumbing is no longer usable, if the totes need refilling, they will be forklifted over to the external, above-ground, hose hook up located at the vault.
4) Once the full totes are placed back in the ES, the oil is manually pumped into “smaller” pieces of equipment, as needed. Since the smaller equipment doesn’t usually require much oil, the totes only need to be refilled maybe twice, or three times a year.
5) However, the ES will sometimes require thousands of gallons at one time to work on larger equipment such as power transformers or oil circuit breakers, on a scheduled or emergency basis. Instead of using the totes, the ES has a separate process.
    a. Use the large tanker trailer or the smaller Isuzu tanker truck stored at Beacon Substation.
    b. More often than not, the ES will work on large equipment in the field / at the substation. They will fill the Isuzu or our tanker trailer at our vault at Mission Campus. After filling, they will then drive to the substation to dispense.
6) Lastly, whenever the ES needs a refill of either 10,000 gallon tank in the underground vault, they will usually have to “shuffle” some oil between the 10,000 gallon tanks and the 5000 gallon tanks in order to receive the full approx. 8000 gallons of oil for any tanker truck delivery from our vendor.

All of the above current processes will be replaced by the new processes as described above in Section 2.2.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

There was some discussion to build a new GPSS Shops Maintenance Building either at the Mission Campus, or at another off-site location. There is significant risk that the scope of such a building could fluctuate and produce a project requiring anywhere from $15M - $25M. At this time, this is not a reasonable solution to the main problem – the environmental issues with the underground vault and tanks.

Doing nothing was also considered, but given the difficulties numerous departments such as Facilities, Environmental, and GPSS have endured the past few decades, as well as the risk of a major future environmental event, the do nothing option is also not reasonable.

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.

This business case is considered a project, as it is not intended to be an ongoing project beyond 2023. The major milestones and timeline of the project is estimated to be the following:

Complete Design Drawings: Completed

Bidding / permits complete, General Contractor (GC) selection: 2 months

GC procure tanks and long lead items: 6 months

GC complete new tanks: 4 months

GC complete demolition of underground vault: 2 months

The project is expected to complete and become used and useful in early-to-mid Q4 of 2023, with all of its $1.5M transferring to plant in 2024, around the same timeframe.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

The major reason to perform this project is to align with Avista's strategic vision of environmental stewardship. This Business Case clearly identifies the environmental regulatory issues that could occur at some point if no action is taken.

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 environmental regulatory issues and O&M maintenance described in the business case earlier makes a strong case that this investment makes sense, as to avoid significant operational and environmental risks. As the project progresses, the scope and budget will be re-baselined as required, with the expectation of meeting scope, schedule, and budget targets.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Major customers/stakeholders:

Environmental Department

Generation Production / Substation Support Department

Facilities

Minor customers/stakeholders:

Electric Operations, Fleet Maintenance, Warehouse/Stores

2.8.2 Identify any related Business Cases

Not applicable.

3.1 Steering Committee or Advisory Group Information

A. The Steering Committee (SteerCo) (as of August 2022) shall consist of the following: Alicia Gibbs, Jody Morehouse, Alexis Alexander, David Howell, Jim Corder, Adam Munson, Mike Magruder, and Bruce Howard.

B. The Advisory Group that assisted in shaping this Business Case consisted of the following stakeholders:

Environmental Department (Bruce Howard, Darrell Soyars, Bryce Robbert)

Generation Production / Substation Support Department (Alexis Alexander, Brad McNamara)

Facilities (Dan Johnson, Eric Bowles, Robert Johnson, Dave Schlicht, Nick Lasko, Conor Craigen)

3.2 Provide and discuss the governance processes and people that will provide oversight

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 Lifetime 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.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

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 they are within tolerances, or not.

Oil Storage Improvements

The undersigned acknowledge they have reviewed the *Oil Storage Improvements 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 4ACC724D18764C2...	Date:	Aug-31-2022 | 2:55 PM PDT
Print Name:	Eric Bowles		
Title:	Corp Facilities Manager		
Role:	Business Case Owner		

Signature:	DocuSigned by: Alicia Gibbs 49C42855345E483...	Date:	Aug-31-2022 | 6:14 PM PDT
Print Name:	Alicia Gibbs		
Title:	Director of Shared Services		
Role:	Business Case Sponsor		

Template Version: 05/28/2020

Appendix A – Cost Estimate Breakdown

Presented and approved by Facilities Steering Committee to request additional funds through the Capital Planning Group on June 10, 2021.

YEARLY		2022	
Category		**Planned Spend**	**Scope**
Avista Resources		$ 104,280	Group 1 - 12 hr/month Group 2 - 20 hr/month Group 3 - 48 hr/month
Benefits	95% of Wages	$ 94,895	Matches hours shown above
		$ -	
Contract Project Support		$ 1,145,628	$1.02M + tax for general contractor $21K for special inspections $13K for consultant construction administration
		$ -	
Avista Supplied Equipment and Materials		$ -	
Material Overheads	8% of Mo Total	$ -	
AFUDC		$ 48,620	estimated
Other Expenses		$ -	
Capt OH - Functional and A&G	3.25% of Mo Total	$ 45,286	3.25% of all charges
Contingency	6% of Planned	$ 86,323	If needed for any items as described above
		1,525,031	
		$ 1,500,000	Budget
		$ (25,031)	Variance

2022-2023 CAPITAL PROJECT

SAVINGS AND PRODUCTIVITY REPORTING FORM

1. Business Case Name:

Oil Storage Improvements

2. Business Case Owner:

Eric Bowles

3. Director Responsible:

Alicia Gibbs

4. **Direct Savings**

Not applicable.

5. **Indirect Savings**

Employee Productivity: From Section 2.1 of the Business Case Justification Narrative:

Avista Facilities employee time to contend with the other issues in Section 1.1 of the BCJN can range from a few hours to several days. A conservative estimation of an average Avista Facilities maintenance employee labor rates, which includes hour rates, overhead, and benefits, is at least $60 an hour. If an average estimate of each event requires 2 employees for 4 hours, 1 time a month, then yearly O&M savings could be assumed to be $5,760.

In addition, the Avista senior hazardous waste technician ($75 per hour) spends at least two and a half hours per event (with 5-10 events every year) to dewater the vault as described in Section 1.1 (C) of the BCJN. The 10 event estimate would calculate to a yearly O&M savings of approximately $1,875, plus disposal costs of approximately $1000. Should cross contamination of water occur, costs would increase by orders of magnitude.

Note: the figures shown below mean that the Avista employees will be able to re-allocate their time to other work (and not that the employees will not work those hours at all).

Employee Productivity Quantified direct savings:

2022	2023	Lifetime
$8,635	$8,635	$8,635 yearly

Environmental Risk: As per Section 1.3 of the BCJN:

With the past failures as outlined (in Section 1.1 of the BCJN), it is Avista's belief that a major environmental event with the underground vault is a matter of when, not if. Avista cannot predict when that event would *occur, be it months or years. However, in general, the longer this Business Case is not implemented, the greater the chance the risk could occur without the problem being fixed.*

And as per Section 2.1 of the BCJN:

If (and when) a major environmental risk were to occur with the underground vault, such as a burst oil tank and vault containment failure, a remediation cost of the soil below the vault would probably start at $200,000, and would potentially reach multiples of that amount if the contamination reached groundwater. Avista would be subject to environmental enforcement, penalties, and significant reputational harm.

For this calculation, working with Avista's Environmental Department, the cost impact was assumed to be anywhere from $200,000 to $1,000,000. These values were based on past incident expenses and serve as a baseline for future events if they occur. Avista has then taken the average of these ranges ($600,000) and divided it over the 30 year accounting depreciation rate of this investment ($20,000 per year). Lastly, a conservative estimate of likely occurrence of this risk over 30 years would be approximately 50%, so it reduces the $20,000 yearly figure to $10,000.

Environmental Risk Quantified indirect savings:

2022	2023	Lifetime
$10,000	$10,000	$10,000 yearly for 30 years

6. No Direct or Indirect Savings

There are limited inherent safety improvements to a new oil storage facility, such as easier and more ergonomic access to equipment, but it is not a main source of offsets in this Business Case.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

Director Name: Alicia Gibbs

Director Signature DocuSigned by: Alicia Gibbs 49C42855345E483...

Date Oct-27-2021 | 8:33 AM PDT

Business Case Owner Name: Eric Bowles

Business Case Owner Signature DocuSigned by: Eric Bowles 4ACC724D18764C2...

Date Oct-27-2021 | 7:31 AM PDT

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, including the purchase of the property, to cost $25M.

The proposed solution is to relocate the Pullman Service Center to an entirely new location and sell the existing building to offset the cost. The building will be located on a new property more in line with our current 10-acre, square of rectangular yard standard. The site would be large enough to locate the Service Center, the pole yard, and the warehouse together. This option would allow us to find a property allowing 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*	*4/11/2023*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements Steve Carrozzo*	*4/26/2023*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$2,000,000	
2025		
2026	$6,000,000	
2027	$17,000,000	$25,000,000
2028		

Project Life Span	*4 years*
Requesting Organization/Department	Facilities
Business Case Owner | Sponsor	Eric Bowles | Kelly Magalsky
Sponsor Organization/Department	Shared Services
Phase	Initiation
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.*

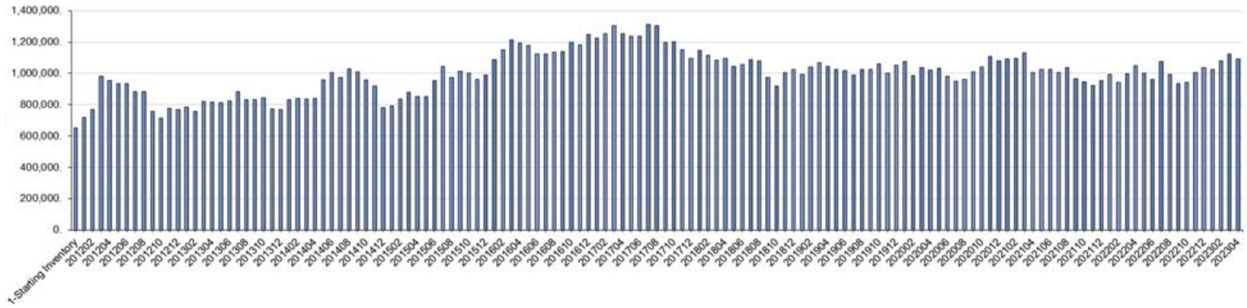
1.1 What is the current or potential problem that is being addressed?

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.

Materials/ Storage

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 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

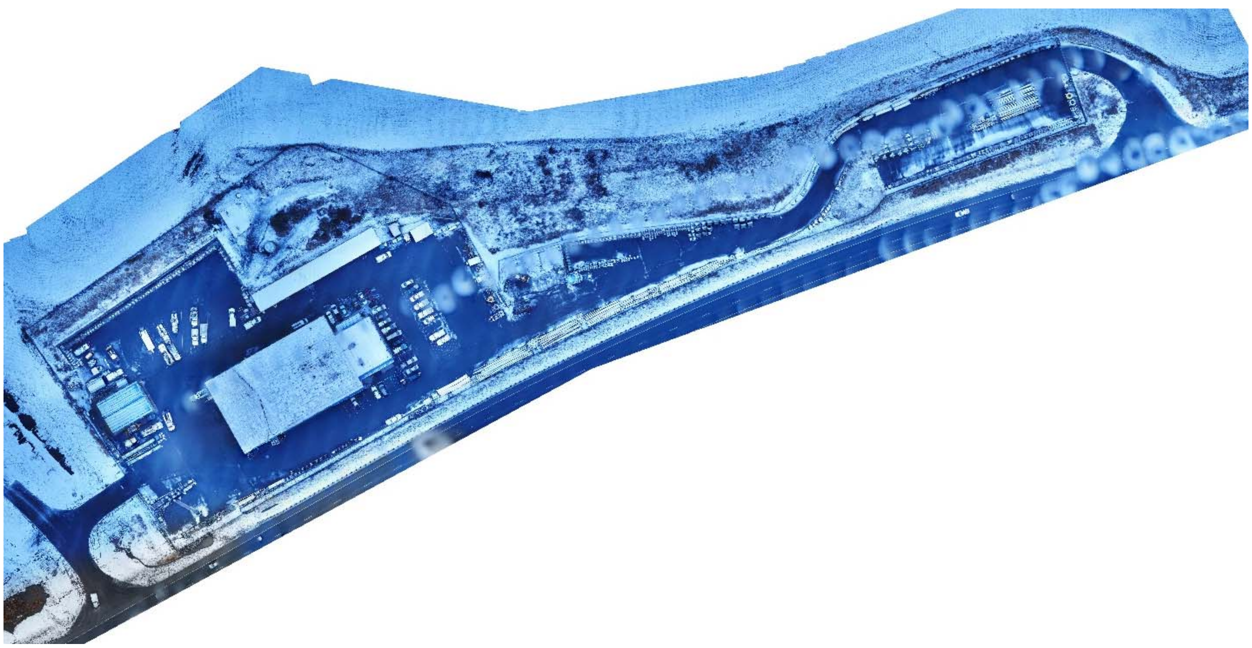
Traffic must enter and exit from the Service Center straight onto/ from a 55mph highway. This is problematic for hauling poles, trailers and equipment which is done daily. This is a safety concern in the winter as well and crossing traffic can be dangerous. While we have made improvements to the entrance 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.

Palouse Service Center

Previous Pullman Service Center Aerial

Current Pullman Service Center Aerial- Revised Highway entrance

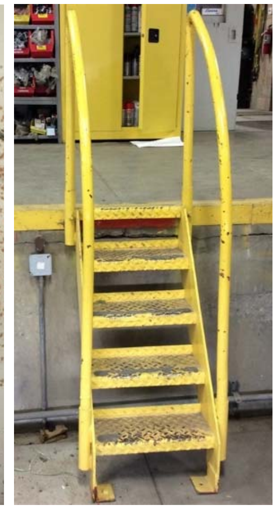


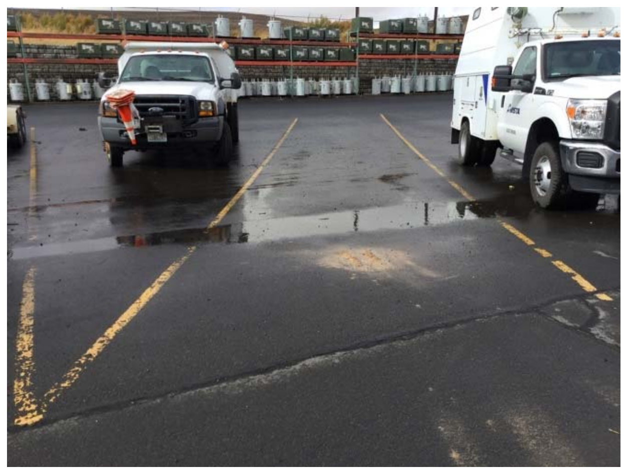
Building Condition

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.

Palouse Service Center

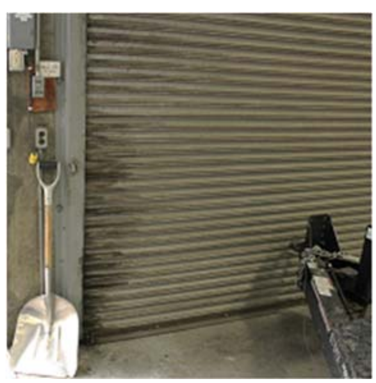




Some of the immediate repair and replace items identified:

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.

Palouse Service Center


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.

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.

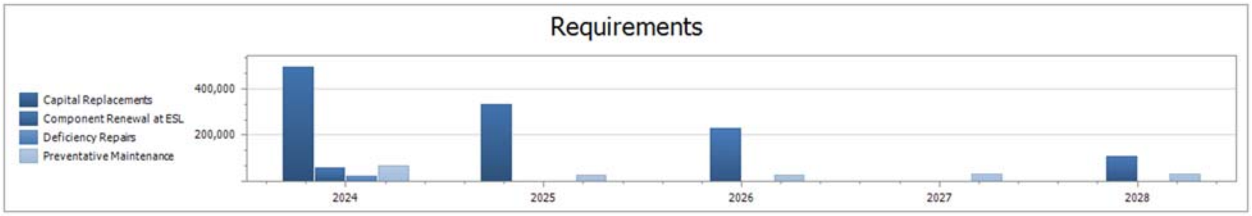
This project would benefit external customers in that the new Service Center can improve efficiencies. Having all materials, supplies and staff in one location that is efficiently laid out allows for improved use of resources and response times. Internal Customers benefit from improved communication 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 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:



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

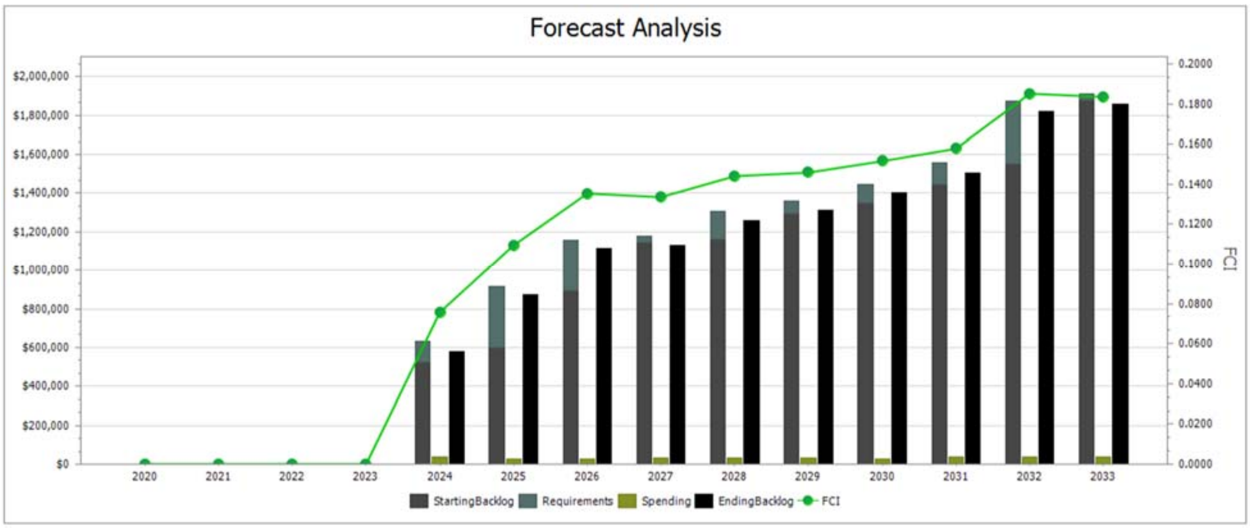
The major reason to perform this project is to align with Avista's Focus Areas of Our Customer and Our People. Being able to provide service to our customers safely and efficiently is a cornerstone of Avista and the facilities our crews report to is a vital piece of this service effort. Having facilities 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.

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:



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

Palouse Service Center

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.

<u>Recommended Solution- New Pullman Service Center</u>

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.

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	2024	2025	2026	2027	2028
Capital	-	$	$	$	$	$

[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.

O&M	Utility savings/ Sale of Building	$0	$0	$0	$0	$3,000,500

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	Business Operations Improve	$	$	$	$	$283,985

Direct:

- Reduction in energy usage due to more efficient equipment, estimated at 1% per square foot year over year.
  - $50,108 yearly energy costs x 1% = $501 yearly
- Sale of existing building and yard (Pullman)- O&M
  - $3-5M. $3M used for offsets but may very based on Real Estate costs

Indirect:

- 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.
  - 25 emp x 0.25 hr./day x 260 workdays x $85/hr. avg loaded rate= **$138,125**
- Efficiencies created through improved storage, more efficient workspaces and expanded workspaces as required for growth.
  - 44 emp x 0.15 hr./day x 260 workdays x $85/hr. avg loaded rate= **$145,860**

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: 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

[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.

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.

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
5) 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 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.

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 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.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Palouse 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:	Eric Bowles	Date:	4/26/23
Print Name:	Eric Bowles		
Title:	Corporate Facilities Manager		
Role:	Business Case Owner		

Palouse Service Center

Signature:	Kelly Magalsky	Date:	4/27/2023
Print Name:	Kelly Magalsky		
Title:	Director, Shared Services		
Role:	Business Case Sponsor		

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

CHANGE REQUEST #2 – JUNE 15, 2023

Previous Requests	Requested	Approved
5-Year Plan	$4,500,000	$4,500,000
C.R. #1	$300,000	$300,000

For new change requests, update the Change Request # and Date. Add a new line to the table to log previous change requests

Month - Year	LTD Spend	Current Approval	Requested Change	Proposed Life Total
06-2023	$4,605,306*	$4,800,000	$700,000	$5,500,000

*Total life-to-date spend is the net utility contribution, after subtracting grant funding received from the Department of Commerce for the work already completed on the project. Similarly, the proposed life total of the project represents the utility contribution after subtracting the total grant funding.

Type of Change	In-year Update
Primary Reason for Change	Timing Change, Externally Driven
Response needed by	7/15/2023

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

The project has experienced cost impacts related to two separate major tasks. The first is related the DC electric infrastructure, which caused significant delays. The second cost impact is related to the control system design.

The DC electric infrastructure issue was discovered during the factory acceptance test of the battery energy storage system in 2022. The Eco District project is utilizing a common DC bus and single power conversion system to connect solar and storage to the grid. During testing, the DC bus voltage was not stable due to a vendor issue (DC/DC converter). The result of this was a requirement to re-design the DC bus around different conversion equipment, which impacted the project schedule by approximately 6 months. Costs directly related to this delay include:

1) Design and construction fees (change orders) associated with modified DC bus: $144,384
2) Procurement of new DC bus equipment: $69,651 (including tax)
3) Avista Labor: $35,000
4) Additional AFUDC for months delayed by DC bus: $72,045

The control system design cost impacts are a result of several changes to the design. The project requires an optimizer/controller which can predict the building behavior and stage assets appropriately to achieve outcomes which are beneficial for the grid and customer. The initial vision of the optimizer has evolved as the project team learned more about the innovative new technologies being installed. Some approaches were found to be infeasible, and the design team pivoted toward solutions which could be implemented in the field. Avista's consultant responsible for the design did not exceed their budget, but the timeline of their work was extended, and internal Avista resources were required to take a much more active role than expected in order to ensure successful controller development and deployment. Costs directly related to the controller design changes include:

1) Avista Labor (Engineering and Project Management): $200,665

In the process of implementing new project controls (internal project management), the team identified the following items which also contribute to the funding change request:

1) Sales Tax associated with electrical construction and battery installation was not accounted for in the original estimate. This adds an incremental $116,710 to the budget beyond the original construction contract.
2) Avista Distribution Operations required a Harmonic study in addition to the internal interconnection system impact study, causing an additional $16,000 in consulting engineering fees.
3) The project team feels, given the unpredictable nature of the project, that the inclusion of a 7%, $45,545 contingency will reduce the risk of additional requests.

Summary of cost impacts:

DC design/construction change orders	$144,384
DC equipment	$69,651
Avista Labor	$235,665
Additonal AFUDC	$72,045
Construction Tax	$116,710
Harmonic Study for Avista DX Ops	$16,000
Contingency	$45,545
Total Change Request	**$700,000**

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

The work is necessary to fulfill the obligations of Avista's contract with the Washington State Department of Commerce. Without commissioning the battery (which requires the DC bus changes) or completing the optimization controller, the project would not receive the remainder of expected milestone payments of $1.3M. Deferring the request would increase AFUDC because the battery energy storage asset cannot be placed into service until work is complete. In addition to direct financial risks, failing to complete the project could cause reputational damage and cause important grid benefits to go unrealized.

1.1.3 Please reference analysis or information that support the problem and attach to this document.

Internal Avista labor, AFUDC, and sales tax on equipment and construction were forecasted using excel. **"Amend_1_[Term_Extension_to_10-30-2023]docx_W"** reflects the McKinstry change order amount, and "**Avista__ELM_CEF3_DC_Bus_Document_-_Rev_1doc"**" reflects ELM's DC Bus pricing.

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

To achieve battery energization, the remainder of the work relies on the vendors and suppliers contracted with Avista, so there are no internal impacts other than the costs outlined above. Internal Avista engineering labor is required to demonstrate and operate the controller/optimizer. The engineering labor is in the Innovation Lab, meaning there will be a larger percentage of Lab resources assigned to CEF3 in 2023 than initially expected. The result of this will likely be a small decrease in O&M labor costs in the lab, due to the staff time needed to complete the capital work.

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

When confronted with the DC equipment issue, the project team considered alternative designs such as reverting to a more traditional AC-interconnected system. That approach would have caused similar re-design and equipment procurement costs, so the team decided to continue with the DC approach because it provides efficiency benefits and aligns with our obligations under the Commerce contract. The controller design modifications are a result of analyzing alternatives and selecting the least cost option to achieve the requirements of the project.

Given the unexpected costs incurred, one alternative to consider is whether or not the project continues. The project team feels strongly that abandoning the effort would not be in Avista's or customers' best interest. First, we would not be able to receive the remaining milestone payments from Commerce, which total $1.3M and serve to offset the costs associated with innovative new technologies. Second, we would miss out on the opportunity to demonstrate impactful and strategic ways to integrate customer assets with the grid, paving the pathway for future business models, customer participation in non-wires alternatives, and benefits from from increased infrastructure utilization.

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

The investment in the CEF3 project is still prudent even with the additional costs. The optimized use of the assets installed during the project will deliver value to customers in the form of feeder capacity and increased infrastructure utilization, and provide a model for equitable customer participation in non-wires alternatives on the grid. These concepts are critical to ensuring our energy system of the future remains safe, reliable and affordable while transitioning toward a more distributed and clean resource mix.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

The original justification narrative is still valid given this change. The increases in cost are the result of taking innovative approaches to creating the future grid. Avista's customers will still benefit from the assets and the original intent will be realized with the help of the additional funding.

CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
John Gibson	BC Owner		
Jason Thackston	BC Sponsor	J JT	6/30/22
Adam Munson	FP&A		

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:

The UIASSIST project seeks to better enable and demonstrate the integration of grid automation, energy storage, and renewable energy resources with enhanced cyber security across the energy domains of the United States and India. Avista is but one of 30 collaborating entities from the United States and India incorporating 10 different test sites. The partners include universities, national laboratories, solution providers, and utilities. Avista's role in the project is to leverage the Innovation Lab to provide circuit and power hardware in the loop simulation, demonstration assets in the form of the WSU microgrid, and operational data sharing via Avista's Digital Exchange platform. The total project is $39.7M with $7.5M provided by DOE, $7.5M provided by US partners, $7.5M provided by the India government (GOI) and $17.2M provided by India partners. Avista's capital cost share for the project is $350,000.0 while the DOE is providing $480,000 grant.

Avista is witnessing accelerating customer adoption of rooftop solar as well as energy storage. DOE considers grid efficient buildings (GEB) to be viable resources for grid utilization and Avista has developed the South Landing eco-district which is world leading example of a GEB. How should Avista plan for DERs and GEBs and what types of operational controls and procedures are needed? The renewable energy eco-system is relatively immature when compared to existing utility "bread and butter" infrastructure projects. Within the utility, the design specifications and work practices have not been established to support the implementation of inverter-based assets. Also, the product vendors, suppliers and contractors within the eco-system lack market maturity and are typically operating under thin financial margins. Avista intends to produce standardized design and operational procedures for the WSU microgrid and to successfully demonstrate the results with the larger UIASSIST team. Additionally, the university can leverage Avista's foundation control framework as a platform to build their research layers. This project represents how the Avista Innovation Lab is developing the foundational building blocks to operationalize the technology platforms within the utility as well as support university research goals. The standards developed for this project can be leveraged for DERs in future years. Non-participation in this phase of the overall project would be damaging to Avista's reputation with respect to the partners and the US DOE. That reputation is currently considered top tier.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0				

GENERAL INFORMATION

Requested Spend Amount	$350,000
Requested Spend Time Period	1.25 years
Requesting Organization/Department	
Business Case Owner | Sponsor	John Gibson. | Jason Thackston
Sponsor Organization/Department	
Phase	Execution
Category	Project
Driver	Performance & Capacity

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]

Avista has a clean energy strategy to be carbon neutral by 2027 and carbon free by 2045. Achieving these goals will require diversified renewable bulk power resources as well as localized distributed energy resources and active energy management of connected loads. Electrification of transportation and fossil-based loads will stress distribution capacity and accelerate the need for non-wire alternatives (NWA), a portion of which the customer might provide or participate with in some way. There are many barriers to the successful adoption of DERs and GEBs within the utility that relate to the utility business model and rate design. But perhaps more importantly, the technology solutions available in the renewable domain are not at the same maturity level that utility companies expect. Likewise, utilities do not have a mature understanding of the renewable energy domain either, leaving a gap when integrating them into the grid.

This project intentionally operationalizes and refines the design for the WSU microgrid such that other microgrids can be deployed in a standard manner while accounting for operational concerns. The results of this project will help inform the interconnection process, hosting capacity assessment methodologies, and planning for non-wire alternatives with clear expectations for DER behavior. The customer benefits by providing participation as well as reduced rate pressure from capacity additions that can be offset by NWAs. The research institutions benefit from demonstration of the solutions and access to the operational data platform.

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

Planning for and integration of distributed energy resources either customer or utility owned into the distribution grid. Standards for design, hosting and operations are needed.

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

Performance & Capacity can be improved with DERs for grid benefit. The heat dome shifts might have been averted with appropriate DER deployment. Additionally, customer participation can be facilitated leading to benefits with respect to **Customer Service Quality & Reliability**.

1.2 Identify why this work is needed now and what risks there are if not approved or is deferred

Avista is witnessing accelerating customer adoption of rooftop solar as well as energy storage. Capacity challenges are being exposed with elevated summer temperatures. The Microgrid in the University district installed as a part of Clean Energy Fund II revealed the need for operational standards and a clear path for cyber security within the the grid control network. The DOE grant affords the opportunity to reduce the cost by 50%. Failure to complete this project will challenge the planning and integration efforts, delay operating standards and damage Avista's reputation with the participating universities, national laboratories, and the U.S. DOE.

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.

Success comes in the form of standards and process definition that is difficult to measure but which is critical if not established.

1.4 Supplemental Information

1.4.1 Please reference and summarize any studies that support the problem

The most appropriate documents for reference are the Avista Lab plan for the project and the proposal submitted to DOE by the lead partner WSU. Both documents can be found on the Teams site for the project.

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.

This project does not replace any assets. It establishes standards around the existing WSU microgrid.

2. PROPOSAL AND RECOMMENDED SOLUTION

This project leverages the existing WSU microgrid as a demonstration asset for the larger project team and establishes a data sharing platform for collaboration and operational data. Avista will deliver standards that define the design for the microgrid, the interconnection requirements, and operational procedures expected for future microgrids. Simulation with control and power hardware in the loop as required will be integral to the demonstration as well as the standards development.

The recommended solution is to participate in this project as a means for completing these design standards which can only be done within the Innovation Lab environment. The larger team is providing benefit to Avista via the very diverse partner makeup and highly competent team membership. There are really no alternatives to compare short of hiring a consultant to develop the standards without simulation and demonstration which may leave Avista personnel out of the equation.

Option	Capital Cost	Start	Complete
UIASSIST Microgrid	*$0.350M*	*01 2022*	*12 2023*

2.1 Describe what metrics, data, analysis, or information was considered when preparing this capital request.

Reference key points from external documentation, list any addendums, attachments etc.

Lack of standards has been a hinderance to incorporating DERs in a way that is advantageous for the grid and hosting capacity is not currently incorporated in the planning process that considers the capabilities of current technologies. Clean Energy Fund projects II and III as well as interconnection of the eco-district has revealed the shortcomings of the existing approach to DER integration. The current approach creates barriers for adoption due to lack of standardization. The return is represented in the ability to host DERs as is needed to meet CETA and Avista clean energy goals. Because no assets are being deployed, the return on investment comes from enablement of the WSU

Microgrid and future asset integration which can help better utilize existing capital investments.

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 because 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.?

The total cost of the project is broken down to three phases as described below:

Phase 1 Avista implementation of WSU microgrid control system which aligns with Avista standards and work artifacts. In this phase, the following tasks will be performed by the end of the year 2022.

- Develop Control Standards and Specifications
- Develop offline model and load profiles
- Develop test procedure for controller
- Deploy Digital Exchange Platform catalog

Phase 2 Avista implementation of control and power hardware in the loop. The tasks under this phase will be performed by the end of year 2022

- Program control for islanding, VVC in RTAC
- Testing scheme performance using HIL testbed
- Development of PHL for Inverter settings
- Digital Exchange Platform meta data

Phase 3 Avista will field deploy the microgrid control with new configuration requirements. The tasks under this phase will be performed by the end of year 2023.

- Communications and physical control architecture for deployment
- VVC demonstrations on the microgrid
- Final demonstration and commissioning
- Digital Exchange Platform CIM modeling

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.
Operational standards will be developed in cooperation with operational and engineering personnel on the deployment of solar inverters and microgrid controllers.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.
This project was proposed by WSU and the partner team to create a global solution for DER integration. Avista joined due to the quality, focus, and

methodology proposed by the project team and the need to establish standards for operation as it relates to the WSU Microgrid and future DERs.

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.

[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).]

The project was started in 2022 and complete by end of year 2023. The project should transfer to plant by the end of 2023.

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: The UIASSIST project supports Avista's Mission by designing and operationalizing a microgrid. The microgrid will "improve our customer lives through innovative energy solutions.

Focus Areas: *Our People:* The UIASSIST project is creating design standards, work plans and artifacts necessary to safely deploy microgrids for our customers. *Our customers:* Microgrid assets can be coordinated to improve system utilization of the grid and reduce cost to customers. *Perform:* The microgrid assets illustrate Avista's ability to deploy sustainable services at the edge of the grid. *Invent:* The microgrid will be a first of a kind and enable the workforce to train on future projects.

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 UIASSIST microgrid control assets can be coordinated to improve system utilization by leveling the load at the point of common coupling. If microgrids assist in system utilization, they can be deployed across the system to offset capacity constraints. The microgrid assets of solar, storage and controls can be deployed to defer large capital investment. Often referred as non-wire alternatives. The commission expectation is Avista would leverage non-wire alternatives were cost beneficial.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Avista is interfacing with Washington State University as a partner to help fund and specify the microgrid on their campus in Spokane.

2.8.2 Identify any related Business Cases

N/A

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The steering committee is the Invent Council.

3.2 Provide and discuss the governance processes and people that will provide oversight

The Invent Council will provide oversight and governance.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The Invent Council will review all change requests. The Avista Innovation lab will resource the project and make decisions regarding prioritizing the work.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *UIASSIST* 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:		Date:	02/13/2023
Print Name:	John Z. Gibson		
Title:	Avista Innovation Lab Director & Chief R&D Engineer		
Role:	Business Case Owner		

Signature:		Date:	03/14/2023
Print Name:	Jason Thackston		
Title:	Senior Vice President Chief Strategy & Clean Energy Officer		
Role:	Business Case Sponsor		

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

Colstrip Transmission

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.

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 are expected to remain roughly commensurate with past expenditures. The original Business Case was submitted and approved in April, 2017. Applicable service code and jurisdiction are 098-ED, common system-wide, electric direct.

[1] Avista owns a 10.2% share in the Colstrip-Broadview segment and a 12.1% share in the Broadview-Townsend segment.

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*	
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements Steve Carrozzo*	*10/11/2023*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$590,000**	**$590,000**
2025	**$570,000**	**$570,000**
2026	**$100,000**	**$100,000**
2027	**$350,000**	**$350,000**
2028	**$400,000**	**$400,000**

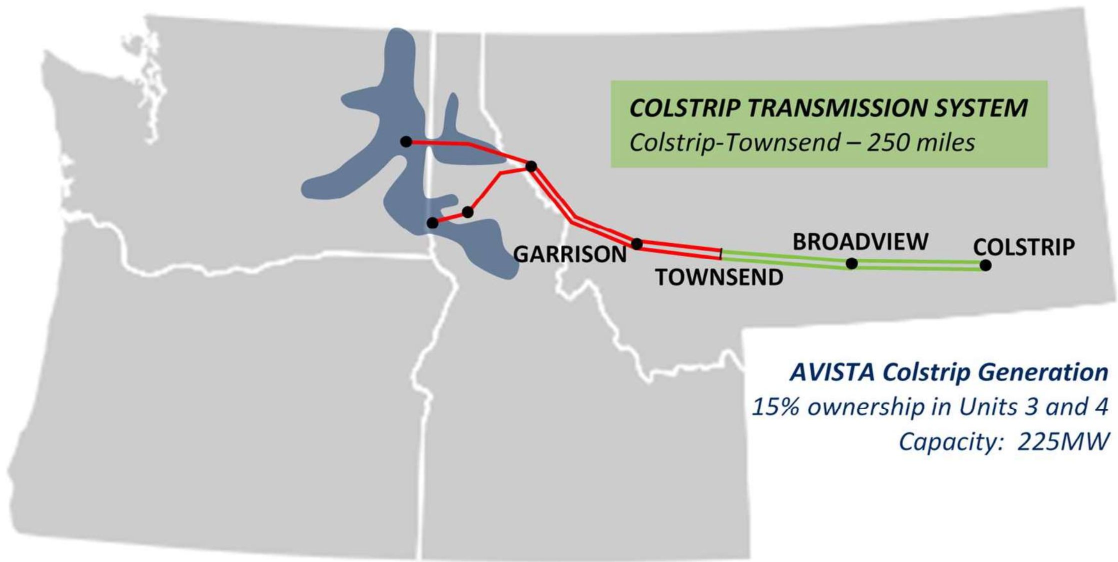
Project Life Span	*Ongoing Annual Program*
Requesting Organization/Department	Energy Delivery / Transmission Services
Business Case Owner | Sponsor	Kenny Dillon | Josh DiLuciano / Mike Magruder
Sponsor Organization/Department	Energy Delivery / Transmission Services
Phase	Execution
Category	Mandatory
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

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 2.7 below.

As NERC transmission planning and operational reliability standards[2] evolve, compliance with both operational and planning standards may require replacement of, or upgrades to, Colstrip Transmission System facilities.

[2] 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.[3]

Not applicable

[3] 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).[4]

Not applicable

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		$	$	$	$	$
O&M		$	$	$	$	$

Not applicable

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		$	$	$	$	$
O&M		$	$	$	$	$

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.
[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.

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:

- Colstrip and Broadview 500kV relay and relay panel upgrades
- Broadview capacitor battery bank replacement
- Microwave communications equipment upgrade (multi-year project)
- Broadview capacitor replacement (multi-year project)
- Broadview spare circuit switcher purchase

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.

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: 2023.10.13 14:30:09 -07'00'	Date:	10/13/2023
Print Name:	Kenny Dillon		
Title:	Senior Manager, FERC Policy and Transmission Services		
Role:	Business Case Owner		

Signature:	Michael A. Magruder Digitally signed by Michael A. Magruder Date: 2023.10.13 14:44:13 -07'00'	Date:	10/13/2023
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		

Electric Replacement and Relocation

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 there 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. The 3 year average spend is $7.4M and the 2022 spend was $10.1M. Since Electric Relocations are directly correlated with the number of highway and street projects, the reason for the upward trend in spend is due to an increase in transportation project spending by local entities.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Katie Snyder*	*Initial draft of 2023 Business Case Refresh*	*03/28/2023*
BCRT	*BCRT Team Member – Katie Snyder*	*Has been reviewed by BCRT and meets necessary requirements*	04/18/2023

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$10,100,000	$10,100,000
2025	$10,100,000	$10,100,000
2026	$10,100,000	$10,100,000
2027	$10,100,000	$10,100,000
2028	$10,100,000	$10,100,000

Project Life Span	***Ongoing***
Requesting Organization/Department	Electric Operations
Business Case Owner | Sponsor	Katie Snyder | David Howell
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 (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 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, typical 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 state highway districts and railroads.

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.

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 Electric Replacement and Relocation program meets our strategic vision, goals, objectives, and mission statement by collaborating with state and local entities in order to allow us to install electric equipment along ROW's so we can continue to provide our customers with safe, reliable, and affordable service.

[Avista Strategic Goals]

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.

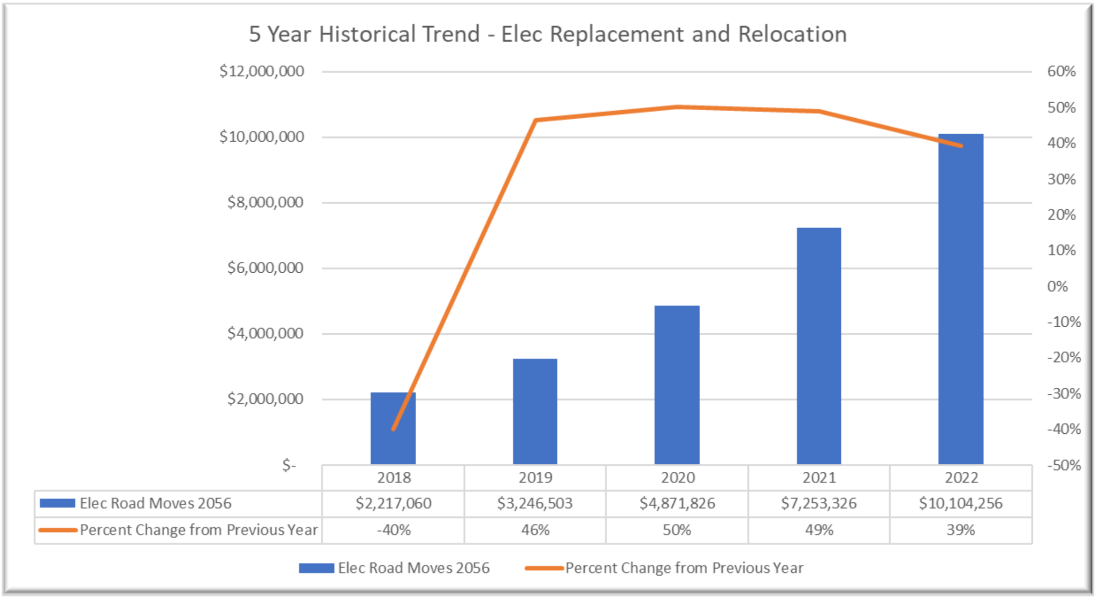
This solution is to perform the necessary mandatory work as set forth by state and local entities under the Franchise Agreements and Permits Avista has entered. This is in order to stay in compliance and continue to be allowed to install electric equipment along ROW's that will enable us to continue 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 $5.5m and our spend has been increase by an average of 29% per year. This would reason that if our spend was $10.1m in 2022 would have the potential to require as much as $13.1m for Road Moves in 2023.

[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.

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 2018.



	2018	2019	2020	2021	2022
Elec Road Moves 2056	$2,217,060	$3,246,503	$4,871,826	$7,253,326	$10,104,256
Percent Change from Previous Year	-40%	46%	50%	49%	39%

***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	2024	2025	2026	2027	2028
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	2024	2025	2026	2027	2028
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:

Alternative 2:

Alternative 3:

[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.

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.

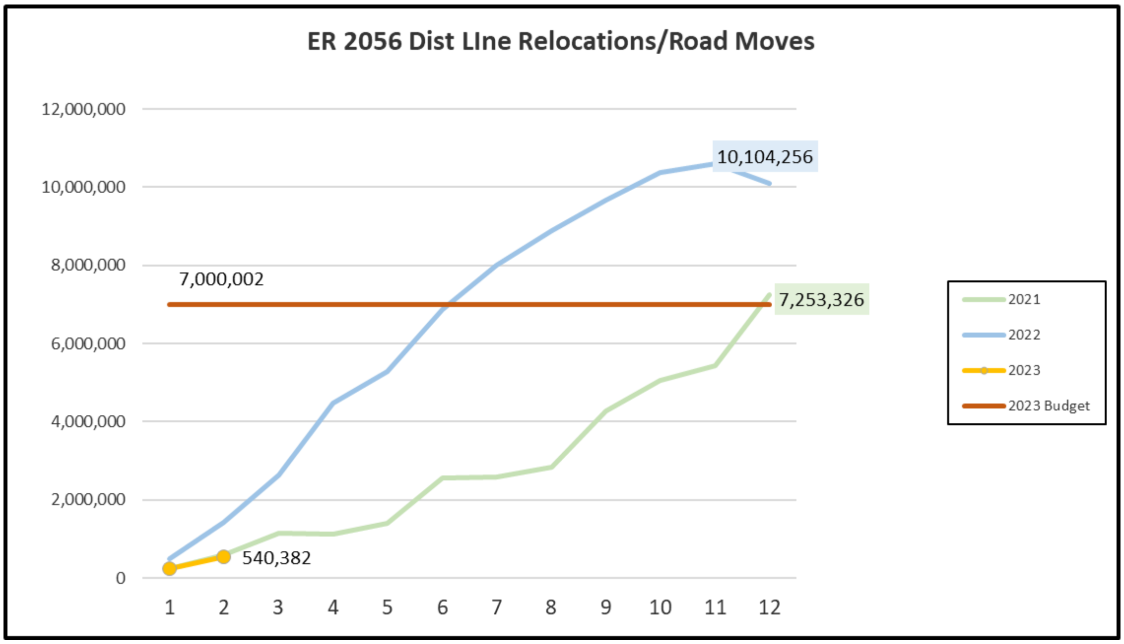


Figure 2: *ER 2056 (Electric Relocations and Road Moves) Year-to-Date Spend*

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.

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: 04/18/2023
Print Name: Katie Snyder
Title: Asset Maint. Business Analyst
Role: Business Case Owner

Signature: David Howell Date: 04/24/2023
Print Name: David Howell
Title: Director of Operations
Role: Business Case Sponsor

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

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 adequate. 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 202 active above grade crossing sites across all three states. 159 are located in Oregon, 24 are in Idaho, and 19 are in Washington. All 159 sites in Oregon have already been risk assessed and prioritized, but none of the sites in WA or ID have been risk assessed. The plan is to have all Idaho and Washington sites assessed and prioritized with the OR sites by the end of 2023. Starting in 2024, the annual capital budget for this program will be split amongst the three states based on risk, remediation scope, and Gas Engineering assessments.

Out of the 159 sites that have been risk-assessed in Oregon, 33 were identified as exceeding the program's scoring threshold for allowable risk. Washington and Idaho are expected to produce approximately 9 sites that exceed the risk threshold for a grand total of 42 sites across all three states. The plan is for all of these sites 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 38 capital projects with an average cost of $170,000 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 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.

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.

ER 3009 Cost Offsets[1]	2024	2025	2026	2027	2028	2029 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
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

ER 3009 Budget Proposal	2024	2025	2026	2027	2028	2029 to 2032
Capital (+3% inflation / year)	$650,000	$669,500	$689,500	$710,000	$731,500	$3,152,500

[1] Reference Section 2 of the document for offset details

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*
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements*	*4/20/2023*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2023 (YR1)	**750,000 (CURRENT YR)**	**750,000 (CURRENT YR)**
2024 (YR2)	**650,000**	**650,000**
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	Mike Yang / 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

Gas Above Grade Pipe Remediation Program, ER 3009

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 piping 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 appropriate.

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 outages (500 or more outages) and/or large uncontrolled releases 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 202 active above grade crossing sites across all three states. 159 are located in Oregon, 24 are in Idaho, and 19 are in Washington. All 159 sites in Oregon have already been risk assessed and prioritized, but none of the sites in WA or ID have been risk assessed. The plan is to have all Idaho and Washington sites assessed and prioritized with the OR sites by the end of 2023. Starting in 2024 the annual capital budget for this program will be split amongst the three states based on risk, remediation scope, and Gas Engineering assessments.

Out of the 159 sites that have been risk-assessed in Oregon, 33 were identified as exceeding the program's scoring threshold for allowable risk. Washington and Idaho are expected to produce approximately 9 sites that exceed the risk threshold, which will result in a grand total of 42 sites across all three states being considered high risk. The plan is for all of these sites to be prioritized and remediated over the next 10 years through the combination of both O&M and Capital dollars. Preliminary estimates forecast the need for approximately 35 capital projects with an average cost of $170,000 per site. This puts the total 10-year budget at about $5.8 million with a recommended annual spend of $650,000 (+ 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. Customer Service Quality & Reliability and Asset Condition are additional drivers for remediating high risk above grade piping. Aboveground piping 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 a major events such as earthquakes, floods, vehicular damages, etc. Above grade pipeline facilities assessed as being high risk are typically more susceptible to failing 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 per customer[2], 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. If this program is approved and in place, it will show to 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 needs to be addressed. Each of these 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. Some 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.

[2] See Section 2.4 for more details on the estimated gas outage cost per customer

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.

1.5 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 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. The plan will be to do a similar review of the above grade pipe in both Washington and Idaho in 2023. There are a total of 43 sites between Washington and Idaho, 24 in Idaho and 19 in Washington. Once that data is collected it will then be added to the existing evaluation matrix to produce a risk score. Sites that exceed a pre-defined risk score threshold of 65000 are identified as high risk and prioritized against all high risk sites for remediation.

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 SCOR
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

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 $650,000 (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 time 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[3]	2024	2025	2026	2027	2028	2029 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
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

ER 3009 Budget Proposal	2024	2025	2026	2027	2028	2029 to 2032
Capital (+3% inflation / year)	$650,000	$669,500	$689,500	$710,000	$731,500	$3,152,500

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	2024	2025	2026	2027	2028	2029 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

[3] Reference Sections 2.3 and 2.4 of this document for offset details

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.

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

ER 3009 Indirect Cost Offsets	2024	2025	2026	2027	2028	2029 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.

[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.

Risk Probability Definitions: | **Risk Probability for Calculating Indirect Offsets:**

Level	Definition	Risk Probability for Calculating Indirect Offsets
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 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.

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.

Alternative 1: Lower Funding

The lower funding alternative option slows the pace of remediation and the resultant reduction of known risk in the system. 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. When the program is completed at a slower pace, the risk of protentional fines increase. 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 high risk sites identified during the 2023 WA & ID risk assessment. It is estimated that approximately 9 high risk sites will be identified in WA & ID for a program total of 42 high risk sites throughout Avista's service territory.

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.

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 38 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.

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.

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:	Jeffy a Webb	Date:	4/21/2023
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	Alicia Gibbs	Date:	4/23/2023
Print Name:	Alicia Gibbs		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

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

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, they 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 $715,000 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

Gas Cathodic Protection Program, ER 3004

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*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	*4/19/2023*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**715,000**	**715,000**
2025	**715,000**	**715,000**
2026	**715,000**	**715,000**
2027	**715,000**	**715,000**
2028	**715,000**	**715,000**

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

Gas Cathodic Protection Program, ER 3004

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 coating that prevents 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.

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 250 anode beds in the system, it would be expected that approximately 10 are replaced every year. Only 7 have been replaced in the last 5 years. This indicates that anode beds are being replaced at 1/7 the expected rate. During the last 5 years, 21 new anode beds were added to meet increasing CP current requirement.

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.

[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. 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 of 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.

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] 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	Replacing corroded and leaking steel pipe.	$60M	$60M	$60M	$60M	$60M
O&M	Repairing corroded and leaking steel pipe and fittings.	$10M	$10M	$10M	$10M	$10M

Avista has approximately 4,000 miles of buries steel pipe. If no CP systems were used, the pipe would readily corrode. Replacing 5% of the system each year to address corrosion damage would cost approximately $60M annually. Not all pipe repair and replacement work is a capital expenditure. Approximately $10M in O&M budget would be spent annually to repair leaks.

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	Addressed in Direct Offsets	$0	$0	$0	$0	$0
O&M	See note below	$18,000	$18,500	$19,000	$19,500	$20,000

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.

[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.

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 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.

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.

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 is 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.

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: Jeffrey a Webb Date: 5/4/23
Print Name: Jeff Webb
Title: Mgr Gas Engineering
Role: Business Case Owner

Signature: Alicia Gibbs Date: 5/4/2023
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 July 2023 the GFRP has 335 miles of Aldyl-A remaining to be replaced across Avista's service territory and 626 STTR's left to address via construction or map correction.

Avista has a regulatory mandate to complete this program 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-$29M 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 also a high likelihood of increased consequences from failures in Washington State 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 programs inception. This data is available in "Avista Utilities Aldyl-A Pipe Analysis (slow crack growth leaks in WA, ID, OR)".

Gas Facility Replacement Program (GFRP)
Aldyl-A Pipe Replacement

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*	*$2.53 returned*
7	*Karen Cash*	*Budget Change*	*2021*	
8	*Karen Cash*	*Budget Change*	*2022*	*$1.31 approved*
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements*	*9/13/23*	***Steve Carrozzo***

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$27,187,251**	**$27,187,251**
2025	**$28,000,000**	**$28,000,000**
2026	**$30,000,000**	**$30,000,000**
2027	**$33,881,901**	**$33,881,901**
2028	**$34,009,686**	**$34,009,686**

Project Life Span	20 years in Washington and Idaho & 25 years in 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

Gas Facility Replacement Program (GFRP)
Aldyl-A Pipe Replacement

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 & Idaho (until the end of 2031) and in 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. 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. There is 335 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 July 2023 there are 626 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 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 submittied 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.

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.

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	≈ $635M	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.

Gas Facility Replacement Program (GFRP) Aldyl-A Pipe Replacement

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.

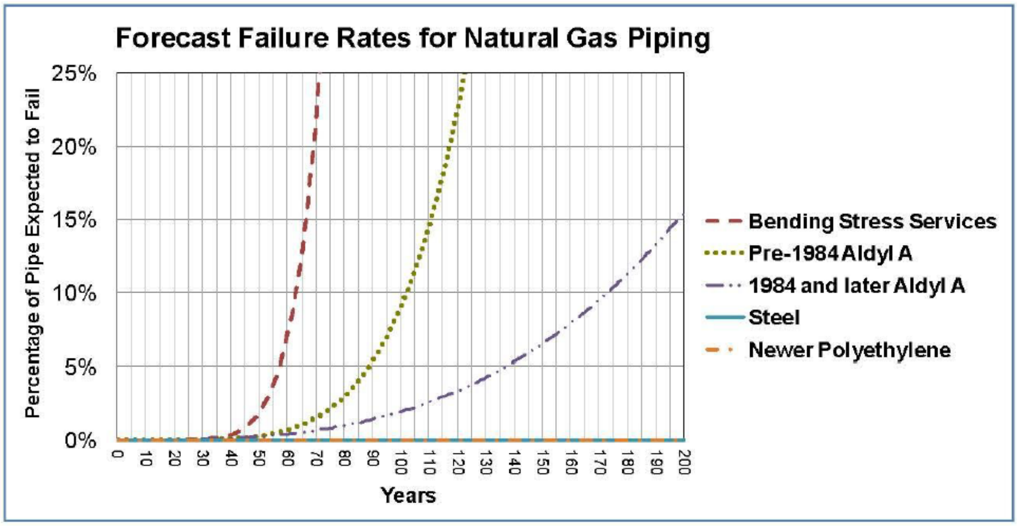
Potential Risk	Potential Risk Over Time					Cost Estimate
	1 Year	2 Years	5 Years	10 Years	15+ Years	
Regulatory Fines	L	P	H	VH	VH	$225,134 per day per violation (Max)* $2,252,334 Total (Max)*
Pipeline Leak	H	H	VH	VH	VH	$5,000 to $150,000 per site (site dependent)
Pipeline Failure & Outage	L	L	P	P	VH	$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.

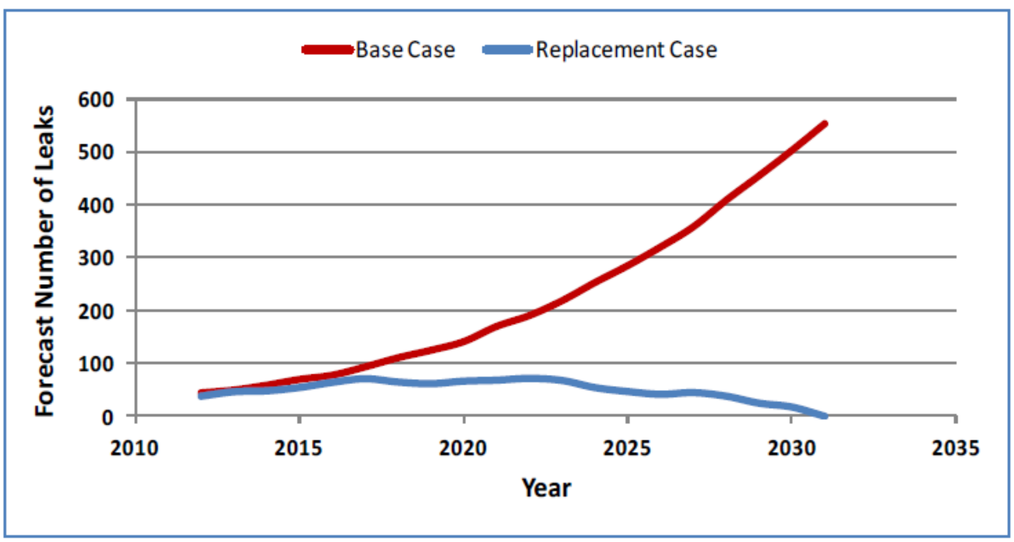
It has been determined that this type of pipe is at risk and is approaching unacceptable levels of reliability without prompt attention. The "Do Nothing" option exposes Avista to increased operational risks, decreased system reliability, and worse, is a potential harm to customers and the public through 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).

Gas Facility Replacement Program (GFRP)
Aldyl-A Pipe Replacement

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 time 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.



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	Leak Survey **Cost Avoidance**	$104,630	$112,037	$119,389	$126,789	$134,244

Aldyl-A gas main is leak surveyed on an annual basis rather than the standard five year cycle of other intermediate pressure natural gas mains. The 2023 contracted cost to survey one linear foot of gas main is $0.0458. The 402 miles of Aldyl-A that has already been removed from Avista's system since 2012 and the forecasted 2024-2028 replacement schedules are taken into account for the above O&M direct cost savings. This calculation does not take into account, 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 offsets4 (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	Mitigatable Risk Cost Value	$35,150	$69,991	$103,940	$136,545	$167,934
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 also takes into account geographic location, ground composition and history of previous failures. The 402 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-ran 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.

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 programs 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.

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:

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.

There are circumstances where lower priority Aldyl-A projects may be accelerated if it makes sense to coordinate the timing of pipe replacement projects with prior phasing or with other utility and road projects. The individual projects for GFRP are typically managed by the Customer Project Coordinators (CPC’s) while the overall program budget is managed by the GFRP Manager.

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: 10/4/2023
Print Name: Cody Lee
Title: Manager, GFRP
Role: Business Case Owner

Signature: Alicia Gibbs   Date: 10/4/2023
Print Name: Alicia Gibbs
Title: Director, Natural Gas
Role: Business Case Sponsor

Signature: ____________   Date: ________
Print Name: ____________
Title: ____________
Role: Steering/Advisory Committee Review

Avista Utilities Asset Management

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

May 2013

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.

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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."

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.

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.

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

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 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 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.

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

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 "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.

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.

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

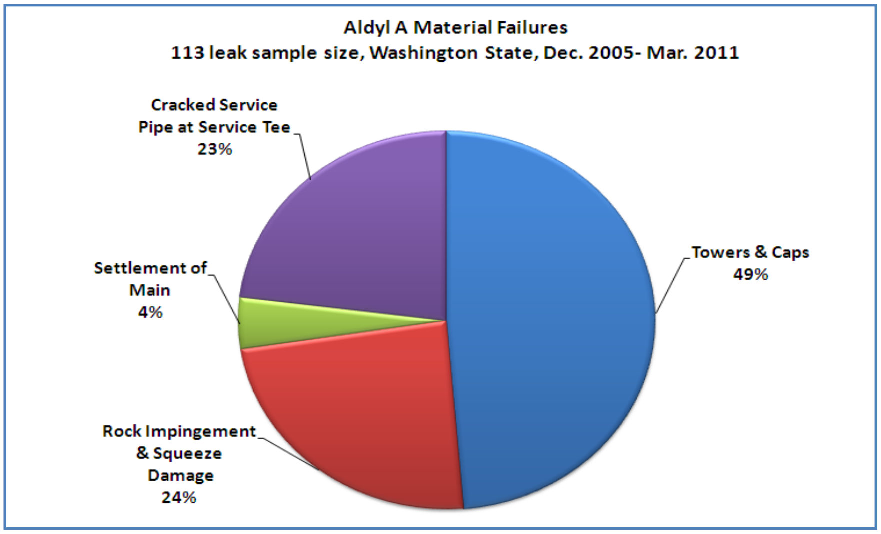
As described briefly above, the Integrity Management approach, now required by law, begins with the aggregation of historical leak-survey data and other facility information relevant to Avista's natural gas piping system. Then, in conjunction with the input of subject matter experts, individual threats 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.

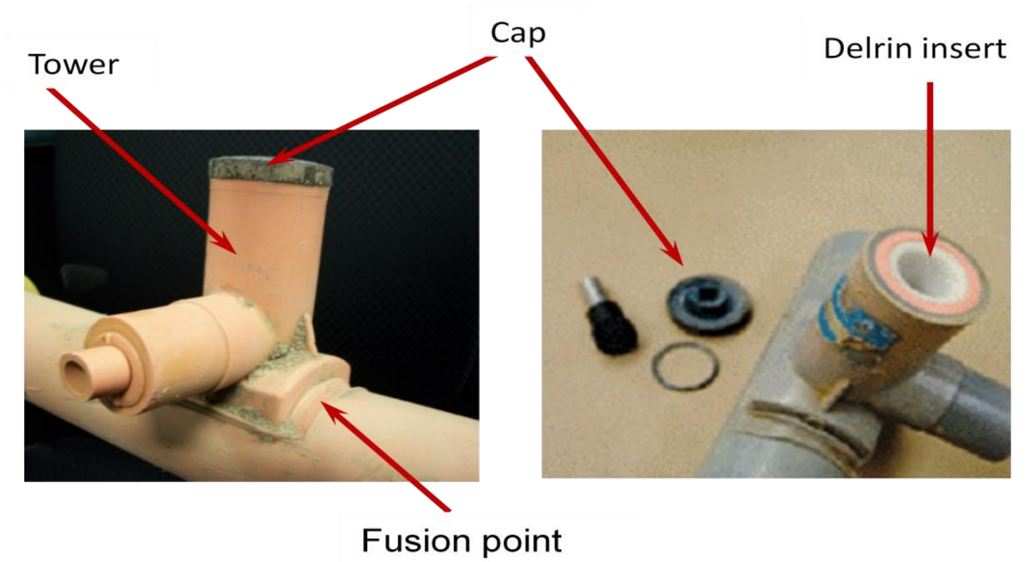
Figure 1. Modes or types of material failures documented in a sample of 113 leaks in Avista's Aldyl A piping in Washington State, December 2005 through March 2011.



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.

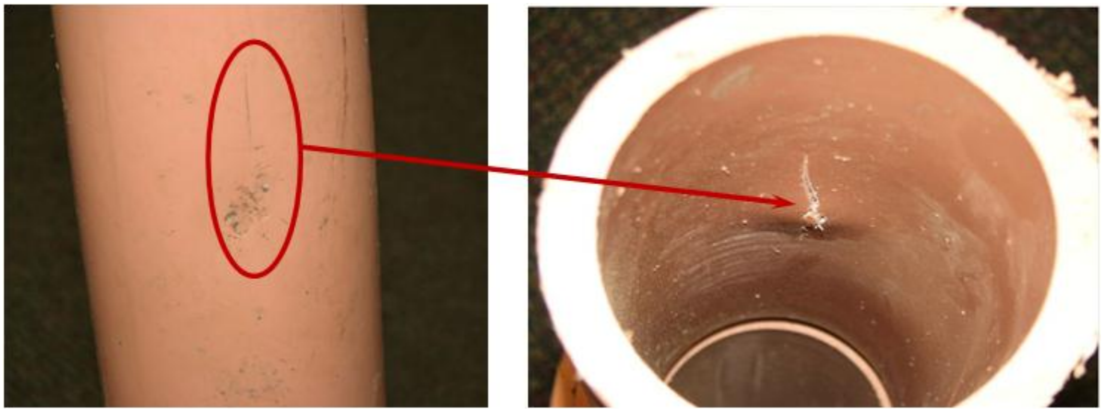
Figure 2. External features and internal components of a typical Aldyl A service tee, as fused to Aldyl A main pipe.



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.

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

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 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.

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.

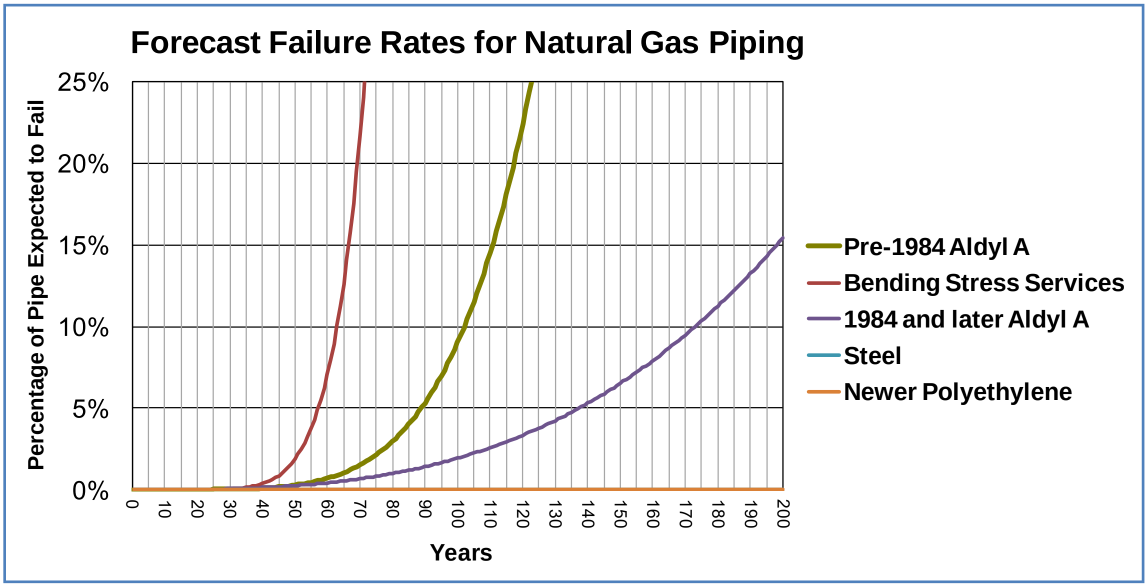
Services Tapped from Steel Mains - Avista identified 16,000 such services in its system, also referred to as 'bending stress tees.' For the reliability modeling, the individual service is the discrete element.

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 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.

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

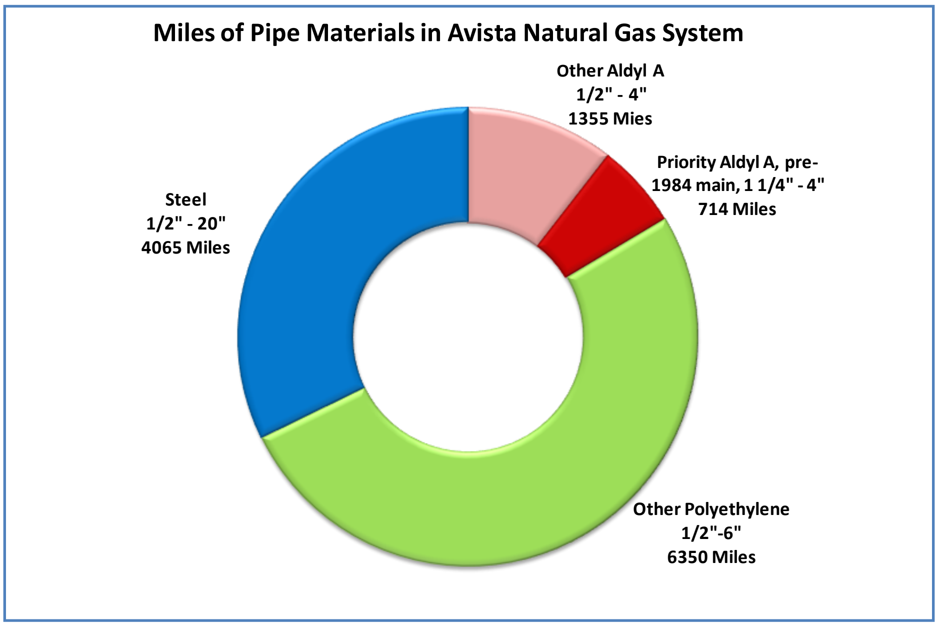
Avista has determined these classes of pipe are at risk of approaching unacceptable levels of reliability without prompt attention. Accordingly, Avista believes the decision to formulate a management program for its priority Aldyl A pipe is both timely and prudent, and is consistent with results of our 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.

Priority Aldyl A Piping in Avista's System

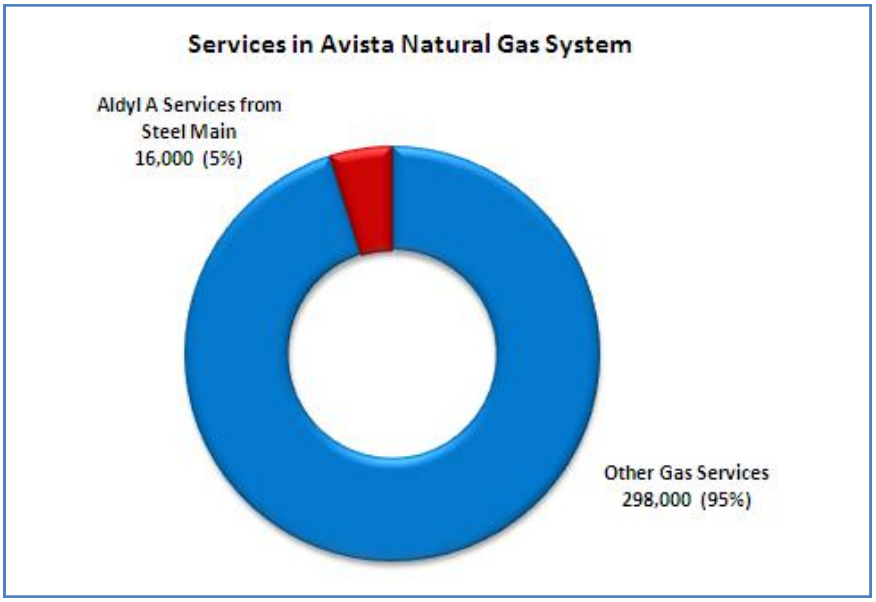
Main Pipe - Avista has approximately 12,500 miles of natural gas main pipe in its service territories in the States of Washington, Oregon and Idaho. Approximately seventeen percent of this total, or 2,000 miles, is Aldyl A pipe of all classes and sizes. Proportions of various classes of piping in Avista's 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.

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.

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.

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.

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.

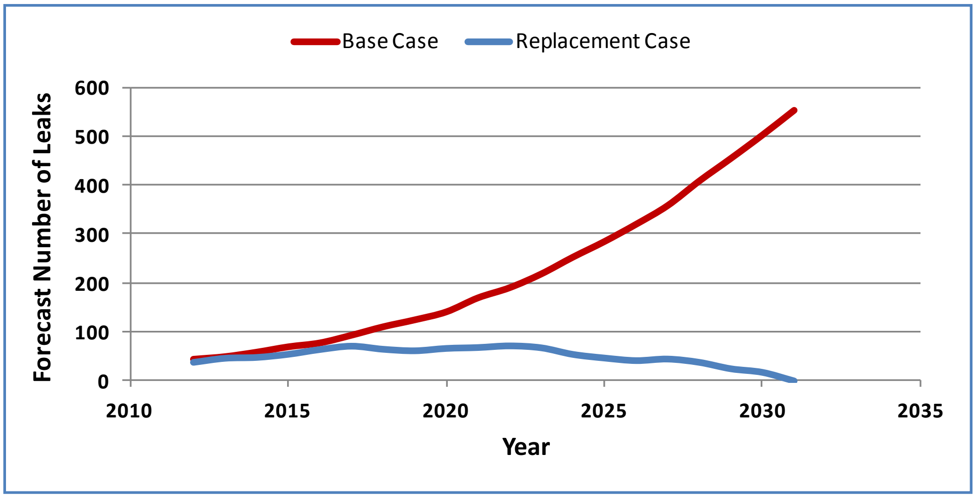
Avista's Integrity Management approach provides the analytical tools that integrate key knowledge and information needed to effectively prioritize replacement activities based on the potential hazard. In the prioritization process, each segment of Aldyl A pipe in Avista's system is assigned a relative 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 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.

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.

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 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.

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.

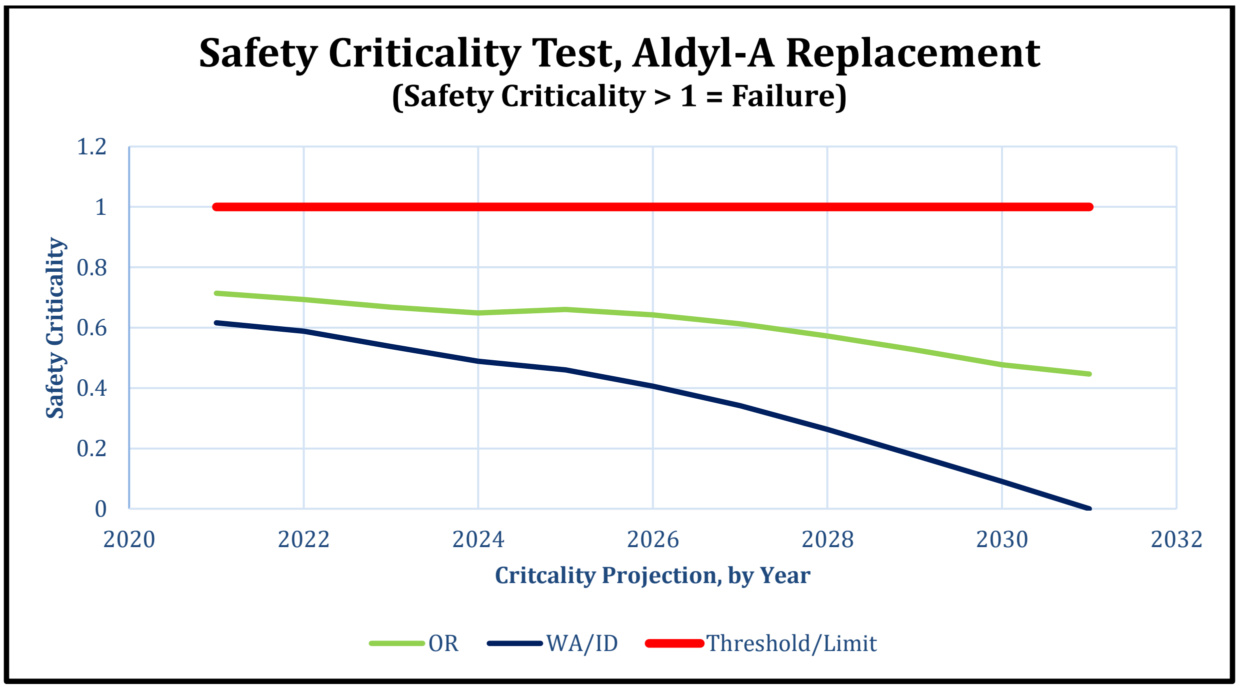
Linear Regression Assumptions

- 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).



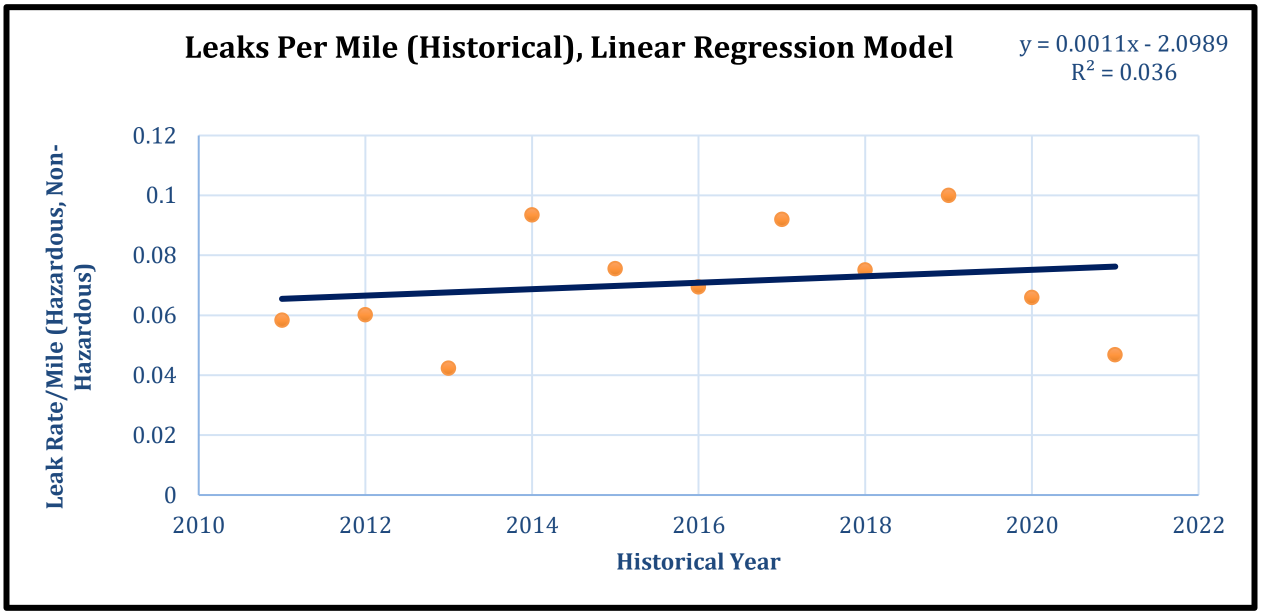
- Safety criticality test success does not eliminate all risk. Rather, the likelihood of a catastrophic failure is unlikely.[11]

[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:

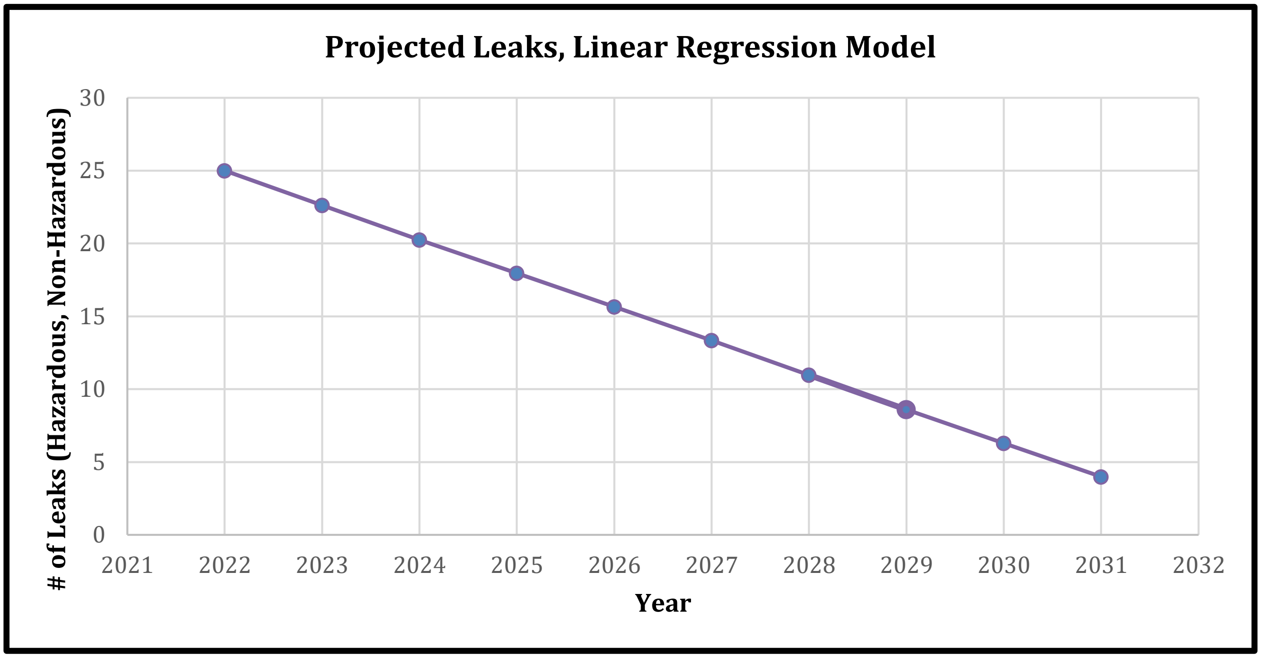
The Linear Regression Model (below) measures the number of hazardous and non-hazardous leaks since 2011.[12] The leak rate per mile can be determined through linear regression. As shown, there has been a slight uptick in the number of leaks per mile but the overall the trend is relatively flat and stable.



- 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.



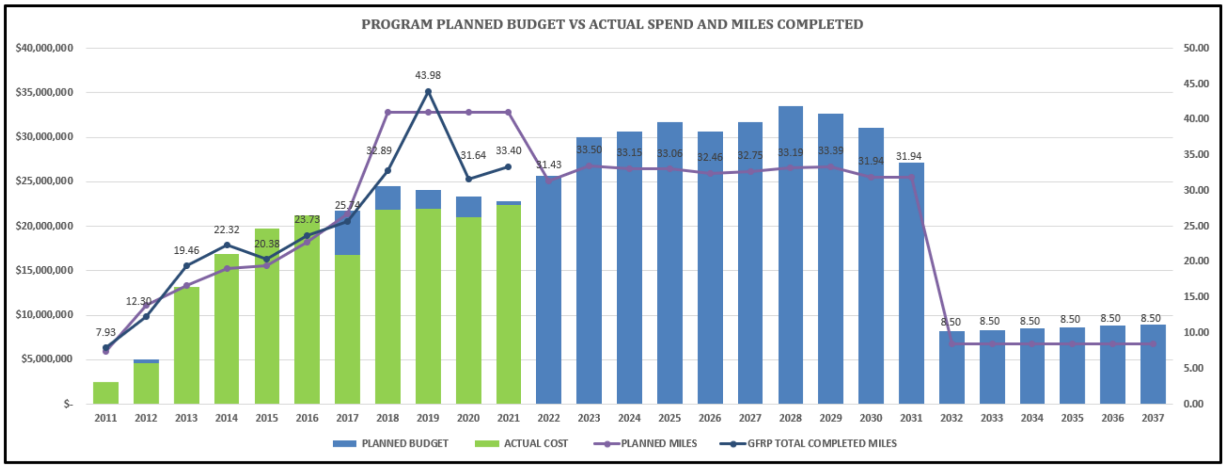
The Projected Leaks, Linear Regression Model (above) demonstrates continued risk reduction through pipe replacement and covers the combined service territory (WA, ID, and OR). The modeling does not indicate a need for any material adverse changes in the program's timeline and supports extending Oregon 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.

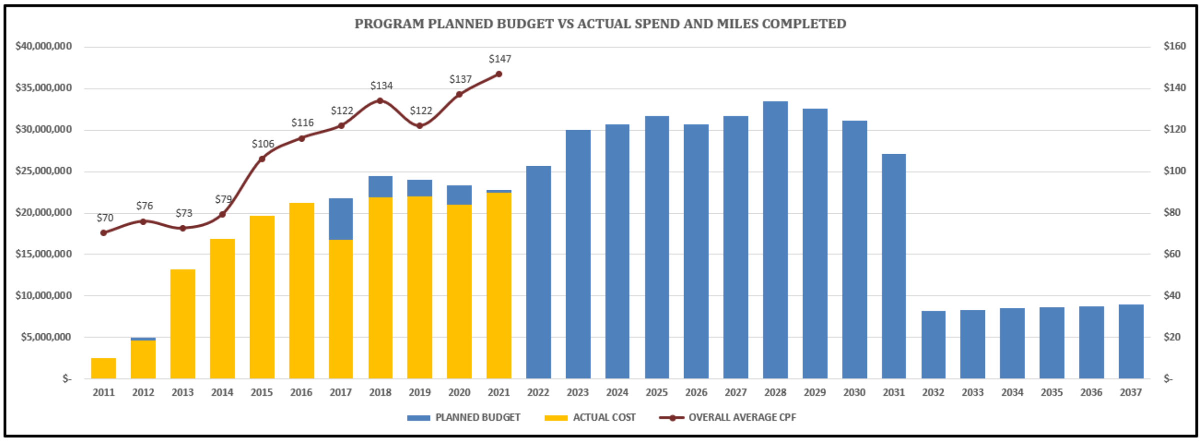
The program is getting more expensive as the cost per foot (CPF) has increased:

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.

Gas Isolated Steel Replacement Program, ER 3007

EXECUTIVE SUMMARY

In accordance with a Stipulated Agreement with 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 identify and remediate steel piping and risers that are isolated from or lack the necessary cathodic protection within Avista’s Washington State natural gas pipeline systems. Inadequate cathodic protection can result in corrosion of steel pipe and ultimately 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.

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 State, the focus of the Gas Isolated Steel Replacement Program moving forward will be in Idaho and primarily Oregon. Avista has finished identifying isolated steel in Idaho and is in the early stages of identifying 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 program until the full scope can be better defined through the inspection process. Currently, the approved level of capital funding does not support completing the volume of inspections required to truly understand the extent of the work that will be generated in Oregon. The replacement jobs generated during inspection work often have a quick timeline for remediation. We require additional capital funding to be able to generate more replacement jobs in order to forecast and understand the full scope and duration of the Oregon 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*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	5/2/2023

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	3,000,000	3,000,000
2025	4,000,000	4,000,000
2026	5,000,000	5,000,000
2027	5,000,000	5,000,000
2028	5,000,000	5,000,000

Project Life Span	***Ongoing***
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. 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 replace all unknown sections of isolated steel pipe including isolated steel main, services and service risers within a specified timeframe. These efforts have been carried over into Idaho and are now also ongoing in our Oregon service areas.

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 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.

Per the initial Stipulated Agreement in Washington, Avista was required to replace all isolated steel, identified through the Washginton 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 program inspections in Idaho and Oregon, we have historically replaced them to meet the requirements of 49 CFR 192.455 and 192.465. Avista has incorporated and maintained this standard of 90-day (isolated & unprotected) and 10-year (isolated & protected) replacement timeframes to stay compliant. The alternative to replacement, in order 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 is a required action called out 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 for Washington. 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.

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 good way to predict what the severity of an incident or penalty might be. However, by maintaining and expanding this program, Avista is showing an effort to locate isolated steel within our natural gas system and to operate within Federal and State regulations. By operating in this manner, 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 additional inspection work (O&M) is needed now in Oregon to be able to better assess the remaining isolated steel risk and the best direction for the program. However, these inspections will create follow-up work (Capital) that will be 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 result in the ability to perform fewer inspections and will limit the Program's ability to forecast the full scope, timeline and risk associated with a likely significant compliance and integrity issue.

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 mitigating isolated steel pipe, we are staying in compliance with Federal and State regulations, remaining innovative, and improving our current systems. This program further shows our customers that we are a responsible operator that puts customer safety first. Corrosion related leaks can not 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.

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 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 57K locations still require inspection. The nature of the program often requires multiple inspections at a single location. At this time, it is estimated that more than 120K 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 rate 2 to 3 times 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. With the information we have now it is estimated there may be anywhere between 5K and 20K jobs in Oregon that would require remediation within either 90-days or up to 10-years. At this time, 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.

replacement jobs are costing on average about $12K in Oregon, but we have seen as high as $25K depending on the circumstances involved. Replacement at these quantities and cost would result in a significant capital investment ($60M to $240M). While the inspection work is O&M, the remediation work is capitalized. Current capital funding levels limit the number of jobs that can be created each year from the inspections. Current operational resources limit the number of remediation jobs we can complete each year. Because of this, we are limited in the number of inspections we can complete, which only serves to perpetuate Avista's ability to understand the scale of the problem and plan for the risk associated with a known system integrity issue. We believe the proposed capital funding will help us to generate the information we require to fine tune these estimates and build the program scope and schedule. While doing all of this we will continue to reduce risk within our natural gas system both from an operational and a compliance standpoint.

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, the proposed solution for Idaho and now Oregon is to maintain similar standards and practices set out for the Washington program. The goal is to systematically identify and remediate all sections of isolated steel pipe and service risers in all our 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 57K locations remaining in Oregon that require multiple inspections to determine whether they are isolated. Ideally, we would approach this program by completing all inspections over a 2-3 year period and at the same time be addressing the remediation efforts as follow-up in up to a 10-year timeframe, similar to Washington State. The challenge with this program is managing the budget and resources required to complete the amount of required replacement work within the required 90-day or 10-year timelines. We do not have enough information at this time to estimate the quantity of 90-day and 10-year jobs we will be required to complete. Our best estimates indicate there may be anywhere from 5K and 20K follow-up jobs created by the inspections. In order to fine tune these estimates, we need to be able to complete more inspections. Since the O&M inspections generate capital replacement jobs, we are requesting additional capital to support additional remediation work that will be generated by an increased number of inspections. This will provide better data to be able to forecast the full scope and timeline for the remaining program in Oregon.

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. At this time, more information is required from the Oregon inspection program to be able to generate valuable risk and risk reduction analyses on isolated steel in Oregon. We believe that isolated steel is a significant integrity issue in our system and that the risk is significant enough that the investment should be made now to maintain compliance and eliminate these risks. The ultimate threat is a catastrophic event that would pose risk to life and property. That said, isolated steel pipe and service replacements do put new, more reliable plant in the ground as a capital investment which improves the overall reliability of our system.

The current requested amounts 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. 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. This level of replacement is not sustainable over the long term with the quantity of replacement jobs we anticipate from the Oregon inspection program. As stated in Section 1.5, it is estimated there may be anywhere between 5K and 20K replacement jobs generated in Oregon that would require remediation within either 90-days or up to 10-years. Currently, full service isolated steel replacement jobs are costing on average about $12K in Oregon. We have seen replacement jobs as high as $25K depending on the circumstances involved and these costs are only increasing. Replacement at these quantities and cost would require a significant capital investment ($60M to $250M) 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.

This data is constantly changing as more inspection information for Oregon 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.

[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	-	$0	$0	$0	$0	$0
O&M	Reduced Costs of Inspection and O&M Related Follow-Up	$0	$0	$0	$150K	$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 120K inspections required at over 57K locations. At current costs, this would be approximately $720K over the life of a 5-year inspection project or about $150K/year. Depending on the level of capital available, we might be able to support completing the inspections as soon as a 3-4 year period. 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. The timing of when this offset would be recognized is difficult to predict at this time without knowing the full scope of the project. However, 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.

[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	2024	2025	2026	2027	2028
Capital	N/A	$0	$0	$0	$0	$0
O&M	Cathodic Protection	$3000	$3000	$3000	$3000	$3000

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 be able to be cost refocused 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 $3000, 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 continue to locate and remediate isolated steel in Idaho and Oregon at current 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. Within a few years there will only be steel risers left to inspect. Maintaining current funding levels will only perpetuate a reduced quantity of 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 program funding levels. 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.

Deferring the costs to replace or remediate these integrity issues will only extend the program for a potentially significant timeframe (i.e. decades). 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: $60M to $250M 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. Installing anode protection may allow for additional inspections to completed because it could extend the remediation timeframes. However, we only just recently determined that the installation of anodes on service piping can be capitalized. Anode installation may be a way to meet compliance, but these pipes may 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.

We are still in the early stages of understanding how best we would utilize this alternative and whether it should be a best practice moving forward. Because of this, it is difficult to estimate what the costs might be. Assuming the installation of anode protection is approximately $1,200 per service, we might see initial capital costs in the range of $6M to $24M to mitigate these isolated locations. Future additional capital costs to replace pipe would need to be determined once the inspections were complete and we have a better understanding for the number of locations that would require service pipe replacement.

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 17 open 10-year isolated steel service replacement jobs. Oregon has about 400 known isolated steel service replacement jobs open, but it is important to note that Oregon's numbers 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 and information for this program 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 completion date set for the Oregon program. 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 to complete.

Additional inspection work (O&M) is needed to better assess the remaining isolated steel risk in Oregon. These inspections will create a significant number of 90-day and 10-year mitigation jobs. These jobs need to be completed to remain in compliance with the Federal Code of Regulations, State codes and Avista's Standards for Gas Construction. The current capital budget for this program does not support creating the required number of jobs to effectively progress the program. The level of capital funding also limits the ability to forecast the full scope and timeline (schedule) for the program, therefore limiting Avista's understanding of the associated risk in our Oregon service territories. The risk associated with this program is likely a significant compliance and integrity issue.

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 group 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.

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:	Jeffy a Webb	Date:	4/28/23
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	Alicia Gibbs	Date:	4/28/23
Print Name:	Alicia Gibbs		

Title: Director of Natural Gas

Role: Business Case Sponsor

Signature: ______________________ Date: ____________

Print Name: ______________________

Title: ______________________

Role: Steering/Advisory Committee Review

Gas Overbuilt Pipe Replacement Program, ER 3006

EXECUTIVE SUMMARY

Overbuilt pipe refers to gas pipes that either located directly under or very close to building structures. Except in rare case, Avista does not intentionally install gas pipes under structures. In most cases, overbuilt pipe occurs in mobile home parks where homes are moved over time. 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.

All the known mobile home parks with overbuilt pipe in Avista's Oregon districts were catalogued at one time, analyzed, and risk ranked as part of the utility's Distribution Integrity Management Program (DIMP). In addition to these known mobile home parks, with numerous overbuilt facilities, each local District (including those in Idaho and Washington states) periodically finds individual locations with newly overbuilt facilities. These projects and the risk associated with them are mitigated, over time, as part of the Overbuilt Pipe Replacement Program. As the number of known overbuilds in the company has decreased, the level of requested and approved funding has decreased as well.

This program is scheduled to be complete at the end of 2024.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Seth Samsell	Initial version	4/17/2017	
2.0	Seth Samsell	Revision for 2020 Oregon GRC filing	2/12/2020	
2.1	Tim Harding	Updated to the refreshed 2022 Business Case Template	9/1/2022	

GENERAL INFORMATION

Requested Spend Amount	$400,000
Requested Spend Time Period	Annually
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Jeff Webb / Tim Harding | Jody Morehouse
Sponsor Organization/Department	B51 – Gas Engineering
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

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

Overbuild conditions usually 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.

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

The main driver for this program is Mandatory & Compliance. Resolving overbuilt gas pipes keeps Avista compliant with state and federal codes, and increases the safety of customers in the immediate project areas.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Overbuilt gas pipes pose a safety risk for occupants in the area. Leaking gas can accumulate under mobile homes and storage sheds. Relocating the gas piping is the most straight-forward approach to resolving the issue.

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.

The locations of known overbuilt gas pipes have been catalogued and the completion of these projects is tracked by the DIMP Program Manager.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

The DIMP study of known project locations can be obtained from the Gas Compliance group.

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.

This program replaces existing assets, however the asset condition is not generally a factor in project prioritization. This program replaces and relocates overbuilt gas pipes, regardless of the condition of the existing pipe.

2. PROPOSAL AND RECOMMENDED SOLUTION

The requested level of spending for this program is consistent with past years, and that level will allow the program to be complete at the end of 2024. A reduction in funding will extend the time required to complete all projects within the program.

Option	Capital Cost	Start	Complete
Recommended Solution, Complete planned projects at requested funding level	$400,000	January	December
Alternative Solution, Complete planned projects at a reduced funding level	$200,000	January	December

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

A DIMP risk analysis was performed on known overbuild projects by the Gas Compliance group. Information on this analysis is available from the Gas Compliance group.

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 capital program is focused on installing new gas mains and services, and retiring the previous overbuilt mains and services. This program does not significantly lower O&M costs. Instead, it is addressing a safety issue.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

None

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

The alternative is to leave known overbuilds in place. This is a violation of code and standard practices. Only in rare cases is gas piping intentionally installed under a structure. The gas pipes addressed by this program were never intended to be built over, and therefore were not installed to comply with the special requirements needed to make such an installation compliant with code and Avista's Gas Standards.

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.

Projects completed within this budget will be transferred to plant upon completion, typically within the same year they are started.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This program aligns with Avista's organizational focus to maintain a safe and reliable infrastructure to achieve optimum life-cycle performance, safely, reliably, and at a fair price for our customers.

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

This program addresses a known safety issue. A thorough evaluation was performed by the DIMP group to validate the need for this program. Construction on this program will be complete at the end of 2024.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Stakeholders include Gas Engineering, Compliance, Integrity, and Operations.

2.8.2 Identify any related Business Cases

N/A

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

This program budget is overseen by Gas Engineering. Construction activities are overseen by Gas Operations. Projects are prioritized with input from the DIMP Program Manager, the impacted Operations Managers, and Gas Engineering.

3.2 Provide and discuss the governance processes and people that will provide oversight

DIMP risk scores are assigned to each proposed project. The highest-ranking projects are generally completed first, but some flexibility is required to ensure that specific operations groups are not overloaded during any given year. Gas Engineering oversees the program budget and reports on spending monthly.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

At the beginning of each year, the prioritization process is completed and the program budget is divided between offices. This information is formally handed off to the operations offices at that time. Rarely will anything change for the rest of the year. Gas Engineering reviews program spending with the operations offices on a monthly basis to keep within the program budget. Monthly updates are documented via email and fund requests are made using the appropriate forms from the CPG.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Overbuild Program ER 3006 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:	Jeffrey A Webb	Date:	9/1/22
Print Name:	Jeff Webb / Tim Harding		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	Jody Morehouse	Date:	9/1/2022
Print Name:	Jody Morehouse		
Title:	Director Natural Gas		
Role:	Business Case Sponsor		

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

Gas PMC Program, ER 3055

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. On average, approximately 6,000 meters are removed annually for this program resulting in an average cost of $1,500,000 ($250/meter).

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.

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*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	*4/27/2023*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**2,800,000**	**2,800,000**
2025	**3,600,000**	**3,600,000**
2026	**3,000,000**	**3,000,000**
2027	**2,600,000**	**2,600,000**
2028	**1,700,000**	**1,700,000**

Project Life Span	***Ongoing***
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Dave Smith / 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?

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.

Our 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:

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.

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.

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.

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		$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 offsets4 (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	Avoid Meter Replacements by Adjusting the Installation Constant	$5.2MM	$5.3MM	$5.5MM	$5.7MM	$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.

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 of 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.

A weekly Cognos report named *MR-130121 Gas PMC FF Meters Pulled and Tested.xlsx is* generated and sent to the program manager in Gas Engineering. This report summarizes the status of the random sampling program and the removal of the failed family meters. This report is used to track the progress of the program throughout the year. The image below shows the weekly report:

- Red rows indicate failed family meters.
- White rows indicate meter families in the random sampling program that have not had the minimum number of meters pulled for the year.
- Green rows indicate meter families in the random sampling program that have had the minimum number of meters pulled for the year.

AVISTA

PMC/FF Weekly Summary Meters Pulled

Data Source Maximo

Data Updated Daily

Gas Meters Pulled by Meter Family for Current Year

****Test Families will display when at least 1 Meter is Pulled ****

Sampling Group-Asset	MFG Year	Model #	Sampling Template Final	Meters Pulled	Remaining Meters	% Complete - Meters Pulled
5B_1959	1959	5B	858	10	848	1.17%
5B_1960	1960	5B	50	11	39	22.00%
5B_1961	1961	5B	50	6	44	12.00%
5B_1962	1962	5B	7	7	0	100.00%
5B_1963	1963	5B	35	17	18	48.57%
AC250_1980	1980	AC250	50	9	41	18.00%
AC250_1983	1983	AC250	7	7	0	100.00%
AC250_1984	1984	AC250	7	7	0	100.00%
AC250_1985	1985	AC250	35	7	28	20.00%

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.

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:	Jeff a Webb	Date:	4/25/23
Print Name:	Dave Smith / Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	Alicia Gibbs	Date:	4/25/2023
Print Name:	Alicia Gibbs		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

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

Replacement Street & Hwy Program, ER 3003

EXECUTIVE SUMMARY

Virtually 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.

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 planned spend amounts for the next five years are based on average expenditures in this budget over the last several years.

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

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*
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements*	

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**3,718,000**	**3,718,000**
2025	**3,718,000**	**3,718,000**
2026	**3,718,000**	**3,718,000**
2027	**3,718,000**	**3,718,000**
2028	**4,063,000**	**4,063,000**

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 roadways 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 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. This does not enable long term project planning or budget forecasts.

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 our 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 will 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*.

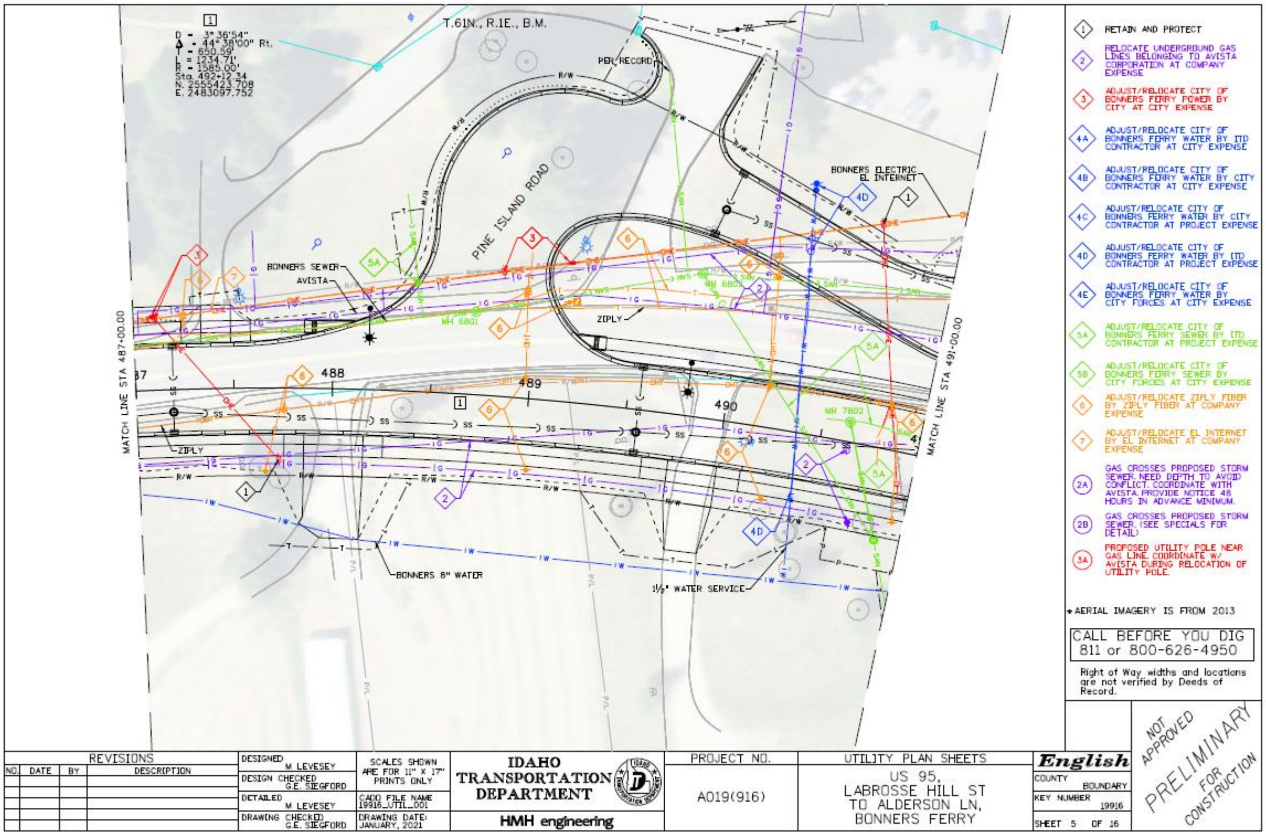
Avista Strategic Goals

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.

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.

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



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.

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 municipalities in its service territory. In addition, 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 offsets4 (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] 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.

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 and the gas facilities must remain in service, then there are no alternatives for the projects under this Business Case.

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.

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 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:	Jeff a Webb	Date:	9/18/23
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	Alicia Gibbs	Date:	10/25/2023
Print Name:	Alicia Gibbs		
Title:	Director Natural Gas		
Role:	Business Case Sponsor		

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

Gas Transient Voltage Mitigation Program, ER 3010

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 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*
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements*	5/5/2023

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	500,000	500,000
2025	250,000	250,000
2026	250,000	250,000
2027	250,000	250,000
2028	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 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 will 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.

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 also cause unsafe conditions when gas is released and when it ignites. 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.

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 will be damaged by nearby electric systems, or those that will expose employees and the general public to unsafe voltage levels.

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.

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.

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, 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, or 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 issues 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.

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	2024	2025	2026	2027	2028
Capital	None	$0	$0	$0	$0	$0
O&M	Labor related to extra safety procedures	$5,100	$5,200	$5,400	$5,600	$5,700
O&M	Labor and materials to respond to fault damage events and make repairs.	$3,400	$3,500	$3,600	$3,700	$3,800

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.

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	2024	2025	2026	2027	2028
Capital		$0	$0	$0	$0	$0
O&M	Labor and materials to repair system leaks caused by AC corrosion	$3,600	$3,700	$3,800	$3,900	$4,000

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)

*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. Because there is currently a 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 followed.

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.

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. 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:	Jeffrey a Webb	Date:	5/4/23
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		
Signature:	Alicia Gibbs	Date:	5/4/2023
Print Name:	Alicia Gibbs		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Generation Interconnection

EXECUTIVE SUMMARY

The Company must provide for the interconnection of new generation resources with its Transmission System under the terms and conditions of its Open Access Transmission Tariff ("Tariff") under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). In compliance with federal statute, the terms and conditions of the Tariff, and FERC rules and regulations, the Company must study, design, and construct the necessary facilities ("Network Upgrades") to provide Interconnection Service to all eligible generation projects, regardless of whether such generation is intended to serve bundled retail native load customers of Avista or any third-party load. 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 (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.

Consistent with FERC rules and regulations regarding the funding of Network Upgrades, the Company may elect to fund all such costs up front or may require the Interconnection Customer to provide initial advanced funding for Network Upgrades, for which the Company must provide repayment (or Transmission Service credits) to the Interconnection Customer over a specified period of time not to exceed twenty years after the generating facility commences commercial operation. (Tariff Section 11.4) All repayment or Transmission Service credits must include FERC interest. Determination of repayment schedule, and resulting capital additions, will be made in consultation with the Company's Financial Analysis, Treasury and Accounting groups. Annual amounts requested under this Business Case will reflect both committed and planned capital funding consistent with such collaborative determination.

All aspects of the generation interconnection process, including application, studies, evaluation of new or upgraded facilities, construction of new or upgraded facilities, cost allocation of new or upgraded facilities, and repayment of advanced amounts are prescribed by the Tariff and FERC rules and regulations. This Business Case provides for the repayment of advanced funding of Network Upgrades, currently forecast to be begin at approximately $38,000 in 2025 and increase to $1.2 million for 2027 and 2028, that are required to design, procure, and construct Network Upgrades, including repayment and capitalization of any advanced amounts. Interconnection projects expected to commence the construction phase for this Business Case are the 126MW Saddle Mt. Wind and 375MW Cloudwalker Wind.

Transmission service revenue directly associated with this business case for 210MW is under agreement to begin in September 2026, this service will result in nearly $7 million in revenue for both 2027 and 2028.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Jeff Schlect*	*Initial draft of original business case*	*3/23/2023*
2.0	*Randy Gnaedinger*	*1st revision to original business case*	*4/18/2023*
BCRT	*BCRT Team Member*	*Steve Carrozzo*	*4/18/23*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$0	$0
2025	$38,000	$38,000
2026	$554,000	$554,000
2027	$1,203,000	$1,203,000
2028	$1,203,000	$1,203,000

Project Life Span	***Determined on a yearly basis***
Requesting Organization/Department	Ongoing
Business Case Owner | Sponsor	Kenny 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

1. BUSINESS PROBLEM –

In compliance with federal statute, the terms and conditions of the Tariff, and FERC rules and regulations, the Company must design and construct new or upgraded transmission facilities to provide for the reliable interconnection of new generation projects. Upon completion of a FERC-prescribed study process, the Company must tender a standard form of Small Generator Interconnection Agreement ("SGIA") (for projects less than or equal to 20MW in capacity) or Large Generator Interconnection Agreement ("LGIA") (for projects greater than 20MW in capacity) to the generation project developer ("Interconnection Customer"). Consistent with the study process and FERC's cost allocation principles, the SGIA or LGIA must specify the Network Upgrades associated with each generation project. Network Upgrades are those new or upgraded facilities that must be funded by the Company. Generally, engineering, procurement, and construction of Avista's interconnection facilities takes 2-4 years, the last 1-2 years happen in parallel with the Generating Facility construction. Both construction timelines ultimately align towards meeting the SGIA or LGIA Commercial Operation Date.

Documentation providing justification of FERC rules and requirements regarding the funding of Network Upgrades associated with generation interconnection projects can be provided upon request.

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

Pursuant to the Company's mandatory federal compliance requirements under the Tariff and applicable FERC rules and regulations, the Company must fund the design and construction of new and/or upgraded transmission facilities to provide generation interconnection service under the Tariff. The Interconnection Customer providing initial advanced funding for Network Upgrades, the Company must ultimately provide repayment (or Transmission Service credits) to the Interconnection Customer over a specified period of time not to exceed twenty years after the generating facility commences commercial operation. Section 11.4 in Attachment M to the Tariff details the repayment terms for Network Upgrades.

1.2 Discuss the major drivers of the business case.

The applicable driver for the Company's construction investment in FERC jurisdictional generation interconnection projects is *Mandatory & Compliance.*

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: (i) an act of default under the applicable Small Generator Interconnection Agreement ("SGIA") or Large Generator Interconnection Agreement ("LGIA") for each project, and (ii) 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*.

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, as well as being Trustworthy as one of Our Values. Investment complies with applicable SGIA and LGIA contract obligations, the Tariff, and FERC rules and regulations. Timing of repayments to Interconnection Customers (with associated transfers to capital) provides the Company with some flexibility in the planning of its capital funding requirements.

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]

Each generation interconnection project must be studied consistent with the generation interconnection procedures under the Tariff. Attachment M to the Tariff specifically describes Avista's Cluster Study process, and the technical studies to be completed. The applicable study reports must be made available to the Interconnection Customer and any other Eligible Customer under the Tariff who requests the study; therefore Avista's Cluster Area study reports are posted on OASIS. The study reports document the necessary interconnection facilities to safely and reliably interconnect each generation project. The studies go on to document the necessary cost estimates and milestones to meet the applicable SGIA and LGIA contract obligations.

The Company's election to require the Interconnection Customer to provide advanced funding of Network Upgrades is outlined in *Generation Interconnection Facilities Allocation Practice - Transmission Provider Interconnection Facilities vs. Network Upgrades*.

2. PROPOSAL AND RECOMMENDED SOLUTION

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

The Company must fund Network Upgrades associated with generation interconnection projects in compliance with the Tariff, the applicable SGIA or LGIA, and FERC rules and regulations. Interconnection projects expected to commence the construction phase for this Business Case are the 126MW Saddle Mt. Wind and 375MW Cloudwalker Wind.

While the Company must ultimately fund all Network Upgrades, the Company is able to manage its overall capital obligations, and correlating transfers to plant, under this Business Case over a period of time following the commercial operation date, to be set forth in either the SGIA, LGIA, or a separate Network Upgrades funding and repayment 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).[2]

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

[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.

per day. Meeting Avista's contract obligations by providing repayment of amounts advanced for Network Upgrades (or Transmission Service credits) to the Interconnection Customer would be consistent with the Ethical Decision Making policy under the Company's Code of Conduct and remove the risk compliance penalties.

A hypothetical 100MW generator that takes transmission service to move the generation off Avista's system would result in $32.98/kW-yr * 100,000kW = $3,298,000 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.

Transmission service revenue directly associated with this business case for 210MW is under agreement to begin in September 2026, this service will result in nearly $7 million in revenue for both 2027 and 2028.

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		$0	$0	$0	$0	$0
O&M		$0	$0	$0	$0	$0

Generation interconnection projects are generally new facilities constructed to safely and reliably interconnect each generation project to the transmission system. Since these are new facilities associated with a new or increased generation resource, no direct offsets or savings are expected to result from this investment.

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		$0	$0	$0	$0	$0
O&M		$0	$0	$0	$0	$0

[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.

Generation interconnection projects may create new revenue that goes to offset retail customer rates. A hypothetical 100MW generator that takes transmission service to move the generation off Avista's system would result in $32.98/kW-yr * 100,000kW = $3,298,000 per year in revenue. Transmission service revenue flows through the ERM and then offsets retail customer rates.

Transmission service revenue directly associated with this business case for 210MW is under agreement to begin in September 2026, this service will result in nearly $7 million in revenue for both 2027 and 2028.

No indirect capital or O&M offsets are expected to result from this investment.

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.

Failure by the Company to provide design and construction funding for these projects would be: (i) an act of default under the applicable Small Generator Interconnection Agreement ("SGIA") or Large Generator Interconnection Agreement ("LGIA") for each project, and (ii) 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.

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).

Avista's Project Delivery team tracks and monitors project spend on a monthly cadence. Project spend is a key metric for monitoring investment, each months spend is invoiced to the Interconnection Customer, and the Network Upgrade portion ultimately becomes the basis for repayment of advanced funding.

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

Ongoing program year-to-year dependent upon generation project status and advance funding repayment requirements.

Saddle Mt Wind is expected to commence design in July 2023 and complete commercial operation in July 2025.

Cloudwalker Wind is expected to commence design in August 2023 and complete commercial operation in January 2026.

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.

Design and construction scheduling are coordinated through the Engineering Roundtable and Project Delivery team. Capital funding is coordinated with the Financial Analysis, Treasury and Accounting groups with final determinations made through the Capital Planning Group. The Company's Transmission Services group administers all SGIAs and LGIAs. The Company's Substation Project Delivery group provides project management services for all major generation interconnection projects.

Project milestones, scope, and cost changes are documented through administration of the applicable SGIA or LGIA with each Interconnection Customer. All material adjustments will be managed through in-year change requests submitted to the Capital Planning Group.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Generation Interconnection 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: 2023.04.25 10:15:24 -07'00'	Date:	4/25/2023
Print Name:	Kenny Dillon		
Title:	Senior Manager, FERC Policy and Transmission Services		
Role:	Business Case Owner		

Signature:	Michael A. Magruder Digitally signed by Michael A. Magruder Date: 2023.04.25 13:48:42 -07'00'	Date:	4/25/2023
Print Name:	Mike Magruder		
Title:	Director, Transmission Operations and System Planning		
Role:	Business Case Sponsor		

Generation Interconnection

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

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 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 attacher. Avista is also allowed to recover a portion of the cost of replacing & maintaining shared infrastructure via a regulated yearly pole rental fee. Avista would face potential regulatory and or civil legal action if timelines and obligations are not met due to a lack of funding. 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*	*3/21/2022*
BCRT	*BCRT Team Member – Katie Snyder*	*Has been reviewed by BCRT and meets necessary requirements*	*04/13/2023*

Joint Use Projects

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$5M	$5M
2025	$5M	$5M
2026	$4M	$4M
2027	$3.5M	$3.5M
2028	$3.5M	$3.5M

Project Life Span	Perpetual
Requesting Organization/Department	Operations/Joint Use
Business Case Owner | Sponsor	Jesse Butler | David Howell
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

Joint Use Projects

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 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.

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.

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] 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.

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.

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.

[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.

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 – (December)

Average Application Approval Time/
Joint Use Company

Company	Average Approval Time	Company	Average Approval Time
AVISTA	17	MCI	33
CHARTER	36	NOANET	30
CMC	18	POC	22
COM	2	POL	21
COS	0	POW	18
CTL	20	SPARKLIGHT	21
ELI	12	SPOCOUNTY	12
FSI	29	SUDDENLINK	22
FTBM	14	TDSM	44
FTR	23	VZW	8
INLAND CELLULAR	1	XO	21
INTERMAX	11	ZAYO	16
KFSD	1	ZIPLY	52
LEVEL 3	11		
LSD	18		

Joint Use Mutual Licensing Agreement Information

Total number of contracts in place	New Contracts 2020	New Contracts 2021	New Contracts 2022	Pending New Contracts 2023
73	1	0	3	2

Joint Use Projects

Work Demand - Attachment Requests 2022

COMPANY	PRELIMINARY	BACKLOG	WAITING	APPROVED	CANCELLED	GRAND TOTAL
CMC		2	48	167	10	227
ZIPLY	30		57	58	2	147
TDSM	1		12	90	2	105
CTL	1	6	17	48		72
FTBM	1			23	1	25
CHARTER		1	1	17	2	21
ZAYO			1	17		18
MCI				15		15
VYVE-NORTHLAND			1	13		14
SUDDENLINK			1	9		10
SPARKLIGHT			1	6		7
POL			1	6		7
POC				6		6
POW			1	4		5
AVISTA			1	4		5
LINCOLN COUNTY		1	2	1		4
INTERMAX				4		4
WHOLESAIL			2	2		4
XO				3		3
ELI				3		3
Mobilitie				1		1
COM				1		1
NOANET				1		1
TDS				1		1
GRAND TOTAL	33	10	146	500	17	706

COMPANY	NEW TOTAL INSPECTION POINTS	NEW ATTACHMENTS	OVERLASH
CTL	3,456	952	2,487
CMC	2,681	552	1,919
LINCOLN COUNTY	952	759	
TDSM	563	277	208
ZIPLY	402	204	145
POC	358	295	36
ZAYO	299	49	238
VYVE-NORTHLAND	293	29	249
AVISTA	289	215	14
FTBM	277	174	72
MCI	197	91	71
CHARTER	194	72	88
INTERMAX	83	73	
SUDDENLINK	72	52	11
SPARKLIGHT	54	2	51
POW	52	38	5
XO	52	-	52
POL	44	28	10
ELI	33	7	25
WHOLESAIL	14	14	
TDS	5	5	
NOANET	4	1	2
COM	1	-	
MOBILITIE	(1)	(1)	
GRAND TOTAL	10,374	3,888	5,683

Data as of 12/31/22
Preliminary (Clock on hold) – Incomplete applications, does not meet Avista's minimum design criteria.
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.

AVISTA

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: 2023.04.13 11:19:43 -07'00'	Date:	
Print Name:	Jesse Butler		
Title:	Joint Use Business Manager		
Role:	Business Case Owner		

Signature:	David Howell — Digitally signed by David Howell Date: 2023.04.14 07:59:35 -07'00'	Date:	
Print Name:	David Howell		
Title:	Director of Electric Operations		
Role:	Business Case Sponsor		

Signature:	David Howell — Digitally signed by David Howell Date: 2023.04.14 07:59:58 -07'00'	Date:	
Print Name:	David Howell		
Title:	Operations Director		
Role:	Steering/Advisory Committee Review		

Saddle Mountain 230-115kV Station (New) Integration Project Phase 2

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 >>

Large commercial customers in the Othello area have continued to expand their businesses. The business expansion has created demands on the electric system that are not able to be adequately backed up with the reliability that they deserve. Meeting the increased load demands are possible, but equipment failures could cause outages that would be time consuming and difficult to restore quickly.

This business case would replace the Othello City substation with a new station having two 30MVA transformers. The business case also includes substantial upgrades to the transmission system in the area to integrate the new Othello City substation with the new Saddle Mountain substation. This business case is important to customers that they can continue to have the reliability of the electric system that they have become accustomed to receiving. This project has been approved and prioritices by the Engineering Roundtable Committee.

Service: ED – Electric Direct

Jurisdiction: AN – Allocated North

Engineering Roundtable Request Number: ERT_2017-64

Cost of Solution: $43,800,000

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Unknown	Initial Version	2017	
2.0	Karen Kusel / Glenn Madden	Update to 202 Template	6/2020	
2.1	Karen Kusel	Project Cost Update, 2022 Template	6/2022	

Saddle Mountain 230-115kV Station (New) Integration Project Phase 2

GENERAL INFORMATION

Requested Spend Amount	$43,800,000
Requested Spend Time Period	6 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]

This business case would replace the Othello City substation with a new station having 2-30MVA transformers. The business case also includes substancial upgrades to the transmission system in the area to integrate the new Othello City substation with the new Saddle Mountain substation.

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

There are performance issues in the Othello area. It is also difficult to maintain the equipment at the Othello 115kV Substation due to load levels on all feeders.

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 are the main priority of this project due to TPL-001-4 non-compliance at this time. There are also Performance & Capacity issues that will be remedied with this project. Overall, this rebuild will relieve load and outage concerns for large commercial customers.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Due to increased load in the area, we are risking large customer outages due to equipment failure.

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.

System Planning Assessments.

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]

Project Report: Saddle Mountain Study.pdf

2016 Avista System Planning Assessment Report (Page 56)

Othello City Substation Area Load Analysis

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.

System Planning Assessments.

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)]

Alternative 1: Status Quo. This alternative is not recommended because it does not mitigate the expected capacity constraints, and does not adhere to NERC Compliance regulations.

Alternative 2: Build new 115kV Transmission Line. This alternative is not recommended as it does not mitigate the low voltage issues in the Othello area.

Alternative 3: Close “Star” Points. This alternative is not recommended due to its high cost. It is anticipated that $75M of reconductoring would be needed to mitigate any potential violations comparable to the preferred alternative.

Alternative 4: Install Generation. This alternative is not recommended due to its high financial costs, the potential for must run operation and the lead time on this project will be well beyond the time this project is needed per NERC requirements.

Alternative 5: Build Saddle Mountain 230/115kV Substation Phase 2 Project with associated support projects. This alternative is the most cost effective option considered and provides enough voltage support and capacity into the area for the next 50 years. This alternative mitigates all identified deficianencies in the Othello area documentes in the 2016 Planning Annual Assessment. This alternative is the best solution for the long term.

Phase 1: See Associated Phase 1 Business Case Narrative.

Phase 2:

1) Rebuild Othello Substation to 115kV Ring Bus with 5 positions.
2) Build new Transmission line from Saddle Mountain 115kV to Othello Substation 115kV.

This alternative is the most cost effective option considered and provides enough voltage support and capacity into the area for the next 50 years. This alternative mitigates all identified deficiencies in the Othello area documented in the 2016 Planning Annual Assessment. This alternative is the best solution for the long term.

Saddle Mountain 230-115kV Station (New) Integration Project Phase 2

Option	Capital Cost	Start	Complete
Recommended Solution: Build Saddle Mountain 230/115kV Substation Phase 2 Project with associated support projects	$11M	01 2020	12 2021
Alternative 1: Status Quo	$0M		
Alternative 2: Build new 115kV Transmission Line			
Alternative 3: Close "Star" Points	$75M		
Alternative 4: Install Generation			

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, previous outage information.

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.]

2018 $1,100,000

2019 $3,000

2020 $2,300,000

2021 $28,000,000

2022 $10,600,000 (Expected Spend)

2023 $1,950,000 (Forecast)

2023 – Closeout

O&M will be comparible to 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 in the Othello area.

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.

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).]

Design work was begun in 2020, construction will be completed by 2022 and closout may continue into 2023. Transfers to plant will occur when the new station is commissioned and energized.

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

This project will alleviate concerns regarding large customer outages and will provide the ability to maintain major substation equipment.

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 in the Othello area as well as to increase reliability by creating the switching station is the least cost option. 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]

Saddle Mountain 230/115kV Station (New) Integration Project Phase 1 was completed in 2020.

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.]

The Engineering Roundtable initially is designated as the Steering Committee for this project, with a more project-specific Steering Committee to be potentially identified at a later date.

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

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Saddle Mountain 230-115kV Station (New) Integration Project Phase 2 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 7D4B3DF5CBD8463...	Date:	Jun-28-2022 | 3:50 PM PDT
Print Name:	Glenn Madden		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		
Signature:	DocuSigned by: Josh DiLuciano A3C71874F6584DB...	Date:	Jul-05-2022 | 7:43 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

2022-2023 CAPITAL PROJECT

SAVINGS AND PRODUCTIVITY REPORTING FORM

1. **Business Case Name**: Saddle Mountain Integration Project Phase 2

2. **Business Case Owner**: Glenn Madden / Substation Engineering

3. **Director Responsible**: Josh DiLuciano

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):
<Answer and Please Show $$>

Quantified direct savings:

2022	2023	Lifetime

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 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).
<Answer and Please Show $$>

Risk of Customer Outages if this project is not completed:
Risk Cost = Prob of Failure * Prob (consequence) * Cost (consequence)

Risk Cost = 1 outage per year for 8 hours
Risk Cost = 1% Prob of Failure * both Othello and Lee & Reynolds stations out of service ($100,000 per hour due to major industrial customers feed from these stations) * 8 hours outage = $8,000 per outage

Assuming 1 outage per year.

Quantified indirect savings:

2022	2023	Lifetime
$8,000	$8,000	$8,000 Annually

6. No Direct or Indirect Savings – These are projects where there are NO identifiable direct or indirect cost savings for customers, as they are required by law, or simply after thorough review have no offsets. (For these projects, please think through any potential offsets, as having no offsets is a high hurdle). If the work is required by law or rule, please identify the law and describe and quantify any risk or penalty Avista's customers will endure due to non-compliance.

<Answer and Please Show $$>

The new Othello substation will provide large reliability gains for our industrial customers served by this substation. Currently, the old substation cannot be maintained without an outage to an industrial customer. Equipment failures have caused sudden outages at these locations in the past. The design of the new substation keeps our large customers in mind and allows for maintenance to be performed at the substation without a major outage. The benefits of this new substation are canceled by the increased cost of a larger substation to inspect, test and maintain. Plus with the added technology (relays and SCADA data) more data will be collected and more personnel will be needed to analyze and maintain the information collected.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

Director Name Josh DiLuciano

Director Signature

Date 10/29/2022

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 2023 there are twenty-three (23) structures that need to be replaced on six (6) 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 $3,500,000 is needed to complete the planned 2024-2028 projects . This Program will have a Service Code of Electric Direct and a Rate Jurisdiction of Allocated North.

The 2024-2028 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.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Ken Sweigart*	*Initial draft of original business case*	*5/02/2023*
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements Steve Carrozzo*	*5/5/2023*

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

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

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 2023 there are twenty-three (23) structures that need to be replaced on six (6) 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:

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 2023 there are twenty-three (23) structures that need to be replaced on six (6) 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.

- 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.

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)

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.

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.

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	2024	2025	2026	2027	2028
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

[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.

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	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no additional indirect offsets associated with projects between 2024-2028. 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.

Alternative 2:

Reinforce ($2,500 per pole when appliocable – 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 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.

[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.

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 twenty-three (23) structures that need to be replaced on six (6) 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).

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: [signature] Date: 5/9/2023
Print Name: KEN SWEIGART
Title: MANAGER, TLD
Role: Business Case Owner

Signature: [signature] Date: 5/9/2023
Print Name: Vern Malensky
Title: Director, Electrical Engineering
Role: Business Case Sponsor

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

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				

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.*

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

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.

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

2022-2023 CAPITAL PROJECT

SAVINGS AND PRODUCTIVITY REPORTING FORM

1. Business Case Name: Low Priority Ratings Mitigation

2. Business Case Owner: Ken Sweigart

3. Director Responsible: Josh DiLuciano

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):

Quantified direct savings:

2022	2023	Lifetime

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 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).

The business case includes indirect savings realized when replacing an existing conductor with another that has fewer losses due to a reduced impedance. Power loss savings were made using the average line loading that was provided by Avista's Transmission System Planning Department. A Mid-C Heavy Load price of energy was used to calculate the savings.

Quantified indirect savings:

2022	2023	Lifetime
$0	$0	

6. No Direct or Indirect Savings – These are projects where there are NO identifiable direct or indirect cost savings for customers, as they are required by law, or simply after thorough review have no offsets. (For these projects, please think through any potential offsets, as having no offsets is a high hurdle). If the work is required by law or rule, please identify the law and describe and quantify any risk or penalty Avista's customers will endure due to non-compliance.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

Director Name Josh DiLuciano

Director Signature ______________________________

Date 11/3/2022

Westside 230/115kV Station Rebuild

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	

Westside 230/115kV Station Rebuild

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.

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.

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.

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.

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

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 7D4B3DF5CBD8463	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

WSDOT Control Zone Mitigation

EXECUTIVE SUMMARY

Please provide a one-page summary of the business case and high-level summary of the projects or programs included. Please describe the need for the project (a synopsis of the problem, the current state, and recommended solution), alternatives considered, the cost of the recommended solution, applicable metrics, customer benefits, Avista benefits or offsets derived from the investment, and risks, to customer and Avista, if the business case is not funded.

This Mandatory and Compliance Business Case was developed to mitigate poles identified to be in the control zone within Washington State highway right-of-way. Twenty-nine of Avista's thirty-five State Route WSDOT Franchise Agreements have expired, and as part of renewing the agreements, the poles located within the control zone must be moved to meet the WSDOT Control Zone requirements. There are approximately 1,000 pole locations that must be mitigated as part of this plan. However, the movement of the identified poles will impact the alignment of neighboring poles and therefore additional poles will also need to be moved. This program will also address scenic highway compliance, crossing wire heights, and previously red-tagged poles left in place due to expired Franchise Agreements. In 2020 the WSDOT Control Zone Steering Committee worked to create a plan to mitigate this issue which led to this business case. The service code for this program is Electric Direct and the rate jurisdiction is in Washington. The funding is tracked under ER2627.

The Control Zone poles have been identified and documented in Avista's AFM system, but additional poles that are subject to control zone requirements are being identified by the drafting department. Drafting has also identified clearance issues that were not part of the original survey. This information allows designs to be completed based on the Steering Committee's approved ranking methodology. Solutions to this issue include moving poles to the back of the right-of-way, to private easements, or overhead to underground conversions. The projects are ranked by the Risk Reduction Credit/Alternative Estimate Average Ratio assigned to each project to mitigate higher-risk projects first. However, projects can be moved up on the schedule based on company business needs. The estimated cost of the solution is based on an average of the three proposed solutions for each project. The 5-year average Capital Planning Group approved budget per year is currently $1M. At that funding level, this program will be completed in 2033 at the earliest. The recommended solution: If $1.7M is approved as recommended the program will then be completed in 2032. This program has an overall estimated $19.4M cost to complete.

The program is designed to meet the WSDOT Clear Zone requirements and allow Avista to obtain renewed franchise agreements that allow Avista to maintain its facilities in a prompt manner. Our customers will benefit by moving poles considered to be elevated risk for hitting if a vehicle leaves the traveled path and reduces unplanned outages from identified failed assets. The risks of not approving this business case means:

- Avista facilities will be maintained in a run-to-failure mode as identified rejected poles are not replaced promptly
- Wildland-urban interface (WUI) required retrofitting may not take place.
- Potential car-hit-poles are left in place.

Finally, RCW Title 47.44.060 Penalties describes the WSDOT out of compliance Franchise risk: Without having obtained and kept the franchise in full force and effect at all times is guilty of a misdemeanor. Each day of violation is a separate and distinct offense. A civil penalty of $100 per calendar day of violation may be assessed until such time that the subject facility is removed. This program also helps ensure that Avista's poles are inspected and maintained within its current twenty-year cycle.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Mark Gabert*	*Initial draft of original business case*	*7/10/2020*
2.0	*Mark Gabert*	*Final Draft of original business case*	*7/31/2020*
3.0	*Mark Gabert*	*Business Case Refresh*	*7/28/2022*
4.0	*Mark Gabert*	*Business Case Refresh*	*6/23/2023*
BCRT	*BCRT Team Member – Katie Snyder*	*Has been reviewed by BCRT and meets necessary requirements*	*10/06/2023*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$1,750,000**	**$1,750,000**
2025	**$1,750,000**	**$1,750,000**
2026	**$1,750,000**	**$1,750,000**
2027	**$1,750,000**	**$1,750,000**
2028	**$1,750,000**	**$1,750,000**

Project Life Span	11 Years
Requesting Organization/Department	M51/ Asset Maintenance
Business Case Owner | Sponsor	Mark Gabert I Heather Webster I David Howell
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 current problem is that twenty-nine of Avista's thirty-five WSDOT Franchise Agreements have expired, and as part of renewing the Agreements, the poles located within the control zone must be moved or otherwise mitigated to meet the WSDOT Control Zone requirements. This program also mitigates poles that have failed a pole inspection, have roadway crossing clearance violations, and have overhead facilities that may impact the driver's scenic benefit experiences. The state of Washington Strategic Highway Safety Plan (SHSP) establishes strategies to reduce traffic fatalities and serious injuries along state highways and identifies utility objects, specifically utility poles, as significant roadside hazards.

Avista will be granted a new Franchise Agreement when we submit our Utility Object Relocation Record (UORR) plan for mitigating the control zone poles with our franchise application. If approved, the franchise is granted on the premise that we will complete the mitigation within the specified timeframe according to our UORR. There are approximately 1,093 poles that need to be moved as part of this plan, but as the identified poles are moved, this impacts neighboring poles due to the necessary reconfiguration of the line. WSDOT will not issue permits for any routine asset replacement work until Avista addresses the out-of-compliance poles. This means we currently operate our facilities in emergency restoration situations only.

The overall benefit to the customer is safer and more scenic highways, and increased reliability since we will be able to work on our facilities in a timely manner.

1.2 Discuss the major drivers of the business case.

This is a Mandatory and Compliance-based business driver. Avista has existing overhead facilities within expired WSDOT franchise agreement right of ways (ROWs). Due to the expired franchise agreements, our overhead facilities can only be maintained in emergency situations and proactive maintenance work is not allowed. Any other work requires poles located in the control zone to be moved. By renewing our WSDOT Franchises, Avista will regain the ability to maintain its assets promptly ensuring an elevated level of customer service and a reduction in potential outages caused by pole or equipment failures. Also, moving out of compliance control zone poles improves safety for Avista customers and the general public by relocating elevated risk control zone poles that if left in place would have an increased likelihood of a car hit pole accident. Additionally, Avista also avoids costly fines for noncompliance with current provisions of the governing RCW. Lastly, moving these facilities significantly reduces legal liability and financial exposure related to a car hit pole accident.

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 needed now because:

- Leaving known poles within the control zone will cause non-compliance with WSDOT franchise requirements, allowing rejected poles to continue to be in service.
- Not replacing other overhead assets that have reached the end of life significantly increases our risk and exposure to unexpected litigation, asset failures, and customer outages.
- Other programmatic like WPM, Grid Hardening, and Grid Modification work is delayed until the mitigation work is completed and a new franchise agreement is granted.

Additional risks if not approved include:

- Increased O&M expenses due to unplanned replacements
- Potential fire risk and associated costs of response
- Decreased reliability
- Increased safety hazards to the public and employees
- Civil fines by the State for noncompliance with RCW requirements

- Increased potential for legal liability and significant financial settlements related to car hit pole incidents
- Avista's overhead assets on WDSOT ROWs are not currently being maintained on a twenty-year cycle which also increases the risk of unsafe facilities. We have communicated with AEGIS, our primary excess liability insurance company, our commitment to meeting the current cycle.

Without having obtained and kept the Franchise in full force and effect at all times, the Franchisee is guilty of a misdemeanor. Each day of violation is a separate and distinct offense. Avista may also be liable for a Civil Penalty of $100 per calendar day the permit is required, or the facility must be removed.

There are currently twenty-nine expired distribution franchise agreements. The calculation is 365 days/year * $100/day=$36,500/year/franchise agreement. The quantified indirect savings for 2024 is $1,058,500 and the lifetime indirect savings is $5,656,750. This is based on mitigating approximately three franchise agreements per year.

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 the strategic goals of Avista because as we renew the Franchise Agreements, we will be able to responsibly manage our out of-compliance facilities into the 20-year maintenance cycle. This improves the safety and reliability of our facilities which increases our trustworthiness to our customers and the public. increasing the reliability of our system increases the quality of the energy we deliver.

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]

Currently Avista's assets located on WSDOT ROW are being maintained beyond the recommended twenty-year cycle. The twenty-year cycle is based on the 2017 Wood Pole Management Program Review and Recommendations, and that is the timeframe to which Avista has committed to our insurance carrier AEGIS. Since our WSDOT Franchise Agreements have expired, we cannot currently meet this twenty-year maintenance commitment without complying with the WSDOT Control Zone requirements. The control zone requirements are documented in the WSDOT Utilities Manual. Utilities Manual M 22-87 Complete manual (wa.gov) .WSDOT also studied, analyzed, and documented the control zone issue in their Strategic Highway Safety Plan: Target Zero That plan's goal is to reduce deaths on State Routes to zero by 2030. Strategic Highway Safety Plan: Target Zero | WSDOT The poles in the control zone that must be moved are also documented in Avista's AFM system.

The work is also required to keep pace with the aging assets and associated expected failure rates. Figure 1 below shows the increased rate at which the poles are reaching the sixty-nine-year economic optimum for replacement. Again, this was studied, analyzed, and documented in the 2017 Wood Pole Management Program Review and Recommendations.

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

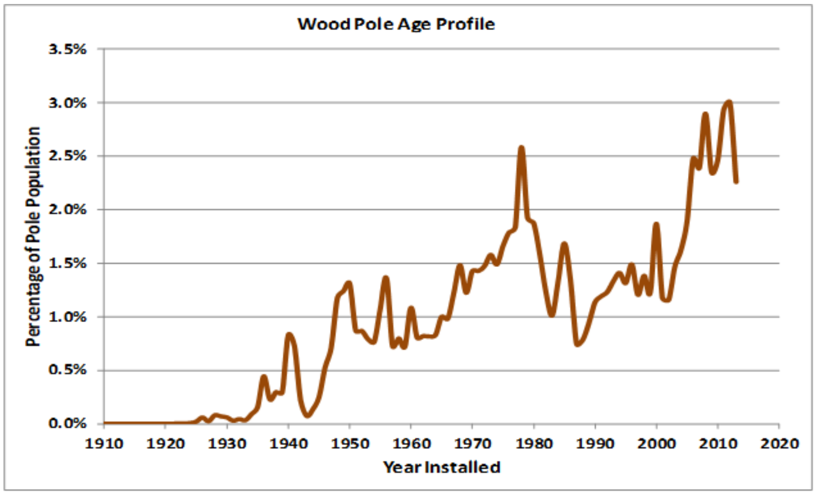


FIGURE 1. WOOD POLE AGE PROFILE

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 project is broken up into segments based on the highway name. These segments are no more than one mile of continuous pole line. We must submit the designs and mitigation plans to WSDOT, and then complete the work within a specific timeframe. As each of these segments are completed it enables Avista to successfully obtain a new franchise agreement from WSDOT. The new franchise agreement will allow Avista to secure the necessary permits to operate and maintain its facilities in a timely manner. Over time, OMT data should reflect reduced unplanned outages and the time crews spend on unplanned maintenance. In addition, the distribution Feeder Status Report should show an improvement in overall feeder health. This is the best solution because we currently are only allowed to work on WSDOT Rights-Of-Way during emergency situations only.

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 is a mandatory and compliance-based business case which is driven by the need to update our franchise agreements. As part of the renewal process, we must move our facilities to meet the control zone requirements documented in the WSDOT Utilities Manual. Utilities Manual M 22-87 Complete manual (wa.gov)

WSDOT also studied, analyzed, and documented the control zone issue in their Strategic Highway Safety Plan: Target Zero. Strategic Highway Safety Plan: Target Zero | WSDOT .That plan's goal is to reduce deaths on State Routes to zero by 2030. Our customers and the

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

public will benefit when we make our facilities safer for drivers on WSDOT highways. This also reduces our risk to car hit poles and unplanned replacements.

When the work plan was built, the risks were identified to prioritize the work. The risks identified were Wildland Urban Interface Tier, existing red tagged poles, and the control zone category. Those risks were summed up for each segment identified for mitigation. The sum of the risk reduction credits divided by the alternative estimate average gives you the risk reduction credit /Alternative Estimate Average Ratio. In summation the higher the ratio the higher the risk.

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	Labor	$	$	$	$	$

This is a mandatory business case, so the work is required by law.

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	Civil Penalties	$1,058,000	$949,000	$839,500	$730,000	$511,000

RCW Title 47 Public Highways and Transportation. Section 47.060 Penalties

Without having obtained and kept the Franchise in full force and effect at all times, the Franchisee is guilty of a misdemeanor. Each day of violation is a separate and distinct offense. Avista may also be liable for a Civil Penalty of $100 per calendar day the permit is required, or the facility must be removed.

There are currently twenty-nine expired distribution franchise agreements. The calculation is 365 days/year * $100/day=$36,500/year/franchise agreement. The quantified indirect savings for 2024 is $1,058,000 and the lifetime indirect savings is $5,656,750. This is based on mitigating approximately three franchise agreements per year.

[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.

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:

This alternative includes signing a master agreement with WSDOT to provide oversight on the progress of the Franchise Renewal. This would give Avista little control over the pace and the Capital funding requirements. This would also require dedicated resources to meet the timeline requirements of the State. This option would require getting all distribution, transmission, and gas facilities on WSDOT ROWs into compliance by 2030. The options the State recommends may not be the most affordable option for our rate payers and would impact Capital funding for other projects. The costs could easily double using this approach if we do not control the pace and design alternatives. This alternative with inflation has an estimated $36,000,000 price tag versus the estimated $19,000,000 utilizing the most practical option. Of course, the risk is to the rate payers in added costs and other company needs as Capital dollars are redirected to meet the Franchise Renewal timeline.

Alternative 2:

Avista currently utilizes Real-Estate resources that integrate this work into their normal work schedule. If we hire dedicated resources to this problem, it will vastly increase the pace of Franchise Renewal and help meet WSDOT's goal of zero deaths on State Routes by 2030. Those dedicated resources include up to two surveyors, two drafters, two Real-Estate Reps, and a permitter. It would also likely include adding one additional designer. Avista is currently on pace to be completed by 2034 which is beyond WSDOT's 2030 goal. This alternative will cost significantly more in the short term but gets Avista back on track with managing our system prudently like the Strategic Goals suggest. This option would cost an estimated $5M / year until year 2030.

Alternative 3:

Do nothing. This alternative is not a viable alternative but is included here to illustrate the risk and associated costs. While the Capital Costs are eliminated, the O&M expense to replace facilities in only emergency situations are elevated. Avista would also be exposed to the removal of facilities and civil penalty fines. RCW Title 47 Public Highways and Transportation.

RCW Title 47.44 Franchises on State Highways

Section 47.44.020 Grant of Franchises-Conditions-Hearings: This section covers granting franchises, hearings, subject to removal if highway is improved at expense of franchise holder, Avista is liable to any person injured by installation or continued occupancy. 50 years is max. Franchise allowed before renewal.

Section 47.44.060 Penalties

Without having obtained and kept the franchise in full force and effect at all times is guilty of a misdemeanor. Each day of violation is a separate and distinct offense. Avista is also liable for a civil penalty of $100 per calendar day the permit is required, or the facility must be removed. If WSDOT sends Avista a notice, there are 45 days to apply for a permit. The minimum cost exposure is 29 Franchise Agreements * $100/day = $2900/day * 365 days = $1,058,000/year. The actual costs are higher as there are not thirty-six distinct franchise agreements but multiple Franchise Agreements for each State Route.

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 every time Avista secures a new franchise agreement. Overall success will be realized when Avista secures new Franchise Agreements for all segments on the 35

State Routes that we have facilities on. Franchise Agreement metrics will be tracked on the monthly WSDOT one-pager. The metrics include annual budget progress, annual and lifetime work progress, and annual workplan updates.

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

The work began in 2021 and is estimated to be completed in 2034 at the current pace. The transfer to plant occurs 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.

The program's Steering Committee consists of David Howell, Heather Webster, Bob Brandkamp, Cesar Godinez, Ted Herman, Karen Phillips.

The Steering Committee meets every quarter for an update on progress and budgetary items. If it's determined that additional funds are necessary, the Program Manager sends the Business Case Sponsor a funds request. The year to date spend is also reviewed by the Director of Operations every three weeks at the ORT (Operations Round Table) meeting.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *<WSDOT Control Zone Mitigation 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:	Mark S. Gabert	Date:	10-6-23
Print Name:	Mark S. Gabert		
Title:	WPM/WSDOT PM		
Role:	Business Case Owner		

Signature:	David Howell	Date:	11/02/23
Print Name:	David Howell		
Title:	Operations Director		
Role:	Business Case Sponsor		

Signature:		Date:	02.Nov.2023
Print Name:	Heather Webster		
Title:	Manager of Asset Maintenance		
Role:	Steering/Advisory Committee Review		

Capital Equipment Program (ER7005/7006)

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.

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 ($)	PLANNED TRANSFER TO PLANT ($)
2024	$2,500,000.00	
2025	$2,500,000.00	
2026	$2,500,000.00	
2027	$2,500,000.00	
2028	$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

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.

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	01/2024	*NA*
[Alternative #1] (Fully fund)	$2.5 M	01/2024	*NA*
[Alternative #2] (Partially fund based on priority)	varies	01/2024	12/2024
[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.

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	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

*** Not Apliccable to this Busines Case.

2.4 Summarize in the table, and describe below the INDIRECT offsets4 (Capital and O&M) that result by undertaking this investment.

Renting all equipment

Offsets	Offset Description	2024	2025	2026	2027	2028
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.

[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.

Repair all equipment

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	Continually Repair all Equipment	($1800,000)	$	$	$	$
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.

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 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.

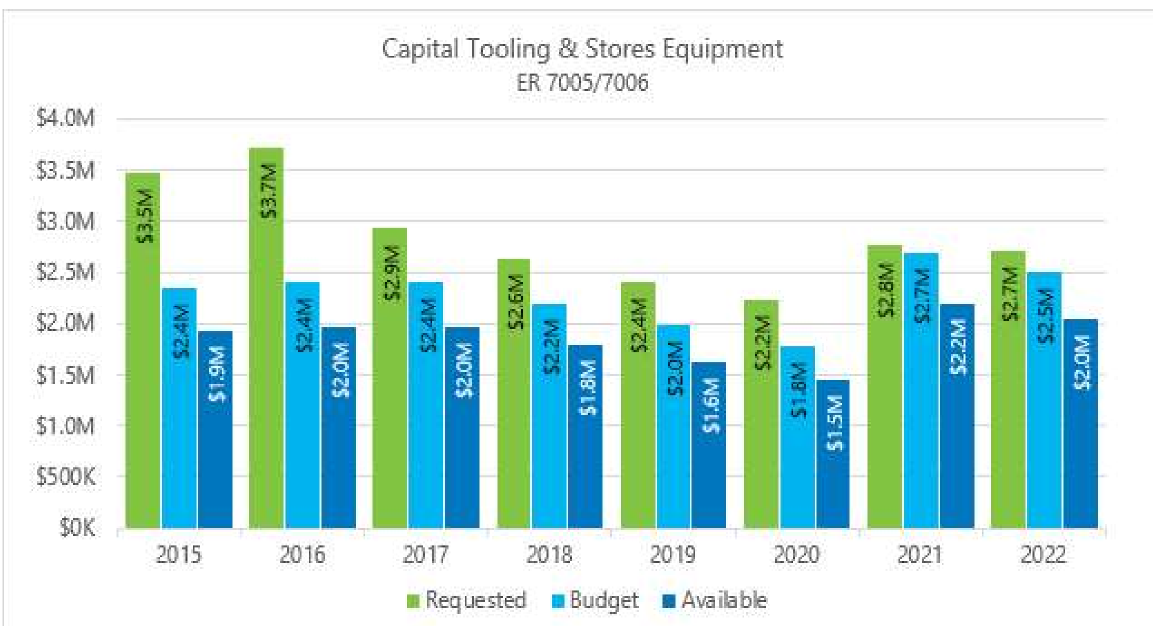


Figure 1

Capital Equipment Program (ER7005/7006)

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.

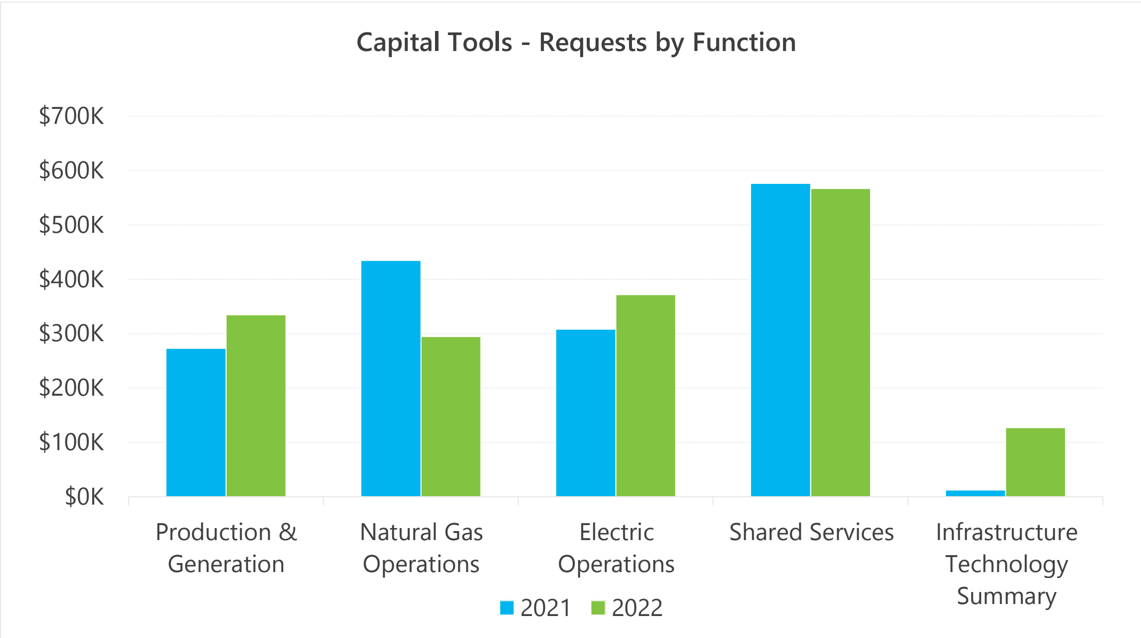


Figure 2

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).

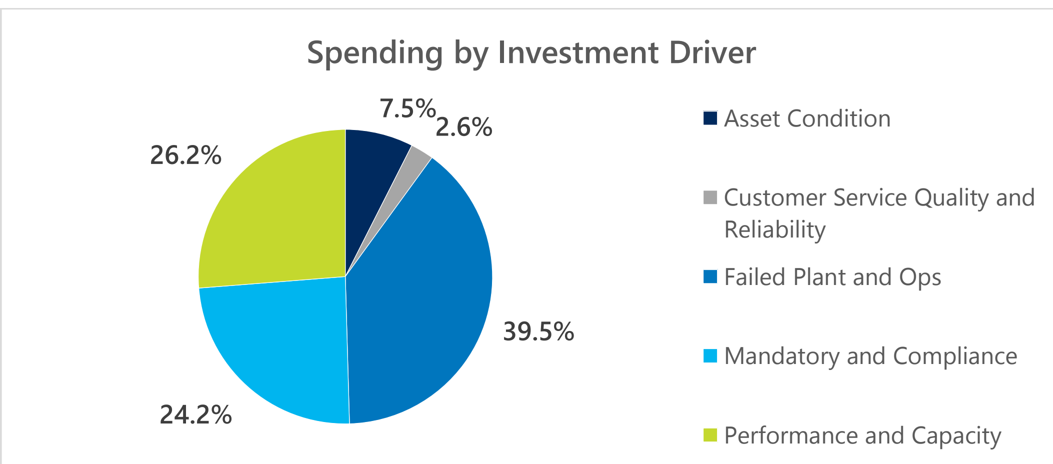


Figure 3

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.

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

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: 72D171DBE3F04F8...	Date: May-05-2023 | 12:43 PM PDT
Print Name:	Cody Krogh	
Title:	Manager Supply Chain	
Role:	Business Case Owner	

Signature:	DocuSigned by: Kelly Magalsky E7A0F731C49442B...	Date: May-07-2023 | 7:58 PM PDT
Print Name:	Kelly Magalsky	
Title:	Director Shared Services	
Role:	Business Case Sponsor	

Signature:	DocuSigned by: 9C296E0734FC4DC...	Date: May-05-2023 | 12:46 PM PDT
Print Name:	Christine Tasche	
Title:	BCRT Member	
Role:	Steering/Advisory Committee Review	

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*	*05/08/2023*
BCRT	*BCRT Team Member – Katie Snyder*	*Has been reviewed by BCRT and meets necessary requirements*	*05/09/2023*

GENERAL INFORMATION

	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$1,145,000	$1,145,000
2025	$1,000,000	$0
2026	$927,000	$1,467,621
2027	$845,000	$1,303,131
2028	$957,000	$957,000

Project Life Span	*1 year, 5 years, 10 years, etc.*
Requesting Organization/Department	Asset Maintenance
Business Case Owner | Sponsor	Robb Raymond | David Howell
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 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

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

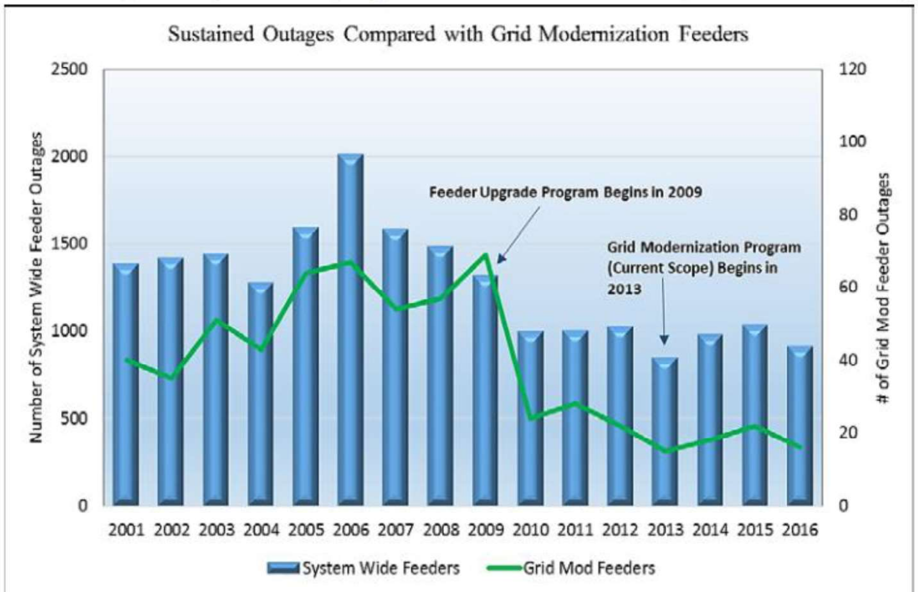
Improvements to Avista's electric distribution system through the Grid Modernization program are an example of proactive efforts that focus on the customer's best interests serving them now by improving reliability as well as preparing for the future addressing capacity. Avista also must be responsible 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.

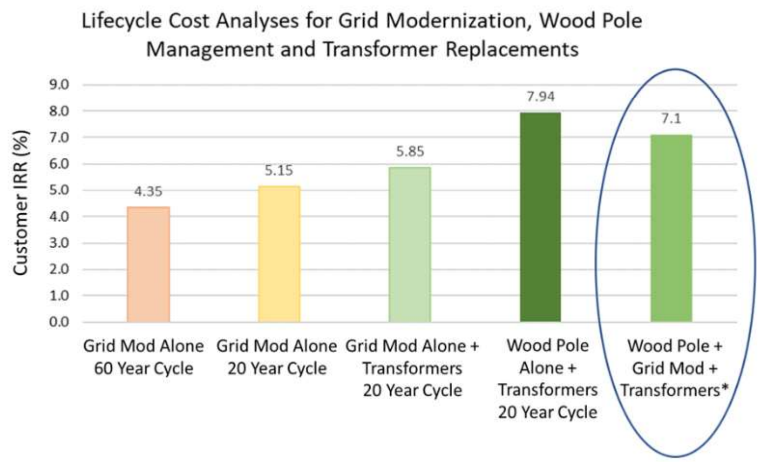
[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.



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).*

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.

Distribution Grid Modernization

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.

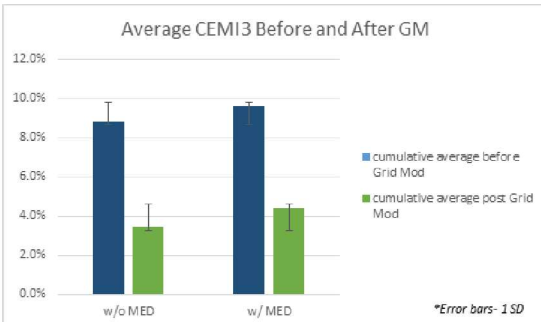


Figure 1.2A: Average CEMI3 on feeders that have been fully addressed by GMP. This includes all the feeders completed through the end of 2018.

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.

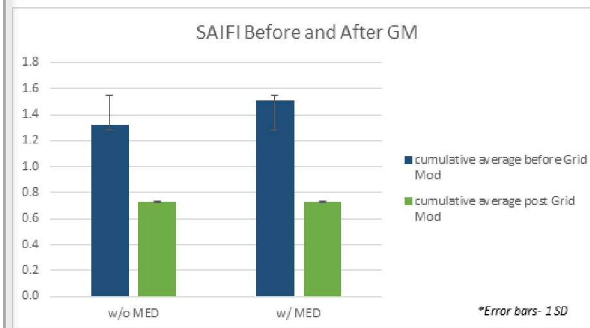


Figure 1.2B: SAIFI before and after Grid Modernization on feeders completed through the end of 2018.

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.

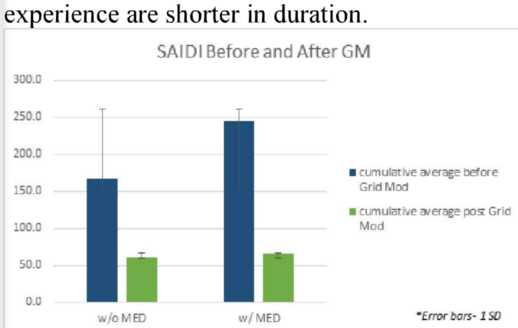


Figure 1.2C: SAIDI before and after GMP for feeders completely addressed by the end of 2018

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.

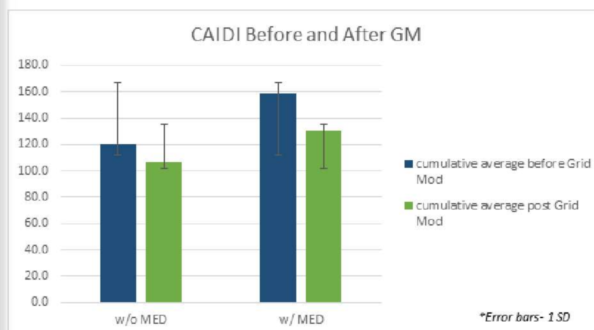


Figure 1.2D: CAIDI before and after being addressed by the Grid Modernization Program.

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
- 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	2024	2025	2026	2027	2028
Capital	n/a	n/a	n/a	n/a	n/a	n/a
O&M	Reduction in Service Calls	$0	$165,900	$267,700	$327,300	$364,600

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"*

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	2024	2025	2026	2027	2028
Capital	Wood Pole Management Deferral	$483,800	$209,800	$227,500	$204,500	$124,500
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. Reconduct or 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
M15 514 Grid Mod	ID	0.0	245.6	245.6	10%	$105	$2,579
SIP12F4 Grid Mod	WA	10.5	272.8	283.3	20%	$105	$5,949
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	$10,114

[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*

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	kWh energy savings[1,2,3]	$0	$8,500	$16,100	$21,400	$26,300
O&M	None identified	$0	$0	$0	$0	$0

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
M15 514 Grid Mod	2.5
SIP12F4 Grid Mod	7.6
ORO1282 Grid Mod	7.3
ROS12F4 Grid Mod	6.1
SIP12F4 Grid ModPH2	2.6
	26.1

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).

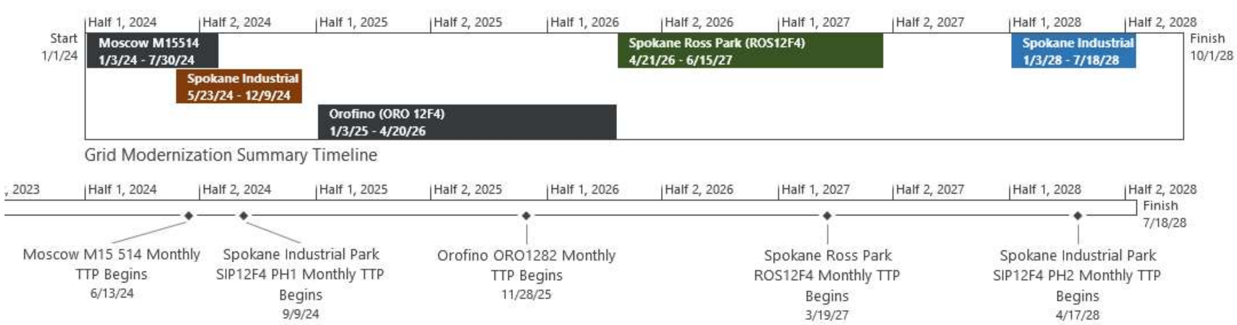
Measuring these goals is defined through the following key attributes organized into three categories.

- 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).

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 2024 through 2028 plan addresses ~26 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.



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.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Distribution Grid Modernization 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.

DocuSigned by:

Signature: Robb Raymond Date: May-10-2023 | 3:27 PM PDT

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Print Name: *Robb Raymond*

Title: *Grid Modernization Project Manager*

Role: Business Case Owner

DocuSigned by:

Signature: David Howell Date: May-10-2023 | 3:49 PM PDT

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Print Name: *David Howell*

Title: *Director of Operations*

Role: Business Case Sponsor

Signature: Date:

Print Name:

Title:

Role: Steering/Advisory Committee Review

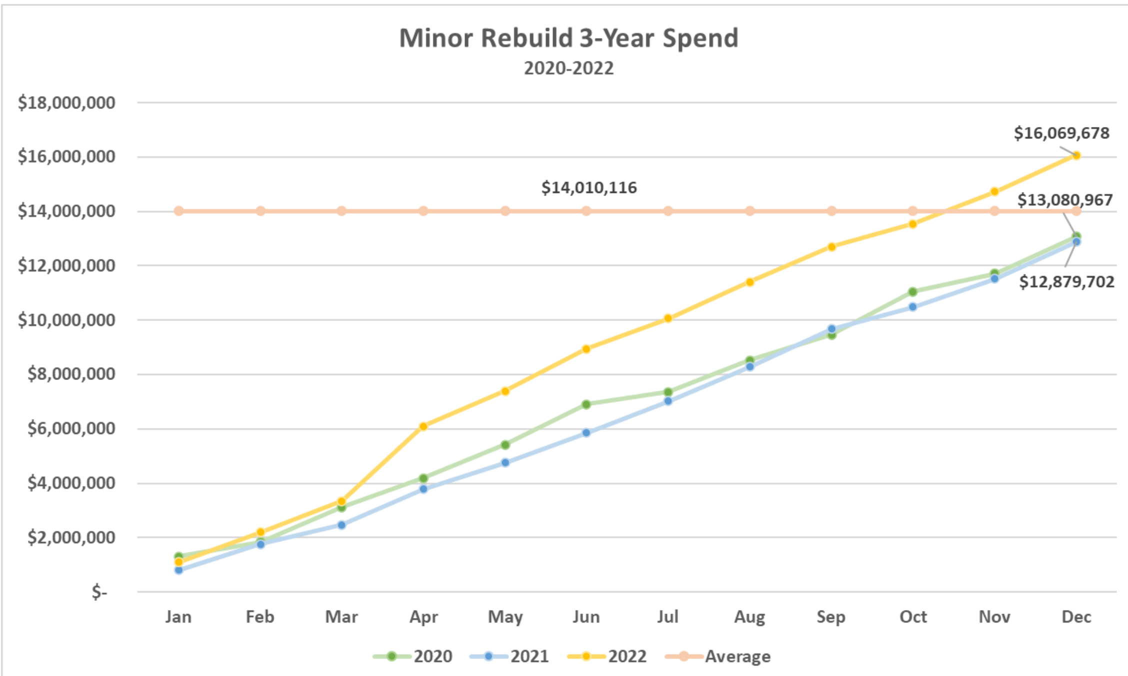
[i] Refer to page 64 of Avista Utilities Electric Distribution Infrastructure Plan

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 business 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 this work demand to continue for the next 5 years. Minor Rebuild spends approximately $1.1m per month; as of March 2023 the spend on Minor Rebuild related work is $3,508,313 and we anticipate the spend for this year to exceed $14m.



VERSION HISTORY

Version	Author	Description	Date
1.0	*Katie Snyder*	*Business Case Narrative Update*	*03/23/2023*
BCRT	*BCRT Team Member – Katie Snyder*	*Has been reviewed by BCRT and meets necessary requirements*	*04/24/2023*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$14,000,000**	**$14,000,000**
2025	**$14,420,000**	**$14,420,000**
2026	**$14,850,000**	**$14,850,000**
2027	**$15,300,000**	**$15,300,000**
2028	**$15,800,000**	**$15,800,000**

Project Life Span	***Ongoing***
Requesting Organization/Department	Electric Operations
Business Case Owner | Sponsor	Katie Snyder | David Howell
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

Distribution Minor Rebuild

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*.

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.

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.

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.

In 2022, 2,339 work orders were created with the average cost equaling $4,235, 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 60 (2.5%) of the 2,339 work orders created in 2022 were over $25,000. Those 60 work orders averaged $50,188.

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*

[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.

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 related to this business case.

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	2024	2025	2026	2027	2028
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.

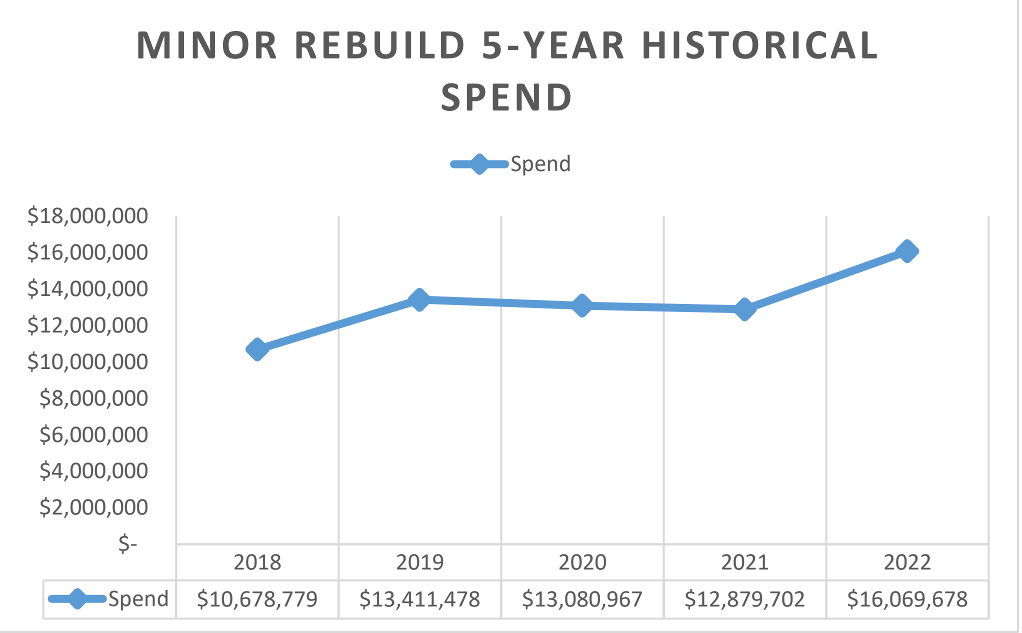
[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[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.

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.

Figure 4 shows the spend over the last five years. Since 2018 the spend under Minor Rebuild has had an average increase of 8% per year and we expect that trajectory to continue.



	2018	2019	2020	2021	2022
Spend	$10,678,779	$13,411,478	$13,080,967	$12,879,702	$16,069,678

Figure 4: *Minor Rebuild 5-Year Historical Spend*

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 2022 the Minor Rebuild spend was $16.1m. 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 2022 for the six general categories above.

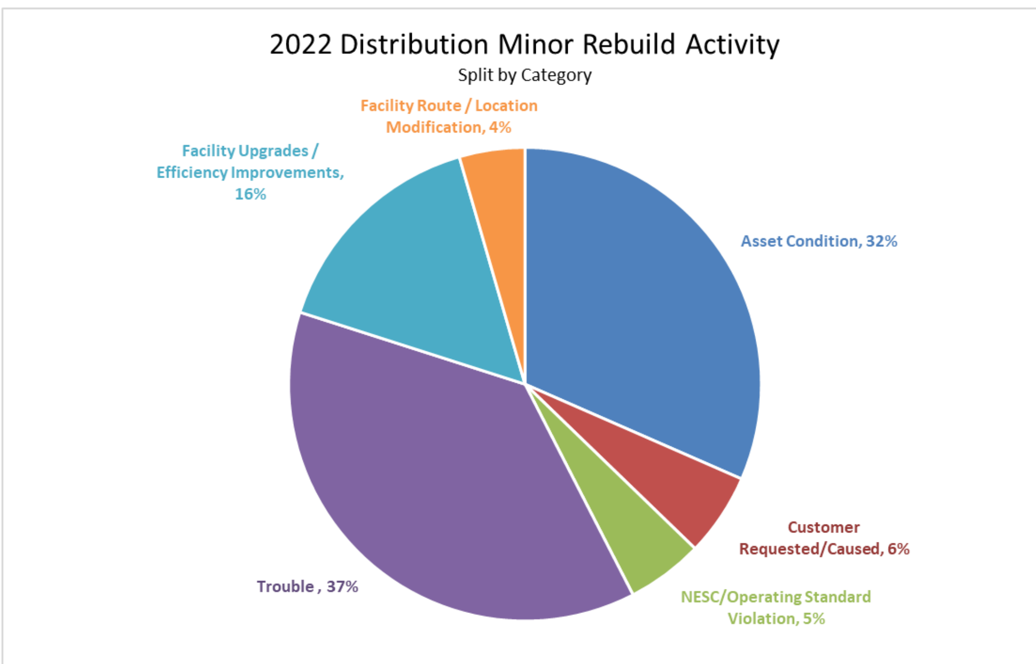


Figure 1: 2022 Activity

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 Distribution Minor Rebuild 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:	Katie Snyder	Date:	04/24/2023
Print Name:	Katie Snyder		
Title:	Asset Maint. Business Analyst		
Role:	Business Case Owner		

Signature:	David Howell	Date:	04/24/2023
Print Name:	David Howell		
Title:	Director of Operations		
Role:	Business Case Sponsor		

Distribution Minor Rebuild

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

Distribution System Reinforcements

EXECUTIVE SUMMARY

Please provide a one page summary of the business case and high-level summary of the projects or programs included. Please describe the need for the project (a synopsis of the problem, the current state, and recommended solution), alternatives considered, the cost of the recommended solution, applicable metrics, customer benefits, Avista benefits or offsets derived from the investment, and risks, to customer and Avista, if the business case is not funded.

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 $7.5 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 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.

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*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements* SMC	4/28/23

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	***7,000,000***	***7,000,000***
2025	***6,500,000***	***6,500,000***
2026	***6,500,000***	***6,500,000***
2027	***6,500,000***	***6,500,000***
2028	***7,500,000***	***7,500,000***

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 and 2022 we experienced major weather events that exposed some system performance issues, some of these system performance issues resulted in Commission complaints from customers who experienced low service voltage. 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%.

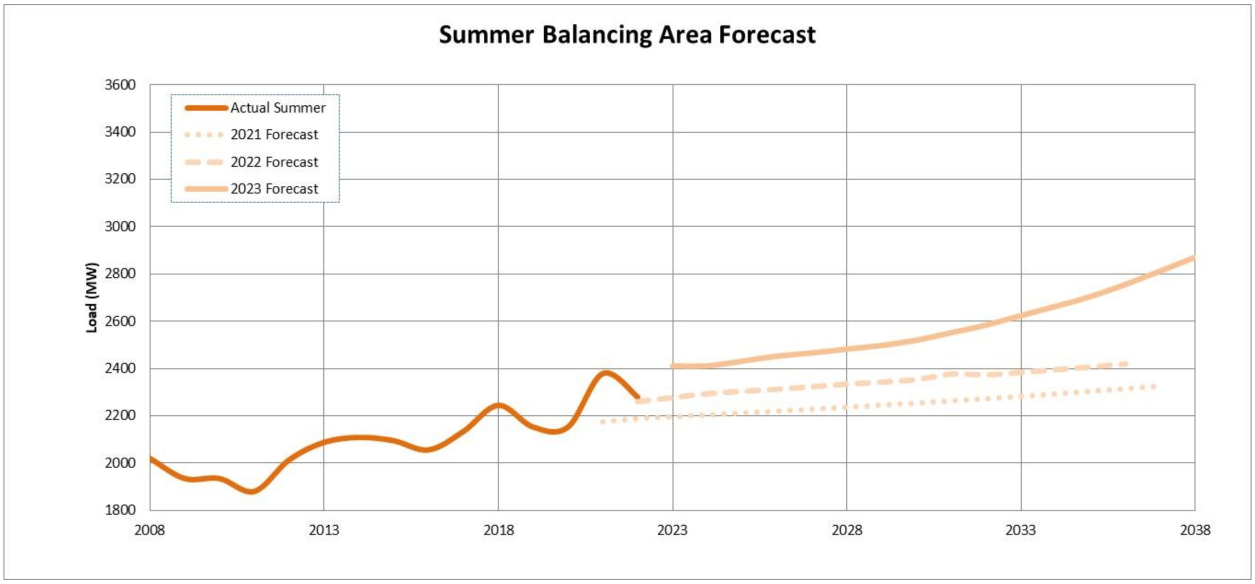


Figure 1: Summer Load Growth Forecast

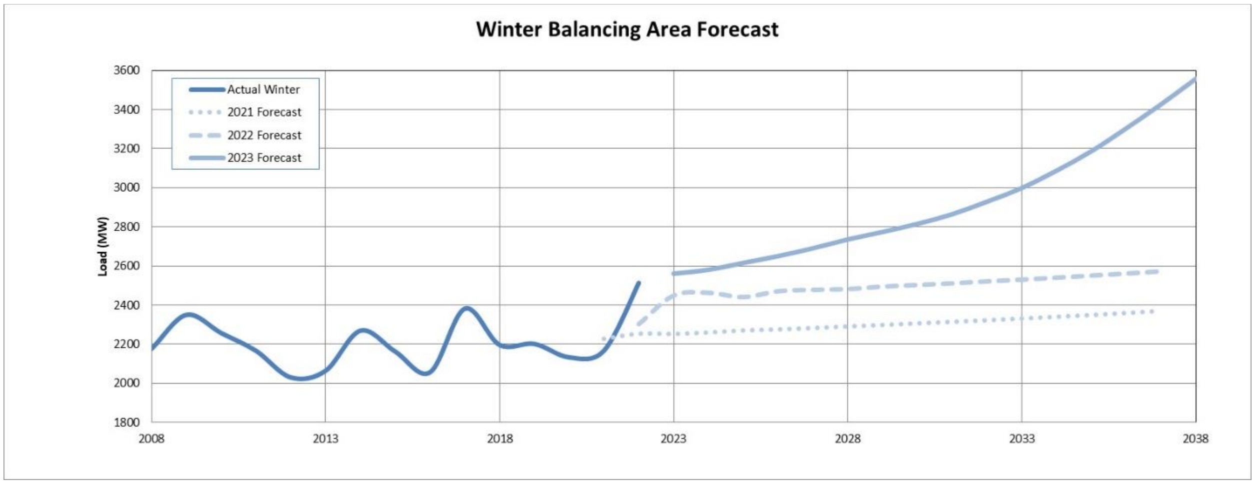


Figure 2: Winter Load Growth Forecast

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 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 "500 Amp FDR" – internal document that defines the performance criteria and limits for both urban FDR tie systems and rural pure radial circuits. 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.*
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.

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).

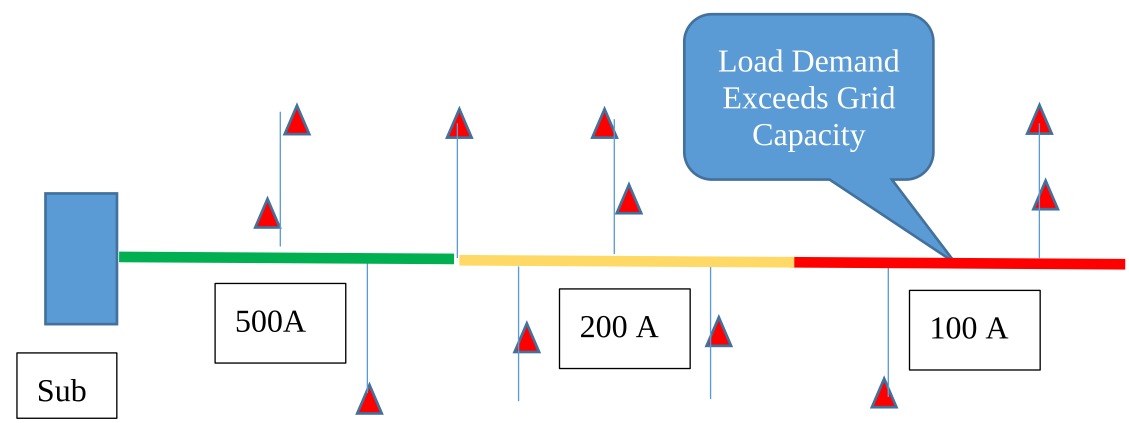


Illustration of Distribution Grid Capacity Constraint

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

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 and 2022 our electric distribution system experienced extreme weather events that stressed the system so much so that we struggled 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 *work in 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 we experienced a cold snap event that stressed our system such that we struggled to keep the lights on for some customers and others experienced service voltage 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.

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 issue. 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

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

derived through industry and regulatory policies including: Washington Administrative Code (WAC), 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 giving us tool to avoid these situations in the future.

2.3 Summarize in the table, and describe below the DIRECT offsets3 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 the yearly average WPM offset value, $504,913.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	*WPM Offset*	*$504,913*	*$504,913*	*$504,913*	*$504,913*	*$504,913*
O&M		$	$	$	$	$

2.4 Summarize in the table, and describe below the INDIRECT offsets4 (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	2024	2025	2026	2027	2028
Capital	*Substation Deferment*	*$28,683*	*$28,683*	*$28,683*	*$28,683*	*$28,683*

[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.

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 avoid upgrades until there is an actual observed violation might up 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 ($7.5 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.

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 $15 million each year for 2 years then back down to original request of $7.5 million a year for the next 3 years.*

Accelerate Funding in Distribution System Reinforcements

Increase the funding amount to double of the requested amount, i.e., increase the funding to $15 million per year for the next 2 years.

Increasing the funding to $15 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 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. 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 a system issue or forecasted issue being corrected. We keep 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.

System Planning is actively developing system performance criteria for the electric distribution system that we will use to further develop our metrics. As soon as these performance criteria are finalized, we will update this business case to incorporate the new metrics.

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:

Marc Lippincott, Caitlin Greeney, & Knute Rognaldson – Spokane and Deer Park

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

Dan Knutson – Othello, Davenport

Tyler Dornquast – Colville

Chris Dux – South Region (Pullman, Clarkston, Grangeville)

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

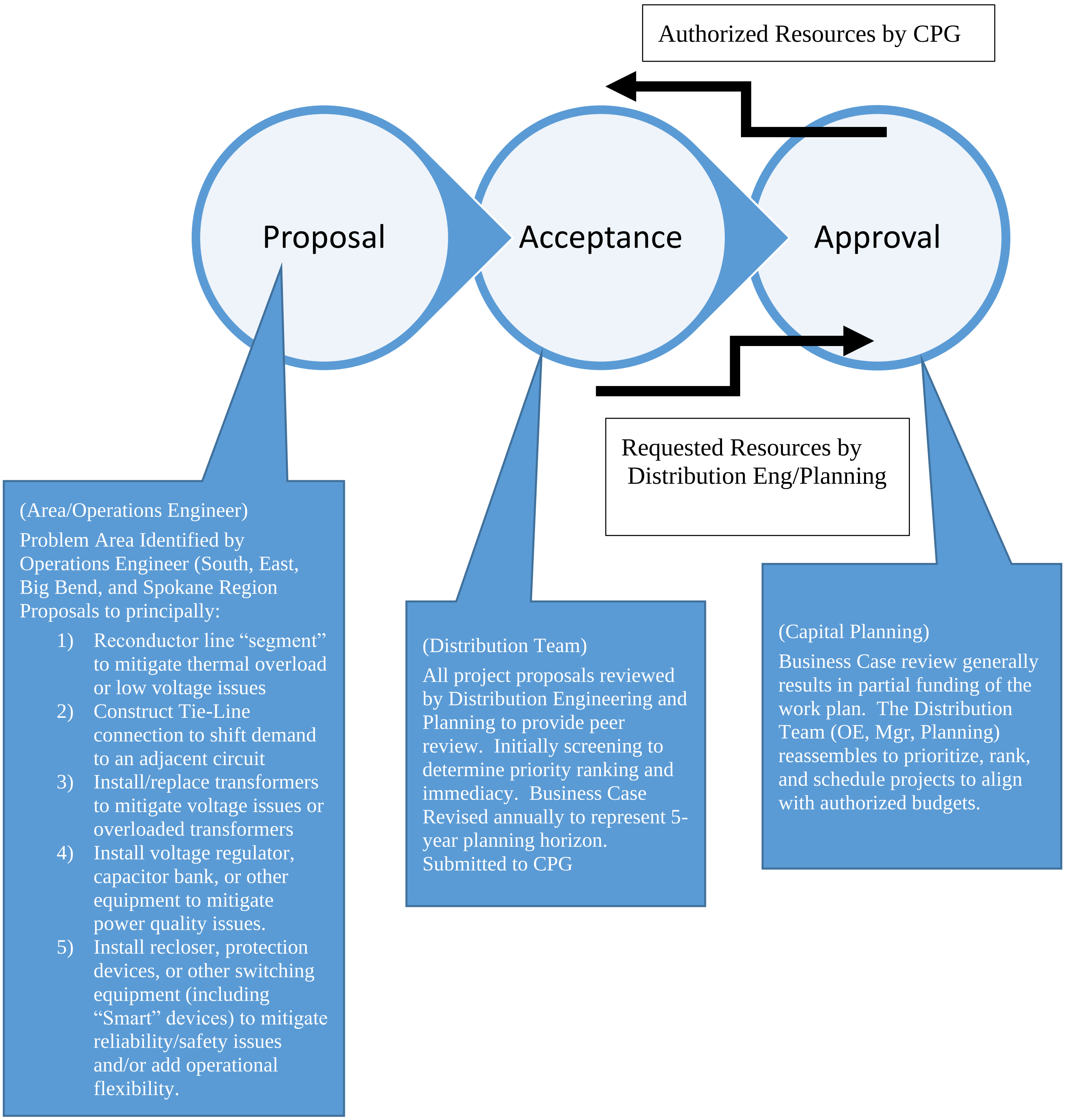
Cesar Godinez – Distribution Engineering Manager

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 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 of 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 on the next page.



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: [illegible] Date: 4/28/2023

Print Name: *Cesar Godinez*

Title: *Distribution Engineering Manager*

Role: Business Case Owner

Signature: Vern Malensky Date: 05.01.2023

Print Name: *Vern Malensky*

Title: *Director of Electrical Engineering*

Role: Business Case Sponsor

Signature: Date:

Print Name:

Title:

Role: Steering/Advisory Committee Review

Downtown Network – Asset Condition

EXECUTIVE SUMMARY

The Downtown Network Asset Condition budget is intended to enable the replacement of aging equipment inside Avista's Downtown Network service territory, located in Spokane, WA, between I-90 and the Spokane River, and between the Ash/Maple and Browne/Division corridors. This business case's requested budget is $2-4M annually throughout the next five years, based on a combination of historical spends and a projection of levelized replacement costs for the categorized fleets of assets that exist in the Downtown Network. The requested budget is a "middle of the road" option that needs to increase in out years as a bow wave of older (primarily) structural equipment comes due for replacement.

Examples of projects funded in this business case include replacement of failing manhole/vault roofs, replacing collapsed/leaking cable splices, and installing new transformers when conditions indicate imminent failure.

Savings generated by dollars spent in this business case result largely from the avoidance of emergency (catastrophic) failure responses, as well as reduced employee skill/training needs on obsolete classes of equipment. These savings are estimated at over $11M over a 40-year equipment life cycle (this value is based on historical rates of expenditure in the Failed Plant category).

Delays or cancellations of funding to this business case will result in increased threats to employee safety (arcflash incidents leading to severe burns and or death) and increased possibilities of catastrophic and potentially fatal public accidents, such as car/semi/bus traffic collapsing through a failed vault roof, or a manhole fire causing mass casualties during crowded Downtown events such as Bloomsday, Hoopfest, or the Lilac Parade. Put simply, projects funded by this business case are ethical obligations that Avista has to its stakeholders (ratepayers, shareholders, customers, employees, and the general public), and they align with Avista's mission statement in the various focus areas that reference these groups.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Brian Chain*	*Initial draft of original business case*	*3-14-23*
BCRT	*BCRT Team Member – Katie Snyder*	*Has been reviewed by BCRT and meets necessary requirements*	*04/26/2023*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$2M**	**$2M**
2025	**$2.4M**	**$2.4M**
2026	**$2.8M**	**$2.8M**
2027	**$3.4M**	**$3.4M**
2028	**$4M**	**$4M**

Project Life Span	***N/A – Program, not Project***
Requesting Organization/Department	C57
Business Case Owner | Sponsor	Sam Helms | David Howell
Sponsor Organization/Department	Electric 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?

The Downtown Network Asset Condition budget is intended to deal with proactive and reactive replacements of equipment due to age and condition. The problems that crop up if we fail to do so can be observed in recent year's Failed Plant Budget Item; they include closing streets due to structural failures, outages due to cable faults, and equipment out of service due to age-related problems. The budget covers both electrical and structural elements of the Downtown Network system.

1.2 Discuss the major drivers of the business case.

The major driver in this business case is Asset Condition. Our Downtown Network equipment fleets are aging; by managing the overall conditional age of each class of equipment, Avista can minimize system down time (outages) as well as public/employee safety hazards.

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.

Our transformer fleet is widely aged. We test for condition as part of a four-year inspection cycle and replace units as soon as they show signs of failure (usually due to dissolved gas analysis of the oil quality inside each unit). Without replacement, these transformers will fail in place. Generally, this means a catastrophic failure such as a ruptured tank, with the possibility of a large oil spill and the likelihood of a transformer vault fire, both of which have severe public safety ramifications.

Our cable fleet is the oldest electrical component on our system. We average several cable failures per year. We need to accelerate the replacement of the oldest style of cable, paper-insulated lead cable (PILC) or we will face even more failures in the years to come. Failures generally cause outages but can also cause manhole fires, as observed on Riverside in 2020.

Structurally, a significant portion of our transformer vaults are approaching 100 years old. An even more significant portion of our manholes are constructed of brick. Despite most structures being underneath downtown arterial streets, they are designed to accommodate horse and buggy loading profiles more than HS20 truck axles or transit authority busses. Structural failures are a significant public safety risk and generally shut down multiple lanes of arterial streets for months while fixes are retroactively implemented (e.g., Spokane Falls Boulevard in 2018, Washington in 2019, etc.).

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 invests in the heavily utilized downtown core of Spokane. It supports both the general public and a specialized business community that relies on extremely reliable power. It puts our customers first by ensuring that equipment failures do not negatively impact our reliability track record while also improving the lives of anybody who works or visits downtown Spokane.

This Business Case also supports Avista's employees who work near Downtown Network equipment. Safety is a key priority in secondary networks throughout the country; the combination of confined spaces and incredibly high fault duties requires that we keep up on equipment replacements to avoid employee accidents.

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 most recent update of the annual Downtown Network System Report is available at the Downtown Network SharePoint site. It covers in much more detail the age ranges of our assets and goes over particular failure threats.

Downtown Network - Home (corp.com)

The graphics and photos below give a good overview of the problems we are tackling in this case. In addition, a summarized analysis of expected levelized spending in this business case is included in Section 2.2 below.

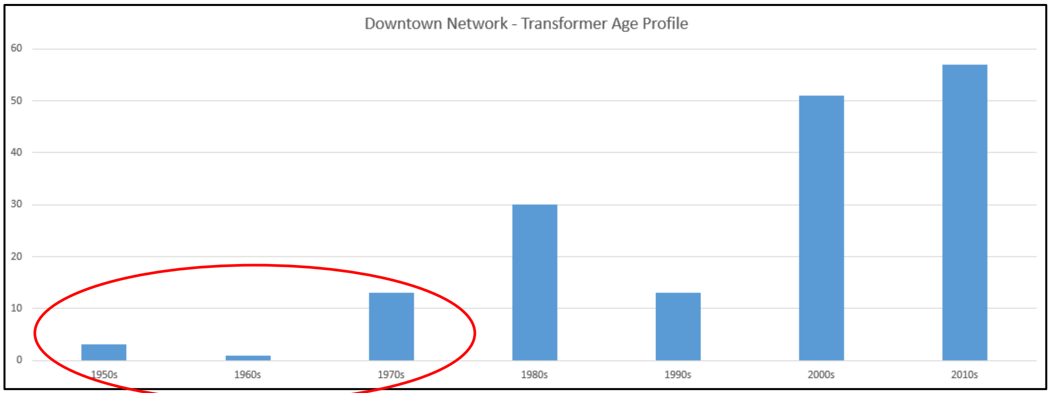


Figure 1: Downtown Network Transformer Age Profile

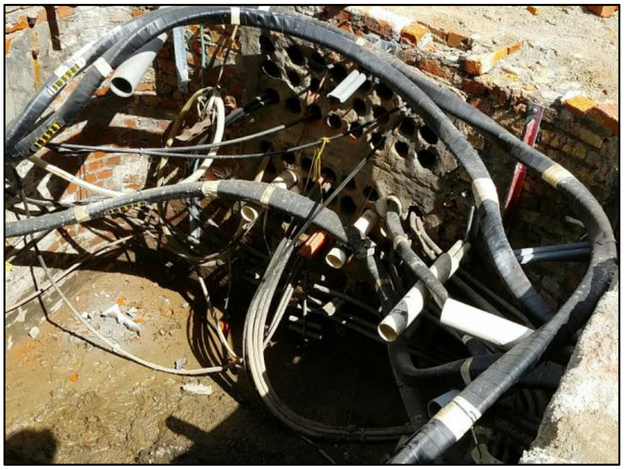


Figure 2: Brick handhole w/assortment of PILC cable / Failed insulation on grid bus (Hotel Ruby Service)

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

Downtown Network – Asset Condition

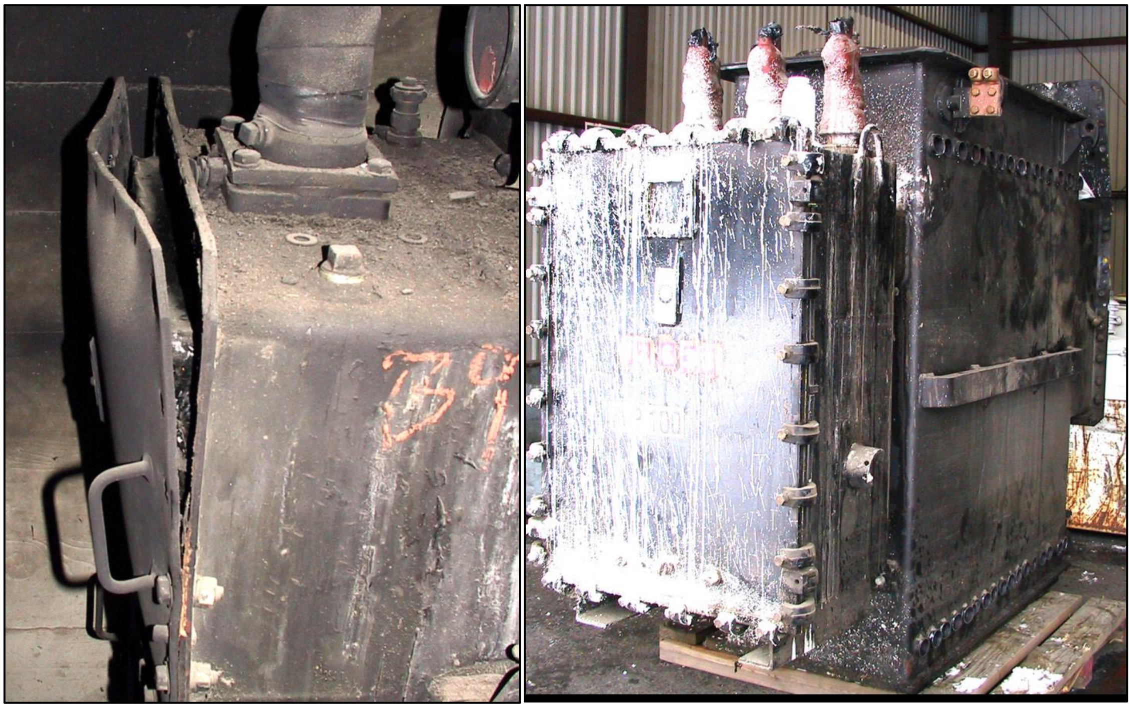
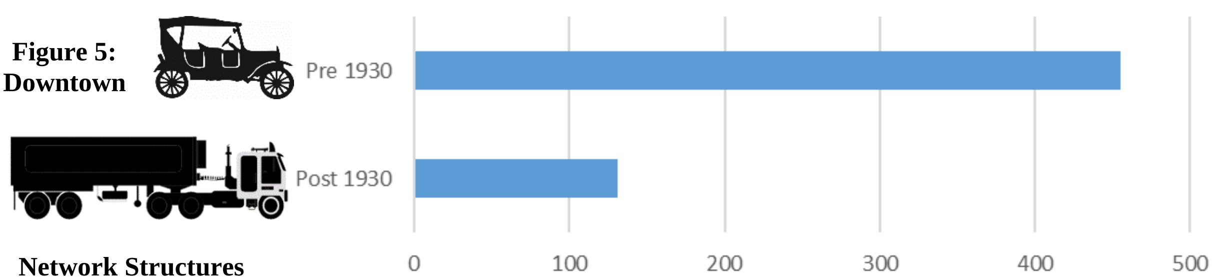


Figure 3: Faulted primary terminations on network transformer / Faulted network transformer

Figure 4: Faulted PILC cabling from peak summer 2018 loading period

Figure 5: Downtown



Network Structures (Age & Design Profile)

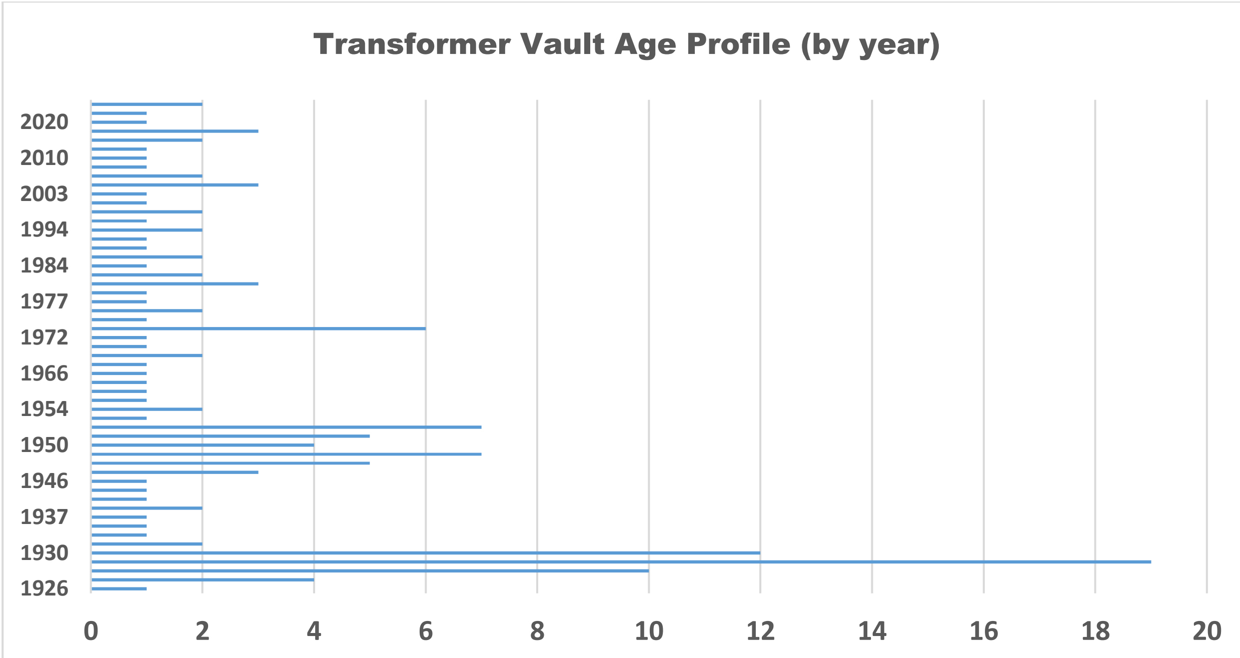


Figure 6: Transformer Vault Age Profile

Figure 7: Transformer vault concrete beam deteriorating from open grate

Figure 8: Rusted Trolley Rails in Manhole Roofs

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 to work to eliminate the worst known/presently-identified issues on the system, and steadily increase funding year-over-year to move toward systematic replacement of assets based on age and condition.

This solution stands in contrast to decades (pre-2010) of a strategy in the Downtown Network to only perform asset replacements as a method of "breakdown maintenance".

This approach of slow increased funding growth over the 5-year horizon allows time to onboard and qualify contractors in the extremely difficult downtown environment, build standards and inspection models to support these contractors and our internal crews, and finish the field assessments necessary to more fully document a complete Asset Management program for the Downtown Network equipment fleets.

In the meantime, by targeting the worst electrical and structural issues that are already known, we will improve relaibillity for our customers by removing failure threats that may put us into abnormal system operations. This will also remove safety hazards to both the public and our employees.

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]

Please also refer to the latest copy of the Downtown Network System Report, which is published on the Downtown Network SharePoint site (link above).

Here is what our electrical fleet downtown consists of and what was considered when preparing this business case:

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

Downtown Network – Asset Condition

- 184 network transformers and 184 network protectors
- A budget estimate to replace the entire fleet of transformers and protectors (without replacing associated structural elements) is $48M...
- Given an industry standard life assumption, a levelized (present value) annual investment for just transformers and protectors should be **$1.2M.**
- There is approximately 96,000 feet of primary cabling in the Downtown Network. Assuming standard industry life cycles, a levelized (present value) annual investment for triplex primary cable should be around **$600k.**
- There is approximately 125,000 feet of secondary cabling in the Downtown Network. The levelized (present value) annual investment for secondary cable should be around **$1.1M.**
- The Downtown service area is the oldest in the company and it is most obvious when looking at building services. Many buildings are refreshing switchgear, providing us the perfect opportunity to also refresh the often 80+ year old service cabling. Presently services are only replaced after catastrophic failures and during customer-requested upgrades (rare, but largely funded by the customer).
- The Downtown Network street light fleet consists of approximately 200 lights. A 2019 pole by pole survey marked 64 of these as “severely deteriorated” and 3 more as “unsafe”. Cabling and conduit between these lights is often re-purposed 4 kV PILC DC cable dating back a century (which is why many “underground-fed” lights are now connected with overhead duplex, on poles that are not rated for such a connection). We have done no proactive replacements of light strings for decades due to a lack of funding. The streetlights compare very poorly when viewed down the street from the City of Spokane’s ongoing streetlight refresh projects (something that the City has been very vocal about).
- Based on the estimates above, a total levelized annual investment of **$3.4M** would be sufficient to keep up with our aging Downtown electrical fleet.
- Realize that many decades passed Downtown with less investment than necessary, on a levelized basis, which has created a bow wave. This means that the levelized annual investments listed above are likely lower than what is actually needed. For example, the age profile shown below indicates that 16 transformers are presently past industry-standard end of life. The Transformer Replacement Program includes analysis that shows several others have dissolved gas analysis results indicating overheating and associated loss of life… in other words the problem is worse than simply 16 transformers.
- Present funding levels only support replacement of two transformers per year (outside of growth, and assuming Failed Plant across all asset classes does not negatively impact our limited Asset Condition budget). Further analysis (an adjusted age profile) would likely add to the

number of units past recommended end of life. Similar conditions can be observed for other asset classes.

- 73% of the ~600 manholes in the Downtown Network were constructed prior to 1916. An annual budget of **$700k** is enough to fund a levelized replacement program; however, the bow wave built up by over a century of underfunding replacements will take more support.
- Transformer vault structures in the Downtown Network have an average age of around 80 years. Levelized replacements could be funded with only **$500k** per year; however, the bow wave built up by more than a century of underfunding replacements will take more support.

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	Failed Plant – Capital Replacements	$250k	$250k	$250k	$250k	$250k
O&M	Failed Plant – Maintenance Responses	$50-100k	$50-100k	$50-100k	$50-100k	$50-100k

Asset Condition projects in the Downtown Network system generally deal with one of two categories – deteriorated structural issues in our handholes, manholes and transformer vaults, or predicted failures in our transformers, network protectors, and cable.

Adequate investment in the Asset Condition category will result in reduced investment in an adjacent category – Failed Plant. Downtown Network's Failed Plant is, by definition, unplanned failures, so predicting future years can be difficult. In 2022, for example, the Failed Plant category spent over $360k.

If Asset Condition spends were adequate for long enough, and dedicated to the correct "about to fail" assets (predictive replacements), immediately prior to failure, then theoretically Failed Plant spend could be reduced to zero dollars per year. See the Asset Condition Business Case documentation for further information on the different asset classes in the Downtown Network and our approach to achieving this target for each of these classes.

[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	2024	2025	2026	2027	2028
Capital	NA	$	$	$	$	$
O&M	Reduction in Training/Expertise	$33k	$33k	$33k	$33k	$33k

Replacement of obsolete equipment classes such as PILC (Paper Insulated Lead Cable) and live-front network protectors reduces the skillset that our cablemen must learn, and keep up to date through annual training. Downtown Networks are a rare system and much of the training available is on the East Coast (Con-Ed in New York, Eaton in South Carolina).

In addition to these quantifiable indirect offsets, there are some factors which are difficult to quantify but should not be ignored. Asset Condition business case work orders are also sometimes put forth in the name of public and/or employee safety. Such projects may avoid costly public or employee-driven lawsuits; however, the cost savings associated with avoiding these is difficult to quantify. For example, we may replace a manhole roof in order to, as previously noted, avoid spending unplanned Failed Plant dollars on it. However, at the same time, we are focusing on replacing a manhole whose roof failure could mean injury to members of the public using the road crossing over the top of the manhole, or employees working inside the manhole, or fire damage due to chunks of concrete spalling off and causing an electrical fault.

All such examples are also in consideration as we prioritize spend on Asset Condition projects, but they do not necessarily carry easily quantifiable savings. Put more simply, these kinds of capital asset replacements are done in order to protect the public (since the Company operates in public rights-of-way) and to hold to the obligation to keep our employees safe as they perform work.

[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.

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: Reactive Replacements

The existing option for much of our ongoing work is essentially "breakdown replacements" using only Avista crews. Customer growth and road move related work must be prioritized higher than asset condition projects. City projects and customer growth are currently higher than they have been in the past 15 years and are expected to continue for the next five years. Therefore this option is expected to continue to build a "bow wave" of failed equipment and facilities. This will result in customer outages and increased dangers (fire, explosion, manhole collapses, electrical contact incidents, etc.) to both our employees and the general public.

Cost: $1M (for 2024, increasing "failed plant" will cause further increase over budget period)

Alternative 2: Eliminate Worst Known Electrical and Structural Issues

This option mitigates the worst known existing equipment and facility threats (while ignoring anything that has not recently been a visible failure threat). Avista Downtown Network crews must focus on enabling and inspecting limited contract crews and replacing failed or near-failed equipment such as transformers, protectors, grounds, cable, structures and duct banks. The prioritization of replacements will be considered together based on estimated reduction of risk of catastrophic failure…but without being compared against the entire fleet. While this strategy has mititaged some failures in recent years, the amount of spend in the Failed Plant category proves that many unplanned failures still occur. How impactful these failures are to our customers, our employees and the public are depends on when and where they occur; for the most part we have been lucky to avoid serious injuries or incidents (fire, explosion, manhole collapses, electrical contact incidents etc.) but that trend may not continue.

Cost: $2M (for 2024, increasing "failed plant" will cause further increase over budget period)

Alternative 3: Create/Follow Programmatic Replacement Programs

The proposed programs would incorporate all known data (along with any data that must be sought out in the field) and recommend replacements to conquer the existing bow wave of electrical equipment and structures that has built up due to decades of underfunding. A consultant proposal to do this work for Avista is already in hand and ready to approve but does require O&M funding commitment from both Engineering and Operations.

This option incorporates various sources of recent surveys and inspections, in order to create programmatic replacement programs for all classes of equipment and structures. This will involve creating adjusted age profiles that direct the replacement of the right assets at the right time. It will lead to better use of capital dollars due to the identification of synergies between different classes of equipment. It will also reduce Avista liability in the busy and high risk service territory Downtown, while building better relationships with both our customers and the City of Spokane.

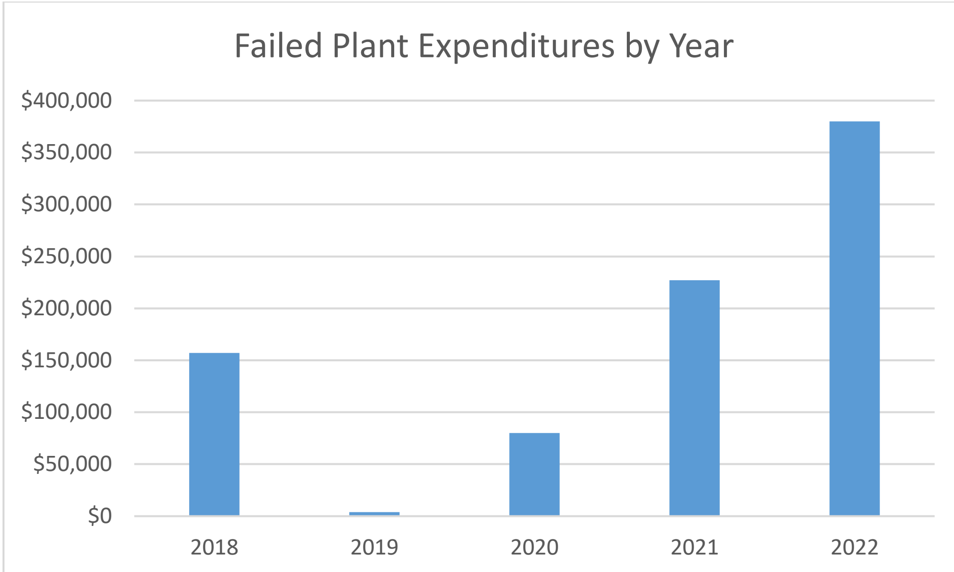
Cost: $5.7M

Option	Capital Cost
Reactive Replacements, Rely on Failed Plant Budget Item	$1M, increasing
Eliminate Worst Known Electrical & Structural Issues	$2M, increasing
Create/Follow Complete Systematic Replacement Programs	$5.7M

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 use of Asset Condition budget will prevent future increases of the “Failed Plant” Budget Item that is contained within this business case. If the Failed Plant Budget Item is seen increasing, then Asset Condition dollars are not being appropriately supported or allocated.

Failed Plant expenditures from recent years are shown below.



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

This Business Case transfers to plant monthly; dollars are "used and useful" as soon as the smaller individual projects contained within this Business Case are energized.

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.

Projects (both the Vault Integration Project and smaller programmatic capacity-driven projects) are prioritized by Engineering (Brian Chain, Landen Grant) and Downtown Network management (Sam Helms, David Howell), based on input from the field personnel as well as data gathered from various systems and surveys.

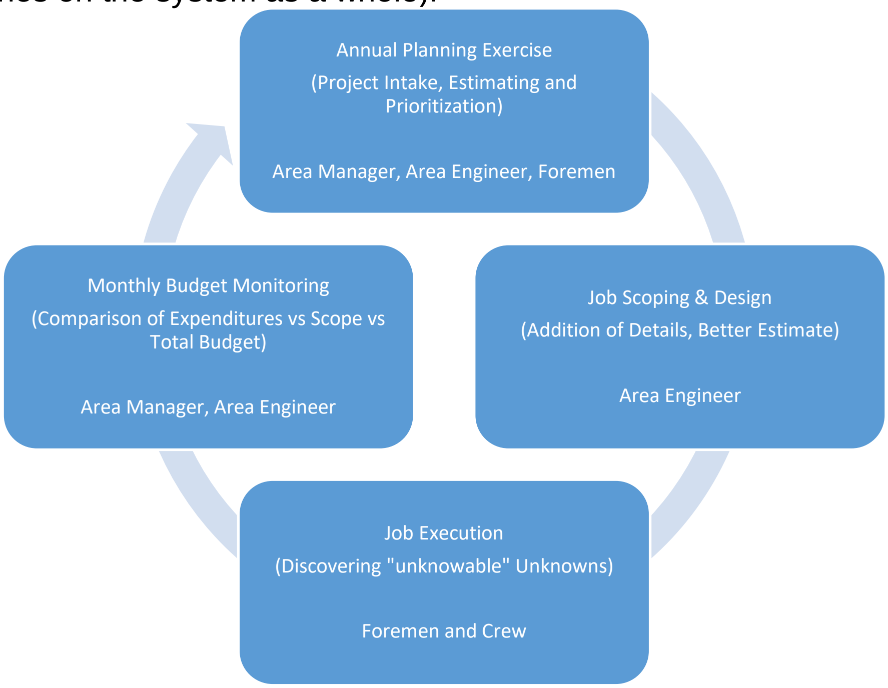
Job planning and budget monitoring is a constantly iterative process Downtown. An annual job planning board is constructed ahead of the beginning of each year, including carry over from the prior year, known upcoming projects, and slack for unknown customer-driven and failure-driven projects.

Budget tracking and balancing occurs monthly throughout the year and is reviewed with Engineering (Brian Chain and Landen Grant) and Downtown Network management (Sam Helms and David Howell). Adjustments are made as necessary to ensure that required projects have the budget resourcing they need to be completed, and to make sure that the overall budget is not being exceeded without approval.

Downtown Network – Asset Condition

See the following chart for high points of this process.

Offramps are available at each step of this process that allow individual jobs to be stopped or delayed if more information comes to light that makes the project less prudent (e.g., delay in connected customer work, City re-pave jobs that impact our schedule, or de-prioritization of the job in question due to other discoveries on the system as a whole).



3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Downtown Network – Asset Condition 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: Date: 4/26/2023

Print Name: Sam Helms

Title: Network Operations Manager

Role: Business Case Owner

Signature: David Howell Date: 5/2/2023

Print Name:

Title:

Role: Business Case Sponsor

Signature: Date:

Print Name:

Title:

Role: Steering/Advisory Committee Review

Downtown Network – Performance & Capacity

EXECUTIVE SUMMARY

The Downtown Network Performance & Capacity budget is intended to enable the installation of new and upgraded equipment to cover deficiencies in Avista's ability to serve customers inside the Downtown Network service territory, located in Spokane, WA, between I-90 and the Spokane River, and between the Ash/Maple and Browne/Division corridors. This business case's requested budget for 2024 is $2.2M.

Examples of projects funded in this business case include larger vaults to allow for additional grid transformers to be installed, larger duct banks to support additional grid cable to be installed, and larger transformers to support increasing grid loading. This business case also covers the ongoing installation of fiber-optic communications to network protectors for control and data acquisition, to increase efficiency in construction and improve reliability for customers inside the Downtown Network. Savings generated by this project exceed $6M over the life of the system.

Delays or cancellations of funding to this business case will result in trending down in reliability to Avista's Downtown Network customers, less efficient construction overall and, worst case, the inability to serve Downtown Network customers under contingency conditions during peak load periods.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Brian Chain*	*Initial draft of original business case*	
BCRT	*BCRT Team Member – Katie Snyder*	*Has been reviewed by BCRT and meets necessary requirements*	*04/26/2023*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$2.2M**	**$2.2M**
2025	**$1.25M**	**$1.25M**
2026	**$1.3M**	**$1.3M**
2027	**$1.35M**	**$1.35M**
2028	**$1.4M**	**$1.4M**

Project Life Span	***Ongoing Program***
Requesting Organization/Department	C57
Business Case Owner | Sponsor	Sam Helms | David Howell
Sponsor Organization/Department	Electric Operations
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?

Customer growth in the Downtown Network, on a collective basis, drives the need for upgrades of Avista's system further upstream of the radial service feeding the customer. Per Avista's Service Policy, upgrades to the network itself are done at Avista's cost. Without these upgrades, the system will lack the capacity to service customers without overloading network cables. These capacity issues are identified in a similar manner to those on Avista's transmission system, with ongoing powerflow studies performed in PowerWorld, using real time data whenever possible (e.g. AMI metering output).

Beyond these basic capacity issues, which are fixed on a programmatic basis, a very large specific project is being funded under this business case, due to the lack of support for individual business case funding. The Vault Integration Project, chartered at $5.2M, is installing fiber-optic based SCADA (System Control and Data Acquisition) to all Avista's ~100 transformer vaults. With this system in place, our capacity planning will be much improved (due to even more real time data being available to assist modeling). Our operational procedures will also be vastly improved, with remote monitoring and control mitigating the hazards of individual vault visits in many cases. Our reliability will be improved, as outage responses can be sped up due to readily available information.

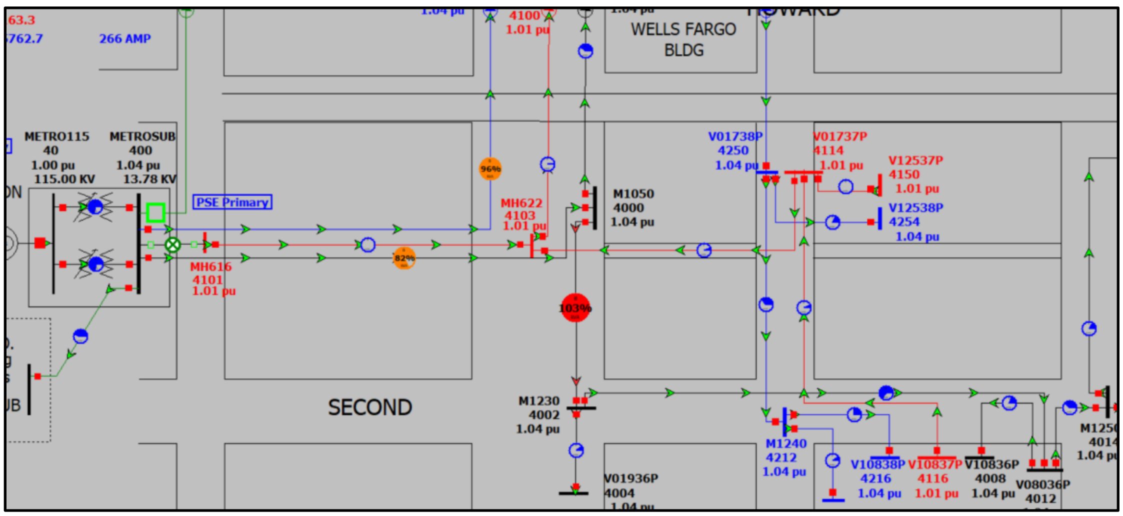
1.2 Discuss the major drivers of the business case.

The major driver in this business case is Performance & Capacity; however, with regard to the Vault Integration Project, almost every other business driver also applies.

As discussed above, the benefit to our customers is similarly wide ranging. At the core, the benefit is that the system remains reliable due to capacity increases being installed where they are necessary in order to maintain reliable service by avoiding cable overloads and subsequent outages. However, the inclusion of the Vault Integration Project also provides increased response times when there are outages, better safety for our crews by mitigating in person vault visits, and better data available for capacity planning. This data allows us to use our PowerWorld model accurately and delay capital projects until they are definitively proven as necessary, thereby lowering upward pressure on rate increases toward all 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.

Cable overloads that are identified in PowerWorld that are not fixed prior to the next peak demand period will result in customer outages. Due to the nature of the Downtown Network these outages will be widespread (at least ¼ of downtown Spokane). An example of the modeling software is shown below; note that while "System Normal" overloads are watched for (as with the rest of our radial distribution system), the real focus in the Network is "Contingency" modeling, to see what happens next when each element of the system is lost. In this sense, the Downtown Network modeling works to produce projects in a fashion that is much more similar to Avista's Transmission Network than it is to the radial distribution system.



Additionally, the Vault Integration Project mitigates a host of issues as discussed above. Much of the rest of the network industry has already implemented similar measures. Avista would be doing both our customers and employees a disservice by not following suit with customers paying for upgrades which may have been forestalled given better operational knowledge, and employees (cablemen) taking risks which may have been fully mitigated by operating dangerous electrical equipment remotely via communications.

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]

Without solutions to network capacity issues, blackouts will result. The programmatic portion of this annual spend is intended to prevent these reliability issues by providing appropriate upstream capacity to support customer load.

This puts our customers at the forefront by providing the reliability they have come to expect from Avista in downtown Spokane.

The Vault Integration Project improves employee safety, streamlines operational efficiency, and provides information that guides our future investments in our system. All of these, and especially the latter, put downward pressure on the overall future cost of service 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]

Refer to the Vault Integration Project Charter and Scoping Memo at the link below for more detail around the spending on this project. Refer to the latest copy of the Downtown Network System Report for more information on the latest Powerworld studies, their results, and the deficient areas of the system that must be addressed with upgrades.

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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 individual capacity increases that are installed as part of this business case are modeled an annual basis. The cable that is pulled in and the vaults that are upgraded based on this modeling are designed to mitigate potential overloads on the system.

Implementation of the Vault Integration Project provides operational visibility into the system to ensure that overloads not identified in the model are not occurring, as well as remote operability that results in increased safety by limiting physical crew visits to facilities.

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

2.2 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]

Refer to the Annual Downtown Network System Report at the link below for capacity issues identified in the latest powerflow studies. This is one of the analysis that was considered when preparing this business case. In order to continue to provide service during peak load periods, any identified overloads must be addressed; otherwise outages may result.

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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	2024	2025	2026	2027	2028
Capital	Switching Order Efficiency	$40k	$40k	$40k	$40k	$40k
O&M	Switching Order Efficiency	$40k	$40k	$40k	$40k	$40k

This business case supports the Vault Integration Project, which is extending remote Supervisory Control and Data Acquisition (SCADA) to all Downtown Network transformer vaults. SCADA enables Avista's Distribution Operations Office to remotely switch, and verify success of switching, without sending cablemen to physically enter and verify each transformer vault, for each switching order. Compared to pre-SCADA switching processes, this is estimated to save ~30 switching orders per year, with six cablemen on vault patrol processes, at an estimated loaded cost of $110/hour, for four hours per switching order totaling an estimated $79,200/year saved. This is split between O&M and capital, depending on what kind of work the switching is supporting.

[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.

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	1/3 FTE (Cap Time Charging)	$20k	$20k	$20k	$20k	$20k
O&M	1/3 FTE (O&M component)	$60k	$60k	$60k	$60k	$60k

30 switching orders per year, with six cablemen on vault patrol processes, for four hours per switching order…totals an estimated 720 man-hours saved, or approximately 1/3 of an FTE. This provides downward pressure on the need for additional employees to support ongoing construction, operations, and maintenance of the Downtown Network system.

Savings are estimated again at an average loaded cableman hourly rate of $110/hour, for 1/3 of a year.

This business case also supports system improvements that are further upstream into the utility's system and are not appropriately assigned to any single customer or group of customers. For example, a cable exiting a substation, that supports thousands of downstream customers, may become overloaded as new customers are added to the feeder (and also as existing customers increase their usage). This business case is the avenue used to upgrade the cable such that the cable does not face thermal issues resulting in long term outages to all customers downstream. There are many similar examples throughout the system.

This work may also avoid costly lawsuits in the downtown core business environment; however, it is difficult to quantify these potential avoided costs.

Put more simply, this capital system reinforcement work is an obligation that the Company has to both new and existing customers. We are not doing this work in order to create savings; we are doing this work in order to provide reasonable service to our customers. In this sense, some of the work is more akin to work performed under ER 1000 (New Revenue), except that the work occurs on parts of our system that are not assigned directly to customers in the Electric Service Requirements book.

[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.

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 Vault Integration Project portion of this Business Case is scheduled to be spent over the next few years (depending on level of budget support and amount of other critical capacity upgrades that cohabit this Business Case). Presently we are about 60% installed with two quadrants (Metro West and East) commissioned.

The Vault Integration Project portion of this Business Case reduces upward pressure on O&M going forward as described in the attached Charter. Reduced truck rolls, regular time and overtime crew callouts, and vault visits in the middle of busy downtown streets should all be reduced. Estimated O&M reductions are in the $50-100k annual range, based on cableman salaries, overtime rates, and overheads. Annually these do vary based on the number of outages that occur.

Note that it is also expected that more accurate real time field measurements should result in delayed capital expenditures to mitigate perceived capacity issues that do not show up in the real time data. This should provide downward pressure inside the Downtown Network Performance & Capacity Business Case.

Alternatives for a system communicating to our Network vaults have been considered multiple times over the course of about 15 years as the project was scoped, piloted, and re-scoped. Prior attempts included varying technologies (copper wiring vs fiber, older relay programming, and different backhaul routes). Most of these proved infeasible due to electrical shock hazards, a lack of expertise related to testing/commissioning, and a lack of Avista consensus over operational authorities.

For this most recent effort, the project considered multiple types of communication (copper, fiber, ethernet, managed vs unmanaged). Fiber was chosen for its relative affordability due to the lack of splicing and overall cable length, along with an inversely related increase in capability. The selection of a definitive operational authority within Avista enabled other technical decisions to be made, and the project to finally move forward. More detail is in the documentation at the link below.

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With regard to system studies in Powerworld to solve deficient system performance during peak loading periods, as mentioned earlier, every individual problem is looked at from many angles for many different solutions. This can range from deciding to pull extra secondary down a street, install a new grid vault to support load, or even split existing load off on to a spot vault in order to free up capacity to serve the grid. Again, the System Report is the best place to see this in more detail.

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).

Continued investment in network capacity where shown as necessary should continue to lower the amount of outage minutes experienced by Downtown Network customers.

Capital investment in this business case after the next year (where investment is asked to increase in order to allow for faster completion of the Vault Integration Project) should have less “upward pressure” as individual overloads predicted by the PowerWorld model are shown not to actually be an issue compared to real time measurements.

In person vault visits during switching are being reduced (and will reduce further) as new operational procedures are implemented as part of the Vault Integration Project. These procedures are already approved by Safety & Health, L&I, and System/Distribution Operations.

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

Capacity upgrades completed as part of the normal course of business under the “Program” portion of this Business Case generally transfer to plant monthly, as they are used and useful immediately upon becoming energized.

The Vault Integration Project expenditures have been transferring to plant as network quadrants become commissioned i.e. data starts flowing into the SCADA historian software from our fiber connected field devices. At this point the data is available for both operations and future capital planning, and again, it is expected that this data will put downward pressure on the cost of both of these.

Given the lack of funding for the Project under the last four budget requests, the TTP schedule has been extended, and at this point we do not expect to TTP anything on the project in 2023 (same as 2022), unless manpower and funding are made available to commission quadrants prior to end of 2023.

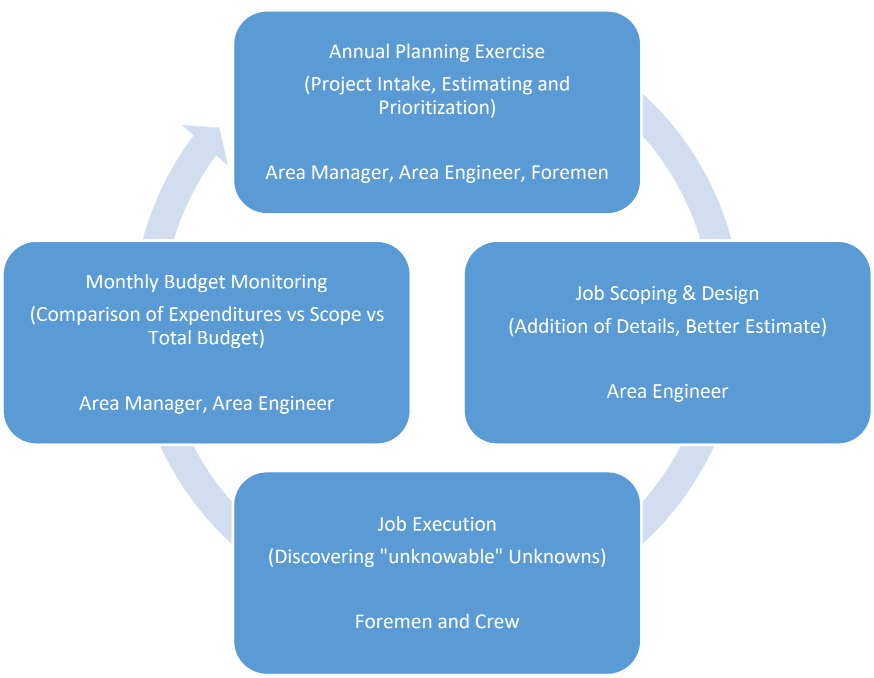
2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Projects (both the Vault Integration Project and smaller programmatic capacity-driven projects) are prioritized by Engineering (Brian Chain, Landen Grant) and Downtown Network management (Sam Helms, David Howell), based on input from the field personnel as well as data gathered from various systems and surveys.

Job planning and budget monitoring is a constantly iterative process Downtown. An annual job planning board is constructed ahead of the beginning of each year, including carry over from the prior year, known upcoming projects, and slack for unknown customer-driven and failure-driven projects.

Budget tracking and balancing occurs on a monthly basis throughout the year and is reviewed with Engineering (Brian Chain and Landen Grant) and Downtown Network management (Sam Helms and David Howell). Adjustments are made as necessary to ensure that required projects have the budget resourcing they need to be completed, and also to make sure that the overall budget is not being exceeded without approval. See the following chart for high points of this process.

Offramps are available at each step of this process that allow individual jobs to be stopped or delayed if more information comes to light that makes the project less prudent (e.g. delay in connected customer work, City re-pave jobs that impact our schedule, or de-prioritization of the job in question due to other discoveries on the system as a whole).



3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Downtown Network – Performance & Capacity 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:	[signature]	Date:	4/26/2023
Print Name:	Sam Helms		
Title:	Network Operations Manager		
Role:	Business Case Owner		

Signature:	David Howell	Date:	5/2/2023
Print Name:			
Title:			
Role:	Business Case Sponsor		

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

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*

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

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.

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.

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.

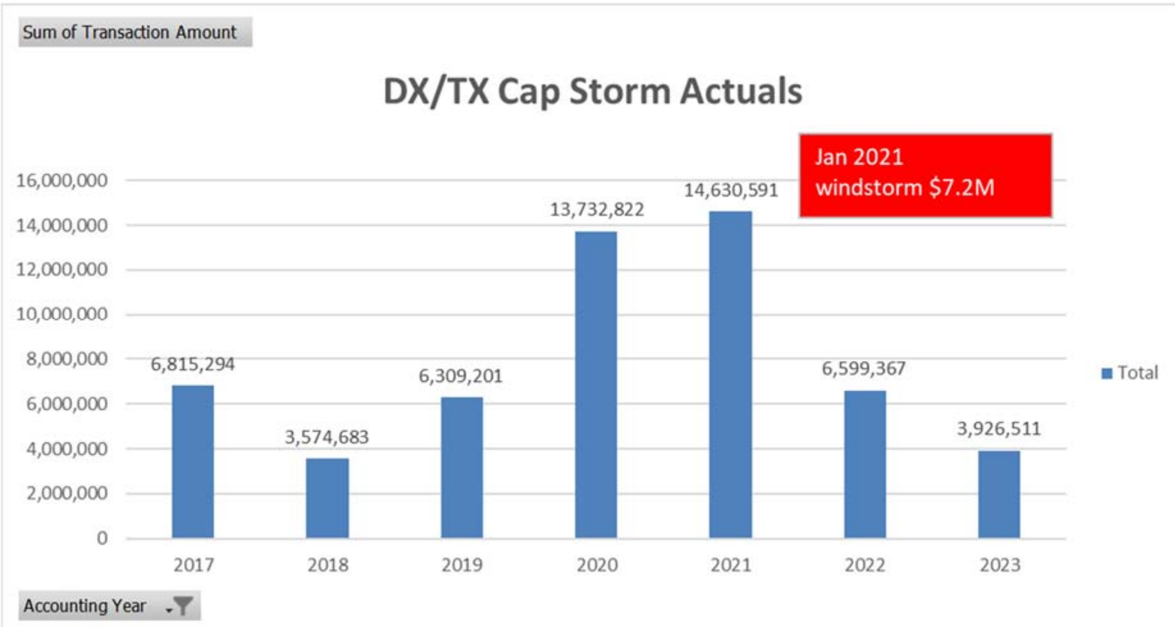


Figure 1: Storm Historical Costs

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.

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.

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.

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

Fleet Vehicle Refresh Capital Program

EXECUTIVE SUMMARY

A 2018 study of Avista's brand found that 65% of customers are most likely to identify Avista by our fleet of trucks and equipment working in the community. Our vehicles and associated gear are an essential part of our ability to address customer needs and perform work required to be an effective and efficient electric and gas utility. 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 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 test 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 serve 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 request as market prices fluctuate.

To develop this model 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. 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 $41.5M. The investment in Avista's fleet, over the past decade, means that we have a highly 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. The Fleet Vehicle Capital Refresh Program was reviewed with the Facilities & Fleet Steering Committee in May of 2022.

VERSION HISTORY

Version	Author	Description	Date
Draft	*Loew / Potter*	*Initial draft of original business case*	*4-14-23*
2.0	*Loew Potter*	*Updated with current data*	*4-26-23*
3.0	*Loew / Potter*	*Edits*	*4-27-23*
BCRT	*BCRT Team Member-Christine Tasche*	*Has been reviewed by BCRT and meets necessary requirements*	*4-27-23*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$5,594,822**	**$5,594,822**
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**

Project Life Span	*5 years*
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

Fleet Vehicle Refresh Capital Program

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.

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 the safest most 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 100 hours of operations and are in the 1st quartile when compared to peer utility fleets. Our fleet of vehicles includes advanced safety features, modern efficient engines and operational tools that make many tasks more efficient. We work very 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 by having a small and predictable annual portion of their bill tied to the acquisition and operation of our fleet. 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. It 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]

			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 AVISTA

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 stated 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 emissions milestone 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

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)	*$41.5M*	*01 2024*	*12 2028*
Current Allocated Funding	*$28.1M*	*01 2024*	*12 2028*
Lease	*$M*	*01 2024*	*12 2028*

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.

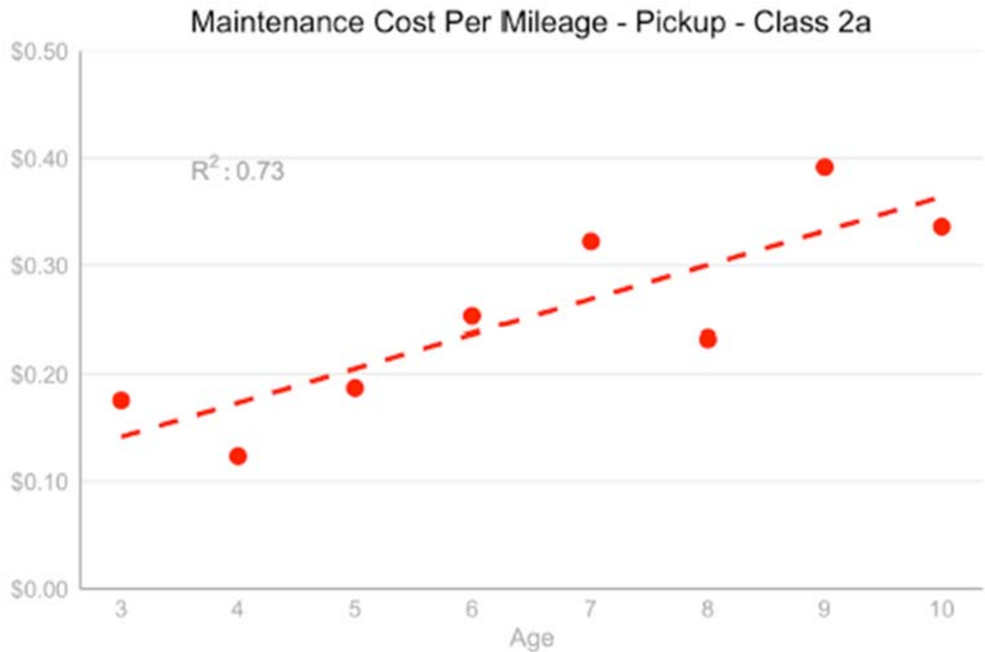
A vehicle is identified as a candidate for replacement when it reaches its replacement range for age or lifetime mileage. Replacing within these ranges ensures operating within 1% of the lowest total ownership cost of the vehicle over its lifetime. A standard regression model is used in this analysis. 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.

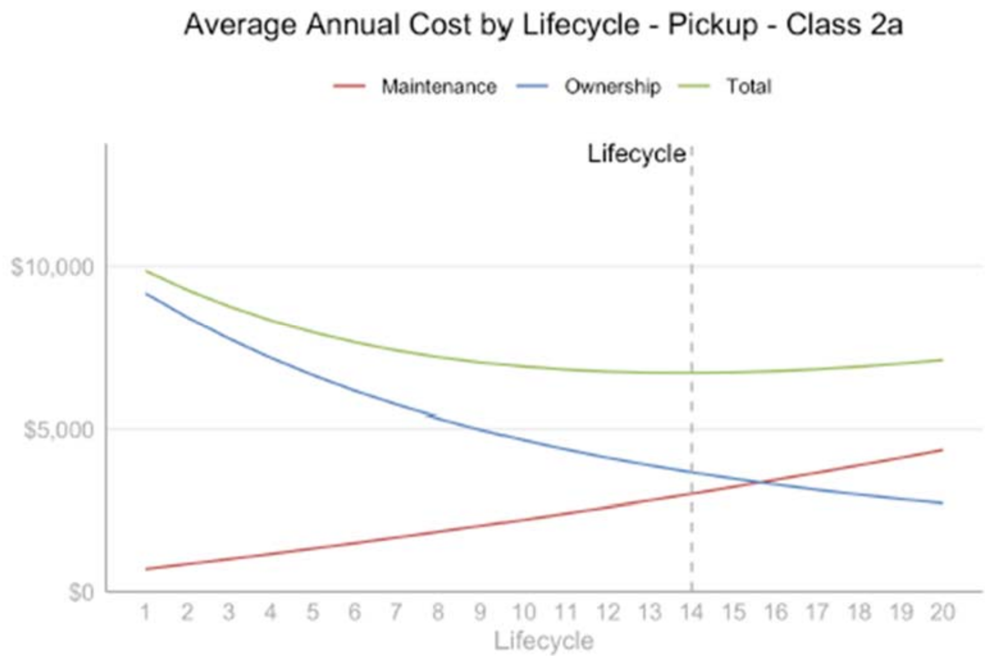
[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

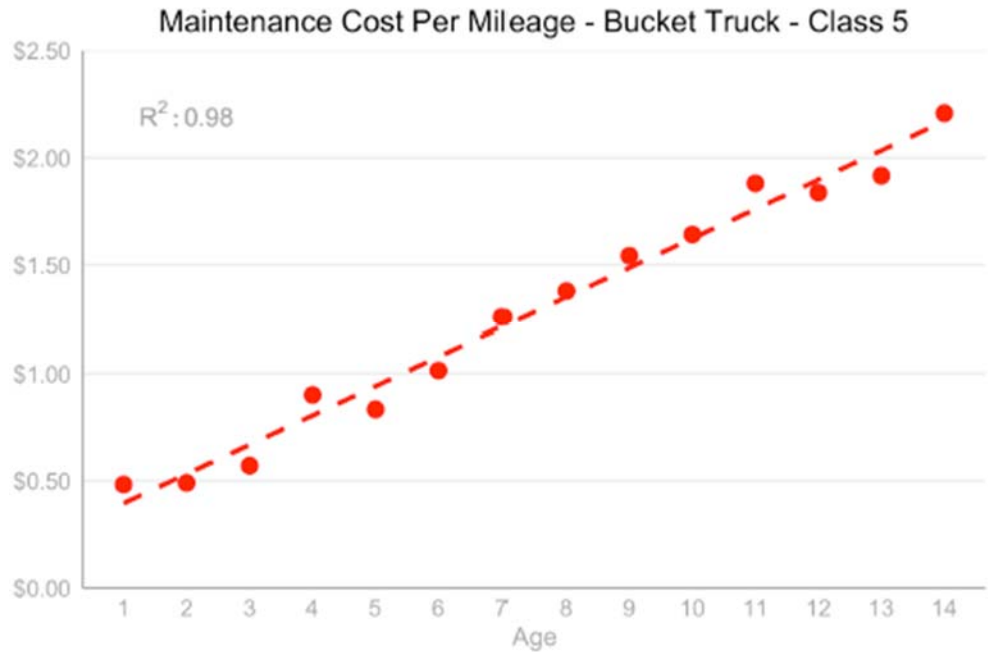
Pickup - Class 2a

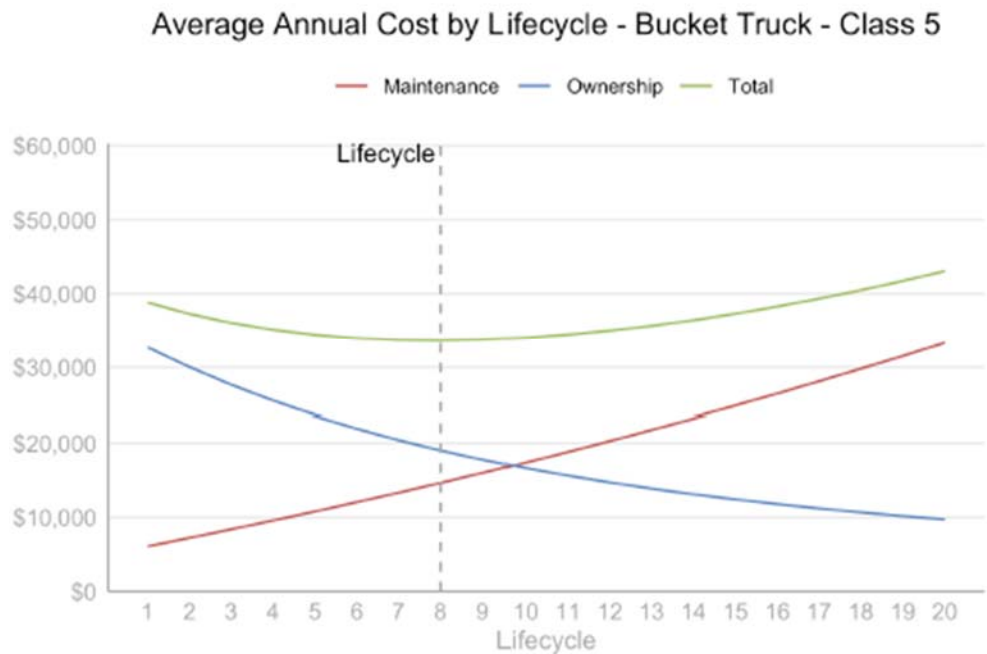
	Value
Lifecycle	14
Purchase Price	$56,000
Average Salvage at Sale	$3,480
Market Depreciation Rate	18%
Inflation Rate	2%
Average Annual Mileage	8,789

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%


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


Maintenance Cost Per Mileage - Bucket Truck - Class 5
R^2: 0.98
$2.50
$2.00
$1.50
$1.00
$0.50
$0.00
1 2 3 4 5 6 7 8 9 10 11 12 13 14
Age


Average Annual Cost by Lifecycle - Bucket Truck - Class 5
Maintenance
Ownership
Total
Lifecycle
$60,000
$50,000
$40,000
$30,000
$20,000
$10,000
$0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
Lifecycle

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 will be spent evenly over the 5 year period. The investment of capital in this case will provide a consistent replacement plan which enables a predictable parts and labor cost, vehicle downtime and technician requirements

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

[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] 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		$	$	$	$	$

The Fleet Vehicle Refresh Program does not provide any 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	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M	Additional FTE & Crew Downtime	$0	$37,945	$131,814	$247,511	$381,799

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, 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 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.

[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.

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%. 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 adequate technician capacity constraints. However, the amount is mitigated by the focusing on the highest cost and most critical assets. Additionally, we risk the potential that additional funding would need to be apportioned 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%. This route would create 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 will be 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 had been 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.

Signature:		Date:	
Print Name:	Greg Loew		
Title:	Fleet Manager		
Role:	Business Case Owner		

Signature:		Date:	4/27/2023
Print Name:	Kelly Magalsky		
Title:	Director of Shared Services		
Role:	Business Case Sponsor		

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

Gas ERT Raplacement Program, ER 3054

EXECUTIVE SUMMARY

An Encoder Receiver Transmitter (ERT) is an electro-mechanical device that allows gas meters to be read remotely. These ERTs are powered by lithium batteries, which discharge over time and must eventually be replaced.

Most of the gas meters in Washington, Idaho, and Oregon have ERT modules. The large quantity of ERT installations will result in an unmanageable quantity of battery failures in the future if the ERT is not replaced at an optimized frequency. When batteries fail, the customer's usage is estimated and entered into the billing system manually. This manual process causes a high chance of customer dissatisfaction because of potential billing errors associated with bill estimation. Customers often express their dissatisfaction through commission complaints when this happens.

In most areas of Washington, the ERT modules were replaced in 2019 as part of the Advanced Metering Infrastructure (AMI) project. These ERTs will not need to be replaced for approximately 15 years unless they experience a premature battery failure. This business case also covers instances where the ERT module is not communicating with the AMI network as intended, causing a replacement that is compatible with the mobile meter read routes. This will ensure reliable metering reading and billing.

In Idaho the ERTs will likely be changed out in mass when the AMI project starts in 2024, however it is estimated that up to 30,000 40G ERT modules may have a battery failure in 2022 and 2023 due to their age. These 40G ERT modules may be replaced to avoid battery failure and billing issues before the AMI project is implemented.

In Oregon the ERTs will not be changed out in mass because the AMI project will not be implemented there, therefore the recommended solution is to replace the oldest 7,000 ERTs each year on a 15 year cycle. This replacement strategy was optimized by an Avista Asset Management study. The annual cost of this replacement strategy is $220,000 and it expected to increase approximately 5% per year to adjust for increased wages and materials.

If this program is not funded the amount of ERT battery failures will increase to an unsustainable level. If not replaced at the proposed rate, a peak of more than 20,000 ERTs are predicted to fail annually, each requiring an unplanned maintenance visit to replace, causing an undue burden on Operations personnel and equipment. This large number of failed ERTs will also cause an unreasonable number of meters that would need to be read manually and the customer's usage estimated resulting in estimated billing and a negative customer experience.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Dave Smith	Initial version	3/9/2017	
1.1	Dave Smith	Revised per initial review	3/24/17	
2.0	Dave Smith	Revised for 2020 Oregon GRC filing	2/7/20	
2.1	Dave Smith	Updated to the refreshed 2020 Business Case template	6/23/20	
2.2	Dave Smith	Updated to the refreshed 2022 Business Case template. Edited to include WA and ID in the program.	5-5-22	

Gas ERT Raplacement Program, ER 3054

GENERAL INFORMATION

Requested Spend Amount	$220,000
Requested Spend Time Period	Annually
Requesting Organization/Department	Gas Engineering
Business Case Owner | Sponsor	Jeff Webb / Dave Smith | Jody Morehouse
Sponsor Organization/Department	B51 – Gas Engineering
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

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

An Encoder Receiver Transmitter (ERT) is an electro-mechanical device that allows gas meters to be read remotely. These ERTs are powered by lithium batteries, which discharge over time and must eventually be replaced. The average battery life for ERT modules is approximately 15 years. Most of the gas meters in Washington, Idaho, and Oregon have ERT modules. The large quantity of ERT installations will result in an unmanageable quantity of battery failures in the future if not replaced at an optimized frequency. When batteries fail, the customer's usage is estimated and entered into the billing system manually. This manual process causes a high chance of customer dissatisfaction because of potential billing errors associated with bill estimation. Customers often express their dissatisfaction through commission complaints.

Battery replacement was determined to not be the best approach because in order to replace just the battery, a technician needs to remove the module from the meter and bring it back to the shop where the battery can be replaced in a controlled environment. After the battery is replaced the technician needs to return to the meter to re-install the module. This results in twice the travel time and twice the labor time compared to replacing the entire module, negating any cost savings.

Another issue with replacing just the battery is that all of the potting gel surrounding the battery and circuity inside the module needs to be removed in order to access the battery, and once the gel is removed all of the electronic components inside the ERT are now subject to moisture damage in the field, resulting in additional failures. The manufacturer (Itron) does not recommend replacing the battery in ERT modules for these reasons.

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

This program usess a proactive and strategic method for addressing asset condition by replacing ERT modules before their battery fails. Replacing these assets before they fail will avoid a manual process of estimating a customer's gas usage and bill resulting in higher customer satisfaction. It is also more efficient and cost effective to proactively replace old ERTs rather than waiting until their battery fails and having to send out a servicemen to replace a failed ERT.

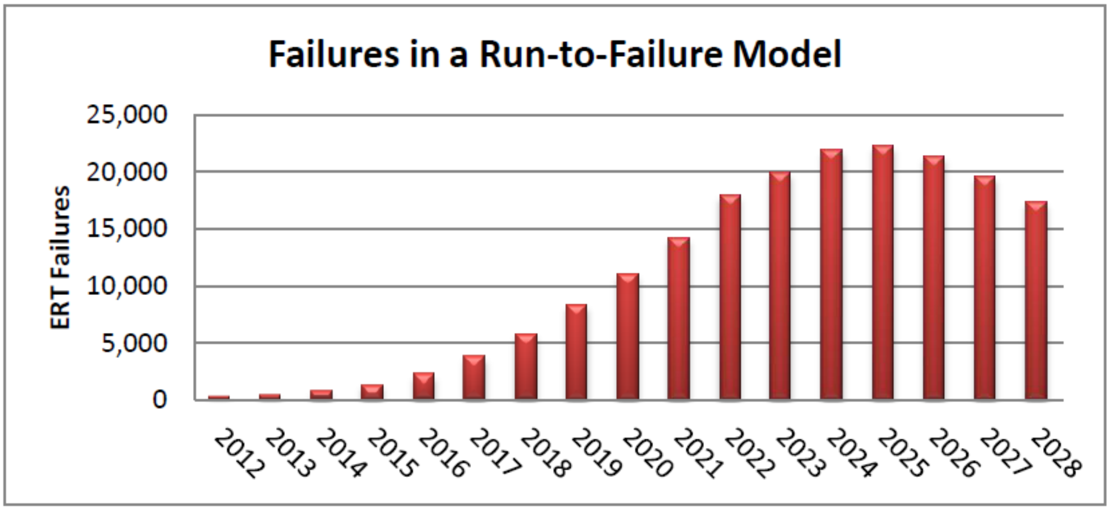
1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

The work is needed now because many of the ERTs have reached their end-of-life and will begin failing or are not communicating with the AMI network as intended resulting in billing issues.

In most areas of Washington, the ERT modules were replaced in 2019 as part of the Advanced Metering Infrastructure (AMI) project. These ERTs will not need to be replaced for approximately 15 years unless they experience a premature battery failure. This business case also covers instances where the ERT module is not communicating with the AMI network as intended, causing a replacement that is compatible with the mobile meter read routes. This will ensure reliable metering reading and billing.

In Idaho the ERTs will likely be changed out in mass when the AMI project starts in 2024, however it is estimated that up to 30,000 40G ERT modules may have a battery failure in 2022 and 2023 due to their age. These 40G ERT modules may be replaced to avoid battery failure and billing issues before the AMI project is implemented.

The graph below shows how many ERT modules are expected to fail annually in Oregon if they are not proactively replaced.

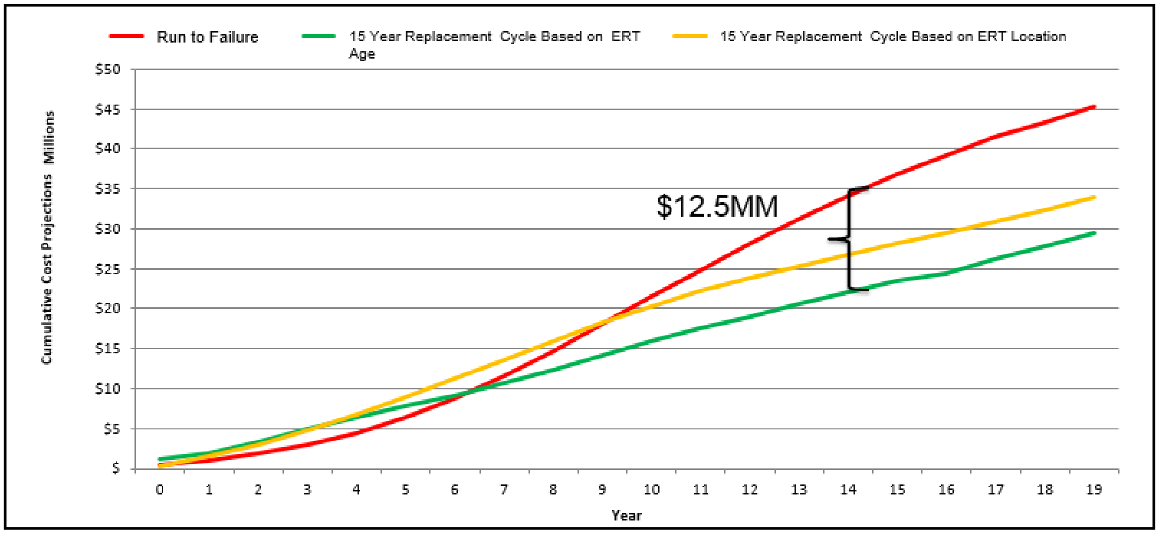


If this program is not funded the amount of ERT battery failures will increase to an unsustainable level. If not replaced at the proposed rate of 7,000 annually, a peak of more than 20,000 ERTs are predicted to fail annually, each requiring a maintenance visit to replace, causing an undue burden on Operations personnel and equipment. This large number of failed ERTs will also cause an unreasonable number of meters that would need to be read manually and the customer's usage estimated resulting in estimated billing and a negative customer experience.

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.

The Asset Management department was consulted by Gas Engineering for assistance in developing a strategic program to replace ERT modules in Oregon since the AMI program would not replace the modules there. The result of the study suggested the most efficient method for replacing these assets resulted in the highest customer satisfaction and the lowest cost. The graph below summarizes the cost savings associated with a proactive and strategic ERT replacement program over a 15 year cycle:

Gas ERT Raplacement Program, ER 3054



1.5 Supplemental Information

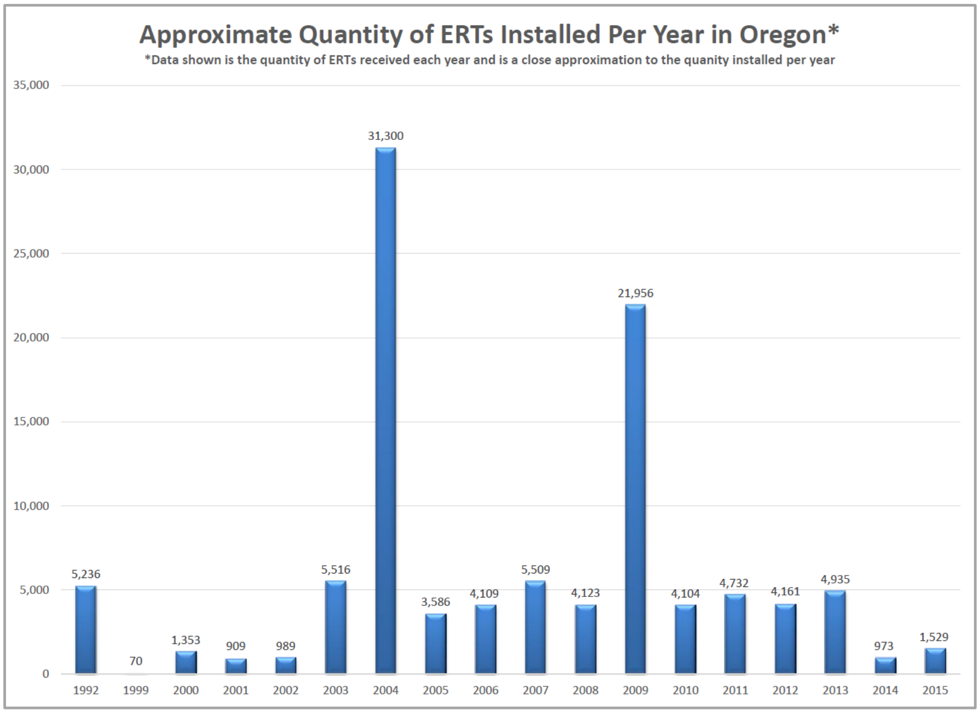
1.5.1 Please reference and summarize any studies that support the problem

The Asset Management study for the Oregon ERT Replacement Program is saved on the Avista network drive c01d44 and can be made available upon request.

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.

In Idaho the concern is the 2005-2007 vintage 40G ERTs failing before the AMI project commences in 2024. There are approximately 30,000 of these modules in the system. If we do not proactively replace these modules in 2022 and 2023 there is a high likelihood that their batteries will fail before AMI is implemented starting in 2024.

The graph below shows the quantity of ERTs installed per year in Oregon:



If these ERTs are run to battery failure there will be an unmanageable quantity of ERT failures each year.

2. PROPOSAL AND RECOMMENDED SOLUTION

The recommended solution for Idaho is to replace the 30,000 +/- 40G ERTs that are at end of life. This work will be completed in 2022 and 2023.

The recommended solution for Oregon is to continue replacing the oldest 7,000 ERTs each year on a 15 year cycle. This approach targets the oldest ERTs resulting in less battery failures and as a result fewer estimated customer bills.

Option	Capital Cost	Start	Complete
Recommended Solution:			
ID – Replace 30,000 +/- 40G modules in 2022 and 2023.	$570,000 (ID)	01/2022 (ID)	12/2023 (ID)
OR – Replace the oldest 7,000 ERTs each year on a 15 year cycle	$200,000 (OR)	01/2016 (OR)	04/2031 (OR)
Alternative Solution:			
ID – Run 40G ERTs to failure.	$5.41MM (ID)	N/A (ID)	N/A (ID)
OR – Replace 7,000 ERTs based on geographic location each year on a 15 year cycle	$126,040 (OR)	01/2016 (OR)	04/2031 (OR)

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Some factors that were considered when preparing this request are the number of ERTs in service, the average battery life of the ERT module, the effects on the customer's bill if the ERT fails, the cost to reactively replace the failed module, and the cost to proactively replace the asset before failure. Refer to the asset management study discussed in Section 1.4.

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.**

In Idaho the replacement of approximately 30,000 2005-2007 40G ERT modules will be replaced in 2022 and 2023. The exact timing is still being evaluated, taking into account supply chain limitations and expected failure rates.

At the beginning of each year the project team determines the location of the oldest 7,000 ERTs in the Oregon. Replacement ERT modules are then ordered. Due to the "pre-capitalization process" the cost of the ERT module will go against ER1053 (Gas ERT Minor Blanket). This program covers the labor and minor material cost for replacing the ERT. Work orders are created for the replacement of each ERT. A third party contractor is utilized to efficiently replace all 7,000 ERTs. The program is completed between January and December each year.

If an ERT battery fails the Mobile Collector will not download the monthly meter read. As a result a servicemen is dispatched to investigate the issue which results in a much higher cost than if the ERT was proactively replaced before the battery dies. This additional cost is primarily composed of personnel labor and travel wages, vehicle costs, and the cost to produce an estimated customer bill.

Reactive ERT Replacement Costs[1], Per Unit	
Avista personnel labor & travel time wages	$100.36
Avista vehicle corrective call out cost	$67.04
Cost to produce estimated bill when ERTs fail	$12.93
Total	***$ 180.34***

[1]These costs were calculated using the ERT Replacement Strategy Development study from 2012 and adjusted by adding a 2% annual inflation rate.

Washington & Idaho Proactive ERT Replacement Costs[2], Per Unit	
Contractor labor	$54.25
Project management	$0.75
Total	***$55.00***

Oregon Proactive ERT Replacement Costs[2], Per Unit	
Contractor labor	$25.00
Project management	$0.75
Total	***$25.75***

[2]These cost reflect 2022 contractor unit pricing per Avista Contract R-40780.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Replacing ERT modules is not a new process for Avista. Existing processes and technologies will be utilized for this program.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

In 2022, an alternative solution that was considered for Washington was to install Star Connected Grid Routers (CGR) devices in the gas only areas where the 500G modules were not able to communicate through the AMI mesh network. The Star CGR option would have taken much longer to implement and would have also been much more costly than replacing the ERT module, therefore the most timely and cost effective solution was to replace the 500G module with a 550G module that would allow mobile reading in the gas only areas.

An alternative solution for Oregon that was considered was to replace 7,000 ERTs based on it's geographic location each year on a 15 year cycle (represented by the yellow line in the graph in Section 1.4). This option involves replacing a geographic cluster of ERTs. The benefit to this approach is that the ERTs are located close to one another, which equates to less travel time in-between ERT locations. The disadvantage to this approach is that the oldest ERTs may not be replaced if they are outside of the geographic zone, so there would be a higher quantity of ERT battery failures and customer billing estimates. A third party contractor provided a cost estimate for both replacement strategies and the cost to replace the oldest ERTs was not significantly more than replacing the geographically located ERT clusters. However the overall cost increase to replace by location was significant, approximately $5,000,000 more over the life of the 15 year program, due to the high number of expected unplanned replacements using this method vs replace by age.

The run-to-failure cost to reactively replace the failed ERT modules was also considered for Idaho and Oregon. When an ERT is run to failure the customer's bill is estimated and then corrected the next month after the ERT is replaced. If this proactive replacement program is not funded there will be an unmanageable quantity of ERTs failing each year and it is likely that the failed ERT will not be replaced in one month's billing cycle resulting in billing estimates for multiple months. This will create customer dissatisfaction and loss of trust. See below for breakdown of these risks.

Assumptions:

1. Except for regulatory fines, cost estimates based on SME input.
2. Costs associated with each risk can vary significantly depending on site conditions.

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 1 Year	2 Years	5 Years	10 Years	15+ Years	Cost Estimate
1	Regulatory Fines	L	L	L	L	L	$225,134 per day per violation (Max)* $2,251,334 Total (Max)*
2	Pipeline Leak	L	L	L	L	L	$5,000 to $150,000 per site (site dependent)
3	Pipeline Failure & Outage	L	L	L	L	L	$150,000 to $3,000,000 per site (site dependent)
4	Negative Reputation	H	VH	VH	VH	VH	Erosion of PUC and Public trust
5	Employee & Public Safety	L	L	L	L	L	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).

Over the life of the 15 year program in Oregon the asset management study estimates that the cost of this run-to-failure approach would be approximately $12,500,000 more than if a proactive and strategic replacement program was executed. Refer to the cost analysis graph in Section 1.4 showing a comparison between the preferred and alternative solutions.

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.

The Idaho program is planned to be competed by the end of 2023. The Oregon program will be completed between January and December each year on a 15 year cycle. The ERT modules are purchased as a pre-capital material item under ER 1053 (Gas ERT Minor Blanket). The ERTs will become used and useful upon installation on the meter.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This program aligns with Avista's organizational focus to maintain a safe and reliable infrastructure to achieve optimum life-cycle performance, safely, reliably, and at a fair price for our customers.

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 replacement strategy described herein was optimized by Avista's Asset Management department to levelized the asset replacement cost, to optimize the asset life-cycle, and to minimize the number of failed ERTs requiring customer billing estimates. The program costs will be monitored monthly by the program manager.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Avista gas customers benefit from the replacement of these ERT modules because they will receive reliable and accurate billing.

Business case stakeholders including the ERT Replacement Program manager, GIS Analyst, Sourcing Professional, Maximo Business Analyst, IT, Service Credit Dispatch, and Oregon Gas Operations all work together to ensure a successful program execution.

2.8.2 Identify any related Business Cases

ER 1053 Gas ERT Minor Blanket

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The Asset Management department was consulted by Gas Engineering for assistance developing a strategic program to replace ERT modules before their battery expires. The result of the study suggested the optimized method for replacing these assets that resulted in the highest customer satisfaction and lowest cost.

3.2 Provide and discuss the governance processes and people that will provide oversight

Using the replacement strategy recommended by Asset Management the ERT Replacement Program manager works with GIS Technical Services to determine the location of the oldest 7,000 ERT modules in Oregon. Each year prior to starting work the oldest ERT locations are re-analyzed to ensure the most accurate and up to date information. The third party contractor performing the replacement work also provide field verification to ensure only old ERTs are replaced.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The ERT Replacement Program is documented in a business plan and prioritized in a spreadsheet. Each ERT replacement is documented in Maximo with a work order.

Year to date spend and budget updates are reviewed monthly. Annually, the Gas Engineering Prioritization Investment Committee (EPIC) reviews the 5 year plan and ensures the budget level is appropriate given other categories of work and risk on the gas system.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas ERT Replacement Program, ER 3054 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:	Jeff A Webb	Date:	8/31/22
Print Name:	Jeff Webb / David Smith		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	Jody Morehouse	Date:	8/31/2022
Print Name:	Jody Morehouse		
Title:	Director Natural Gas		
Role:	Business Case Sponsor		

Gas ERT Raplacement Program, ER 3054

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

Non-Revenue Program, ER 3005

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.

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
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	*9/29/23*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**9,682,000**	**9,682,000**
2025	**9,972,000**	**9,972,000**
2026	**10,272,000**	**10,272,000**
2027	**10,580,000**	**10,580,000**
2028	**10,897,000**	**10,897,000**

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

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 problems 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). 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.

If requested by others (typically customers) to relocate facilities, Avista is bound by tariff language 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 small 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.

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 usually 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.

Figure 1 shows how the budget is typically spread across the different project types discussed above.

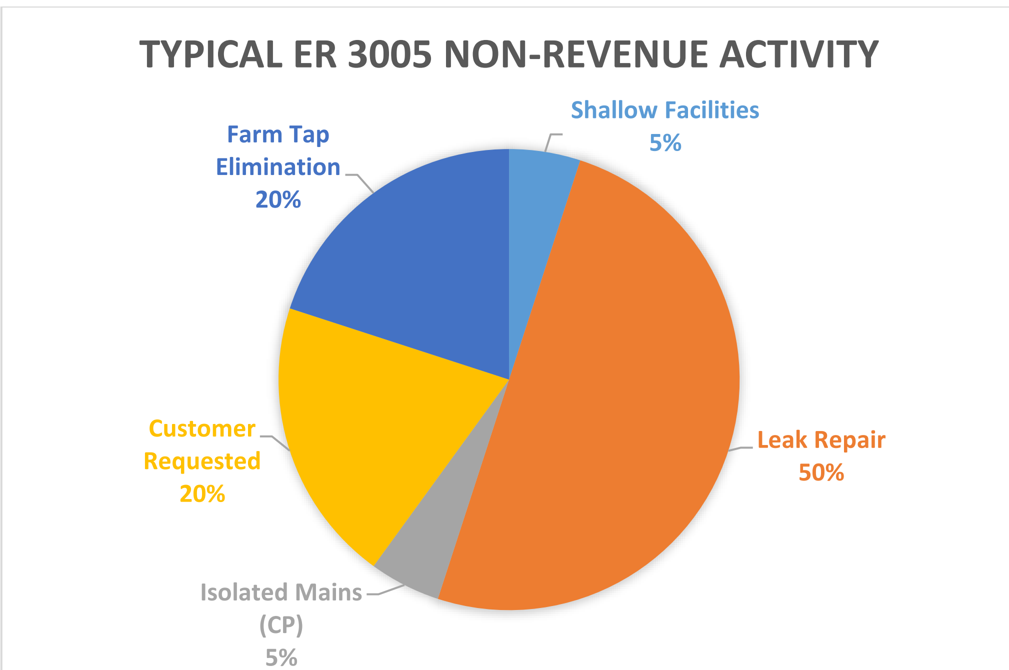


Figure 1. ER 3005 Spend by Project Type

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. 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.

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, we 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. The decision to simply repair the leak or perform the customer requested work (quickest and easiest thing to do) eliminates the chance to improve the system as a whole, while increasing 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 green house gases can negatively impact the environment and they 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 CP 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 projectIf 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. 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.

<u>Overbuilds</u> – Overbuilt gas pipes pose a safety risk for occupants in the area. Leaking gas can accumulate under mobile homes and storage sheds. If the 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.

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 does not get involved with the individual projects.

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.

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.

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 a solution. 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 codes and best practices.

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.

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 is 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

[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.

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 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 eliminated.

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	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M	Temporary Leak Repair	$	$3	$	$	$

[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	2024	2025	2026	2027	2028
Capital		$ -	$	$	$	$
O&M		$3,995,000	$3,995,000	$3,995,000	$3,995,000	$3,995,000

If the capital work under this Business Case was not available, a portion of Avista labor would likely be charged to expense work. The O&M cost offsets were calculated assuming half of the labor under this Business Case would be charged to other capital work, and half to expense. This is estimated to be $595,000 per year.

Additionally, if leaks were to be temporarily repaired when discovered, company crews would have to return to the leak repair site to install a permanent repair later. By permanently repairing leaks the first time, an estimated $3,400,000 per year of O&M costs are offset. These costs are associated with the temporary leak repairs. A temporary leak repairs costs about 80% of what a permanent repair costs.

CFR 192.465 & CFR192.720 determine how a gas utility manages leaks. The other portions of work associated with this Business Case are not mandated work. They consist of customer requested work, mitigating shallow gas facilities, and strategically replacing farm tap style regulators with IP main.

[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.

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. This can end up costing more in future O&M costs than the cost of bettering the system in the first place.

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.

Alternative 4:

The only alternative to farm tap eliminations is to replace each farm tap as needed. 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.

Alternative 5:

There is no alternative to replacing known overbuilds. Leaving known overbuilds in place would be a violation of code and standard practices.

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.

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 represents at the CPG should changes be needed throughout the year.

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:		Date:	10/11/2023
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	Alicia Gibbs	Date:	10/12/2023
Print Name:	Alicia Gibbs		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

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

Gas Regulator Station Replacement Program, ER 3002

EXECUTIVE SUMMARY

This annual program will replace or upgrade existing at-risk Gate Stations, Regulator Stations, Single Service Farm Taps, and Industrial Meter Sets ("stations") located throughout Avista's gas territory in WA, ID, and OR that are at the end of their service life and/or not up to 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].

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: 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, resulting in Avista employees parking 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, 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 a number of factors, some of which include the type of station, size of station components, location,

[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.

and crew resources (company crews or contractor crews). Below are estimated average costs to rebuild each type of station based on historical projects:

Gate Station:	$300,000
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*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	*4/3/2023*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**1,070,000**	**1,070,000**
2025	**1,070,000**	**1,070,000**
2026	**1,070,000**	**1,070,000**
2027	**1,070,000**	**1,070,000**
2028	**1,070,000**	**1,070,000**

Project Life Span	***Ongoing***
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Dave Smith / 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 eventually no longer meet Avista's current design standards, the equipment may become obsolete, or 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: 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 resulting in Avista employees parking 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.

Station	Year Assesse	Score	Station Ty	Location	Paint	Corrosi	Welds Pass Visi	Threaded Fittin	Bypass	Sense Line Configurati	Height	Pipe Settli	Supports	External Forc	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: 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 resulting in Avista employees parking on the shoulder of the road to access the station. 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.

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

[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.

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 there is already a backlog of stations needing replacement. The list of stations needing replacement continues to grow 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 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.

AVISTA

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:

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

The *Station Evaluation Spreadsheet.xlsx* is the master spreadsheet that contains the evaluation scores for each station. A partial screenshot of this spreadsheet is shown below.

Station	Year Assessed	Score	Station Ty	Location	Paint	Corrosi	Welds Pass Visi	Threaded Fitting	Bypass	Sense Line Configurati	Height	Pipe Settli	Supports	External Forc	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/Platforn	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
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34	2021	45	DR		Cracking/Flaking	Minor	No	No	Hard	short	Requires Ladder/Platforn	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

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.

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,

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

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 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.

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 resore 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

[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.

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.

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

[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.

See spreadsheet *Offset Calcs ER 3002 – Reg Reliability 2023.xlsx* for assumptions and calculations.

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	$1,070,000	January	December
Alternative Solution 1, Replace at risk stations at a reduced funding level	$500,000	January	December
Alternative Solution 2, Do nothing	$0		

Alternative 1:

The alternative solution would be to replace at risk stations at a reduced funding level. There is already a backlog of approximately 30 high-risk stations that need to be replaced. This approach would take longer to get through the backlog. Meanwhile, new stations are added to the list every year due to aging infrastructure. Therefore, Alternative 1 will eventually surpass the Recommended Solution in not only cost but inefficiency as well.

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:

If the program were to not be funded, Avista would be forced to operate at-risk stations in an unsafe, unreliable, and sometimes non-code compliant manner. The risk of not doing the work includes, but is not limited to, regulatory fines, pipeline leaks, pipeline failures and outages, negative company reputation, and employee and public safety. O&M costs would escalate as the number of unplanned visits to these stations would likely increase due to operating them at or beyond their useful lives. 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.xlsx*, 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 Settli	Supports	External Forc	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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~~27~~	~~2021~~	~~45.5~~	~~DR~~		~~Cracking/Flaking~~	~~Minor~~	~~No~~	~~No~~	~~Lead/Lag~~	~~short~~	~~Requires Ladder/Platforn~~	~~None~~	~~Not Needed~~	~~None~~	~~Adequ~~
34	2021	45	DR		Cracking/Flaking	Minor	No	No	Hard	short	Requires Ladder/Platforn	None	Not Needed	None	Adequ
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26N05	2020	43	GS		Good	None	Blank	Yes on HP, Yes on IP	None	Blank	Too Short	None	Blank	None	Not Ad

When stations are rebuilt they will be rescored. The station's new lower score will show that the project delivered on improving reliability and reducing risk. For example, station #31 had an initial score of 48, ranking it in the top 10 stations needing to be replaced. Station #31 was replaced in 2022 and its new score is 1, placing it amongst the lowest risk stations in the system.

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.

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:	Jeffy a Webb	Date:	4/23/23
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	Alicia Gibbs	Date:	4/23/2023
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

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. 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.

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 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.

[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.

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*
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements*	4/24/2023

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**1,300,000**	**1,300,000**
2025	**1,300,000**	**1,300,000**
2026	**1,300,000**	**1,300,000**
2027	**1,300,000**	**1,300,000**
2028	**1,300,000**	**1,300,000**

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 number of customers impacted by each reinforcement is different; however, typically the highest priority reinforcements correlate to the highest number of customers at risk of an outage. 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. 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.

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.

[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.

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 52 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. 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; however, typically 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[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. 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 both existing and new customers with reliable energy and will be able to prevent our customers from having an interruption of service on very cold days. 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.

[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 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.

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]

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 52 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. 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.

The list of new reinforcements continues to grow as system deficiencies are discovered and as customer demand changes. At a reduced funding level, project backlogs increase leading to a higher chance of gas outage incidents. Each reinforcement that is completed reduces the risk of an outage event occurring. The number of customers impacted by each reinforcement is different; however, typically the highest priority reinforcements correlate to the highest number of customers at risk of an outage. The estimated cost of

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

an outage is $2,960 per customer[5]. 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.

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).[6]

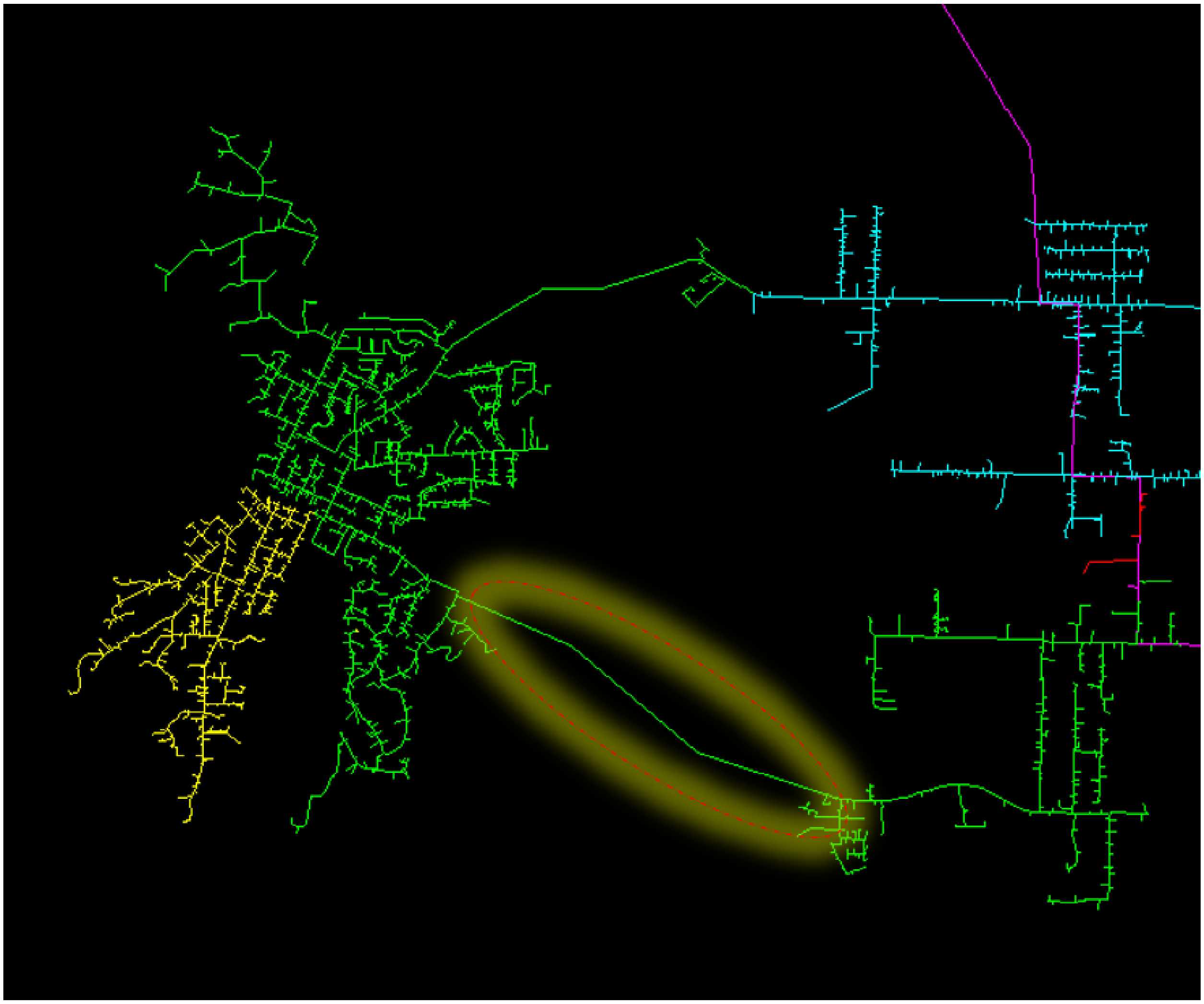
Gas Planning uses load studies to predict system pressures during design day weather (extreme cold) conditions. These studies determine the likelihood of system outages, as well as how many customers are impacted. Gas Planning and Engineering then work together to develop recommendations that will reinforce 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 has identified reinforcement is needed in order to support firm customer loads on a design day:

[5] 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.

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

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:



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.

2.3 Summarize in the table, and describe below the DIRECT offsets[7] 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 offsets8 (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.

[7] 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.

[8] 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:

One alternative is to fund this program at a lower level. 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. 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 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.

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 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.

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.

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:	Jeff a Webb	Date:	4/24/23
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Gas Reinforcement Program, ER 3000

Signature:	Alicia Gibbs	Date:	4/23/2023
Print Name:	Alicia Gibbs		
Title:	Director Natural Gas		
Role:	Business Case Sponsor		

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

Gas Telemetry, ER 3117

EXECUTIVE SUMMARY

ER 3117 provides funding for additions, improvements, and replacements to our Gas Telemetry system. Telemetry equipment includes 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 significant data including consumption for gas procurement, billing, engineering analysis, and system operations. It is important to our customers for safe and reliable operation of our gas system, as well as regulatory compliance for pressure monitoring in accordance with Federal Code Title 49 Part 192.741.

Replacements of existing in-service dial-up equipment that are obsolete and/or failing is required to maintain functionality, efficiency, regulatory compliance, and reliability of the gas operations monitoring system. This obsolete equipment is no longer maintainable because critical spare parts are no longer available from the manufacturer. Prolonged telemetry outages (i.e., years) are a distinct possibility since this equipment interfaces with the company's obsolete SCADA head end dial-up modem bank. This obsolete dial-up modem bank also utilizes unmaintainable equipment and could fail at any time causing 24%[1] of Avista's entire telemetry system to go offline. Waiting for this equipment to fail before replacing increases the probability that an abnormal, non-compliant, or unsafe operating condition could go undetected. If one of these conditions is not detected early enough for corrective action, then this could lead to customer outages or an exceedance of the system's maximum allowable operating pressure.

Failed equipment at dial-up transportation metering sites can also require daily manual meter reads and/or bill estimating which is a less preferred billing method with State Commissions and customers. Many simultaneous dial-up outages can lead to multiple years of expensive manual meter reads and could easily overwhelm Avista personnel resources. Telemetry disruptions at these sites can also result in contractual fines to Avista and/or the customer's agent due to inaccurate gas volume nominations.

A portion of the budget estimates are based on a 5-year plan (three years to go) to upgrade previously mentioned obsolete instruments with wireless modems. By stretching the replacement out over five years, there is a compromise and some risk (as mentioned above) if the dial-up modem bank were to completely fail before all sites are upgraded. The remainder of the annual budget request provides for modest upgrades and additional system monitoring needs. Gas Engineering is responsible for prioritizing and approving specific projects. See below for a summary of projected cost offsets compared to the proposed 5-year budget plan.

ER 3117 Cost Offsets[2]	2024	2025	2026	2027	2028
Capital (Indirect)	$67,168	$67,168	$67,168	$67,168	$67,168
O&M (Indirect)	$189,615	$189,615	$189,615	$189,615	$189,615
Capital (Direct)	$0	$0	$0	$0	$0
O&M (Direct)	$7,561	$7,561	$7,561	$7,561	$7,561

ER 3117 Budget Proposal	2024	2025	2026	2027	2028
Capital	$304,000	$304,000	$304,000	$200,000	$200,000

[1] Based on 67 dial-up sites with obsolete equipment out of a total of 275 permanent telemetry sites on the gas system. 67 divided by 275 = 24.36%

[2] Reference Section 2 of the document for offset details

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*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	4/27/2023

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**304,000**	**304,000**
2025	**304,000**	**304,000**
2026	**304,000**	**304,000**
2027	**200,000**	**200,000**
2028	**200,000**	**200,000**

Project Life Span	*5 years*
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Mike Yang | 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

Gas Telemetry, ER 3117

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?

Telemetry equipment includes flow computers, electronic volume correctors, and electronic pressure monitors installed at new or upgraded regulator and gate stations, customer meter sets, at the ends of pipelines, and on multi-fed gas systems.

The replacement rate of existing Gas Telemetry equipment due to the equipment being obsolete and failing is increasing. A large portion of these sites utilize an obsolete dial-up telephone landline modem bank, head end of the Gas Telemetry System. To fully upgrade the head end of the Gas Telemetry System it is necessary to replace field instruments with IP based/cellular communication. Once the dial-up field devices have been replaced, the head end modem bank can be retired. The modem bank technology is no longer supported by the industry.

Failure of gas telemetry equipment impacts Avista's ability to maintain functionality, efficiency, regulatory compliance, and reliability of the gas operations monitoring system. Lengthy outages due to failed 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.

Ongoing funding for new gas telemetry equipment is required for situational awareness, safety, compliance, new Gas Transportation Customers, and system improvements such as new or rebuilt gate and regulator stations.

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. They can also create a data void, which makes it harder to analyze the system and justify new reinforcement projects to ensure gas reliability.

1.2 Discuss the major drivers of the business case.

The major driver of this business case is Performance & Capacity. ER 3117 provides capital funding for additions, improvements, and replacements for our Gas Telemetry system. The system provides monitoring (including safety related alarms and history) of pressure, temperature, gas volumes, and gas flow rates at Gate Stations, Reg Stations, pipelines, odorizers, and for Transport Customers where applicable.

The system provides data to SCADA for Gas Control, to Nucleus for Gas Procurement, and to the PI data base for use by all departments including Gas Engineering, and Operations (Pressure Controlmen). It is important for safe and reliable operation of our gas system, regulatory compliance with pressure monitoring (Federal Code Title 49 Part 192.741), operational monitoring, and billing data at gate stations and Transport Customers.

For many of the Transport Customers, when replacing the instrument we are also improving safety by buying instruments with a second pressure transducer. The dual pressure monitors allow for monitoring both the metering and delivery pressure and can provide early warning to the Gas Control Room of an abnormal event that could negatively impact the customer.

Continued investment in our Gas Telemetry System is a benefit to our customers since it allows us to continue operating our gas system safely and efficiently. It is also critical in providing accurate and timely billing data for 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.

The requested funding is needed now to prevent extensive equipment failures and the associated risk of not being able to monitor real-time conditions in the gas system, as well as the inability to provide timely billing data. 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 result in fines, customer complaints, and/or regulatory scrutiny.

A portion of the program budget estimates are based on a five-year plan (three years to go) to upgrade most obsolete dial-up modem instruments by replacing them with modern cellular capable communication instruments. By stretching the replacement out over five years there is a compromise, and some risk as addressed in the narrative below, if the head end dial-up modem bank were to completely fail before all these sites are upgraded. The remainder of the annual budget request provides for modest upgrades, replacement of other failed instruments, and additional system monitoring.

In addition to field devices, the obsolete dial up modem bank in the head end of our system located in the SCADA area that communicates with field instruments is experiencing individual modem failures more frequently and could have a complete catastrophic failure any time. It is already operating with reduced capacity causing longer times to poll all instruments. Landline (POTS) dial up modems are obsolete, and parts are no longer available to maintain this modem bank. At the Transport Customer end, many have switched to IP based phone systems which do not work well with dial up modems in the field, this creates extra work for our technicians. It's worth noting that the electric side of Avista has already weened itself off of this dial-up modem bank by upgrading all of their field devices to IP based units.

Significant failure of the POTS modem bank would seriously impair our ability to communicate with approximately 67, or ~24% of our ~275 permanent instruments in the field. Replacing POTS with IP communication also allows for the transfer of all gas telemetry data to our Backup Control Center (BUCC) in CdA, Idaho. The POTS modem bank is not replicated at the BUCC, so failure of the head end communications (modem bank) would involve loss of visibility to critical system operating conditions and less timely data for Gas Procurement and customer agents. Without this communication network in place, Avista would need to send personnel to many of the transport customer sites for manual meter reads. Some transport customer sites would be willing and able to remotely call in their daily meter readings, but it's expected that there would be a subset of customers that would require Avista to visit the site daily for these readings. Timely and accurate billing data is needed to make sure Avista's, and the customer's, daily gas supply nominations are as close as possible to actual consumption. If consumption falls outside of allowable supply nomination tolerances, then Avista risks getting fined of up to $50,000/day and the customer's agent could also get fined an undisclosed amount.

A loss in our ability to communicate with the POTS modem bank would also limit visibility on how the overall gas system is operating. Reduced awareness of how the system is operating can make it difficult to detect abnormal, non-compliant, or unsafe operating conditions. The inability to respond promptly to low pressure situations can result in customer outages. Gas outages are very expensive ($2,960 per customer[3]) and labor intensive to restore service and can also create unsafe conditions if it happens during cold temperatures. Conversely, not responding promptly to high pressure situations can result in prolonged periods of non-compliance and unsafe system pressures. Overpressure or token relief valves may also release gas to atmosphere for a longer period if sufficient system monitoring is not in place.

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 immediately to potentially unsafe or abnormal operating conditions that could have an impact on 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.

The type and vintage (1990’s technology) of telemetry equipment being targeted in the gas system for replacement are obsolete, prone to failure, and incompatible with modern IP communication equipment. Production of this equipment was stopped over 6 years ago, and critical replacement parts are no longer available making these units unmaintainable.

As previously mentioned in Section 1.3, a catastrophic failure of the head end dial-up modem bank would result in 67 locations (~24% of the telemetry system) going offline instantaneously without the ability to get them back online quickly. This obsolete telemetry equipment would require expensive modifications to make it compatible with IP cellular communications, so the most cost-effective way to get these sites back online is to replace them with modern equipment. Based on current staffing levels and site complexity, Avista predicts that it would take almost 2 years to replace all 67 of these sites. During this prolonged outage timeframe there would be major disruptions to the Gas Supply Department and Transport customers who rely on timely data to avoid contractual fines from the transmission pipeline companies. System monitoring capabilities would also be significantly impaired for up to 2 years limiting our ability to promptly detect abnormal, non-compliant, or unsafe conditions.

Avista’s electric system has moved completely away from dial-up phone communication equipment, so they are no longer reliant upon the obsolete and unmaintainable head end dial-up modem bank.

[3] Reference Section 2.4 for more detail on the gas outage cost of $2,960 per customer.

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.

ER 3117 provides capital funding for additions, improvements, and replacements for our Gas Telemetry system. The telemetry system provides pressure monitoring, safety related alarms, pressure history, temperature history, and gas flow rates at Gate Stations, Reg Stations, pipelines, odorizers, and Transport Customers (where applicable).

Replacing obsolete and failing dial-up phone equipment in the field over a strategic five-year period (3 years to go) will allow us to eliminate the obsolete dial up modem bank that could fail at any time. In this situation the equipment on both ends of the dial-up phone set-up (i.e., the field equipment and modem bank) are no longer supported by the manufacturers. There are no commercially available spare parts or units to replace this aging equipment, so the only responsible option is to proactively replace the equipment in the field so they can be converted over to the IP cellular network. Deferring replacement of field equipment and running the modem bank to failure would create many simultaneous billing and system monitoring outages that could take up to two years to bring back online with Avista's current resources.

Funding for capital additions to the gas telemetry system also maintains our ability to identify and install gas monitoring equipment in new areas of the system. The behavior and performance of the gas system is not static, so we must 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).

<u>COST BREAKDOWN:</u>

67 remaining dial-up instruments to be replaced with new IP (cellular) comms x $10,000 = $670,000 total over three years or $223,000 annually for 22 to 23 sites/year for three more years. Cost average per site has gone up due to rising material costs and because the easiest sites were completed during the first two years of the program. Replacement unit cost averaged across all 3 states for dial-up replacements is now estimated at $10,000 each.

22 or 23 sites/year upgrading dial-up instruments for a total of $223,000

1 site/year upgraded to flow computers for a total of $25,000.

2 new pressure monitors/year for a total of $30,000.

3 other instruments to be replaced that are already on IP (cellular) annually as they become obsolete or fail for a total of $26,000.

Estimated Annual Totals $304,000 for years 1, 2, and 3 on current five-budget proposal. Years 4 and 5 are less at $200,000, assuming that the obsolete instruments with dial up modems have all been replaced.

OBSOLETE DIAL-UP EQUIPMENT BY STATE:

WA 50% (QTY 33), OR 28% (QTY 19), ID 22% (QTY 15)

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]

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 direct and indirect quantitative cost offsets. Detailed explanations of these cost offsets can be found in Sections 2.3 and 2.4, but below is a 5-year summary of these offsets compared to the proposed annual cost of the program.

ER 3117 Cost Offsets[5]	2024	2025	2026	2027	2028
Capital (Indirect)	$67,168	$67,168	$67,168	$67,168	$67,168
O&M (Indirect)	$189,615	$189,615	$189,615	$189,615	$189,615
Capital (Direct)	$0	$0	$0	$0	$0
O&M (Direct)	$7,561	$7,561	$7,561	$7,561	$7,561

ER 3117 Budget Proposal	2024	2025	2026	2027	2028
Capital	$304,000	$304,000	$304,000	$200,000	$200,000

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

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	None	$0	$0	$0	$0	$0
O&M	Dial-Up Phone Troubleshooting	$7,561	$7,561	$7,561	$7,561	$7,561

Avista Instrumentation Technicians are currently responding 2 to 3 times a month (~32 times per year) on issues related to dial-up phone connections. Each of these issues takes about 2 hours for the technician to troubleshoot and coordinate a solution with a customer and/or the phone service provider. Successful replacement of the equipment at these dial-up sites will allow us to convert to IP cellular communications and eliminate this troubleshooting labor.

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

[5] Reference Sections 2.3 and 2.4 of the document for offset details

Cost Calculation per Dial-Up Troubleshoot Event:

Item	Cost/Unit	Unit Qty	Cost / event ($)
Labor (hrs)	$ 103.18	2	$ 206.36
Truck (miles)	$ 2.00	15	$ 30.00
		Total =	$ 236.36

O&M Direct Cost Savings Over Time:

Years	Events Eliminated	Cost / event ($)	Time Saved (HRs)	O&M Cost Savings ($)
2024	32	$ 236.36	64	$ 7,561.63
2025	32	$ 236.36	64	$ 7,561.63
2026	32	$ 236.36	64	$ 7,561.63
2027	32	$ 236.36	64	$ 7,561.63
2028	32	$ 236.36	64	$ 7,561.63
				$ 37,808.15

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	New equipment for Risk Item #2 (67% of estimated costs)	$67,168	$67,168	$67,168	$67,168	$67,168
O&M	See Risk Matrix Below	$189,615	$189,615	$189,615	$189,615	$189,615

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.

Annual indirect offset costs in the above table were calculated using the percentage probability at the 5-year mark, multiplying that number by the worst-case cost estimate, and then dividing by 5 for the number of years in the budget timeline[6].

The cost of an outage was estimated at $2,960 per customer[7]. This cost includes the cost for Avista to restore service and the potential economic impacts to the

[6] Reference "Offset Calculations & Assumptions_ER 3117_2023.xlsx" document for details on indirect costs

[7] 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.

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.

Risk Probability Definitions:

Risk Probability Definitions		Risk Probability for Calculating Indirect Offsets
Very High (VH)	Risk event expected to occur	75%
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 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	L	P	$257,664 per day per violation (Max) $2,576,627 Total (Max)	$ 2,576,627
2	Unplanned replacement of all obsolete equip over 2 year period	P	P	H	VH	VH	$332,500 for meter reads (O&M) $670,000 to replace all equip (CAP)	$ 1,002,500
3	Customer Outage	VL	VL	L	P	H	$2,960/outage (ex. ~ $1.5 million for 500 outages)	$ 1,500,000
4	Innaccurate billing	P	P	H	VH	VH	$50,000/day fine for Avista or Customer Agent	$ 350,000
5	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
		2024	2025	2026	2027	2028	
1	Regulatory Fines	$ 51,533	$ 51,533	$ 51,533	$ 51,533	$ 51,533	$ 257,663
2	Unplanned replacement	$ 33,083	$ 33,083	$ 33,083	$ 33,083	$ 33,083	$ 165,413
3	Customer Outage	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 150,000
4	Innaccurate billing	$ 35,000	$ 35,000	$ 35,000	$ 35,000	$ 35,000	$ 175,000
5	Customer & Public Safety	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 200,000
	TOTALS	$ 189,615	$ 189,615	$ 189,615	$ 189,615	$ 189,615	$ 948,075

CAPITAL Indirect Cost offsets over the next 5 years:

#	Risk	CAPITAL Annual Indirect Offsets*					Total Cost per Risk Item
		2024	2025	2026	2027	2028	
2	Unplanned replacement	$ 67,168	$ 67,168	$ 67,168	$ 67,168	$ 67,168	$ 335,838

*Took probability at 5 year mark, multiplied by worst case cost, and then divided by 5 for cost/year over 5 years

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 faster rate

The alternative of replacing equipment more quickly is not feasible based on the current labor resource limitations. In addition to not having enough resources, a faster timeline is not warranted based on the current risk identified in section 2.4.

Alternative 2: Replace equipment at slower rate

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. Based on the risk matrix it was determined that this was not a responsible option to implement.

Alternative 3: Do Nothing (i.e. run to failure)

Doing nothing and running equipment to failure is not considered to be a viable or responsible option. There are resource concerns with the potential of having severely imbalanced workloads from year to year, which could result in our technicians not having enough time to complete compliance related inspections, maintenance, and new installations. There is also the potential for the modem bank to fail, which would result in 67 sites immediately going offline with the only restoration option being to replace the obsolete equipment as quickly as possible. This scenario would potentially create a multi-year outage and impair our ability to monitor portions of the system for abnormal, non-compliant, or unsafe conditions. This would also significantly disrupt sensitive transport customer billing operations as well as Avista's internal Gas Supply operations.

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 by identifying avoided O&M costs as well as mitigating indirect safety, outage, and compliance risks associated with the inability to monitor the gas system due to failed equipment. We are also tracking the reduction of obsolete equipment and dial-up modem sites so that we know at any given time how many replacements we have left to complete.

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

Estimated annual budget totals of $304,000 for years 2023, 2024, and 2025 include the last 3 years of the 5-year budget plan to replace obsolete dial-up equipment. Years 2026 and 2027 will be less at $200,000, assuming that the dial up equipment have all been replaced. This $200,000 budget is for new additions to the system, replacement of newer vintage equipment that fails prematurely, and continued replacement of obsolete equipment that are not on dial-up phone lines (i.e., equipment on IP cellular communication but still need to be replaced because they are obsolete). It is expected that that this budget will continue indefinitely since the gas telemetry system will continue to need modest and ongoing modifications, improvements, and maintenance as long as the gas system is operational.

Field work completed under this budget occurs throughout the year as equipment is delivered and whenever the technicians can fit the work into their schedules. 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 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. 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 *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:	Jeffrey a Webb	Date:	4/21/2023
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	Alicia Gibbs	Date:	4/21/2023
Print Name:	Alicia Gibbs		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

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

LED Street Lights

EXECUTIVE SUMMARY

Any local or state government which has jurisdiction over streets and highways has an obligation to the general public they serve to provide acceptable illumination levels on their streets, sidewalks, and/or highways intended for vehicle driver and pedestrian safety. Avista manages streetlights for many local and state government entities to provide such street, sidewalk, and/or highway illumination for their streets by installing overhead streetlights. Upon light burn-out, lights are converted to LED. This work occurs in WA and ID.

Since this is a service our customer's pay for, they benefit from lighting service being restored upon light burn-out. Based on our historical burn-out rate, a spend of approximately $300,000 is needed. If this business case is not approved, failed lighting may not get replaced, resulting in customer dissatisfaction and increased public safety risks.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	*Katie Snyder*	*5 Year Planning Draft*	*06/10/2022*	*Draft*
1.1	*Katie Snyder*	*Business Narrative Update*	*07/25/2022*	*Draft*

LED Street Lights

GENERAL INFORMATION

Requested Spend Amount	$300,000
Requested Spend Time Period	1 Year
Requesting Organization/Department	Electric Operations
Business Case Owner | Sponsor	Katie Snyder | David Howell
Sponsor Organization/Department	Operations
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

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

Any local or state government which has jurisdiction over streets and highways has an obligation to the general public they serve to provide acceptable illumination levels on their streets, sidewalks, and/or highways intended for driver and pedestrian safety. Because they have an overhead distribution system in most urban areas, Avista provides a convenient streetlight service in almost every local and state government entity they serve, and manages the streetlights to provide street, sidewalk, and/or highway illumination.

Initially, the LED Change-Out Program was on an accelerated five-year schedule (2015 – 2019) to change-out all existing Avista owned streetlights to LED (Light Emitting Diode).

In the spring of 2018, upon Asset Management review, Avista executives, directors, and team leaders decided to adapt the replacement strategy to replace lights as they burned out.

Background:

The desire to begin the LED Change-Out Program in 2015 stems from a delay in energy savings, negative financial impacts, associated personal injury and property theft risks, and resource needs. Benefits are also found in the 2013 Asset Management Street Light Plan.

- Each 100 watt and 200-watt HPS light replaced will save 65 watts and 128 watts, respectively, per fixture. Once all the 100 watt and 200-watt HPS streetlights are replaced, the annual energy savings will be 9,903 MWH each year.
- With respect to the financial impacts of converting to LED streetlight technology, the customer internal rate of return is 8.46%, assuming the current cost of materials and life expectancy of the photocells and LED streetlight fixtures.
- From a public safety perspective, the consequence of converting to LED streetlights in lieu of replacing burned-out HPS bulbs shows a risk reduction of nearly eight times less for potential injury, a serious fatal accident, and property theft.
- Lastly, company resource demands are reduced after the initial conversion to LED technology. The average annual labor man-hours for current practices of changing burned-out HPS bulbs is estimated at 5,200 man-hours and 2,600 equipment hours, while the average man-hours required during the life of the LED fixtures are 3,200 man-hours and 1,800 equipment hours.

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

The primary driver for converting overhead streetlights from High-Pressure Sodium (HPS) lights to LED lights is Asset Condition. By focusing on Asset Condition, there will be a significant improvement in energy savings, lighting quality for customers, and resource cost savings.

Secondly, converting streetlights to LED technology helps bring Avista in compliance with the Washington State Initiative 937 (or the Clean Energy Initiative), which ensures that at least fifteen percent of the electricity Washington state gets from major utilities comes from clean, renewable sources, and that Washington utilities undertake all cost-effective energy conservation measures. LED streetlight technology is part of the mentioned energy conservation measure.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Any local or state government which has jurisdiction over streets and highways has an obligation to the general public they serve to provide acceptable illumination levels on their streets, sidewalks, and/or highways intended for driver and pedestrian safety. Due to having an overhead distribution system in most urban areas, Avista provides a convenient streetlight service in almost every local and state government entity they serve, and manages the streetlights to provide street, sidewalk, and/or highway illumination.

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.

Measures to determine success include:

- Count of Replacements per year.
- Energy savings per year.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

- LED Replacement Analysis - One Pager
- 2013 Street Light Asset Management Plan - Final

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.

A lifetime material usage analysis on the HPS light fixtures estimated a mean time to failure (MTTF) for the various light fixture components. Table 1 shows the results for each streetlight component.

Component Groups	Material Usage Quantities	Replacement Ratio	MTTF (Years)
fuse	641	1%	84

Lamp	7,930	15%	7
photocell	5,151	10%	10
starter board	1,126	2%	48
streetlight fixture	683	2%	55

Table 1: 2011 Mean Time to Failure (MTTF) for HPS Streetlights

Upon completion of all streetlights changed out to LED fixtures, energy savings can be measured on an individual light fixture basis and then extrapolated to the entire system. Also, once all the streetlights are converted to LED, the number of service requests for streetlight burn-out should drop from the number of service requests prior to 2015.

Option	Capital Cost	Start	Complete
RECOMMENDED: Base Case (current practice of replacing burned-out HPS bulbs or replacing a fixture if broken)	$300,000	Ongoing program	
ALT #1: Optimized Case (planned replacement of HPS bulbs and photocells)	$1.67M	1/1/2015	Ongoing - 15-year cycle replacement
ALT #2: LED Case (change-out all fixtures to LED)	$2.32M	1/1/2022	5- or 10-years cycle bulb vs photocell.

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Three alternative cases were initially considered in the analysis of converting the streetlight to LED technology. **Base Case** replaces streetlight components only when they fail. The second case, called the **LED Case**, replaces the current HPS streetlights with new LED fixtures and implements a planned replacement at fifteen years for the fixture and photocell. At the time of the initial analysis, a fifteen-year replacement strategy proved more cost effective over the lifecycle than running LED lights to failure. Thirdly, the **Optimized Case** represents keeping the current HPS light fixtures and performing planned replacements of the bulbs and photocells at five-year cycles for the bulbs and ten-year cycle for the photocells.

In 2018, the replacement strategy moved from a five-year proactive program strategy to a run to failure (or "burn-out") strategy. A run to failure strategy is the same as the Base Case mentioned above. By the end of 2018, nearly all Avista owned cobrahead streetlights had been converted to LED, with the majority of the remaining HPS streetlights in Idaho; mainly Coeur d Alene, Lewiston, Moscow, and Grangeville. However, thousands of customer area lights and thousands of decorative streetlights remained as HPS throughout the entire service territory and were being converted to LED on a burn-out replacement strategy. Because LED conversions of area lights and decorative streetlights have nearly the same cost savings and energy savings as the cobrahead streetlights, the program sponsors supported Asset Maintenance's proposal to expand the scope of the program to include both types of lights. Starting in 2019, all area and decorative streetlights changed out will be charged to the LED Change Out Program.

Key assumptions made in the alternative's analysis are outlined below.

- The **Base Case** and the **Optimized Case**, because they propose using HPS fixtures, have the same failure characteristics shown in Table 2.

Table 1, HPS Light Component Failure Characteristics

Component	Initial Population Failure Rate (10%) by Year___	Initial Population Failure Rate (20%) by Year___	Mean Time to Failure (50% of the initial population will have failed by ____ Years)
100-Watt Bulb	3.4	4.4	6.7
Photocells	5.7	7.3	10.6
Starter Board	7.4	10.5	16.3

Table 2 shows the failure characteristics assumed for LED fixtures and components based on manufacturer's information and an assumed failure shape characteristic.

Table 2, Assumed LED Light Component Failure Curves

Component	Initial Population Failure Rate (10%) by Year___	Initial Population Failure Rate (20%) by Year___	Mean Time to Failure (50% of the initial population will have failed by ____ Years)
New Style Photocell	7.9	10.2	14.9
LED Light Fixture	12.1	15.5	22.6

For each of the cases, a model was created to help compare the risks, resource needs, potential energy savings, and financial impacts of each case. In the end, the **LED Case** will save customers money over the **Base Case**. While the **Optimized Case** provides a better financial return to our customers compared to both the Base Case and LED Case. The customers will still see savings over the life of the LED fixtures compared to today's practices in the Base Case and eliminate the need for 2.3 Megawatts of generation at night.

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.

The LED Change Out program replaces LED lights upon failure (burn-out). Funding calculations are based on historical spend (2020 spend was approx. $411,000). We anticipate as more bulbs are replaced due to failure, there will be less spend each year.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

The impacts of the LED Change-Out Program span across many departments at Avista. Operations is responsible for managing the work and executing the light change-outs in the field, primarily by Avista's servicemen and local reps. Avista's Operations Support Group (Mobile Dispatch) and EAM Technology are responsible for creating work orders for all change-outs and dispatching them to the field. The Customer and Shared Services department, particularity the Enterprise Systems – CC&B, is impacted by the project because the customer billing changes upon converting to LED light fixtures.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Three alternative cases were initially considered in the analysis of converting the streetlight to LED technology. **Base Case** replaces failed streetlight components only when they fail. The second case, called the **LED Case**, replaces the current HPS streetlights with new LED fixtures and implements a planned replacement at fifteen years for the fixture and photocell. The analysis noted that inside the new LED Case model, a fifteen-year replacement strategy proved more cost effective over the lifecycle than running LED lights to failure. Thirdly, the **Optimized Case** represents keeping the current HPS light fixtures and performing planned replacements of the bulbs and photocells at five-year cycles for the bulbs and ten-year cycle for the photocells

For each of the cases, a model was created to help compare the risks, resource needs, potential energy savings, and financial impacts of each case. In the end, the **LED Case** will save customers money over the **Base Case**. While the **Optimized Case** provides a better financial return to our customers compared to both the Base Case and LED Case. The customers will still see savings over the life of the LED fixtures compared to today's practices in the Base Case and eliminate the need for 2.3 Megawatts of generation at night.

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.

This is an ongoing program that started in 2015.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

The LED Change-Out Program is in alignment with the company's strategic vision of delivering reliable energy service and the choices that matter most to our customer's. As part of the program, infrastructure is replaced with longer lasting equipment. By providing more efficient equipment and quality lighting, this results in an energy savings and an increase in driver and pedestrian safety for our customers and communities we serve.

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

Any local or state government which has jurisdiction over streets and highways has an obligation to the general public they serve to provide acceptable illumination levels on their streets, sidewalks, and/or highways intended for driver and pedestrian safety. Due to having an overhead distribution system in most urban areas, Avista provides a convenient streetlight service in almost every local and state government entity they serve, and manages the streetlights to provide street, sidewalk, and/or highway illumination.

Results of this program include; significant improvement in energy savings, lighting quality for customers, and resource cost savings.

Secondly, converting streetlights to LED technology helps bring Avista in compliance with the Washington State Initiative 937 (or the Clean Energy Initiative), which ensures that at least fifteen percent of the electricity Washington state gets from major utilities comes from clean, renewable sources, and that Washington utilities undertake all cost-effective energy conservation measures. LED streetlight technology is part of the mentioned energy conservation measure.

The YTD spend is tracked and reviewed each month during the Electric Operations Roundtable (ORT) meetings. The ORT reviews monthly spend and manages any additional funds requests.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The LED Change-Out Program extends across multiple departments at Avista impacting them directly or indirectly. Each department identified as a stakeholder will nominate an engaged representative to act as the liaison between the program and their department. The department stakeholder representative will also take part to promote their department's interests in the business. Some internal departments include; Construction Services, Distribution Engineering, Warehouse and Investment Recovery, Supply Chain, External Communications, Mobile Dispatch, Enterprise Asset Management, Customer Enterprise Technology, and Regional Business Managers.

External stakeholders in the program include all state, county, and local agencies that have a streetlight account with Avista, as well as neighborhood councils, and local law enforcement agencies. All external stakeholders have a vested interest in the business because the streetlights illuminate their streets and sidewalks for the purpose of public safety.

2.8.2 Identify any related Business Cases

- **Grid Modernization:** With HPS lights changed out as they fail, Grid Modernization projects are likely to find and convert more HPS lights on selected feeders. (The System Wide DFMP says on page 34 that designers should change HPS lights when performing work in the supply space of a pole.)

3.1 Steering Committee or Advisory Group Information

The Operations Roundtable (ORT) acts as the advisory group for the LED Change Out Program.

3.2 Provide and discuss the governance processes and people that will provide oversight

The governance in place over the business case is set by the Operations Roundtable (ORT) group, which sets forecasted budgets, monitors the incurred costs and submits any additional funds requests as needed. LED Change Out Program work is overseen by the local area operations engineers and area construction managers**.**

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Decision making, prioritization and change requests will be documented and monitored though the Operations Roundtable (ORT).

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

LED Street Lights

Signature:	Katie Snyder	Date:	07/25/2022
Print Name:	Katie Snyder		
Title:	Asset Maintenance Business Analyst		
Role:	Business Case Owner		

Signature:	David Howell	Date:	7/28/2022
Print Name:	David Howell		
Title:	Director of Operations		
Role:	Business Case Sponsor		

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

Template Version: 05/28/2020

2022-2023 CAPITAL PROJECT

SAVINGS AND PRODUCTIVITY REPORTING FORM

1. Business Case Name:

    LED Street Lights

2. Business Case Owner:

    Amy Jones

3. Director Responsible:

    David Howell

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):

Quantified direct savings:

2022	2023	Lifetime

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 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).

The indirect savings for this Business Case are due to the energy savings obtained from replacing older HPS bulbs for LED bulbs. An average of 96.5-watt savings occurs when each 100 or 200-watt HPS bulb is replaced. Since 2018, over 5000 LED bulbs have been installed. Utilizing the off-peak price from 2021 of $40/MWH results in an estimated energy savings cost of $192,720. Currently the program only replaces HPS bulbs when they burn out so the energy savings for 2022 and 2023 is not expected to change.

	2018	2019	2020	2021	Grand Total			
Average Watts Saved/year (based on # of bulbs installed)	**388,316**	**500,353**	**537,795**	**544,936**	**544,936**		**Watts Savings**	
MWH	0.39	0.5	0.54	0.55	0.55		65	100 Watts
Hours per year	8760	8760	8760	8760	8760		128	200 Watts
Estimated Energy Savings/Year (MWH)	**3416.4**	**4380**	**4730.4**	**4818**	**4818**		96.5	Ave
Off-peak price in 2021				$ 40.00	$ 40.00			
Annual Savings (Average)					**$ 192,720**			

Quantified indirect savings:

2022	2023	Lifetime
$192,720	$192,720	

6. No Direct or Indirect Savings – These are projects where there are NO identifiable direct or indirect cost savings for customers, as they are required by law, or simply after thorough review have no offsets. (For these projects, please think through any potential offsets, as having no offsets is a high hurdle). If the work is required by law or rule, please identify the law and describe and quantify any risk or penalty Avista's customers will endure due to non-compliance.

This business case is also to maintain compliance with WA State Initiative 937 (Clean Energy Initiative).

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

Director Name ____David Howell________________

Director Signature David Howell________________________

Date 02/13/2023________________________

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	Notes
Draft	*Geena Duczek*	*Initial draft of original business case*	*09/21/2022*	

GENERAL INFORMATION

Requested Spend Amount	$250
Requested Spend Time Period	1 Year- Reoccurring annually
Requesting Organization/Department	Z08 Electric Meter Shop
Business Case Owner | Sponsor	Geena Duczek | David Howell
Sponsor Organization/Department	A50/Electric Operations
Phase	Execution
Category	Program
Driver	Failed Plant & Operations

1. CURRENT STATE/BUSINESS PROBLEM/RISK

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 is a result of 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 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 requirements that mandate Avista's obligation to serve existing customer load within our franchised area.

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

Replacement of failed electric meters. If the meter has failed the customer will not be able to see their usage data online. This data helps customers make wise decisions on their daily usage and may even encourage conservation.

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.

Major Driver – Failed Plant. It is necessary to have an operating meter to properly bill our customers and provide customers benefits in areas with AMI (Automatic Meter Reading).

1.3 Identify why this work is needed now and <u>what risks continue or develop</u> if funding is not approved or deferred.

The work is required, when there is a failed meter to better understand the customer is facing if there is an outage as well as to properly measure and charge customers for electric energy services.

1.4 Identify measures that will be used to determine whether that the investment will successfully mitigate the problem/risk(s) listed above.

Electric meters are approved by the commission to monitor and charge customers for usage as well as provide customer benefits related to AMI services.

1.5 Supplemental Information

1.5.1 Please summarize and reference any studies that support the problem/risk(s)

Using historical averages, the cost of labor and materials related to meter replacements following failures is approximately $250,000 per year. If the new RIVA meter fails, it likely will not display a read at all, making making reads impossible. Avista can typically can however, identify a failed RIVA meter within days of it failing vs. when the meters were manually read, that could result in a delay of a month or more.

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.

N/A

2. RECOMMENDED SOLUTION, ALTERNATIVES, IMPACT TO O&M BUDGET AND OFFSETS

Option	Option Desc	Capital Cost	Start	Comp
Replace the meter in kind		*$250,000*	*01/2023*	*Ongoing*
[Recommended Solution]		*$M*	*MM YYYY*	*MM YYYY*
[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.

Request is based on historical trends of replacing failed meter.

Estimated cost of $100+ loaded costs to roll a truck out to check a meter or get a manual read.

Direct Offset - N/A – Replacement of failed plant.

Indirect Offset – Replacement of an older asset with a newer asset. Potential for an extended life

2.2 Describe how the requested capital amount will be spent during the life of the project/program. (i.e. what are the expected functions, processes or deliverables that will result from the capital spend

Funds will be spent in the replacement of failed electric RIVA meters.

2.3 Describe how any other business functions, processes, projects or programs may be impactedby the recommended solution.

The replacement of failed meters supports the billing department to enable them to properly bill customers for usage as well as enables the customers to obtain the benefits from the Riva meters.

2.4 Discuss each alternatives that was considered, the benefits, risks, ROI, and potential offsets for each alternative

Refurbish and repair in-house: This is no longer a viable option. To refurbish and reuse the RIVA meters, they must be sent back and rebirthed through Itron. When these refurbished meters come back to Avista and get deployed back into the field, they do not mesh to the HES or perform correctly.

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.

This business case is a program that is ongoing each year. Transfers to plant occur monthly.

2.6 Discuss how the recommended solution aligns with strategic vision, goals, objectives and mission statement of the organization. How does it benefit the customer (external/internal).

This work is required to ensure Avista properly bills our customers for electric energy consumption and meets the

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

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

2.8.2 Identify any related Business Cases

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The meter minor blanket business case is reviewed as part of the Operations Round Table (ORT) capital project steering committee monthly.

3.2 Provide and discuss the governance processes and people that will provide oversight

The manager of the electric meter shop is responsible for director oversight of the business case and to ensure project charges are appropriate. The overall business case performance is the responsibility of the Electric Operations Director and administered through the Operations Round Table capital project steering committee.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Changes to the process to manage the business cased will be documented within this business case.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Meter Minor Blanket 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: Geena Duczek Geena Duczek Date: 10/17/22
Print Name: Geena Duczek
Title:
Role: Business Case Owner

Signature: David Howell Date: 10/17/2022
Print Name: David Howell
Title:
Role: Business Case Sponsor

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

New Revenue - Growth

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	2024	2025	2026	2027	2028
Connects Forecast: Res & Comm	9,294	8,949	8,757	8,496	8,627
Extensions, Services	53,672,194	49,649,912	48,987,155	46,631,139	47,322,145
Lighting	2,688,182	2,768,827	2,851,892	2,937,449	3,025,572
Meters & Devices	6,895,335	7,495,899	5,266,252	5,812,844	6,618,619
Transformers & Network Protectors	15,349,551	13,873,273	18,927,853	15,416,540	15,884,100
Business Case Total	**78,605,262**	**73,787,911**	**76,033,152**	**70,797,972**	**72,850,436**

The 5 yr average annual spend for this business case has been around $75M. 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 2024, there are updated impacts to Growth costs, see 2.2 for more detail.

VERSION HISTORY

New Revenue - Growth

Version	Author	Description	Date
1.0	*Joe Wright*	*Initial draft of original business case*	*12/12/23*
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements*	

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$78,605,262**	**$78,605,262**
2025	**$73,787,911**	**$73,787,911**
2026	**$76,033,152**	**$76,033,152**
2027	**$70,797,972**	**$70,797,972**
2028	**$72,850,436**	**$72,850,436**

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.

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.

Transmission Interconnects:

- Periodically, Avista receives requests from 3rd party generation customers seeking interconnection on our Transmission facilities. Two types of customers seek service on our system:
  - First, those who want to wheel on our Transmission system. For this type of customer, Avista receives Transmission revenue for wheeling service. These customers are classified as New Revenue, as the construction costs are offset by ongoing revenues much like new retail customers.
  - The second category of generators are those that sell their output directly to Avista under PURPA contracts. Their output is contained in Avista's gross margin calculation as power supply costs.
- For the first class of customer, a financial analysis shall be performed, as justification for the construction costs to be included as New Revenue – Growth, and the capital so constructed shall be treated as growth for ratemaking purposes.
- PURPA customers' facilities shall be constructed under our existing non-revenue programs.

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."

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.

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

2.2 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 2028 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 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	2024	2025	2026	2027	2028
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 is 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

[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.

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	2024	2025	2026	2027	2028
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.

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.

[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.

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.

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:	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		

Exh. JDD-2

		Apr 2023 12 mth rolling COS: Res inc Dev $$		2024	2025	2026	2027	2028
1000	**Electric New Revenue**							
WA	Residential Connects			2,659	2,613	2,538	2,463	2,501
	Residential Cost/Svc	$ 5,514		$ 5,514	$ 5,514	$ 5,514	$ 5,514	$ 5,514
	Residential Dollars			$ 14,661,726	$ 14,408,082	$ 13,994,532	$ 13,580,982	$ 13,790,514
	Commercial Connects			451	444	431	418	425
	Commercial Cost/Svc	$ 12,747		$ 12,747	$ 12,747	$ 12,747	$ 12,747	$ 12,747
	Commercial Dollars			$ 5,748,897	$ 5,659,668	$ 5,493,957	$ 5,328,246	$ 5,417,475
ID	Residential Connects			1,938	1,905	1,850	1,795	1,823
	Residential Cost/Svc	$ 7,726		$ 7,726	$ 7,726	$ 7,726	$ 7,726	$ 7,726
	Residential Dollars			$ 14,972,988	$ 14,718,030	$ 14,293,100	$ 13,868,170	$ 14,084,498
	Commercial Connects			329	323	314	305	309
	Commercial Cost/Svc	$ 8,624		$ 8,624	$ 8,624	$ 8,624	$ 8,624	$ 8,624
	Commercial Dollars			$ 2,837,296	$ 2,785,552	$ 2,707,936	$ 2,630,320	$ 2,664,816
	Large projects			$ -	$ -	$ -	$ -	$ -
	ER1000 Total		-	**38,220,907**	**37,571,332**	**36,489,525**	**35,407,718**	**35,957,303**
	Res connects total			4,597	4,518	4,388	4,258	4,324
	Comm connects			780	767	745	723	734
	Elec Connects Total			5,377	5,285	5,133	4,981	5,058
1001	**Gas New Revenue**							
WA	Residential Connects			509	476	470	458	464
	Residential Cost/Svc	$ 6,216		$ 6,216	$ 6,216	$ 6,216	$ 6,216	$ 6,216
	Residential Dollars			$ 3,163,944	$ 2,958,816	$ 2,921,520	$ 2,846,928	$ 2,884,224
	Adjustment			$ (2,372,958)	$ (2,958,816)	$ (2,921,520)	$ (2,846,928)	$ (2,884,224)
	Total			$ 790,986	$ -	$ -	$ -	$ -
	Commercial Connects			61	57	56	55	55
	Commercial Cost/Svc	$ 21,617		$ 21,617	$ 21,617	$ 21,617	$ 21,617	$ 21,617
	Commercial Dollars			$ 1,318,637	$ 1,232,169	$ 1,210,552	$ 1,188,935	$ 1,188,935
	Adjustment			$ (988,978)	$ (1,232,169)	$ (1,210,552)	$ (1,188,935)	$ (1,188,935)
	Total			$ 329,659	$ -	$ -	$ -	$ -
ID	Residential Connects			1,742	1,629	1,612	1,562	1,587
	Residential Cost/Svc	$ 5,074		$ 5,074	$ 5,074	$ 5,074	$ 5,074	$ 5,074
	Residential Dollars			$ 8,838,908	$ 8,265,546	$ 8,179,288	$ 7,925,588	$ 8,052,438
	Commercial Connects			208	195	193	187	190
	Commercial Cost/Svc	$ 4,857		$ 4,857	$ 4,857	$ 4,857	$ 4,857	$ 4,857
	Commercial Dollars			$ 1,010,256	$ 947,115	$ 937,401	$ 908,259	$ 922,830
OR	Residential Connects			1,248	1,167	1,155	1,119	1,137
	Residential Cost/Svc	$ 7,037		$ 2,500	$ 1,250	$ 750	$ -	$ -
	Residential Dollars			$ 3,120,000	$ 1,458,750	$ 866,250	$ -	$ -
	Total			$ 3,120,000	$ 1,458,750	$ 866,250	$ -	$ -
	Commercial Connects			149	140	138	134	136
	Commercial Cost/Svc	$ 8,468		$ 2,500	$ 1,250	$ 750	$ -	$ -
	Commercial Dollars			$ 372,500	$ 175,000	$ 103,500	$ -	$ -
	Total			$ 372,500	$ 175,000	$ 103,500	$ -	$ -
	Gas Avail & Large Projects			$ 1,200,639	$ 1,200,639	$ 1,200,639	$ 1,200,639	$ 1,200,639
	ER1001 Total			**15,451,287**	**12,078,580**	**12,497,630**	**11,223,421**	**11,364,842**
	Res connects total			*3,499*	*3,272*	*3,237*	*3,139*	*3,188*
	Comm connects			*418*	*392*	*387*	*376*	*381*
	Gas Connects Total			*3,917*	*3,664*	*3,624*	*3,515*	*3,569*
1002	**Electric Meters**							

ER				2024	2025	2026	2027	2028
				1,501,217	1,385,991	1,386,494	1,385,780	1,449,477
	ER1002 Total			1,501,217	1,385,991	1,386,494	1,385,780	1,449,477
1003	Transformers							
	WA			8,445,273	7,809,530	11,025,044	8,634,371	8,924,861
	ID			6,154,278	5,313,742	7,152,809	6,032,169	6,209,239
	ER1003 Total			14,599,551	13,123,273	18,177,853	14,666,540	15,134,100
			2,023					
1004	Street Lights	Inflation assur	8%	5%	3%	3%	3%	3%
	WA		1,099,314	1,154,280	1,188,908	1,224,576	1,261,313	1,299,152
	ID		729,552	766,030	789,011	812,681	837,062	862,173
	ER1004 Total		1,828,867	1,920,310	1,977,919	2,037,257	2,098,374	2,161,326
1005	Area Lights							
	WA		511,000	536,550	552,646	569,225	586,302	603,891
	ID		220,307	231,322	238,262	245,410	252,772	260,355
	ER1005 Total		731,307	767,872	790,908	814,635	839,074	864,247
1009	Network Protectors							
				750,000	750,000	750,000	750,000	750,000
	ER1009 Total			750,000	750,000	750,000	750,000	750,000
1056	Gas Meters & Devices							
	WA			1,502,201	1,735,855	900,935	1,047,200	1,227,454
	ID			1,289,747	1,445,198	1,107,954	1,255,929	1,472,424
	OR			1,769,564	2,023,044	1,227,876	1,410,176	1,654,541
	ER1056 Total			4,561,512	5,204,096	3,236,765	3,713,306	4,354,419
1051	Gas Regulators							
	WA			242,499	267,331	150,794	169,221	191,730
	ID			272,551	292,200	253,078	279,002	319,770
	OR			317,556	346,280	239,121	265,535	303,222
	ER1051 Total			832,606	905,812	642,993	713,759	814,722

siness Case Summary		2023 Budget	2024	2025	2026	2027	2028
ER1000	Electric New Revenue	44,136,629	38,220,907	37,571,332	36,489,525	35,407,718	35,957,303
ER1001	Gas New Revenue	31,750,460	15,451,287	12,078,580	12,497,630	11,223,421	11,364,842
ER1002	Electric Meters	4,235,058	1,501,217	1,385,991	1,386,494	1,385,780	1,449,477
ER1003	Transformers	12,566,290	14,599,551	13,123,273	18,177,853	14,666,540	15,134,100
ER1004	Street Lights	1,719,898	1,920,310	1,977,919	2,037,257	2,098,374	2,161,326
ER1005	Area Lights	957,542	767,872	790,908	814,635	839,074	864,247
ER1009	Network Protectors	750,000	750,000	750,000	750,000	750,000	750,000
ER1051	Gas Regulators	551,258	832,606	905,812	642,993	713,759	814,722
ER1056	Gas Meters & Devices	1,730,007	4,561,512	5,204,096	3,236,765	3,713,306	4,354,419
	Total Growth	98,397,142	78,605,262	73,787,911	76,033,152	70,797,972	72,850,436
	Approved per CPG for 2024		78,605,262	73,787,911	76,033,152	79,807,087	82,003,153
	Difference between request & approved		(0)	(0)	0	(9,009,115)	(9,152,717)

SCADA – SOO and BuCC

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 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 costs for the upcoming five years are $5M. The amount requested is based primarily upon historical typical $700k spending needs, in addition to known upcoming major projects. For example, 2024 and 2025 are expected to be typical $700k spending years accommodating such notable projects as 1) SCADA Front-End upgrades, 2) Inter-Control Center Communication server upgrades, and CIP network switch upgrades. 2027 and 2028 include a $2M effort to upgrade our main Energy Management System. 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.

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
BCRT	Lindsay Miller	Has been reviewed by BCRT and meets necessary requirements	4/28/2023

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	700,000	700,000
2025	700,000	700,000
2026	700,000	700,000
2027	1,450,000	700,000
2028	1,450,000	2,200,000

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) 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, the SCADA Front-End (SFE) servers installed in 2018 are scheduled for replacement in 2025, well past Avista's targeted five year physical hardware refresh 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 December 2023, beyond which GE begins to provide security update validation service on Time and Materials basis.

The other notable project is to upgrade the ICCP servers installed in 2018 as well due for refresh for the exact same reasons.

And finally, 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.

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:

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 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 the only solution to better meeting hardware obscesence constraints and to mitigate against pre-mature hardware failures we seem to be experiencing with server hardware lately.

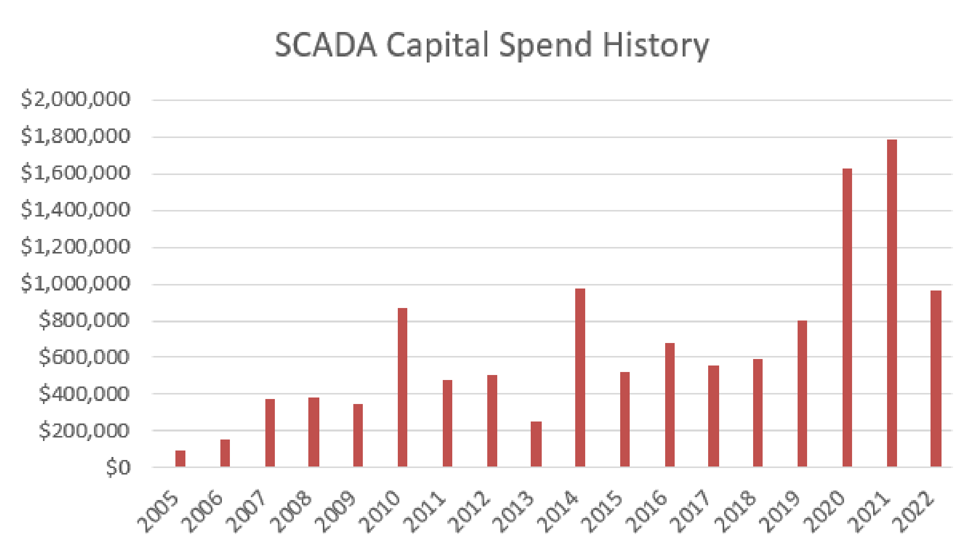
NERC CIP-012 project – In 2022, routers were replaced with AT&T supplied routers to meet encryption requirements for the transmission of all Real-Time Monitoring and Real-Time Assessment data that is exchanged between Balancing Authority Control Centers. CIP-012, as of the July 1, 2023 effective date, 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.

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

2.2 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 average annual $700k costs required to meet the needs for this business case. Additional $2M 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 just under $1M as we took on several upgrade projects inclusive of the following projects for example:

- SCADA Switch Refresh
- SCADA Internal Firewall Refresh
- SCADA External Firewall Refresh
- SCADA SOO NetApp Refresh – network storage device
- Operator Training Simulator
- CIP-012 Protections Project

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

[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.

Capital		$	$	$	$	$
O&M		$	$	$	$	$

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.

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 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 * $130/hr ~ $5,000). In 2024, for example, we will need to replace a set of 12 servers costing about $300,000. 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

[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.

- 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 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 $3 to $10M. Changing server hardware manufacturers is a feasible 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.

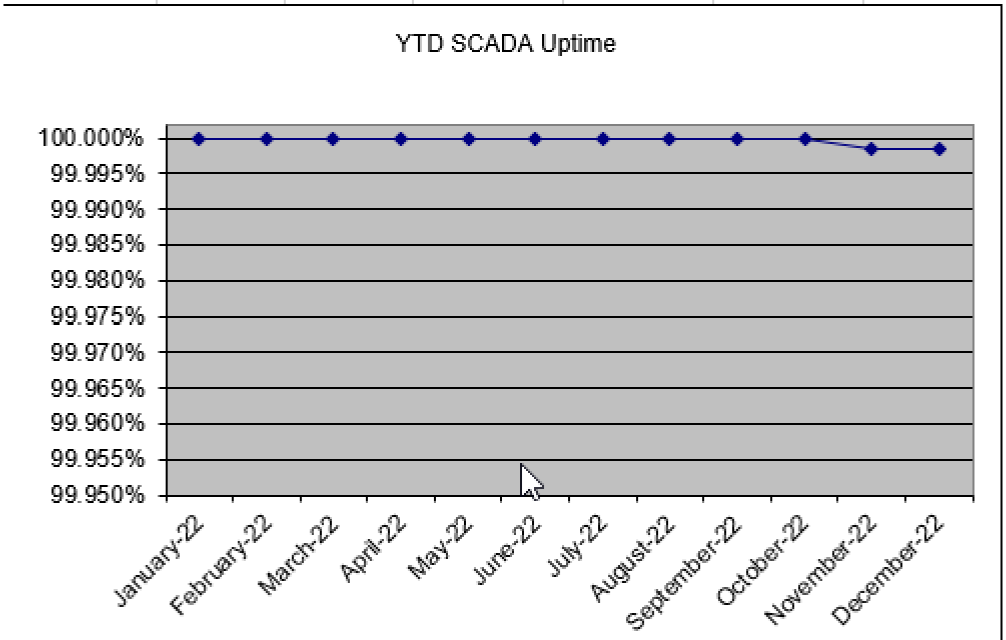
One alternative, however, that we have considered as part of these system upgrades over that past several years is moving from physical to virtual server hardware platforms. These virtual platforms have had sufficient time to prove their reliability and SCADA vendors have given their blessing on implementation 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 running the same virtual EMS software, thus delaying the need for a major $2M capital project to upgrade the EMS software.

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 2022, for example, we met a year-to-date SCADA uptime target of 99.999%, well above the 99.98% objective.



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.

There are two "revolving" projects, however, SCADA Hardware Refresh and SCADA Expansion, that are for minor refresh and expansion items like computer 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

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 weekly meetings scheduled within the Energy Management Systems group 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:	Apr 28, 2023
Print Name:	Craig N. Figart		
Title:	Mgr Energy Mgmt Systems		
Role:	Business Case Owner		

Signature:	*Michael A Magruder*	Date:	May 1, 2023
Print Name:	Michael A. Magruder		
Title:	Director, System Operations & Planning		
Role:	Business Case Sponsor		

Signature:	*Craig N Figart*	Date:	Apr 28, 2023

Print Name:	Craig N. Figart
Title:	Mgr Energy Mgmt Systems
Role:	Steering/Advisory Committee Review

ER7001/ 7003 Structures and Improvements

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 and new furniture additions (to support growth), and business additions or site improvements.

Facilities apportions approximately 50% to Asset Condition work that is identified using Paragon Asset Condition software, 30% is set aside for Manager Requested projects, and 20% is kept aside for unexpected capital needs and furniture replacements. There is currently $13.6M in Asset Condition backlog and requirements identified using the Paragon Asset Condition software. A funding of $5.1M in 2024, 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.

The Facilities Capital Steering Committee approved submission of this Business Case.

VERSION HISTORY

Version	Author	Description	Date
1.0	*L. Miller*	*Initial draft of Revised Template*	*4/04/2023*
BCRT	*Christine Tasche*	*Has been reviewed by BCRT and meets necessary requirements*	*4/18/2023*

ER7001/ 7003 Structures and Improvements

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$5,100,000**	**$5,100,000**
2025	**$5,250,000**	**$5,250,000**
2026	**$5,410,000**	**$5,410,000**
2027	**$5,740,000**	**$5,740,000**
2028	**$5,910,000**	**$5,910,000**

Project Life Span	*Ongoing*
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?

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.

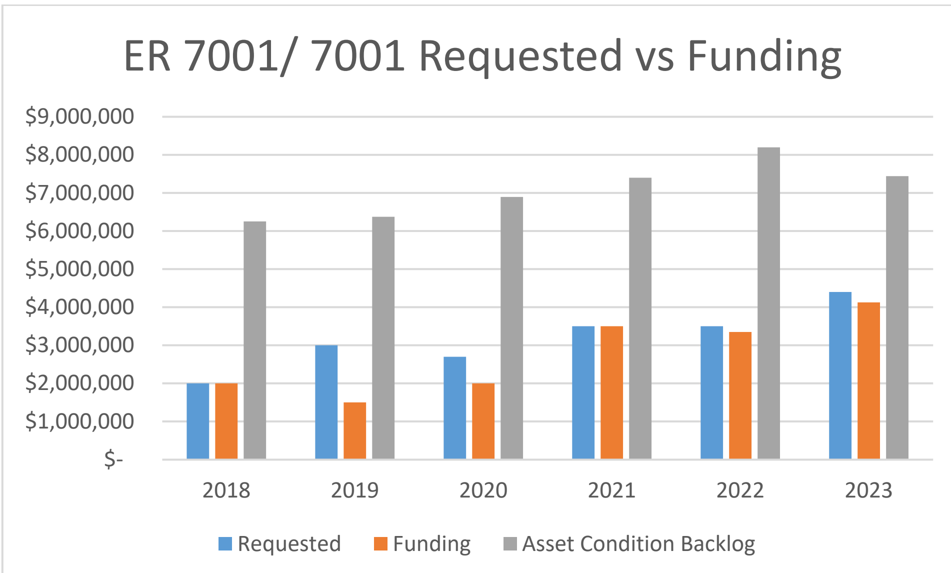
ER7001/ 7003 Structures and Improvements

Location	Date Built	Address	City	State
Airport Hangar	2019	7500 W. Park Dr., Bldg 1060	Spokane	WA
Beacon (battery building and canopy)	2015	2180 N Havana St	Spokane Valley	WA
Clark Fork Bunkhouse	1959	806 Main St.	Clark Fork	ID
Clarkston Service Center	1975	1300 Fair Street	Clarkston	WA
Coeur d'Alene Service Center	1994	1735 N. 15th Street	Coeur d'Alene	ID
Colfax Facility	1990	704 North Clay	Colfax	WA
Colville Service Center	2010	176 Degrief Road	Colville	WA
Davenport Pole Yard and Vehicle Storage	1996		Davenport	WA
Davenport Service Center	1966	327 Morgan Street	Davenport	WA
Deer Park Service Center	2018	Airport Drive	Deer Park	WA
Dollar Road Fleet Shop	2015	2,406 N. Dollar Road	Spokane	WA
Dollar Road Service Center	2019	2406 N. Dollar Road	Spokane	WA
Dollar Road Truck Storage	2014	2406 N. Dollar Road	Spokane	Wa
Dollar Road Wash Bay	2018	2406 N. Dollar Road	Spokane	Wa
Downtown Network Center	2016	1717 W. 4th Ave	Spokane	WA
Downtown Project Center	2016	1717 W. 4th Ave	Spokane	WA
Elk City Facility	2017	Hwy 14	Elk City	ID
Goldendale	2015	912 E. Broadway	Goldendale	WA
Grangeville Facility	1933	201 E. Main Street	Grangeville	ID
Grangeville Pole Yard	2016		Grangeville	ID
Grants Pass Service Center	1960	618 SE J Street	Grants Pass	OR
Jack Stewart North Line Trailer	1985	8308 N. Regal	Spokane	WA
Jack Stewart Office Modular	2012	8307 N. Regal	Spokane	WA
Jack Stewart South Line Trailer	1993	8309 N. Regal	Spokane	WA
Jack Stewart Training Center	1999	8307 N. Regal	Spokane	WA
Kamiah Facility	1992	No Kidd Rd.	Kamiah	ID
Kellogg Covered Vehicle Storage	2012	121 Hill Street	Kellogg	ID
Kellogg Materials Storage	1980	122 Hill Street	Kellogg	ID
Kellogg Service Center	1960	120 Hill Street	Kellogg	ID
Kettle Falls Generating Plant Offices	1976	1151 Hwy 395 N	Kettle Falls	WA
Klamath Falls Service Center	2008	2825 Dakota Ct.	Klamath Falls	OR

ER7001/ 7003 Structures and Improvements

Klamath Falls Storage Building	2012	2826 Dakota Ct.	Klamath Falls	OR
LaGrande Service Center	1994	10201 F Street	LaGrande	OR
Lewiston Call Center	1976	803 Main Street	Lewiston	ID
Main Campus Café/Auditorium	1959	1412 E. Mission Ave.	Spokane	WA
Main Campus Canopy 5	1959	1411 E. Mission Ave.	Spokane	WA
Main Campus Central Operating Facility	1959	1411 E. Mission Ave.	Spokane	WA
Main Campus Investment Recovery	2011	1411 E. Mission Ave.	Spokane	WA
Main Campus Mini Line Dock	1970	1411 E. Mission Ave.	Spokane	WA
Main Campus New Fleet Building	2017	1411 E. Mission Ave.	Spokane	WA
Main Campus Oil Storage Vault	1996	1412 E. Mission Ave.	Spokane	WA
Main Campus Parking Garage	2019	1411 E. Mission Ave.	Spokane	WA
Main Campus Ross Park Building	1903	1411 E. Mission Ave.	Spokane	WA
Main Campus Service Building	1959	1411 E. Mission Ave.	Spokane	WA
Main Campus Warehouse Building	1959	1411 E. Mission Ave.	Spokane	WA
Main Campus Waste and Asset Recovery	2014	1411 E. Mission Ave.	Spokane	WA
Medford Outdoor Storage Canopy	1994	581 Business Park Drive	Medford	OR
Medford Service Center	1994	580 Business Park Drive	Medford	OR
Noxon Bunkhouse	1959	33 Avista Power Road	Noxon	MT
Orofino Service Center	1970	1051 Michigan Ave	Orofino	ID
Othello Service Center	1974	36 South 4th Avenue	Othello	WA
Pierce Facility	1985	104 Moscrip Dr.	Pierce	ID
Post Street Mobius / Annex Parking	1903	337 N. Post Street	Spokane	WA
Pullman Mechanic Shop	2012	5704 SR 270	Pullman	WA
Pullman Service Center	1959	5702 SR 270	Pullman	WA
Pullman Shed	1959	5704 SR 270	Pullman	WA
Pullman Storage Canopies	1959	5703 SR 270	Pullman	WA
Ritzville Facility	1955	401 E First	Ritzville	WA
Roseburg Service Center	2004	1404 Green Siding Road	Roseburg	OR
Sandpoint Covered Storage	1985	103 N. Lincoln	Sandpoint	ID
Sandpoint Service Center	1957	100 N. Lincoln	Sandpoint	ID

Sandpoint Storage Bays	1957	101 N. Lincoln	Sandpoint	ID
Sandpoint Truck Canopy	1985	102 N. Lincoln	Sandpoint	ID
Spokane Valley Call Center	1979	14523 E. Trent Ave.	Spokane Valley	WA
St Maries Offsite Garage and Pole Yard	2011		St. Maries	ID
St. Maries Service Center	1974	528 College Avenue	St. Maries	ID
Tekoa Facility	1971	West 101 Main Street	Tekoa	WA



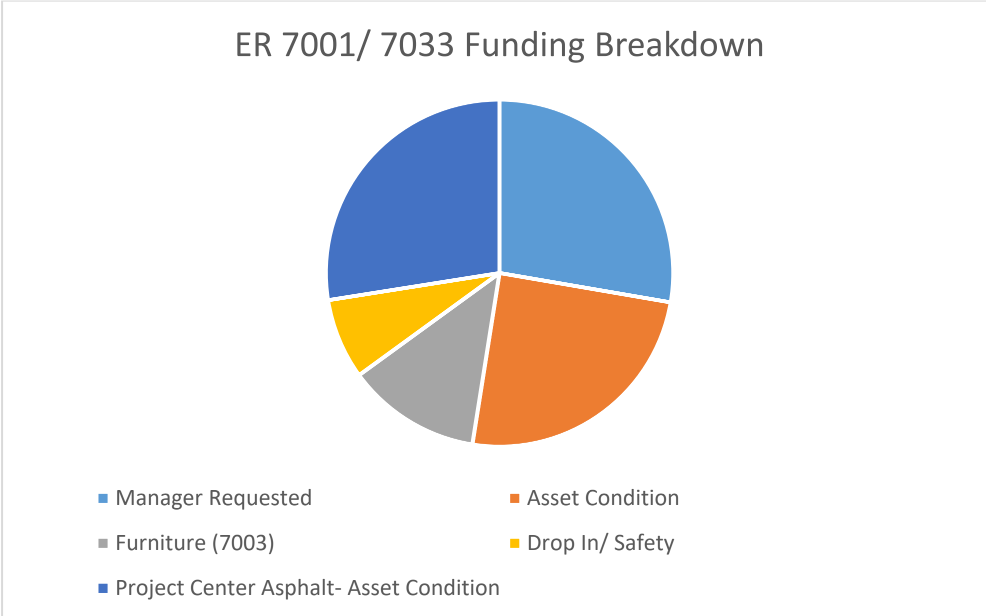
*The Asset Condition drop in 2023 is due to funding some larer Asset Condition projects.

This backlog is continuing to grow due to the average age of our infrastructure.

Funding backlog

There is an identified backlog and requirements totaling over $13.6M (as of April 2023) 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. 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.

ER7001/ 7003 Structures and Improvements



Capital Lifecycle Asset Replacements ER 7001

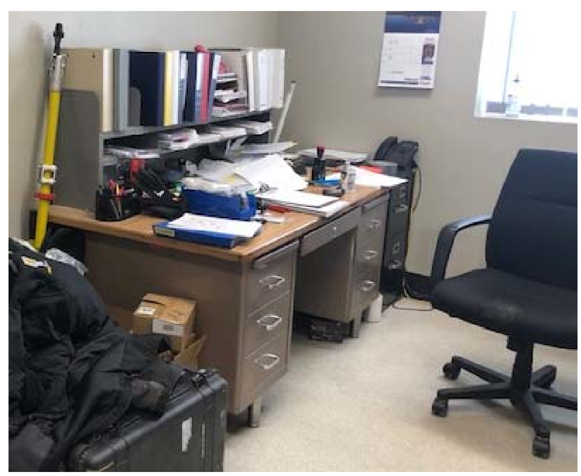
This portion of the Structures and Improvements Program is based on the results of the Facilities Condition Assessment Survey. This survey will consider the condition and lifecycle of each Facilities asset. Assets will be graded and those requiring replacement within the next 10 years will be estimated and scheduled for replacement at an appropriate year during the 10-year time frame of the survey. Buildings as a whole will be 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 new 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.

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 equests 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.

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.

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.

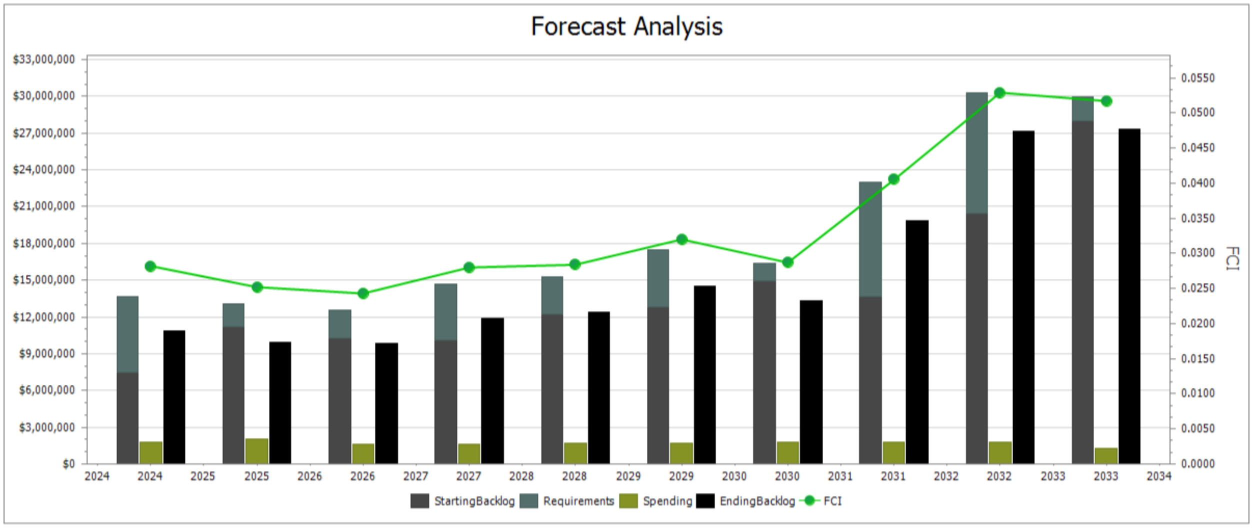
The major driver of this business case is Asset Condition. Facilities apportions approximately 50% to Asset Condition work that is identified using Paragon Asset Condition software (Terracon), 30% is set aside for Manager Requested projects, and 20% is kept aside for unexpected capital needs and furniture 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 $13.6M. 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:



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.

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

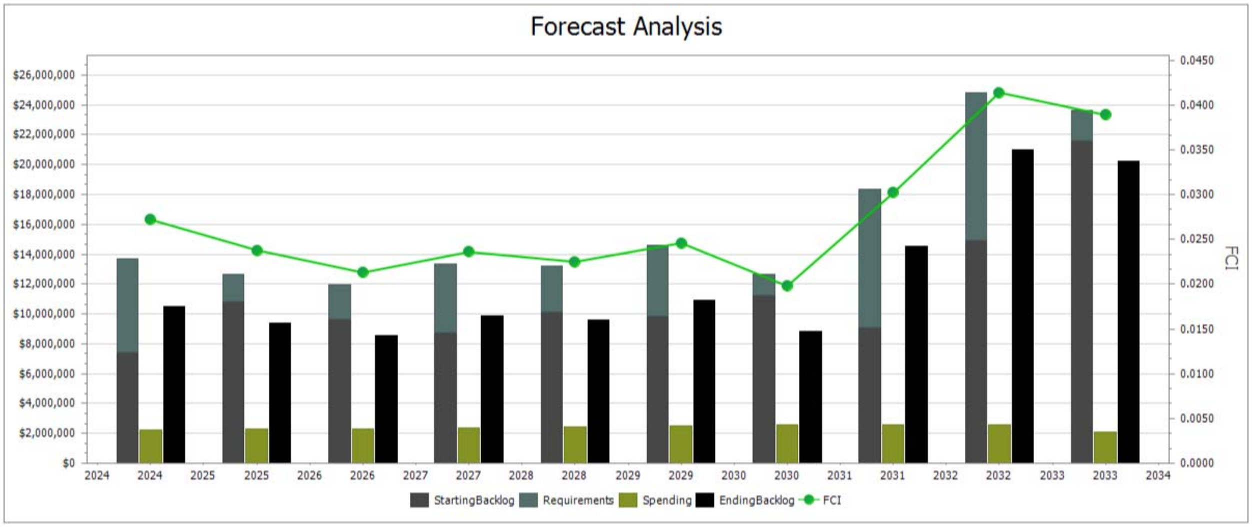
Funding the Structures and Improvements Program and the full proposed amount allows Facilities to address capital asset replacements and business needs. Safety, compliance, and productivity requests are rated highest and given priority first. Many of these replacements can create safety risk if not addressed (sidewalks, structural repairs). Not systematically addressing maintenance needs could ultimately result in complete replacement of the buildings at some point.

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:

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

ER7001/ 7003 Structures and Improvements



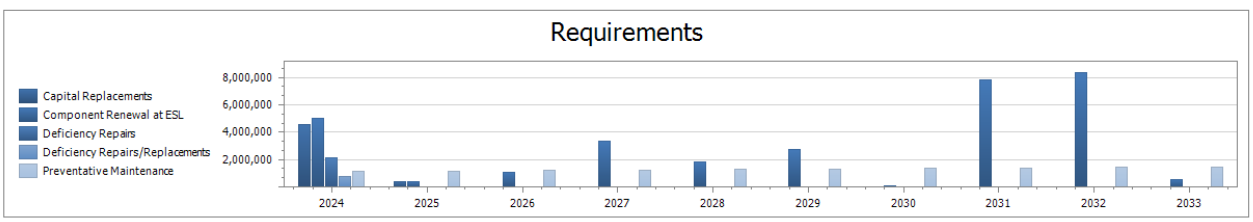
ID	Grouping	Account	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Grand Total
1	Backlog (Start of Year)	Capital Replacements	$5,250,967	$4,977,138	$4,891,430	$4,559,665	$4,134,134	$3,679,071	$3,193,879	$2,675,613	$2,122,656	$1,631,974	
		Component Renewal at ESL	$26,994	$3,738,789	$2,659,775	$2,175,100	$4,003,917	$4,265,977	$6,118,951	$4,527,882	$10,907,568	$18,001,888	
		Deficiency Repairs	$1,457,303	$1,398,189	$1,337,199	$1,274,338	$1,209,766	$1,143,311	$1,074,655	$1,018,781	$1,049,345	$1,080,825	
		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		$7,439,273	$10,839,244	$9,635,287	$8,778,391	$10,140,185	$9,904,498	$11,228,107	$9,088,118	$14,971,385	$21,633,259	
2	Requirements	Capital Replacements	$81,161	$286,594	$65,470	$0	$0	$0	$0	$0	$0	$0	$433,225
		Component Renewal at ESL	$5,004,677	$386,887	$1,043,236	$3,320,802	$1,823,829	$3,374,953	$68,124	$7,881,130	$8,425,749	$528,858	$31,858,245
		Preventative Maintenance	$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	$1,479,400	$12,998,168
	Requirements Total		$6,219,675	$1,841,333	$2,311,593	$4,559,777	$3,099,972	$4,689,380	$1,421,984	$9,275,606	$9,862,059	$2,008,258	$45,289,638
3	Backlog + Requirements		$13,658,948	$12,680,577	$11,946,880	$13,338,167	$13,240,158	$14,593,878	$12,650,092	$18,363,724	$24,833,445	$23,641,517	
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	$499,955	$514,771	$530,041	$545,942	$562,220	$578,218	$596,196	$614,782	$538,215	$0	$4,980,341
		Component Renewal at ESL	$1,499,951	$1,544,969	$1,591,263	$1,639,001	$1,688,104	$1,738,853	$1,791,073	$1,844,782	$1,900,124	$1,957,049	$17,195,168
		Deficiency Repairs	$99,838	$99,937	$99,978	$99,807	$99,756	$99,957	$85,546	$0	$0	$0	$684,820
		Preventative Maintenance	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$99,999	$100,000	$100,000	$100,000	$999,998
	Spending Total		$2,199,744	$2,259,676	$2,321,283	$2,384,750	$2,450,079	$2,517,028	$2,572,815	$2,559,564	$2,538,339	$2,057,048	$23,860,327
6	Variance (Budget minus Spending)	Capital Replacements	$45	$229	$409	$423	$535	$1,417	$829	$153	$95,170	$652,385	$751,594
		Component Renewal at ESL	$49	$31	$87	$94	$161	$52	$2	$23	$31	$106	$637
		Deficiency Repairs	$162	$63	$22	$193	$244	$43	$14,454	$100,000	$100,000	$100,000	$315,180
		Preventative Maintenance	$0	$0	$0	$0	$0	$0	$1	$0	$0	$0	$2
	Variance (Budget minus Spending) Total		$256	$324	$517	$710	$941	$1,512	$15,285	$100,176	$195,201	$752,492	$1,067,413
7	Backlog (End of Year)	Capital Replacements	$4,832,173	$4,748,961	$4,426,859	$4,013,722	$3,571,914	$3,100,853	$2,597,683	$2,060,831	$1,584,441	$1,631,974	
		Component Renewal at ESL	$3,629,892	$2,582,306	$2,111,747	$3,887,299	$4,141,725	$5,940,729	$4,396,002	$10,589,872	$17,477,561	$16,573,698	
		Deficiency Repairs	$1,357,465	$1,298,251	$1,237,221	$1,174,530	$1,110,011	$1,043,354	$989,108	$1,018,781	$1,049,345	$1,080,825	
		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		$10,523,538	$9,354,647	$8,522,710	$9,844,840	$9,616,017	$10,901,075	$8,823,416	$14,535,326	$21,003,164	$20,205,068	
8	Unfunded Preventative Maintenance	Preventative Maintenance	$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	$1,379,400	$11,998,170
9	FCI		0.0272	0.0238	0.0213	0.0236	0.0225	0.0246	0.0198	0.0302	0.0414	0.0389	
10	Total Replacement Value		$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	$555,292,718	
11	Spending as % of TRV		0.52 %	0.52 %	0.51 %	0.51 %	0.51 %	0.51 %	0.51 %	0.49 %	0.47 %	0.37 %	

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 and requirements of $13.6M 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. 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.

Even funding this program at 75% we will never be able to completely reduce the backlog. Providing more than the $5.1M requested would require additional Project Management personnel and possibly FTE's. Facilities can accommodate this request within their current staffing model. It is the goal of this program to maintain a level backlog that projects are selected from using Terracon's risk and the impact the item has on the Company's ability to perform its work, making the highest priority projects readily apparent.

Base known projects over the next 10 years- including backlog:



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	

[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	Scope Reduction: Planned Work	$20,000	$20,600	$21,220	$21,860	$22,510
O&M	Estimated Energy Savings + 3%	$11,000	$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	2024	2025	2026	2027	2028
Capital		$0	$	$	$	$
O&M	Operational Efficiencies +3%	$292,958	$301,746	$310,799	$320,123	$329,726

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:

- 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

[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.

    - 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.
        - 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**

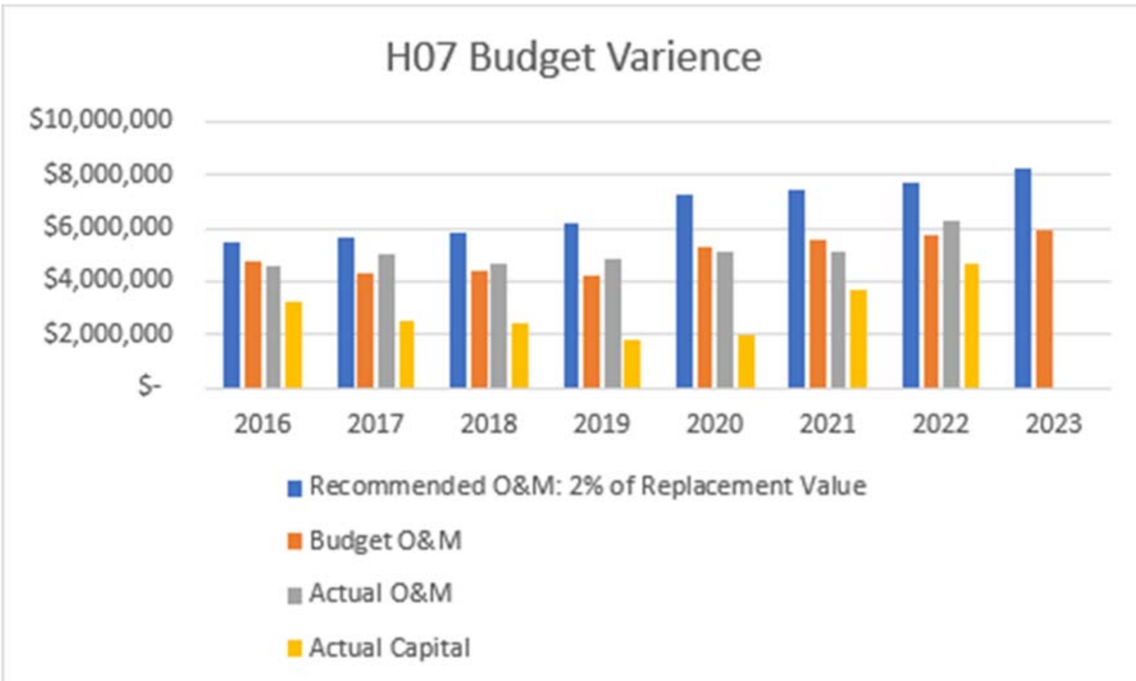
Lifecycle furniture replacements and new furniture additions (to support growth)

- 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 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.

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 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.
    i. 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

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

- 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 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:	Eric Bowles	Date:	4/27/23
Print Name:	Eric Bowles		
Title:	Corporate Facilities Manager		
Role:	Business Case Owner		

Signature:	Kelly Magalsky	Date:	4/27/2023
Print Name:	Kelly Magalsky		
Title:	Director, Shared Services		
Role:	Business Case Sponsor		

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

Substation Asset Condition

EXECUTIVE SUMMARY

Please provide a one page summary of the business case and high-level summary of the projects or programs included. Please describe the need for the project (a synopsis of the problem, the current state, and recommended solution), alternatives considered, the cost of the recommended solution, applicable metrics, customer benefits, Avista benefits or offsets derived from the investment, and risks, to customer and Avista, if the business case is not funded.

The Substation Asset Condition Business Case was formerly the Substation Rebuilds Business Case. The name is being changed to better align the set of projects with the Project Driver. Substation Asset Condition is one of the largest business cases for Avista because there is a vast amount of expensive equipment necessary to serve customers reliably through our electric system

Substations are necessary for serving customers properly. Substations transform electrical energy from high voltage transmission lines to lower voltage distribution lines that feed customers service points. Substations also allow switching, which contributes to reliability and the ability to maintain the system. 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. ER 2215 includes small substation projects (single transformer replacements, regulator upgrades, etc) that have been deemed needed due to asset condition leading to imminent equipment failure. Equipment failures for capital items that have been run to failure are funded through ER 2215

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. There were 95 projects opened and completed in 2020 that aimed at addressing individual pieces of equipment that failed to fulfill their intended purpose or became obsolete.

Good, reliableelectric service to customers 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.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Madden/Kusel*	*Initial draft of original business case*	*5/12/2023*
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements*	

Substation Asset Condition

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$37,500,000	$15,000,000
2025	$38,500,000	$25,000,000
2026	$39,000,000	$35,000,000
2027	$29,500,000	$18,000,000
2028	$24,500,000	$30,000,000

Project Life Span	Ongoing
Requesting Organization/Department	Substation Engineering
Business Case Owner | Sponsor	Glenn Madden | 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 repeated 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.

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 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. See Section 2.1 for a table indicating the plan for which substations are planned to be greenfield and which are planned to be brownfield.

Replacing substation apparatus and equipment as it fails, 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. However, a piece of equipment that no longer provides the function of its intended purpose has failed and should be replaced.

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).

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.

Rebuilding significant portions of substations or the entire substation 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.

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.

Substation major apparatus includes high-voltage circuit breakers, lower voltage circuit breakers and reclosers, circuit switchers, capacitor banks, power transformers and step voltage regulators. Associated equipment includes relays, meters, surge arrestors, station rock and fencing, panel houses, instrument transformers, high voltage fuses, air switches, autotransformer diagnostic equipment, batteries and chargers, and panel houses.

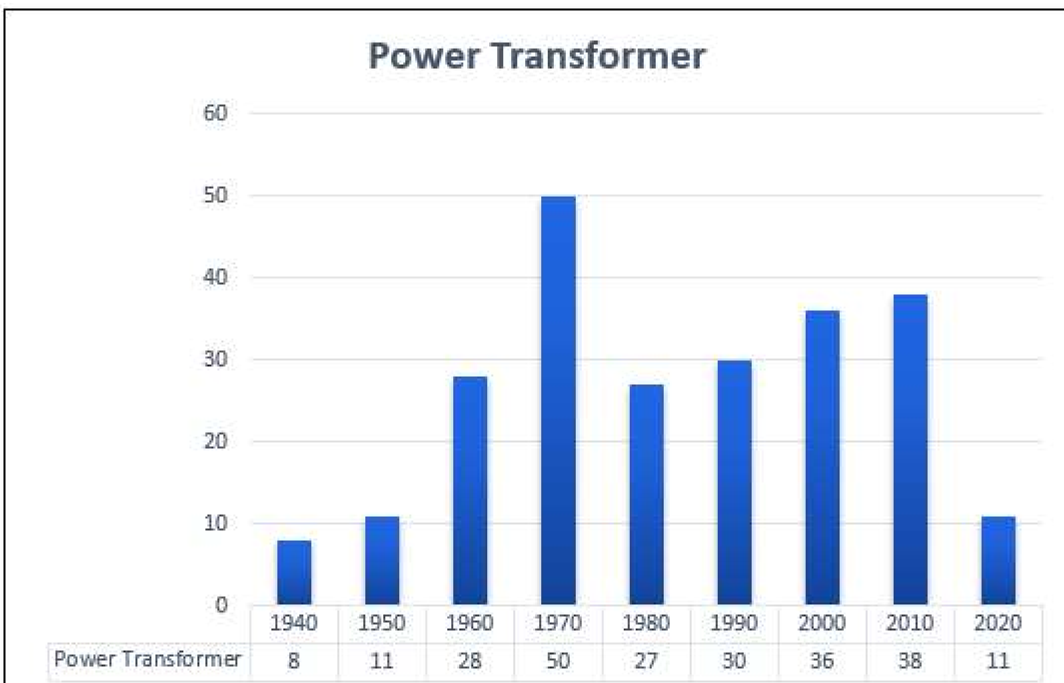
Substation Asset Condition

Equipment Type	System Count
Air Switch (>100kV)	1,063
Battery Banks	142
Circuit Breakers (<100kV)	495
Circuit Breakers (>100kV)	394
Circuit Switchers	121
Power Transformers	235
Voltage Regulators	1,085

Failure to replace failed and obsolete equipment will increase the risk of more frequent and/or extended duration of outages due to major equipment failure and inability to maintain major apparatus. Substation outages may have significant consequences as they tend to impact a large number of customers.

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 for an example of an age profile. While operating and maintaining this equipment, sometimes issues arise and a replacement is necessary to avoid customer outages or maintain employee safety. Currently, Avista owns and maintains 165 substations.



1.2. Discuss the major drivers of the business case.

The work included in this business case is asset condition and failed plant 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	Run to Failure

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.

Asset Condition situations can result in customer outages. Often momentary or short duration outages occur at the time of an equipment failure. However, automated switching or Operations Engineers switching around outages can bring most affected customers’ power back on line. However, with less overall extra capacity on the system there is a stronger likelihood that that an equipment failure will cause sustained customer outages.

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 1000 and 3000 customers.
Because Avista has 165 substations and substations can last at most, 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. See section 2.6 for amounts of replacements and levelized targets for some equipment.

Spare substation equipment is necessary to have on hand so that when a piece of equipment fails to operate or catches on fire 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. Lately, lead times on equipment have doubled on most items, which necessitates having more spare pieces of equipment. Not having enough spare equipment in case of failure 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*.

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:
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.

A couple examples of substations that were in need of rebuilding from mostly asset condition concerns are Sunset Substation (see picture below) and Davenport 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.

Substation Asset Condition

The existing circuit breakers (one is the oldest in the Avista system) at the station do not have sufficient short circuit interrupting capability to interrupt close in faults on the connected transmission lines. It is also a compliance issue because it doesn't meet NERC performance requirements. System performance analysis indicates an inability of the System to meet the performance requirement R2.3 of NERC TPL-001-4 in scenarios representing 2017 Heavy Summer Scenarios for P0 events. No Operating Procedures are available to mitigate the system deficiencies.

The AC and DC service power and control circuit problems make adding or replacing equipment very difficult and expensive. Lack of capacity caused the mobile substation to need to be installed during 2021 Heat Event (see picture below).

The existing Davenport Substation dates to 1936 and is overdue for a rebuild given the existing site conditions (deteriorating panel house and fence, limited feeder flexibility and expansion capability to support future growth). Yard fencing, grading, grounding all present safety issues for employees and the general public. The substation yard has insufficient working safety clearances. The transformer and 115 kV disconnect switches are unsupported and have known issues. Bus regulation is non-standard. Feeder exit cables have hot spots and are an imminent failure risk. Various other condition issues (insulators, reclosers, etc) exist at this site as well. The Substation must be rebuilt off site due to limited space in the existing yard and limited property within close vicinity.

The Davenport Substation has 23 brown glass insulators. Brown glass insulators are an old technology used to insulate the structure from the energized wire. They have a history of breaking and falling on crews when the structure is shaken as they operate switches. Brown glass also has a history of not providing the insulation necessary to keep pole fires from occurring. Planned outages are needed to safely replace brown glass insulators proactively or under an emergency situation when an insulator breaks.

Kooskia Substation with split timbers and moss growing on the horizontal members.

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 potential failure of substations that would lead to degradation of reliability and mitigating the frequency and duration of outages due to equipment failure.

The proposed solution is to increase the current funding level from where the programmatic Substation Rebuilds Business Case has been funded in the past. The spending for the ERs within the Substation Rebuilds Business Case are shown in the table below.

Substation Asset Condition

ER Description	2018	2019	2020	2021	2022	2023 (Expected Spend)
Substation - Capital Spares	$1,159,674	$751,580	$1,055,171	$0	$2,031	$1,400,000
Substation Asset Mgmt Capital Maintenance	$4,100,129	$3,756,452	$2,998,525	$2,822,820	$2,262,446	$5,610,000
Substation Rebuilds	$11,304,965	$6,653,240	$11,648,303	$14,089,960	$23,523,470	$32,184,569
Total	**$16,564,768**	**$11,161,271**	**$15,701,999**	**$16,912,780**	**$25,787,946**	**$39,194,569**

Increase 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 2024 budget, the Metro Project will be its own business case, so the budget estimates for Metro are not show in the budget requests for 2024-2028. However, the request for the Substation Asset Condition Business Case funding continues to increase as shown in the table below.

ER Description	2024	2025	2026	2027	2028
Substation - Capital Spares	$1,250,000	$1,250,000	$1,250,000	$1,250,000	$1,250,000
Substation Asset Mgmt Capital Maintenance	$5,550,000	$4,550,000	$4,050,000	$4,050,000	$4,050,000
Substation Rebuilds	$29,163,285	$31,580,000	$40,745,000	$32,100,000	$24,920,000
Total	**$35,963,285**	**$37,380,000**	**$46,045,000**	**$37,400,000**	**$30,220,000**

Projects comprising the Substation Rebuilds ER portion of the budget requests for the Substation Asset Condition Business Case are shown below. Note that substation rebuild projects typically take multiple years to design and construct. The substation rebuild projects shown below are shown in the year that the largest amount of budget is being requested.

2024	2025	2026	2027	2028
Lolo **Poleline (Prairie)***	Kooskia **Valley***	South Lewiston **Bronx*** Post Falls	Little Falls Northwest	**Ogara***

***Greenfield Substation**

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 reaches 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 has failed to function or 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 and replacement to function reliably for good customer service. Substation designs and operation need to enable equipment maintenance and the replacement of equipment while still maintaining service to customers. Short momentary outages to allow switching may be required to allow maintenance activities to take place but extended outages that allow that occur from even day long maintenance activities are not acceptable customer service.

Avista System Operations is requesting that to properly operate the Avista electric system that substations have simplicity of switching and an intuitiveness in the layout of switching. The outage impacts of station work would be minimized. There is a need for consistency of switching and configuration from one station to another. Additionally, there is a desire for consistency in the equipment interface and how information is presented to operators.

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		$0	$0	$0	$0	$0
O&M		$0	$0	$0	$0	$0

No direct offsets are anticipated because rebuilding substations still requires monthly substation inspections and there are typically more pieces of equipment to inspect in a rebuilt substation than the previous substation.

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

[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.

Substation Asset Condition

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	-	$0	$0	$0	$0	$0
O&M	Substation Rebuilds & Asset Management Offsets	$1,951,000	$1,951,000	$1,951,000	$1,951,000	$1,951,000

<u>Station Rebuild (ER2204 Substation Rebuilds)</u>
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.

Substation rebuilds are usually the result of many issues within a substation. There are often asset condition issues with several pieces of equipment, issues with safety, efficiency, environmental impacts where a rebuild is the only way to avoid risk from all of these factors. All new substation equipment means little maintenance other than the routine inspections, testing and maintenance. Servicemen will spend less time maintaining but will often spend more time completing inspections and testing because substation rebuilds usually result in a larger station with more equipment.

<u>Station Rebuild (ER2215 Asset Maintenance)</u>
This expenditure item is focused on projects that are requested and completed due to Asset Management issues like Asset Condition, Equipment Failures, Safety Issues, and Environmental Issues. Most are substation equipment replacements for equipment that has failed in service and are replaced on an emergency basis.

Assuming that a GPSS Serviceman spends approximately four hours each week driving to a substation, maintaining equipment to 'limp it along' instead of replacing it, and cleaning up. In 2020, 95 substations had Asset Management projects opened or completed. If none of these capital replacement projects were completed this equates to 19,760 hours (95 locations * 4 hours of O&M * 52 weeks = 19,760 hours of additional maintenance would be needed) spent on constantly limping equipment along. 9.5 additional GPSS Serviceman needed to complete this additional O&M work each year. 19,760 hours / 52 weeks / 40 hours = 9.5. Round this up to 10 Serviceman, this will cost $1,768,000 annually (10 Journeyman Electricians * $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.

<u>Risk of Outages due to not replacing equipment.</u>
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.

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.

ER 2000. By not having spare equipment when things like a high voltage (>115kV) circuit breaker or power transformer fails suddenly reliability on the system would be tremendously hampered.

ER 2204. If rebuilding substations is not funded, ER2215 would need to dramatically increase in size to be able to respond to more individual equipment failures. Not rebuilding substations where the majority of equipment has not met its intended use or is obsolete will lead to an increase in O&M work in addition to the increase in expenditures for ER 2215 to respond to a whole host of equipment failures. Continuation of non-standard construction practices and configurations would lead to considerably slower and more dangerous working conditions for field crews.

ER 2215. By not funding the Asset Management section of the Asset Condition Business Case the substation equipment will limp along until the various equipment fails at any time and quite possibly catastrophically. This leads to significant customer outages (thousands of homes and businesses), safety situations for the public and employees. Customers could be out for days, months or even years because this ER is the location where funding for replacing the equipment when it fails comes from.

Option 2: Maintain current funding level – The current spending on the Asset Condition risk category is $13 million annually. 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.

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 oil spill, hazardous waste cleanup, moderate to low volume or level of PCBs, minimal impact to waterways, repeated or moderate air emission exceedence	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 relationships and / or national / global media coverage	Potential for minimal or minor injury Lost Time Incident and Severity Rate increases year over 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 exceedence, 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

Davenport Substation is a Substation Asset Condition job for 2023. Below the alternatives for this project are listed as examples for typical alternatives for Substation Asset Condition projects contained within the Substation Asset Condition Business Case.

Alt1: Status Quo
Do nothing and deal with failed plant and resultant outages as they come up.

Alt 2: Replace Individual Pieces of Equipment
Replace equipment on a case-by-case basis. Based on amount of equipment at site past end-of-life, multiple outages, mobilizations/de-mobilizations would result.

Alt3: Rebuild Davenport
Rebuild substation (either in place or with a short move to a greenfield site). Add three-phase SCADA and comms to site. Will help remote sectionalizing ability on transmission line (DGP-STR).

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 lack of customer outages from substation failures. In addition, measuring the number of substation equipment failures would be another way of measuring success. By ensuring that the number of substation equipment failures is not dramatically increasing over time, customer outages in the future are likely not to be triggered.

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.

The table demonstrates the fact that not all equipment typically 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.

Equipment Type	Avista System Count	Avista Average Replacement per Year (2018-2022)	Avista Average Levelized Replacement Length
Air Switches (>100kV)	1,081	26.80	40.0 years
Battery Banks	138	11.00	12.5 years
Circuit Breakers (<100kV)	508	13.20	38.5 years
Circuit Breakers (>100kV)	400	16.60	24.1 years
Circuit Switchers	126	2.75	45.8 years
Power Transformers	239	5.40	44.3 years
Voltage Regulators	1,118	61.60	18.1 years

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, each and every 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.

ER 2215, the Substation Asset Management ER is governed by the Substation Maintenance Engineers, Distribution Area Engineers, Electric Shop Servicemen, Distribution Area Servicemen, and Substaion Engineering Manager.

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.

DocuSigned by:

Signature: Glenn J Madden — Date: May-12-2023 | 5:31 PM PDT

7D4B3DE5CBD846B...

Print Name: Glenn Madden

Title: Substation Engineering Manager

Role: Business Case Owner

DocuSigned by:

Signature: Vern Malensky — Date: May-14-2023 | 6:00 PM PDT

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Print Name: Vern Malensky

Title: Electrical Engineering Director

Role: Business Case Sponsor

Signature: ____________________ Date: ____________

Print Name: ____________________

Title: ____________________

Role: Steering/Advisory Committee Review

Substation – Performance and Capacity

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 2021 and documented in 2021-2022 System Assessment Version 2 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. An example of the capacity issues identified in the 2021-2022 System Assessment are provided in the below table.

Utilization %					
Station	**Equipment**	**2022**	**2026**	**2031**	**Year of 90%**
Huetter	HUE - XFMR #1	87	99	117	2023
	HUE141	64	73	84	NA
	HUE142	96	108	124	2022
Barker	BKR - XFMR #1	66	78	90	2031
	BKR12F1	74	83	96	2029
	BKR12F2	10	11	12	NA
	BKR12F3	52	59	68	NA
Idaho Road	IDR - XFMR #1	65	74	87	NA
	IDR251	w	38	42	NA
	IDR252	41	47	55	NA
	IDR253	75	86	101	2028
Deer Park	DEP - XFMR #2	55	59	66	NA
	DEP12F1	78	85	94	2029
	DEP12F2	20	21	23	NA
Francis & Cedar	F&C - XFMR #1	76	77	78	NA
	F&C12F1	80	81	82	NA
	F&C12F2	85	86	88	NA
	F&C12F3	67	68	68	NA
	F&C - XFMR #2	78	79	80	NA
	F&C12F4	81	82	83	NA
	F&C12F5	60	61	62	NA
	F&C12F6	90	91	92	2024
Rathdrum	RAT - XFMR #1	32	37	43	NA
	RAT231	62	71	83	NA
	RAT - XFMR #2	41	48	58	NA
	RAT233	65	76	91	2031
Avondale	AVD - XFMR #1	64	73	86	NA
	AVD151	69	78	91	2031
	AVD152	66	75	88	NA
Waikiki	WAK - XFMR #1	96	98	99	2022
	WAK12F1	76	77	79	NA
	WAK12F2	67	68	69	NA
	WAK - XFMR #2	85	86	87	NA
	WAK12F3	74	75	76	NA
	WAK12F4	64	64	65	NA
Prairie	PRA - XFMR #2	84	88	93	2029
	PRA221	77	80	85	NA
	PRA222	74	77	82	NA

The 2023-2024 System Assessment is anticipated to identify additional capacity issues due to increased load forecast which incorporates improved statistical evaluation of peak loading conditions and improved modeling accuracy utilizing additional distribution planning engineers. 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 substation and upgrades to existing stations. Estimated costs for 2024-2028 are expected to total $100 million. The break down for each year will 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 2021-2022 System Assessment associated with this business case includes:

- **Bronx Station Rebuild** - Reconstruct existing Bronx Station to include distribution facilities.
- **Carlin Bay Station** - Construct new distribution station to include single transformer and two feeders. Transmission integration to include constructing a new radial transmission line from O'Gara Station to Carlin Bay and rebuilding the existing O'Gara Station to a switching station. New microwave communication paths will be established to O'Gara Station.
- **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.
- **Huetter Capacity Mitigation -** Upgrade existing facility with second 30MVA lineup and two distribution feeders.
- **Barker Capacity Mitigation -** Upgrade existing Greenacres station with second 30MVA lineup and offload Barker to Greenacres.
- **Idaho Road Capacity Mitigation -** Upgrade existing Idaho Rd. station with second 30MVA lineup and two feeders.
- **Rathdrum Capacity Mitigation -** Add one additional feeder to off load RAT231 and RAT233.
- **Avondale Capacity Mitigation -** Upgrade existing Avondale station with second 30MVA line up and two feeders.
- **Waikiki Capacity Mitigation -** Upgrade existing Indian Trail station with second 20MVA transformer and two new 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*	*May 2023*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements* DS SC	May-15-2023 | 8:58 AM PDT

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$15,600,000	~$5,500,000
2025	$11,013,000	~$9,500,000
2026	$12,050,000	~$15,000,000
2027	$28,550,000	~$13,500,000
2028	$21,465,000	~$25,000,000

Project Life Span	On-Going
Requesting Organization/Department	Substation Engineering
Business Case Owner | Sponsor	Glenn Madden | Vern Malensky
Sponsor Organization/Department	Substation 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

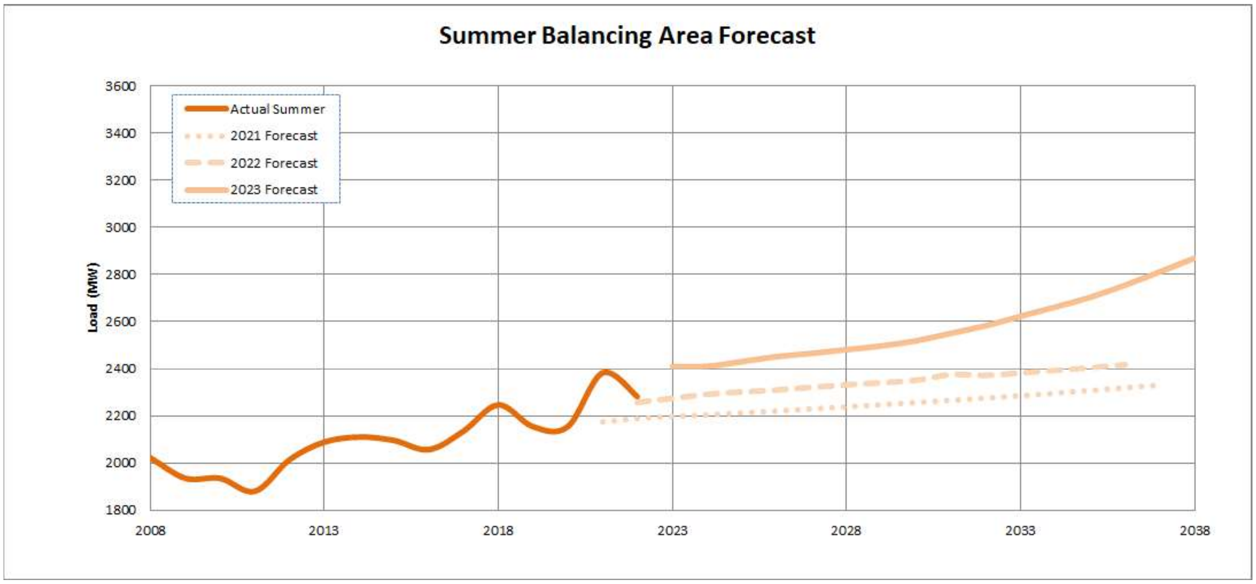
1. BUSINESS PROBLEM - This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.

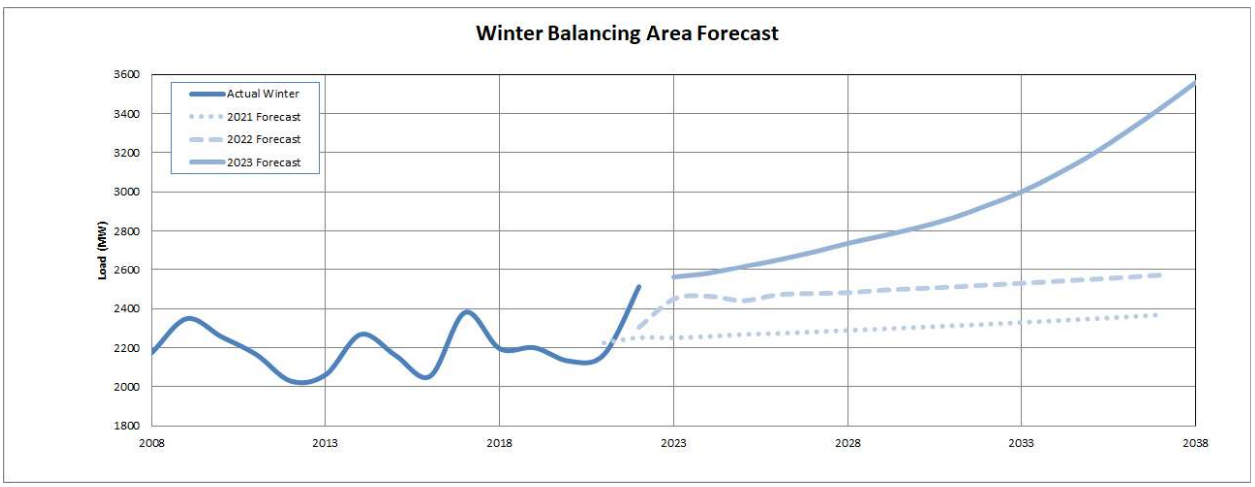
1.1. What is the current or potential problem that is being addressed?

The Substation – Performance and Capacity Business Case provides for 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 15-20MW growth per year and the winter load forecast is estimating approximately 30-40MW 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.

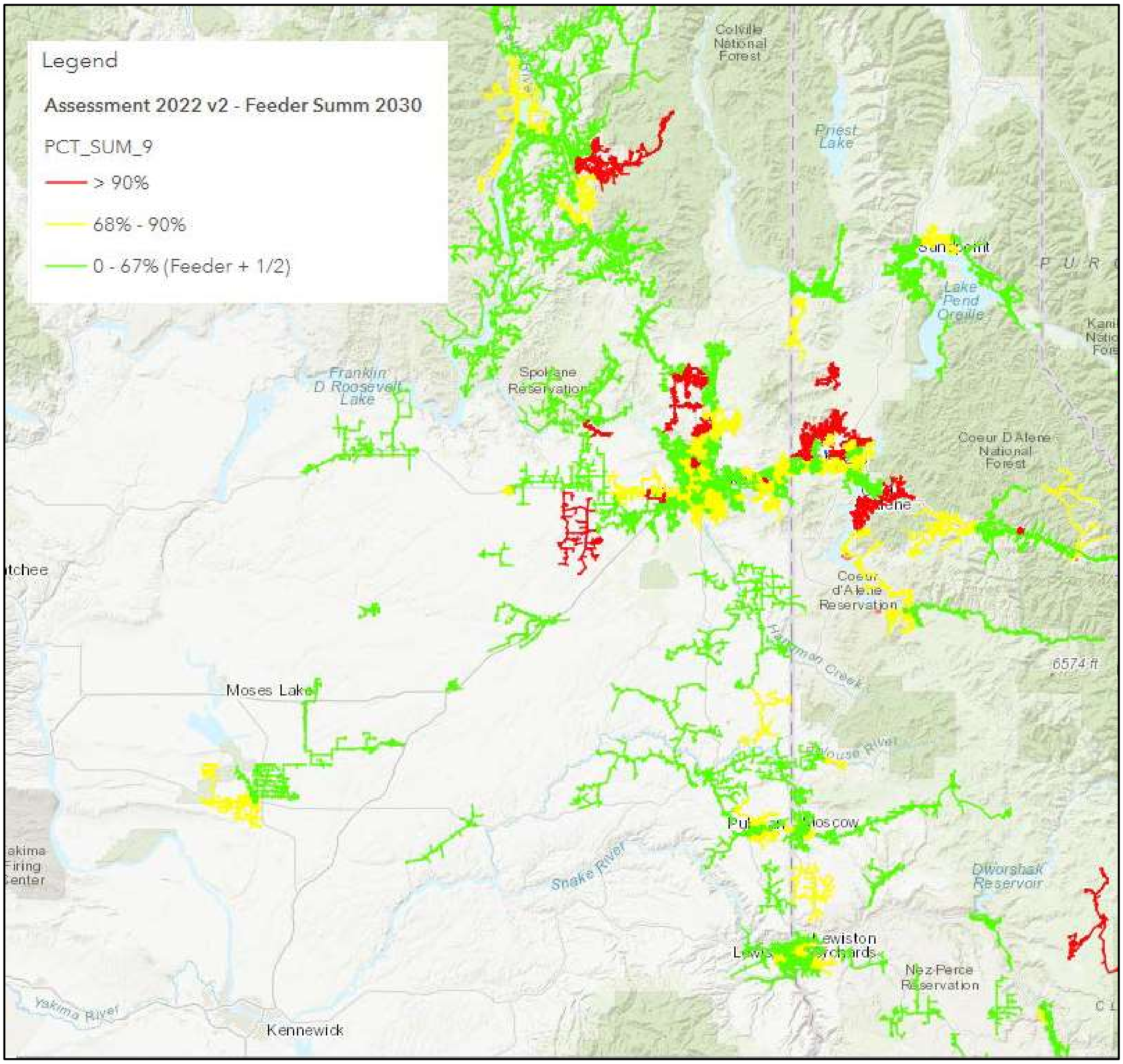
Substation – Performance and Capacity





The additional load forecasted in the above figures will be spread across the Avista service territory, but the specific areas of North Spokane, Spokane Valley, 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 from the 2021-2022 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.

Substation – Performance and Capacity



Specific distribution substation capacity issues observed in the 2021-2022 System Assessment are provided in the following table.

	Utilization %				
Station	**Equipment**	**2022**	**2026**	**2031**	**Year of 90%**
Huetter	HUE - XFMR #1	87	99	117	2023
	HUE141	64	73	84	NA
	HUE142	96	108	124	2022
Barker	BKR - XFMR #1	66	78	90	2031
	BKR12F1	74	83	96	2029
	BKR12F2	10	11	12	NA
	BKR12F3	52	59	68	NA
Idaho Road	IDR - XFMR #1	65	74	87	NA
	IDR251	w	38	42	NA
	IDR252	41	47	55	NA
	IDR253	75	86	101	2028
Deer Park	DEP - XFMR #2	55	59	66	NA
	DEP12F1	78	85	94	2029
	DEP12F2	20	21	23	NA

Substation – Performance and Capacity

Utilization %					
Station	**Equipment**	**2022**	**2026**	**2031**	**Year of 90%**
Francis & Cedar	F&C - XFMR #1	76	77	78	NA
	F&C12F1	80	81	82	NA
	F&C12F2	85	86	88	NA
	F&C12F3	67	68	68	NA
	F&C - XFMR #2	78	79	80	NA
	F&C12F4	81	82	83	NA
	F&C12F5	60	61	62	NA
	F&C12F6	90	91	92	2024
Rathdrum	RAT - XFMR #1	32	37	43	NA
	RAT231	62	71	83	NA
	RAT - XFMR #2	41	48	58	NA
	RAT233	65	76	91	2031
Avondale	AVD - XFMR #1	64	73	86	NA
	AVD151	69	78	91	2031
	AVD152	66	75	88	NA
Waikiki	WAK - XFMR #1	96	98	99	2022
	WAK12F1	76	77	79	NA
	WAK12F2	67	68	69	NA
	WAK - XFMR #2	85	86	87	NA
	WAK12F3	74	75	76	NA
	WAK12F4	64	64	65	NA
Prairie	PRA - XFMR #2	84	88	93	2029
	PRA221	77	80	85	NA
	PRA222	74	77	82	NA

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 server customer demand. The 2021 Heat Wave, see Heat EOP Event Analysis report, is an example of past observed system performance where customers 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***.**

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.

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.[1]

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 2021-2022 System Assessment Version 2 (2021-2022 Avista System Assessment-V2.pdf). The table provided in Section 1.1 above provides the observed performance issues. The 2022-2023 System Assessment studies are anticipated to identify additional new system deficiencies due to higher load forecasts from previous assessment studies.

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.
- **Carlin Bay Station** - Construct new distribution station to include single transformer and two feeders. Transmission integration to include constructing a new radial transmission line from O'Gara Station to Carlin Bay and rebuilding the existing O'Gara Station to a switching station. New microwave communication paths will be established to O'Gara Station.
- **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.

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

- **Huetter Capacity Mitigation -** Upgrade existing facility with second 30MVA lineup and two distribution feeders.
- **Barker Capacity Mitigation -** Upgrade existing Greenacres station with second 30MVA lineup and offload Barker to Greenacres.
- **Idaho Road Capacity Mitigation -** Upgrade existing Idaho Rd. station with second 30MVA lineup and two feeders.
- **Rathdrum Capacity Mitigation -** Add one additional feeder to off load RAT231 and RAT233.
- **Avondale Capacity Mitigation -** Upgrade existing Avondale station with second 30MVA line up and two feeders.
- **Waikiki Capacity Mitigation -** Upgrade existing Indian Trail station with second 20MVA transformer and two new 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 2021-2022 System Assessment. Each project under this program will require planning and operational studies, justifications, and project reports prior to funding.

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 Substation – Performance and Capacity business case. An example of work includes:

- 2021-2022 System Assessment – Version 2, 2022
- Heat EOP Event Analysis – Version 0, 2021

Individual project documentation is under development. Each project report will include detailed study results showing how the project will mitigation identified capacity issues.

[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		$	$	$	$	$

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]

2.4. Summarize in the table, and describe below the INDIRECT offset[4] (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. 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, 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 not adequately fund new distribution substation capacity projects. $Unknown

Alternative 2: Fund two distribution substation projects per year on average. $25 million/year

[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.

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.

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.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Substation – Performance and Capacity 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.

DocuSigned by:

Signature: Glenn J Madden — Date: May-15-2023 | 10:45 AM PDT

7D4B9DF8CBD8463...

Print Name: Glenn Madden

Title: Substation Engineering Manager

Role: Business Case Owner

DocuSigned by:

Signature: Vern Malensky — Date: May-15-2023 | 11:27 AM PDT

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Print Name: Vern Malensky

Title: Electrical Engineering Director

Role: Business Case Sponsor

Signature: — Date:

Print Name:

Title:

Role: Steering/Advisory Committee Review

Transmission Minor Rebuild

EXECUTIVE SUMMARY

Please provide a one page summary of the business case and high-level summary of the projects or programs included. Please describe the need for the project (a synopsis of the problem, the current state, and recommended solution), alternatives considered, the cost of the recommended solution, applicable metrics, customer benefits, Avista benefits or offsets derived from the investment, and risks, to customer and Avista, if the business case is not funded.

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 completing 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 service reliability.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Ken Sweigart*	*Initial draft of original business case*	*2/23/2023*
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements*	SB 2/24/23

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***

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 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

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.

Customer Requested: A small portion of the projects in this Business Case are Customer Requested with an associated Contribution in Aid of Construction (COAC) component.

Mandatory & Compliance: Both the Pole Inspection and Aerial Patrol Inspection programs for Transmission facilities are linked to NERC Standard FAC-501-WECC-1.

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.

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.

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.

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.

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.

This Business Case allows immediate attention to those asset most critically at risk of failure in the near term. 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. Replacement greatly reduces risk of failure and it removes any delay or other consequence associated in replacing failed assets.

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

2.2 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. 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	2024	2025	2026	2027	2028
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 offsets4 (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$2,720	$2,720	$2,720	$2,720	$2,720

There are no additional indirect offsets associated with projects between 2024-2028. The nature of the project (replacing poles, crossarms, or insulators only before end of life) 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.

[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.

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 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: See Sections 1.5, 2.1, and 2.2 for commentary.

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.

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: [signature] Date: 4/13/2023
Print Name: KEN SWEIGART
Title: MANAGER, TRANSMISSION LINE DESIGN
Role: Business Case Owner

Signature: [signature] Date: 4/13/2023
Print Name: Vern Malensky
Title: Director, Electrical Engineering
Role: Business Case Sponsor

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

Transmission Performance & Capacity

EXECUTIVE SUMMARY

The **Transmission Performance & Capacity Business Case** covers new Transmission construction work necessary to either support the addition of new substations due to load growth in a particular area or to reinforce existing substations with new transmission for increased performance. This program is managed through the joint efforts of Avista's Transmission Design & Engineering, Substations, Operations, and Transmission Planning groups, from which the requests for upgrades or additions are initiated. The projects within this program are typically requested by System Planning or System Operations.

The implementation of this business case will be considered successful if these projects are completed when committed to, successfully coordinated with the corresponding substation projects if applicable, and result in increased capacity or reliability to Avista's customers in the local areas where projects are constructed.

The recommended solution is to construct new transmission lines as prioritized by the Engineering Roundtable group to ensure that there is sufficient capacity to serve new customers in growing areas and to increase reliability to existing substations that are currently served by underperforming transmission line configurations. There are no expected business impacts to continuing this program in place. If Avista does not implement this business case, the company is at risk of overloading its existing infrastructure in certain areas of its service territory where load is growing over time. This Program will have a Service Code of Electric Direct and a Rate Jurisdiction of Allocated North. A spend of $16,500,000 (2023-2029) to complete both projects, or $14,250,000 (2023-2027) is needed to complete one project and intitiate the other project as follows:

- ER 2480, BI CT910 ($14,000,000): Carlin Bay Substation 115kV Transmission Integration
    - (2023 through 2027)
- ER 2612, BI ST907 ($2,500,000): Hawthorne Substation 115kV Transmission Integration
    - ($250,000 in 2027)

Note: This Business Case was previously known as Transmission New Construction – Performance & Capacity
Note: This Business Case is connected to the Substation Performance & Capacity Business Case

The customer benefits from this Business Case through increased service reliability.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Ken Sweigart*	*Initial draft of original business case*	*2/23/2023*
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements Steve Carrozzo*	*5/8/2023*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$500,000	$0
2025	$2,000,000	$0
2026	$4,000,000	$0
2027	$7,250,000	$14,000,000
2028	$1,000,000	$0

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	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.

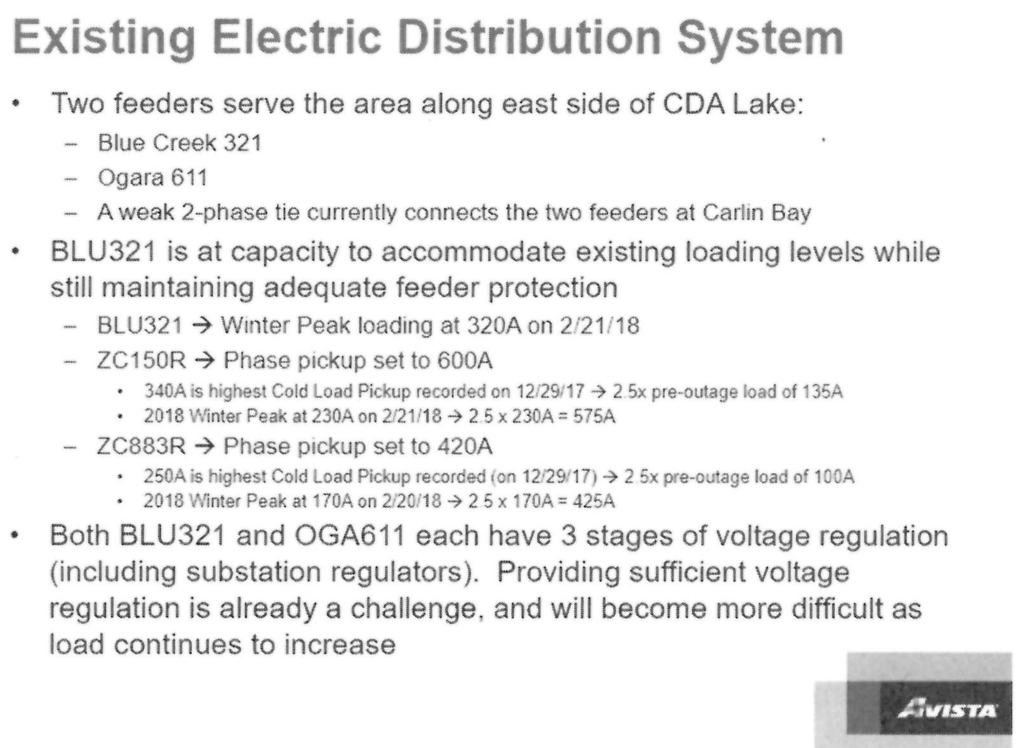
Investment Drivers

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.*

The Transmission Performance & Capacity Business Case covers the new Transmission construction work necessary to either support the addition of new substations due to load growth in a particular area or to reinforce existing substations with new transmission for increased performance. The projects within this program are typically requested by System Planning or System Operations.

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

Avoidance of overloading existing infastructure due to continual load growth or operational restrictions.



1.2 Discuss the major drivers of the business case.

Performance & Capacity: Customer benefits by having a Transmission System capable of supporting Substation Transformation additions needed to service growing loads.

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.

Adding Substations and associated Transmission is based on forecasted load increases. These forecasts can either overshoot or undershoot actual conditions. It is therefore necessary that a structured and measured approach be made to adding this infastructure so as not to overtax budget, design and construction, and outage resources.

History

- The need for a future distribution substation along the east side of Lake CDA was identified in the early 2000's.
- Many distribution system enhancements have been made to delay the need for the substation, including:
  - Reconductoring 4 miles of BLU321 feeder trunk to 556 AAC
  - Adjusting locations of protection devices, types, and sizes to best accommodate load
  - Many iterations of balancing the feeder and laterals
- Preliminary transmission route options were identified in 2010 for the Carlin Bay Tap
- Property was purchased for Carlin Bay Substation in 2011 along Elk Road near Carlin Bay
- Project formerly presented in January 2017 to ERT committee to establish timeline for transmission line construction

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

This program specifically supports the "Safety. Affordability. Responsibly" portion of the Avista Mission Statement.

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]

ERT Form for Carlin Bay-Ogara New Transmission Line
ERT Form for Hawthorne Substation New Transmission Line

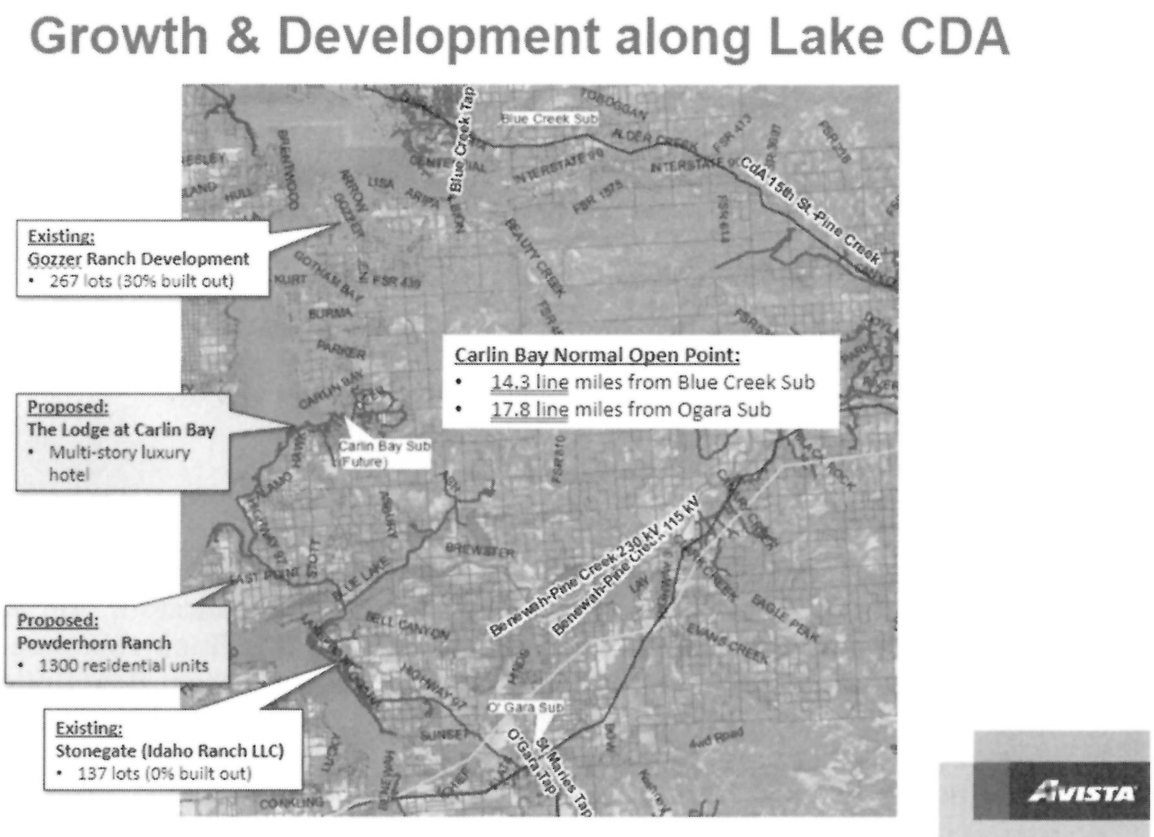
2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

This is the continuation of an ongoing Program, and requires the addition of infastructure to support load growth. Please see Alternatives Evaluation within each ERT submitted document for details.

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

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

This project represents a subset of the request ERT_2017-01 and is meant to work in conjunction with a new substation being built at Carlin Bay and an upgrade to a switching station at O'Gara. A new overhead 115 kV transmission line 12-13 miles in length needs to be constructed to serve the new Carlin Bay substation. This will serve a growing local load, and alleviate system protection issues caused by growing load at the end of the Blue Creek and O'Gara feeders. Please reference request ERT_2017-01 for more information.



Potential Options Evaluated

A. Carlin Bay Sub

- Build new 115kV transmission line from Ogara Sub to Carlin Bay Sub property (approx. 15 miles)
- Build new Carlin Bay Sub with single 115-13.2kV transformer and (2) 13.2kV distribution feeders
- Reconstruct Ogara Sub to be a 115kV switching yard

B. Convert to 25kV

- Add second transformer at Blue Creek with (1) 24.9kV distribution feeder.
  - The existing transformer will continue to have the (2) 13.2kV feeders serving the load north of Lake CDA
  - The new 25kV feeder will be express to south of Wolf Lodge Bay, then all load will be converted to 25kV continuing south to the open point at Carlin Bay. *Note: this will involve converting significant amounts of URD primary (including 600A feeder trunk) from 15kV cable to 25kV cable.*
- Add second transformer at Ogara with (1) 24.9kV distribution feeder
  - The existing transformer will continue to have (1) 13.2kV Avista feeder serving the load south-east and south-west of Ogara Sub, as well as (1) 12.5kV KEC feeder
  - The new 25kV feeder will serve north to Harrison and continuing on to the open point at Carlin Bay. All load on this branch of the feeder will be converted to 25kV.

C. No System Delivery Enhancement

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 program is in the Planning Stage with spend directed primarily at line siting.

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] 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.

There are no direct offsets associated with this project. The nature of the project (building a new Transmission line) does not reduce maintenance schedules, and therefore no offsets were /are realized.

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 direct offsets associated with this project. The nature of the project (building a new Transmission line) does not reduce 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.

Alternative 1:

Maintain As-Is *(Option #1: $0)* is **not an option** because of the growing capacity issue and Avista's responsibility to serve (see Section 2.1).

Alternative 2 (Recommended Option):

Construct a new 115kV Transmission Line *(*Option #2: $14,000,000) from the new Carlin Bay Substation to the future Ogara Substation vicinity is the **recommended** alternative. This is the most economical long-term solution to resolve the problem.

Alternative 3:

Construct a new 115kV Transmission Line (Option #3: $24,000,000 plus) from the new Carlin Bay Substation to the future Ogara Substation vicinity including a submarine segment **is not a recommended** alternative. This is not an economical long-term solution to resolve the problem and presents a "social justice" equity issue where the general rate-payers financially support a specific community.

Alternative 4:

Reconstruct the Existing Distribution System to a Higher Voltage (Option #4: $100,000,000 plus) in the Harrison and Carlin Bay areas from Ogara and Blue Creek Substations **is not a recommended** alternative. This is not an economical long-term solution to resolve 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.

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.

The Carlin Bay-Ogara project will take place in the Summer/Fall months and Transfer to Plant in the 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 requests for additional funding would go through the Capital Planning Group (CPG).

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Transmission Performance & Capacity 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: [signature] Date: 5/9/2023
Print Name: KEN SWEIGART
Title: MANAGER, T&D
Role: Business Case Owner

Signature: [signature] Date: 5/9/2023
Print Name: Vern Malensky
Title: Director, Electrical Engineering
Role: Business Case Sponsor

Signature: ______________________ Date: ______________

Print Name: ______________________

Title: ______________________

Role: Steering/Advisory Committee Review

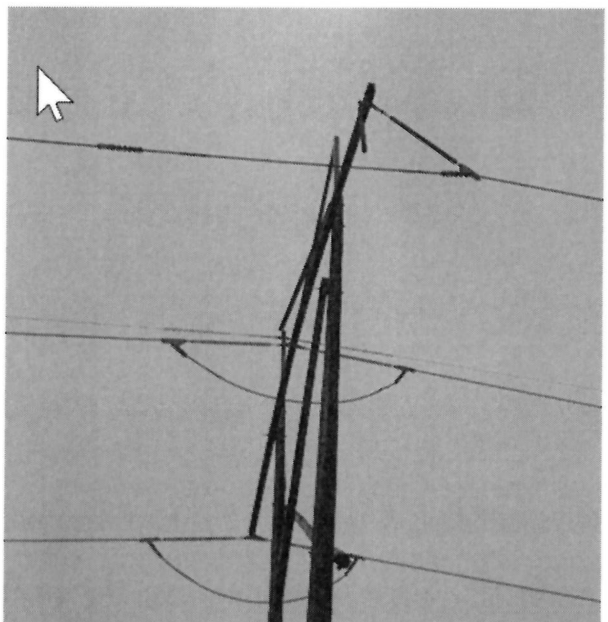
Transmission Critical Crossing Reinforcments

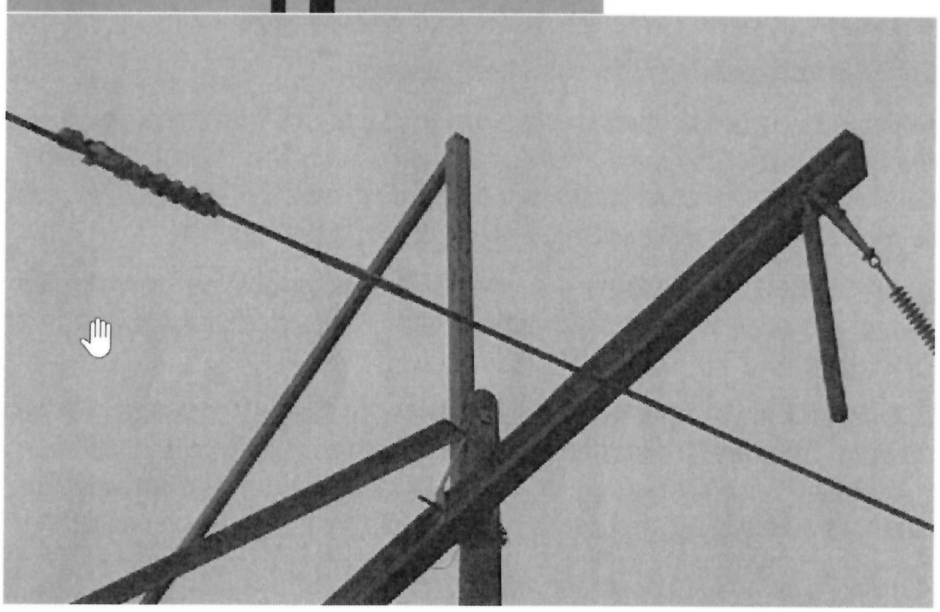
EXECUTIVE SUMMARY

Please provide a <u>one page summary</u> of the business case and high-level summary of the projects or programs included. Please describe the need for the project (a synopsis of the problem, the current state, and recommended solution), alternatives considered, the cost of the recommended solution, applicable metrics, customer benefits, Avista benefits or offsets derived from the investment, and risks, to customer and Avista, if the business case is not funded.

*The **<u>Transmission Critical Crossing Reinforcements Business Case</u>** 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.*

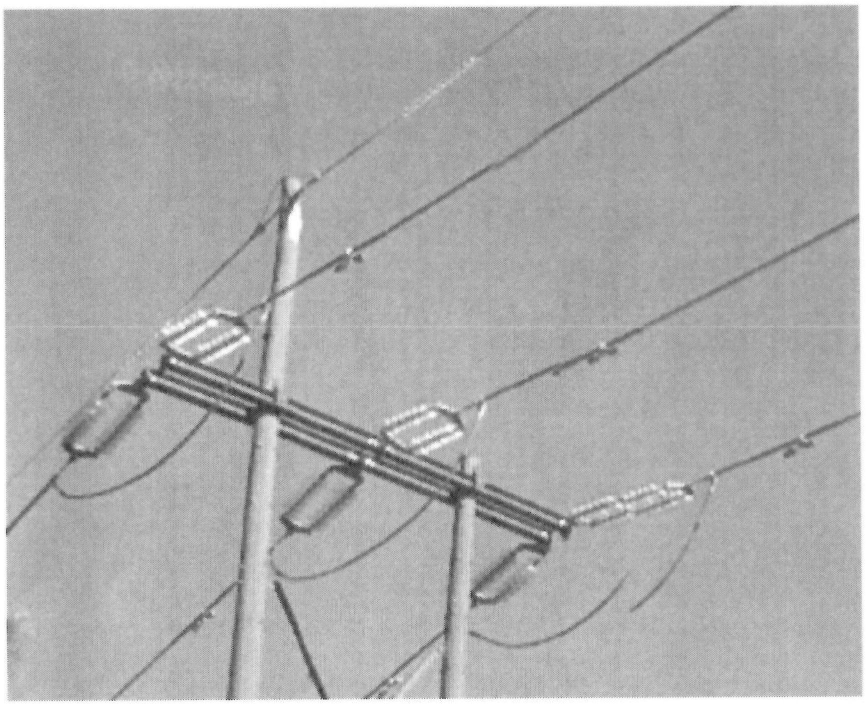
The triggering event for this Business Case is the "near miss" shown in the following photos:





Transmission Critical Crossing Reinforcments

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).



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.

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*	*4/7/2023*
BCRT	*BCRT Team Memember*	*Steve Carrozzo*	*4/17/23*

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***

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.

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 crossing with an 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.

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.

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 recent 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.

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.

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.

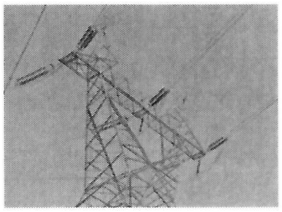
Proposed solution is to replace those assets deemed at risk of failing in the near term and at locations of highest risk consequence. Replacement greatly reduces risk of future failure.

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.



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	2024	2025	2026	2027	2028
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 offsets4 (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$

[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.

O&M		$	$	$	$	$

There are no indirect offsets associated with projects between 2024-2028. 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.

2.5 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.

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.

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:	[signature]	Date:	4/20/2023
Print Name:	KEN SWEIGART		
Title:	MANAGER, TLD		
Role:	Business Case Owner		

Signature:	[signature]	Date:	4/20/2023
Print Name:	Vern Malensky		
Title:	Director, Electrical Engineering		
Role:	Business Case Sponsor		

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

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 ($30,000,000): Lolo-Oxbow 230kV Transmission Line Rebuild Phases 3 through 5 (years 2026-2028)

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	4/3/2023
BCRT	Lindsay Miller	Has been reviewed by BCRT and meets necessary requirements	5/1/2023

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$10,000,000	$10,000,000
2025	$10,000,000	$10,000,000
2026	$10,000,000	$10,000,000
2027	$10,000,000	$10,000,000
2028	$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

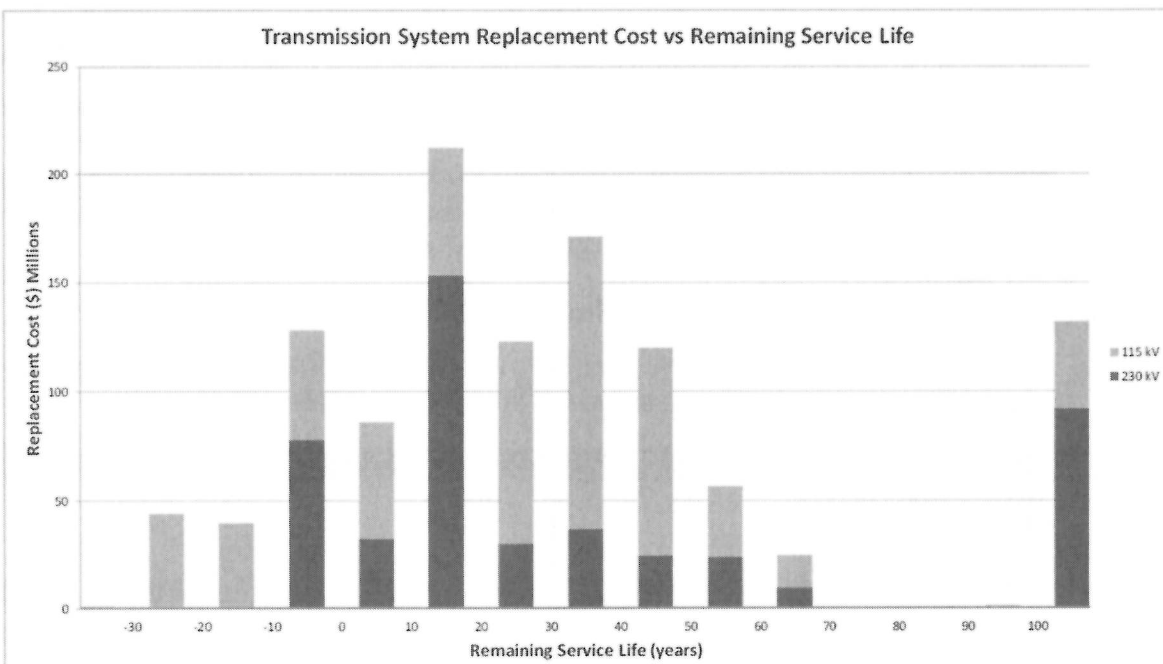
Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

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 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.

Hatwai-Lolo 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. This project was halted due to increased wheeling being sold on this line, increasing revenue for Avista ratepayers. At this time the Lolo-Oxbow project is more of a placeholder and will be evaluated against other transmission lines for the 2026 fiscal year.

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:

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-Rathdrun 115kV linne 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 model version. 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

Hatwai-Lolo 230kV Transmission Line was ranked #1 under the old Asset Management prioritizing system and underwent two phases of reconstruction. This project was halted due to increased wheeling being sold on this line, increasing revenue for Avista ratepayers. At this time the Lolo-Oxbow project is more of a placeholder and will be evaluated against other transmission lines for the 2026 fiscal year.

The below table shows the Lolo-Oxbow (LOL-OXB) 230kV Transmission Line has the highest Risk Score of all Avista transmission lines based on the 2016 model version. 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. Below is a 2016 snapshot of Avista's infrastructure age based on average remaining life. 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.

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

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

- 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. For Pine Street-Rathdrum and Lolo-Oxbow, 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.

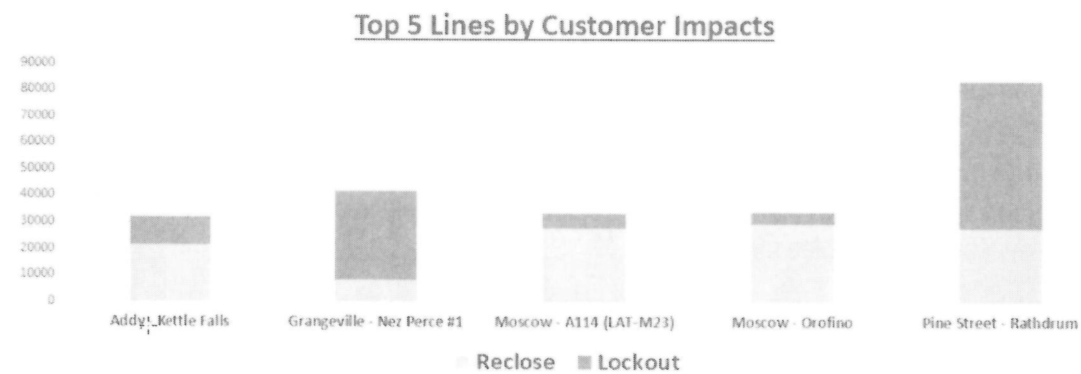
Additionally, the risk of wildfire ignition exists every time the line trips to ground. Rebuilding this line entirely will reduce this risk significantly, thus increasing the safety and resiliency of our infrastructure.

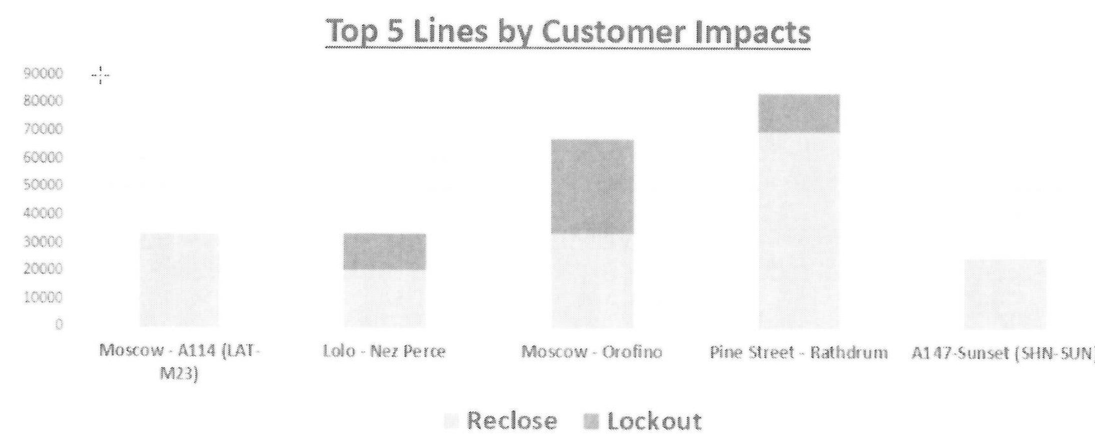
2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to 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).





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[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		$	$	$10,000	$10,000	$10,000
O&M		$	$	$10,000	$10,000	$10,000

Direct offsets associated with this project 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. 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 offsets4 (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 associated with this project. The nature of the project (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.

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).

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[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.

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 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: Date: 5/3/2023
Print Name: KEN SWEIGART
Title: MANAGER, TLD
Role: Business Case Owner

Signature: Date: 5/5/2023
Print Name: Vern Malensky
Title: Director, Electrical Engineering
Role: Business Case Sponsor

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

Wood Pole Management

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 we moved 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 reduced customer outages. 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 $1600/pole, whether work is required or not. To stay on a seventeen-year cycle requires $20,800,000 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. Our customers will benefit 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 decreases, and our Operating and Maintenance Costs increase.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Mark Gabert*	*Initial draft of original business case*	*7/1/2020*
2.0	*Mark Gabert*	*Final Draft of original business case*	*7/31/2020*
3.0	*Mark Gabert*	*Business Case Refresh*	*8/31/2022*
4.0	*Mark Gabert*	*Business Case Refresh*	*4/14/2023*
BCRT	*BCRT Team Member – Katie Snyder*	*Has been reviewed by BCRT and meets necessary requirements*	*04/21/2023*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$17,800,000	$17,800,000
2025	$18,334,000	$18,334,000
2026	$18,884,020	$18,884,000
2027	$19,450,540	$19,450,540
2028	$20,034,056	$20,034,056

Project Life Span	*Ongoing*
Requesting Organization/Department	M51
Business Case Owner | Sponsor	Mark Gabert-Heather Webster- David Howell
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 and replacement work completed annually. 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 aging infrastructure that fails 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 keeps our poles, equipment, and hardware safe for employees and the general public while maintaining a high level of customer satisfaction. Compounding the problem, starting in 2020, the Grid Hardening program impacted the twenty-year cycle. To aid in Grid Hardening efforts Wood Pole Management moved feeders in high fire risk areas to a seventeen-year reinspection cycle. This decreased inspection cycle enables Grid Hardening to complete its work by replacing poles with the potential for failure ahead of Grid Hardening construction. If Wood Pole Management is underfunded, it will push some feeders past the seventeen-year cycle which may impact Grid Hardening efforts. If Wood Pole Management isn't funded the company will manage the overhead distribution assets as they fail.

1.2 Discuss the major drivers of the business case.

From an Asset Condition perspective, the major drivers for the program include safety, system reliability, improved cost performance, reduced customer outages, 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 the aging assets and expected failure rate.

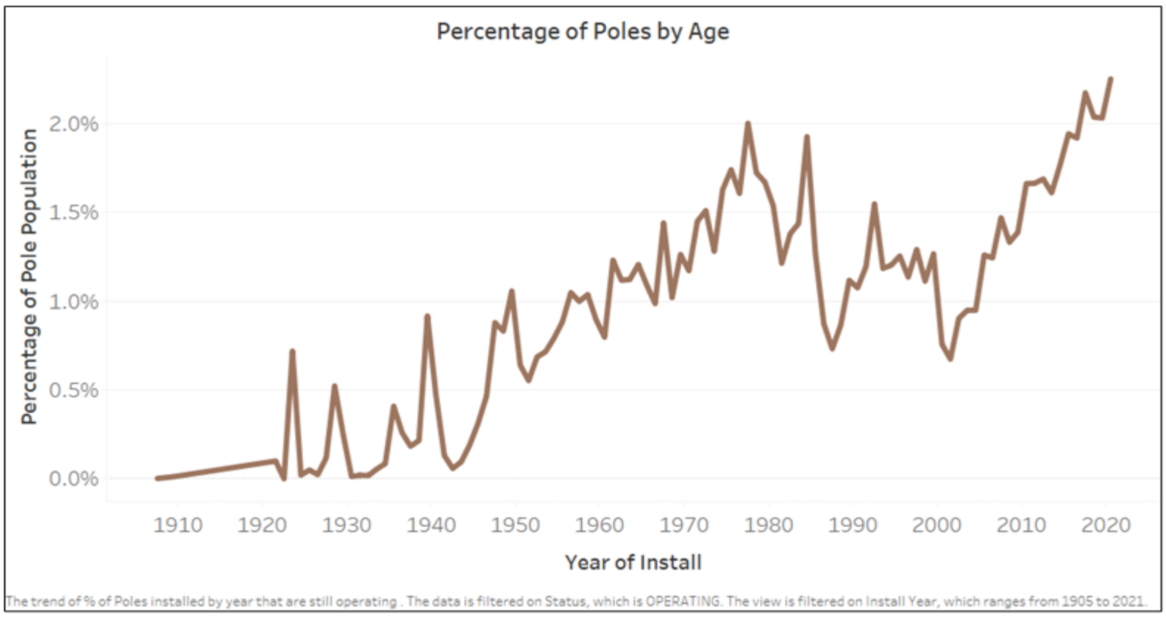
Approximately 26 percent of the poles are older than 60 years of age which will increase over time. The Mean Time to Failure (MTTF) for wood poles is seventy-nine years, but Distribution Engineering recommends replacement at sixty years of age due to the time element of the next cycle and the above groundline decay characteristics of butt-treated wood poles. 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 as it is much more expensive to respond to an asset failure than to have it replaced 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 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 less than one per 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 impact of up to forty-eight hours. If the program is unfunded, the potential occurrence is less than one per ten years. If funded the potential occurrence is less than one per fifty years.

Figure 1.



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 investment replaces end of life assets before they fail which reduces outages and improves safety. 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 by Asset Management to track asset condition and show trends of failure of 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 47% from 2009 to 2022. This reduction in outage events results in significant customer benefit. The reduction also demonstrates increased reliability and safety along with a reduction in outages. The original goal for this KPI was to stay below the number of events averaged over 2005-2009 for WPM Related OMT events. The goal will be re-evaluated by Asset Management in the future.

	WPM Goal Related Number of OMT Events	Actual WPM Related Number of OMT Events	Projected Poles Follow-Up Work	Actual Poles Follow-Up Work
2009	1460	1320	11,400	11,548
2010	1460	1004	11,400	12,010
2011	1460	1004	11,400	10,461
2012	1460	1013	11,400	14,530
2013	1460	816	11,400	10,763
2014	1460	905	11,400	10,588
2015	1460	760	11,400	12,018
2016	1460	717	11,400	13,244
2017	1460	883	11,400	12,996
2018	1460	751	11,400	11,532
2019	1460	742	11,400	10,902
2020	1460	745	11,400	8,694
2021	1460	868	13,116	11,404
2022	1460	705	13,116	10,000

Table 1

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 nearly 750 in 2008 to 250 events today. 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. Both the transformer and cutout/fuse events have been reduced by over 50% through the replacement of aged equipment. In 2017 the calculated cost to customers for a pole failure is $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. Also, approximately eleven years ago

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

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.

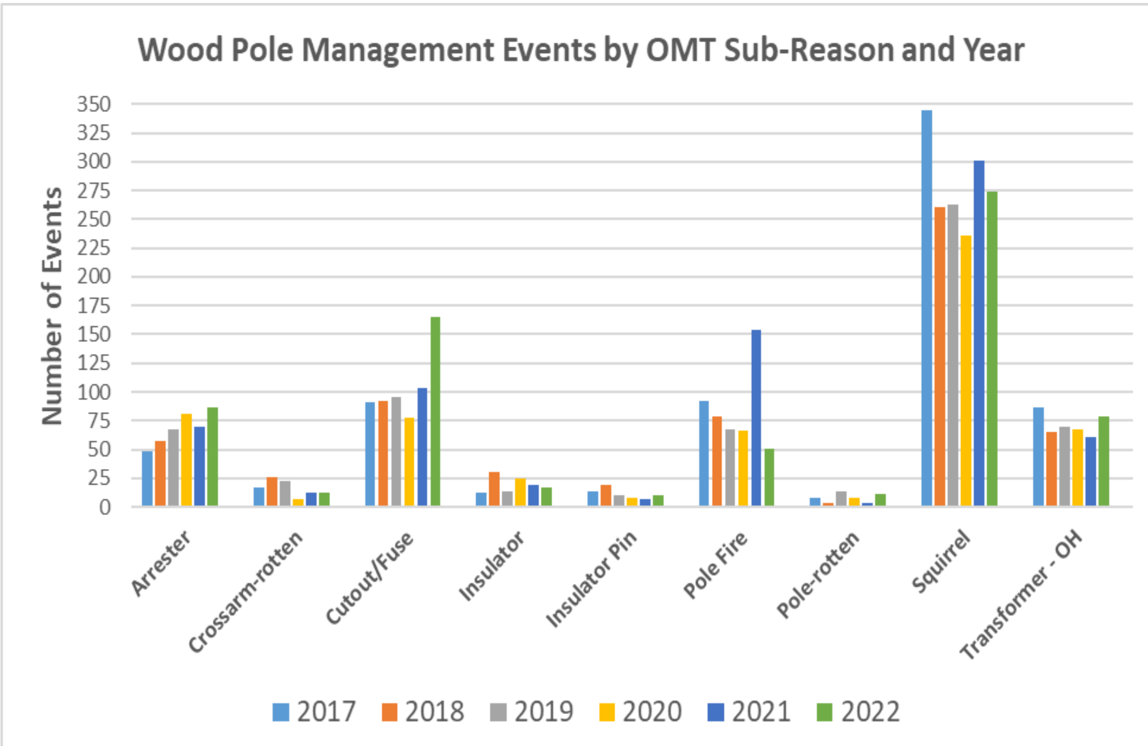


Figure 2

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 1.05 for the year 2015. The Asset Management group created Table 2 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).

Projected Metric Description	Projected WPM Contribution to the Annual SAIFI Number	Projected Number of Dist Poles Inspected	Projected Number of Pole Rotten OMT Events	Projected Number of Crossarm OMT Events
2009	0.214024996	11,400	137	32
2010	0.208489356	11,400	137	32
2011	0.211022023	11,400	137	32
2012	0.211022023	11,400	137	32
2013	0.211022023	11,400	137	32
2014	0.211022023	11,400	137	32
2015	0.211022023	11,400	137	32
2016	0.211022023	11,400	137	32
2017	0.211022023	11,400	137	32
2018	0.211022023	11,400	137	32
2019	0.211022023	11,400	137	32
2020	0.211022023	11,400	137	32
2021	0.211022023	13,116	137	32
2022	0.211022023	13,116	137	32
Actual Metric Description	**Actual WPM Contribution to the Annual SAIFI Number**	**Actual Number of Dist Poles Inspected**	**Actual Number of Pole Rotten OMT Events**	**Actual Number of Crossarm OMT Events**
2009	0.1863468	14,430	44	25
2010	0.19916836	14,992	37	23
2011	0.202462739	14,980	35	28
2012	0.16613099	14,406	52	19
2013	1.15640942	11,903	34	18
2014	0.241571914	11,879	55	26
2015	0.225273848	7,835	43	23
2016	0.132313511	11,636	57	23
2017	0.12662277	10,595	39	22
2018	0.128829384	16,044	25	31
2019	0.126544503	11,187	44	26
2020	0.116836918	9,627	53	15
2021	0.210971466	12,066	45	17
2022	0.113288177	9,683	11	12

Table 2

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 work. Investing in the infrastructure increase life-cycle performance and is cost-effective using unit-based pricing. Figure 3 below shows the significant improvement in" events per mile of feeder" resulting from this program on 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. This would increase the likelihood that crews would need to visit the same pole later if a remaining component were to fail.

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.

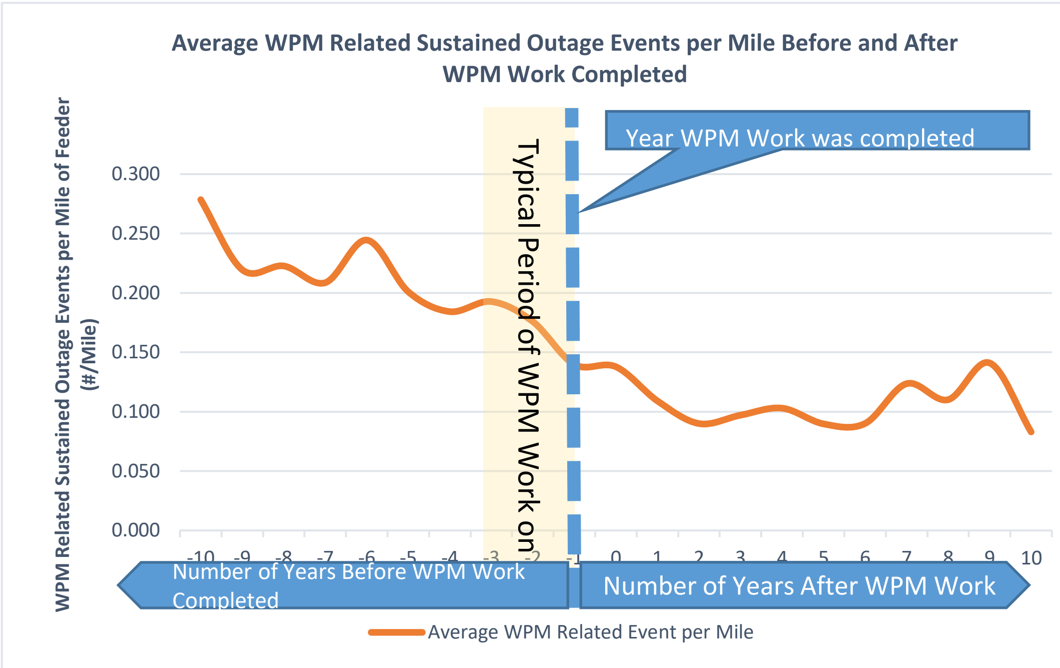


Figure 3.

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 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.

This is the best alternative based on the analysis in 2017, the current twenty-year cycle delivers the best life cycle value for the funding level.

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 that analysis from Asset Management 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 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	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M	Quantified Direct Savings	$1,221,500	$1,221,500	$1,221,500	$1,221,500	$1,221,500

Between 2005-2009 the average number of OMT events related to Wood Pole Management was 1460 per year. Between 2018 and 2022 the average number of OMT events has been reduced to 762 per year. This is an average reduction of 698 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 $1,221,500. 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

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[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 offsets4 (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M	Indirect Savings	$12.7MM	$12.7MM	$12.7MM	$12.7MM	$12.7MM

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 698 OMT events per year on average therefore the indirect benefit is $12,769,212.

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 Managements “Wood Pole Management (Distribution) Inspect Cycle Analysis” compared the Avista utility peer group, shown below, 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. 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 need to 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 the new alternative it is not incorporated until at such time funding is approved

[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.

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 $71,200,000 for capital and $3,200,000 for O&M. The risk of choosing this alternative isn't feasible given the company's many other infrastructures needs and 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 $34,400,000 and the O&M cost would be $1,600,000. 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 on the Wood Pole Management One Pager.

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 a continuous process of inspecting Avista's poles on a feeder basis, 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 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.

Asset Management and Distribution Engineering provide ongoing analysis of distribution asset conditions. The 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 Asset Management, 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 one-pager**.**

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.

Wood Pole Management

Signature:	Mark S. Gabert	Date:	4-21-2023
Print Name:	Mark S. Gabert		
Title:	WPM Program Manager		
Role:	Business Case Owner		

Signature:	David Howell	Date:	4/24/2023
Print Name:	David Howell		
Title:	Director Of Operations		
Role:	Business Case Sponsor		

Signature:	Heather Webster	Date:	4/25/2023
Print Name:	Heather Webster		
Title:	Asset Maintenance Manager		
Role:	Steering/Advisory Committee Review		

Central 24 HR Operations Facility

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 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. If located on the Mission campus, a rough-order-magnitude estimate of approximately $37M 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.

VERSION HISTORY

Version	Author	Description	Date
0.0	Vance Ruppert	Executive Summary Only	7/10/2020
1.0	Vance Ruppert	BCJN Update with 2021 revisions	7/9/2021
2.0	Lindsay Miller	BCJN Update with 2022 revisions	5/24/2022
2.1	Conor Craigen	BCJN Update	08/31/2022
3.0	Conor Craigen	Template + BCJN Update	04/14/2023
BCRT	Steve Carrozzo		04/28/2023

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$2M	$0M
2025	$12M	$0M
2026	$23M	$37M
2027	$0	$0
2028	$0	$0

Project Life Span	3 years
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

1. BUSINESS PROBLEM

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 office cubicle. The modern operator workstation requires 600 square feet (SF) of total space. Due to this, and future growth, 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 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.

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.

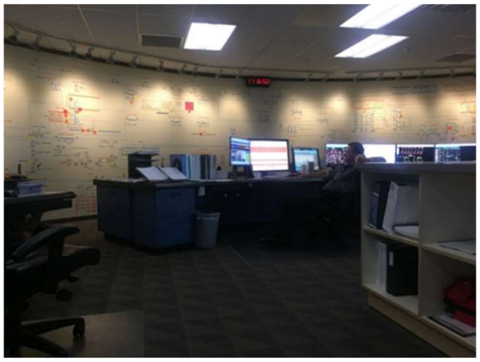
The DO dispatch space is a second PSP location that has become overcrowded not because of growth, but because half of their space was taken away. In their reduced space the DO is not set up for proper storm response. They currently could not support a similar 2015 storm event if it were to happen today. 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 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 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 is looking to add another Mobile Dispatch System Administrator desk in order 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.

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. 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. A new transformer range from $5M-10M to replace. 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.

Central 24 HR Operations Facility



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.

Security - Gap Analysis

LAMB

Present Conditions	Ideal/Best Practices	Significant Gaps
• 2 different buildings house operations. • GCC currently shares a building in Spokane city with non-Avista offices, a restaurant, and bar.	• Purpose-built, fully owned and operated Control and Data Center facility	• The Mission Campus Main Building can be properly secured. • The Steam Plant is not properly secured due to co-location of critical assets with public gathering spaces. It was reported that unwanted guests are at the doors of the GCC.

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. Avistas 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 inaccessible and ergonomically unfriendly working environment. The outdated conditions of all these departments 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 not carried by similar-sized utility companies. 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).

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.

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 comfortably be together, 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 are taking this knowledge and focusing on 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.

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

- 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).

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 to build a new greenfield facility for our critical operations groups and their support staff. The new building could be located on a dedicated piece of land on the Mission Campus. The preferred location on Mission Campus is the northern half of the Warehouse storage yard. If this location were chosen, that portion of the yard could be relocated to the north side of Gate 1. A new greenfield option will allow for optimal layout, security, inclusion, growth, and upgrades.

Proposed	Capital Cost	Start	Complete
Greenfield facility on Mission Campus	$37.1M	2024	2027

Notes:

1) See Appendix A for cost estimate breakdowns 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.
3) The proposed considers a new 40,500 SF building located on the Mission Campus at the northern half of the Warehouse yard. All critical operations groups would be accommodated, and security risks would be minimal, but the Warehouse operations would be affected. Half of their storage yard would need to be relocated to a newly designed space north of Gate 1. An estimated cost for this relocation is considered in the estimate.

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.

Merging the GCC into the new Critical Operations Facility would save in ongoing annual lease expenses. In 2023 a new five-year lease expense of $160,000/year commenced. In 2026 a $15,000/year parking increase will hit.

Offsets	Offset Description	2027	2028	2029	2030	2031
Capital		$	$	$	$	$
O&M	Seehorn Lease	$175,000	$175,000+	$175,000+	$175,000+	$175,000+

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

[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.

Offsets	Offset Description	2024	2025	2026	2027	2028
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.

Option	Capital Cost	Start	Complete
Option 1: Greenfield facility on new property.	$59.9M	2024	2027
Option 2: Service Building 2nd floor east side addition.	$30.9M	2024	2027
Option 3: Service Building 1st floor east side remodel.	$23.8M	2024	2027

Notes:

4) See Appendix A for cost estimate breakdowns of Option 1- 3's capital costs shown in the table above.
5) 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.
6) 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.

7) 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.
8) 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: 2024

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

GC completed construction, and receive Certificate of Occupancy: 2026

Install Furniture, Fixtures, and Equipment: 2026

Testing of all systems: 2026

Move into the new facility: 2026

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, Jim Corder, Adam Munson, Mike Magruder, and Bruce Howard.

B. Advisory Groups that assisted in shaping this Business Case consisted of the following stakeholders:

- Facilities: Eric Bowles, Conor Craigen, Nick Lasko, and Annie Lundy
- Kelly Magalsky, Director of Shared Services
- Mike Magruder, Director of Transmission Ops & System Plan
- Alexis Alexander, Director of Generation Production Substation Support
- Jim Corder, 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
- Mike Busby, Manager of Network Ops Center and Comm Shop
- Andrea Pike, Manager of Customer Service

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.

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 4ACC724D18764C2... Date: May-15-2023 | 7:33 AM PDT

Print Name: Eric Bowles

Title: Corp. Facilities Manager

Role: Business Case Owner

Signature: DocuSigned by: Kelly Magalsky E7A0F731C49442B... Date: May-15-2023 | 9:25 AM PDT

Print Name: Kelly Magalsky

Title: Director of Shared Services

Role: Business Case Sponsor

Signature: Date:

Print Name:

Title:

Role: Steering/Advisory Committee Review

Central 24 HR Operations Facility

Appendix A - Critical Operations Facility Level 4 Estimate

Proposed: 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**

Option 1: 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**

Central 24 HR Operations Facility

Option 2: 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**

Option 3: 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.

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.

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*

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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

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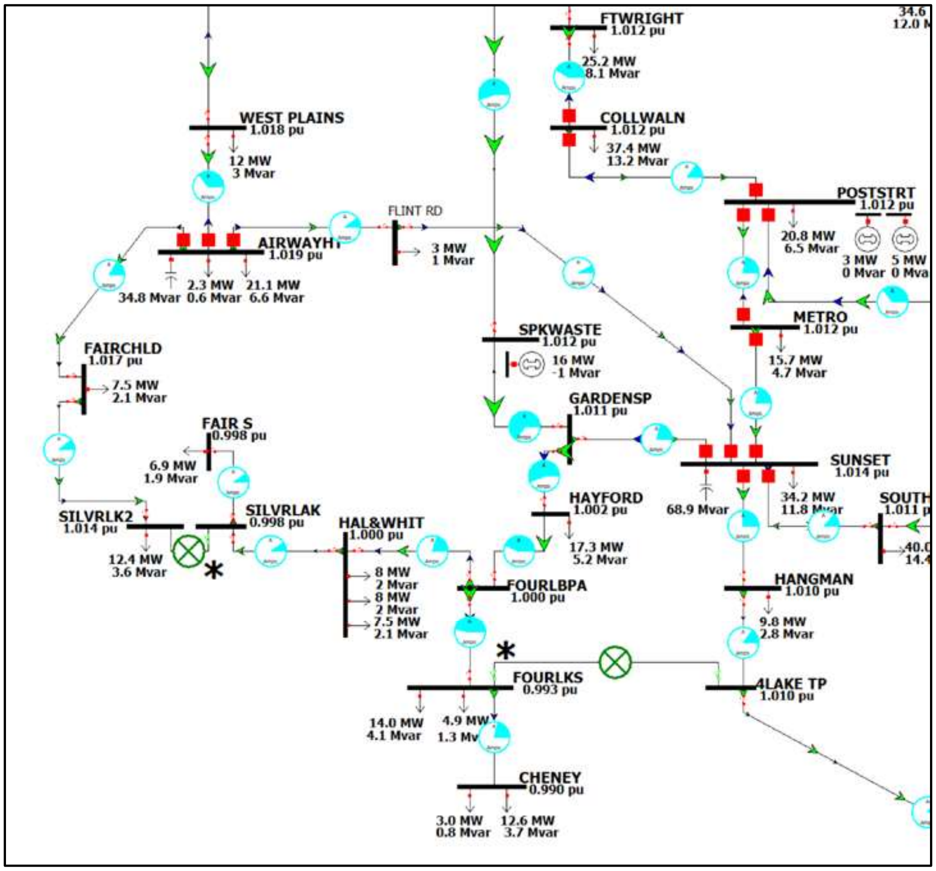
the downtown Spokane area, linking the reliability of these two strategic areas. Devil's Gap Substation is located northwest of West Plains and provides a sturdy source supported primarily from the Little Falls/Long Lake generation within Avista's system. The figure below provides a one line identifying 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.

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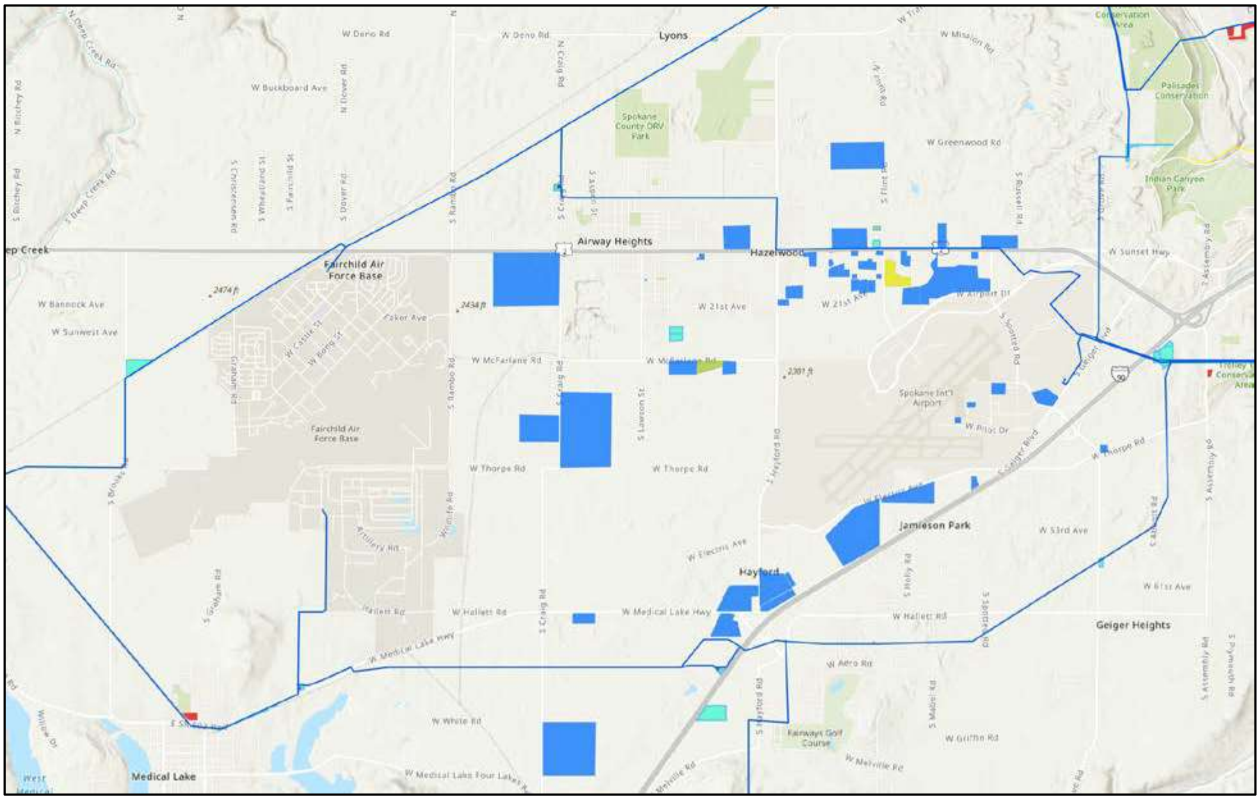

The growth in the West Plains area has accelerated by a concerted effort toward economic development and expansion. Government, tribal, public, and private entities have invested significant time and money toward this endeavor and are working to establish area backbone infrastructure that will be needed. 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.

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:

    <u>If</u> 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,
    <u>And</u> an outage occurs on the Sunset – Westside 115kV Transmission Line,
    <u>Then</u> 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.

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:

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With completion of the project, Avista will be unlocking growth potential in the West Plains area.

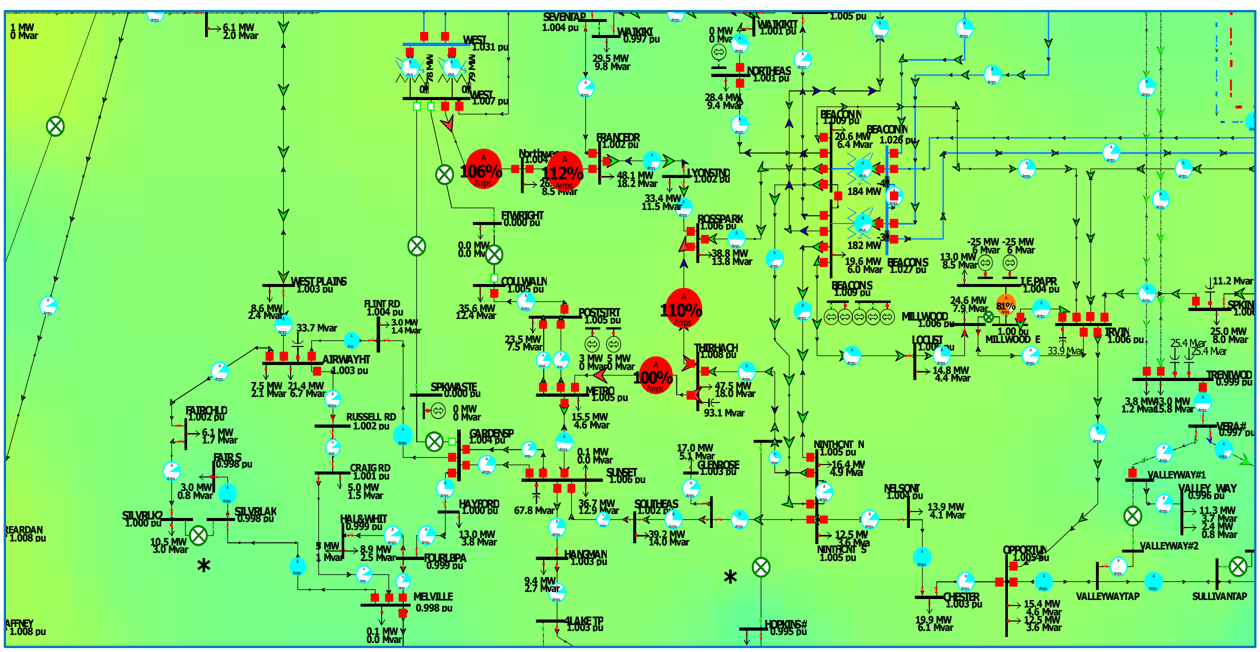
Invent:
Constructing transmission lines and substations are traditional project alternatives but Avista has the opportunity to improve the construction and delivery process as part of such a large-scale project.

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.

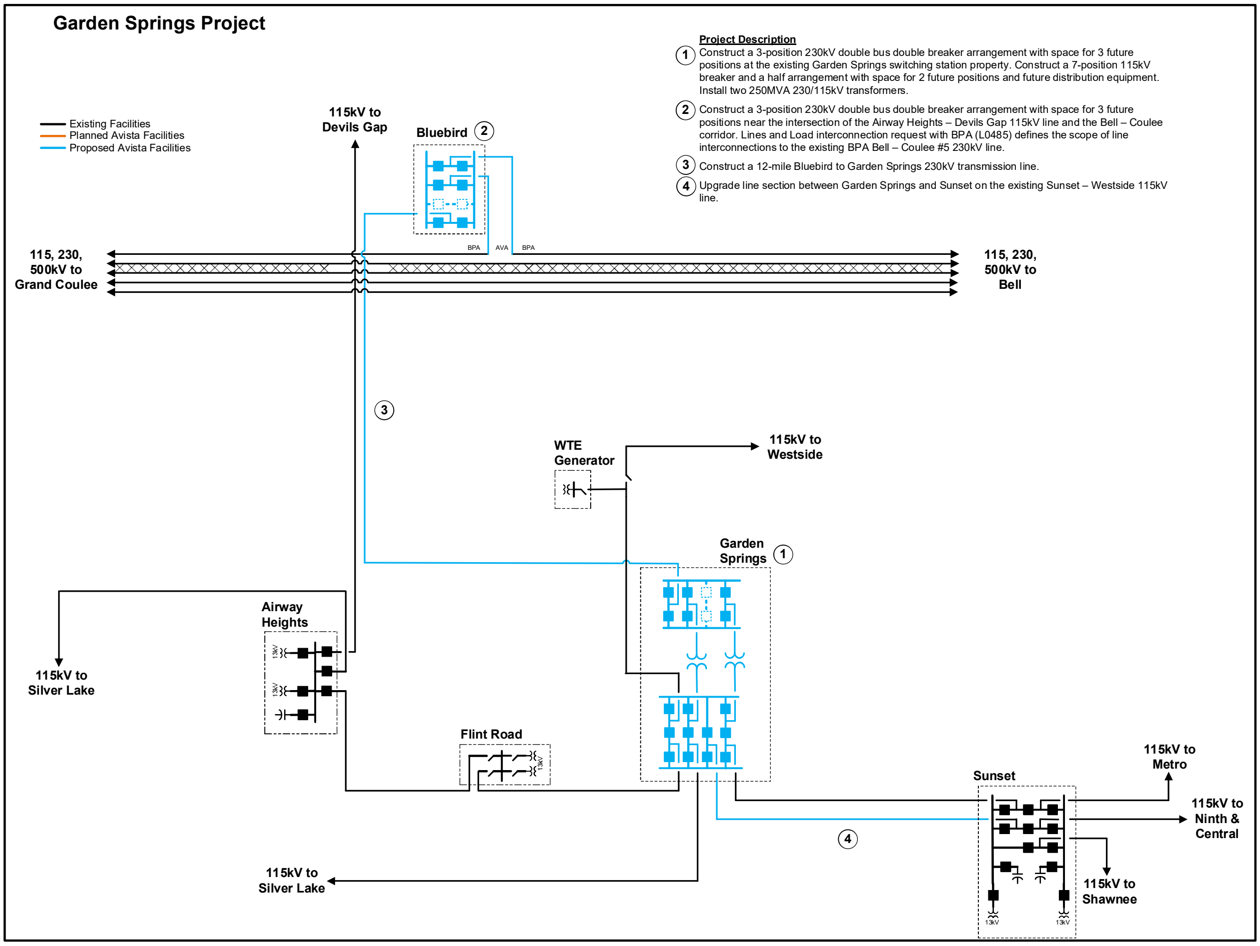


[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

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.

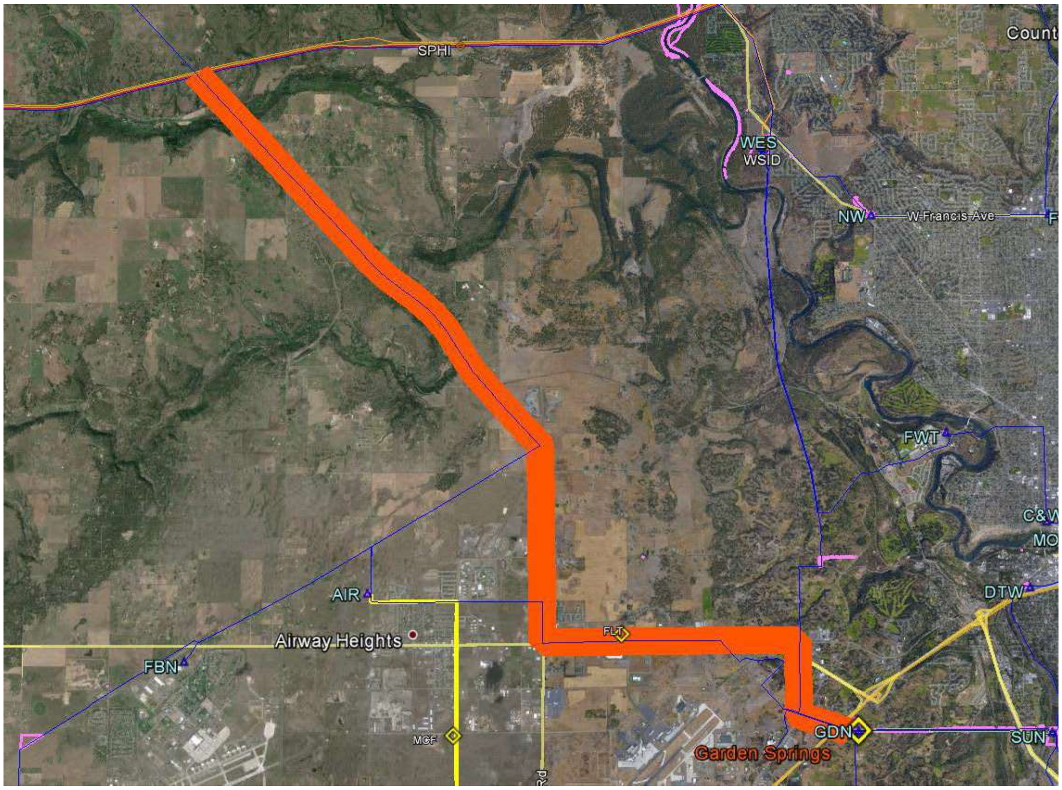
The following figure illustrates the intended scope of the West Plains System Reinforcement project.



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

• 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.

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.

- $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.

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.

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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.

DocuSigned by:

Signature: Glenn J Madden   Date: May-12-2023 | 5:25 PM PDT

Print Name: Glenn Madden

Title: Substation Engineering Manager

Role: Business Case Owner

DocuSigned by:

Signature: Vern Malensky   Date: May-14-2023 | 6:01 PM PDT

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Print Name: Vern Malensky

Title: Electrical Engineering Director

Role: Business Case Sponsor

Signature: Date:

Print Name:

Title:

Role: Steering/Advisory Committee Review