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EXHIBIT: HLR-11
ADMIT ☑ W/D ☐ REJECT ☐

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-20_____

DOCKET NO. UG-20_____

EXH. HLR-11

HEATHER L. ROSENTRATER

REPRESENTING AVISTA CORPORATION

Index for Business Case Justification Narratives Related to Major Investments in the Company’s Electric and Natural Gas Energy Delivery Systems, Fleet, and Office and Operations Facilities for 2018 and 2019

Distribution Grid Modernization

EXECUTIVE SUMMARY

Maintaining system reliability is an important part of providing quality service to Avista's customers. Planned investments in the distribution system are necessary to efficiently maintain reliability while keeping costs low for customers. The Grid Modernization Program (GMP) is the largest program focused on planned maintenance and improvements beyond wood poles driven by a comprehensive engineering analysis across Avista's 19,000 miles of electric distribution lines (Avista 2019 Quick Facts). The GMP's mission is to replace aging and failing infrastructure within the electric distribution system while also improving reliability and performance and capturing energy savings through the efficient use of company resources. 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 increased outages that take longer to restore and fall short of modern expectations that utilities face. The program benefits all Washington and Idaho electric customers and is intended to operate on a 60 year cycle averaging 190 circuit-miles addressed per year. The current average cost per mile requires a $28.88MM annual investment to achieve a 60 year cycle. The 60 year cycle is based on the average lifespan of distribution infrastructure, and the twenty year cycle of the Wood Pole Management Program (WPM) (Avista Utilities Electric Distribution Infrastructure Plan June 2017).

A systematic approach is recommended to address the rebuild and upgrade of the distribution system. This approach utilizes a prioritization method balancing feeder health, performance, and criticality. Design decisions are made through a consistent process and construction adheres to established overhead and underground standards. Upon the completed construction of GMP projects, 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. As Avista's distribution facilities continue to age, it becomes more important to be proactive in their replacement. 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 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. Overall, not funding or delaying this business case would reduce the efficiency that the GMP provides to the company and customers while elevating the risk of an inconsistent application of design and construction standards.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft		*Initial draft of original business case 2020*	*7/31/2020*	
1.0				

Distribution Grid Modernization

GENERAL INFORMATION

Requested Spend Amount	$77,000,000
Requested Spend Time Period	5 years
Requesting Organization/Department	Asset Maintenance
Business Case Owner | Sponsor	Heather Webster | Alicia Gibbs | David Howell
Sponsor Organization/Department	T51/Asset Maintenance
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

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

The Grid Modernization Program (GMP) addresses the aging and failing infrastructure found throughout the electric distribution system. Other issues 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 evaluated 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 NESC and Avista construction standards, fulfill the efforts of Wildfire Resiliency, address the Transformer Change Out Program, 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 *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

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

- Replacement of aging and failed infrastructure.
- Fewer outages that can be resolved more quickly.
- Automation devices produce results immediately optimizing system performance, reducing costs, and reducing outages.
- Cost effective work due to program efficiencies and long-term planning.
- Improved safety.
- Providing additional expertise with design and construction resources that are not available at outlying offices.

Reliability improvements have been quantified that are a direct benefit to the customers in feeders that the 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 at: c01m19:\Feeder Upgrades - Dist Grid Mod\~Program Admin\Data\grid mod reliability data analysis before and after.xlsx

Distribution Grid Modernization

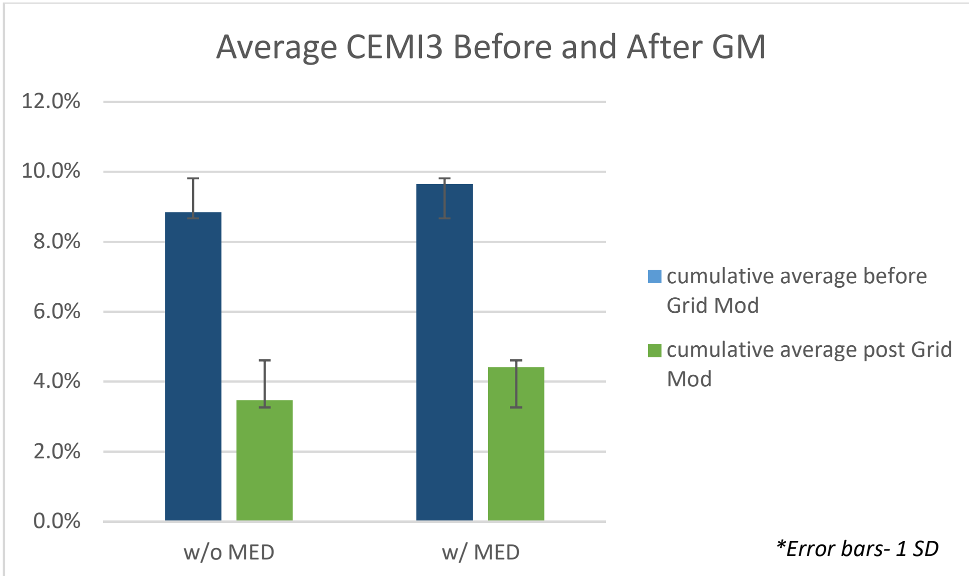


Figure 1: Average CEMI3 on feeders that have been fully addressed by GMP. This includes all the feeders completed through the end of 2018.

Figure 1 shows CEMI3 which is the percentage of customers experiencing 3 or more interruptions per year. The data show 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.

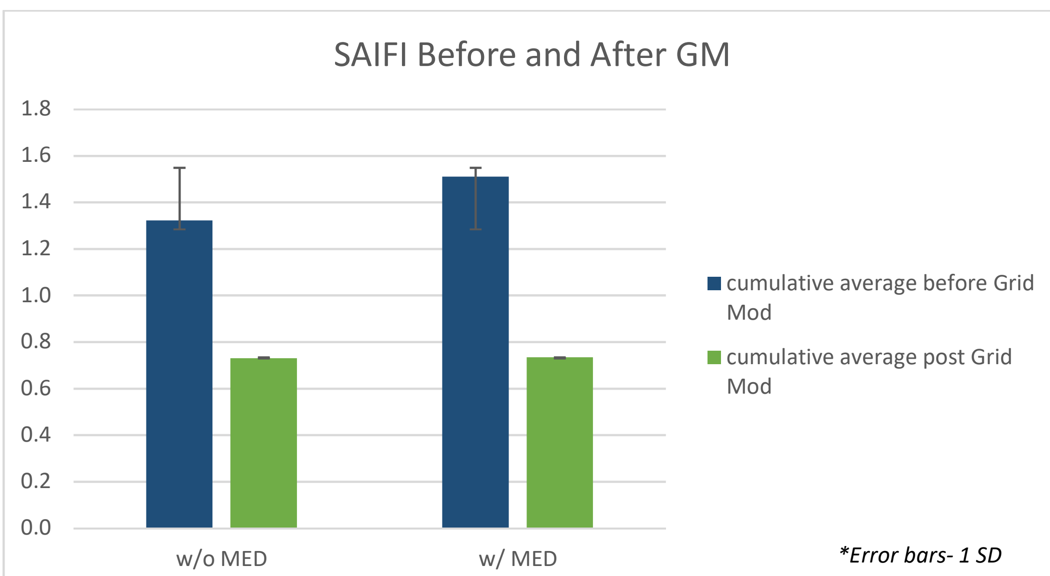


Figure 2: SAIFI before and after Grid Modernization on feeders completed through the end of 2018.

SAIFI is the sustained average interruption frequency index. The data show that customers on feeders addressed by the GMP experience a 51% reduction (with MED) and a 64% reduction in the duration of power interruptions.

Distribution Grid Modernization

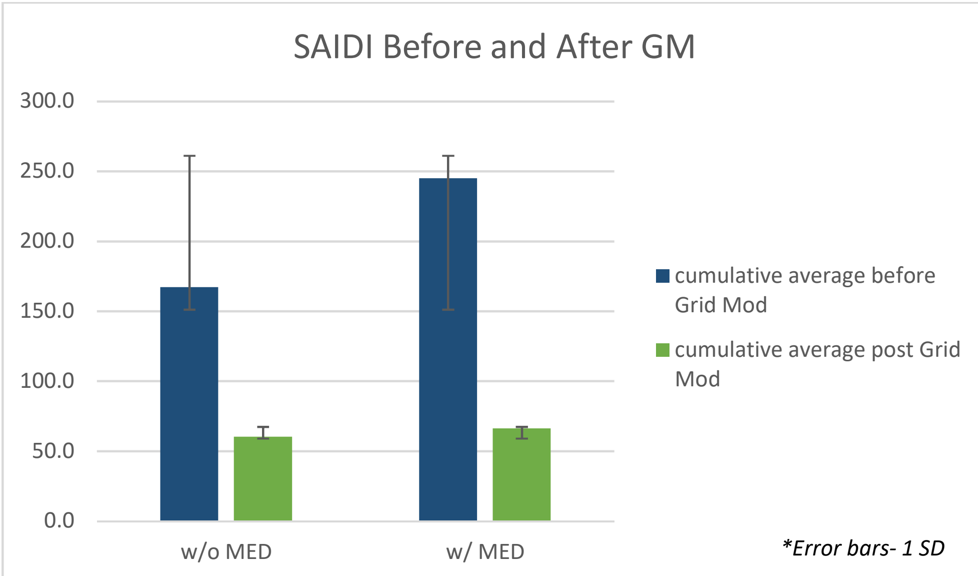


Figure 3: SAIDI before and after GMP for feeders completely addressed by the end of 2018.

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 outages customers experience are shorter in duration.

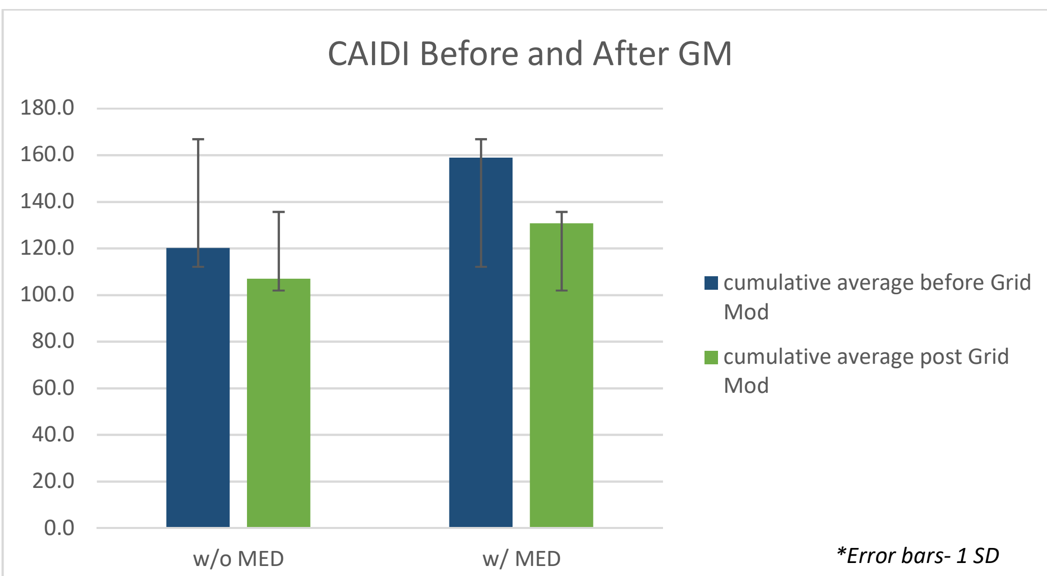


Figure 4: CAIDI before and after being addressed by the Grid Modernization Program.

CAIDI is the customer average duration index, 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.

Distribution Grid Modernization

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

Delaying the work performed by the GMP would result in an increased risk of equipment failure, 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 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 previously mentioned performance metrics; SAIFI, SAIDI, CAIDI, and CEMI3 can all be used to gauge system performance improvements after construction is completed. Voltage quality at any individual point along the feeder can also serve as an indicator of whether a project was successful. Across the entire program, an annual total of the feeder miles addressed serves as a measure of progress toward addressing the entire system across a 60 year cycle as intended.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

Feeder Status Report: The feeder status report details the analysis of attributes of the distribution system in three major categories:

- Performance: Thermal utilization, efficiency, voltage regulation, reliability performance (MAIFI, CAIDI), power factor, FDR imbalance.
- Health: Age, OH/UG ratio, pole rejection rate, reliability health (CEMI3, SAIFI).
- Criticality: Essential services, commercial account density, customer density, load density.

c01m19:\Distribution Feeder Status Report\Feeder Status Report 2019\2019FeederStatusReport.xlsm

Using the information that the Feeder Status Report provides, each feeder is prioritized by a combined score assessing the three categories within a tool in the location below and selected to maintain a balance between work done in Washington and Idaho.

c01m19:\Feeder Upgrades - Dist Grid Mod\~Program Admin\Feeder Selection

Feeder analysis reports: Once selected, a distribution engineer performs a thorough analysis on the entire circuit to determine what work is needed to make the feeder most efficient and to bring the feeder up to current standards to improve operation, safety, and support future loads. These reports are located at the following location:

c01m19:\Feeder Upgrades - Dist Grid Mod\~Feeder Analysis\

2017 Distribution Plan: The 2017 Distribution Plan summarizes a variety of topics including the different drivers for investing in system improvements and planned investments such as Grid Mod, which is cited often.

Avista Utilities Electric Distribution Infrastructure Plan June 2017: c01m19:\Feeder Upgrades - Dist Grid Mod\~Program Admin\Data\Distribution Plan FINAL 2017.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.

The Distribution Feeder Status Report annually quantifies the performance, health, and criticality as outlined in section 1.5.1. More specifically, Wood Pole Management commissions inspections on selected Grid Modernization feeders identifying deteriorating, broken, and/or missing equipment. Individual reports can be found on the c01m19 feeder, the Feeder Upgrades – Dist Grid Mod folder, the specific feeder folder in question, and finally the ~Admin and Wood Pole Mgmt folders.

Option	Capital Cost	Start	Complete
[Recommended Solution] The Distribution Grid Modernization Program provides benefits to customers, employees, and shareholders by replacing problematic poles, cross-arms, cut-outs, transformers, conductor, etc. Additionally, automated line devices are installed which increase energy efficiency and system reliability. The 2021 request is $10MM to begin ramping up to the $28.88MM necessary to maintain a 60 year program cycle.	$28.88MM annually	01 2012	12 2072
[Alternative #1] 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.	$UNK		

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

The GMP capital request was calculated using a 60 year cycle as a goal while addressing almost 12,000 circuit-miles of electric distribution facilities. With the average spend rate of $152,000/mile over the past thirty months, an estimate of $28.88MM is determined.

When considering the prudency of this investment as part of a single program rather than spread across multiple departments, it is worth considering the design and construction support experience that GMP resources provide as a dedicated subject matter expert on projects. Other departments with competing priorities might find it difficult to maintain a focus on projects of this size. Another important benefit of work done is the O&M savings of each automated device that is installed. Using a thirty month long span of data over the past three years, the devices installed by GMP has saved the company an annual amount of $346,825. (c01m19:\Feeder Upgrades - Dist Grid Mod\~Program Admin\Data\Automation device activation data and hard O&M costs.xlsx)

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.

[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.]

The capital cost of the Program is spread across numerous projects that typically span at least two years in a process summarized in Figure 5.

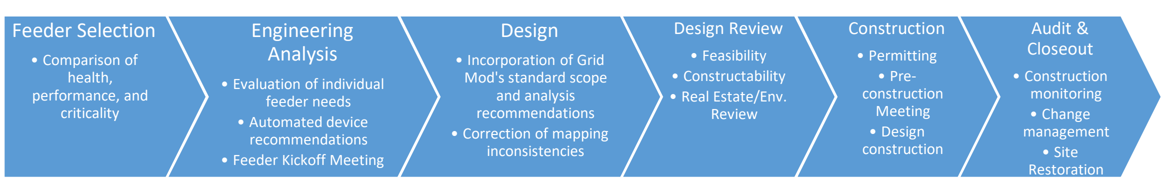


Figure 5: The Grid Modernization Project Life Cycle

Once metrics are gathered, individual feeders are evaluated to determine how they rank in comparison to the rest of the electric distribution system. Once chosen, the Program Engineer analyzes the feeder for opportunities to improve its reliability, power quality, potential for energy savings, and accessibility. That analysis is conveyed in a report to project stakeholders outlining feeder specific opportunities for improvement that have been agreed upon by individuals with experience in the area. Design follows the publishing of the report and in addition to feeder specific improvements, a set of standard criteria are applied to the existing equipment in the field. Designs are reviewed by subject matter experts evaluating the designs constructability and accuracy, real estate needs, and environmental and cultural risks. Construction then takes place along with an audit evaluating workmanship and accuracy relative to the design. Deviations are tracked through a design change order process. The project then moves towards completion as site restoration and accounting activities are completed.

Future O&M costs are reduced by relocating, removing, or converting sections of Avista facilities that present an opportunity to improve the feeder's performance. Vegetation Management costs are reduced by the removal of troublesome species that outpace routine maintenance cycles and the installation of automated devices reduces the need for servicemen to trouble shoot outages and performance issues.

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

- **Wood Pole Management** – The GMP incorporates WPM's scope within its projects thereby assisting with its 20-year cycle target. Grid Modernization also relies on WPM for poles inspection reports.
- **Vegetation Management** – The GMP supports and relies on Vegetation Management during the course and completion of its projects. After design and prior to construction, trimming crews address any conflicts that a proposed design might have with existing vegetation. Upon the completion of a project, the GMP reduces the need for future tree trimming by targeting the removal of cycle-breaking species or the relocation and conversion of electric distribution infrastructure.
- **Real Estate** – Locations throughout the GMP designs are reviewed by the staff within the Real Estate department for conflicts that would arise during construction. Permitting is another consideration that is addressed once a design has been completed. The comprehensive GMP approach that partners with Real Estate's analysis results in the mitigation of outstanding issues that have existed in the field, thereby reducing a litigation risk to the company, and the establishment of sustainable alignments and corridors for Avista facilities.
- **Environmental Compliance** – Environmental items of concern are addressed during design and prior to the construction of proposed GMP work. Examples include avian and wildlife protection, the avoidance of any impact on cultural and heritage sites, and the impacts a project may have on public lands managed by tribal, municipal, state, and federal agencies.
- **Segment Reconductor and FDR Tie** – The GMP's holistic approach on feeders selected after a thorough prioritization process addresses issues that might otherwise be included on segment reconductor and FDR tie projects. The investment of Grid Modernization funding on selected feeders improves local office resource availability.
- **Distribution Minor Rebuild** – GMP's holistic approach on feeders selected after a thorough prioritization process addresses issues that might otherwise be included on minor rebuild projects. The investment of Grid Modernization funding on selected feeders improves local office resource availability.
- **Wildfire Resiliency** – The GMP incorporates efforts to reduce the risk of wildfires caused by electric distribution lines by relocating or converting lines in addition to the scope of the Wildfire Resiliency program.
- **Distribution Transformer Change Out Program (TCOP)** – The GMP incorporates the replacement of PCB transformers into each of its projects fulfilling the objective of the TCOP and reducing environmental risks and liabilities to the company and customers.
- **LED Change-Out Program** – The GMP incorporates the replacement of outdated streetlights to fulfill the mission of the LED Change-Out Program across its projects.
- **Primary URD Cable Replacement** – The GMP incorporates the replacement of outdated underground cable to fulfill the objective of Primary URD Cable Replacement across its projects.

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

Replacing equipment upon failure is an alternative to the GMP business case. It would maximize the value of an individual piece of equipment but result in numerous unplanned outages that could arise from and be the cause of unsafe situations to employees and customers. To mitigate the increase of unplanned outages, additional crews would be needed for trouble responses. Aside from a dedicated resource to respond, a variety of equipment and materials would also need to be available to minimize the impact of system failures.

GMP's scope could be addressed through various company initiatives such as WPM, TCOP, Primary URD Cable Replacement, Segment Reconductor and FDR Tie, etc. Given the poor condition of selected GMP feeders, it would certainly mean that the different initiatives would visit the same location multiple times over a short period resulting in elevated mobilization costs and disturbances to customers and communities as crews complete their work. The additional costs of working on the same feeder through multiple initiatives would be evident in increased rates. A possible solution to these issues would be to attempt a large coordination effort with a single construction resource that would receive all work packages from each initiative and attempt to carry out their construction simultaneously.

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.

Work across the program is intended to be completed on a 60 year cycle becoming used and useful throughout each year as projects are constructed. Figure 5 above (Section 2.2) illustrates the life cycle of individual projects that can last at least two years.

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

GMP aligns with Avista's mission: We improve our customers' lives through innovative energy solutions. Safely, Responsibly, and Affordably. We put those we serve at the center of everything that we do. GMP directly improves the lives of our customers by improving system reliability and performance by planning the work to minimize costs of long-term maintenance or unplanned work to maintain the distribution system. The collaboration that takes place throughout the program improves results upon the completion of each project: an efficient delivery experienced by customers and communities and a reduced risk to Shareholders.

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

- By addressing necessary work on the distribution system through the work of one program, there are reduced costs to the customer due to mobilizing crews one time, closing roads, and having planned outages one time instead of many times.
- The GMP plans work ahead of time and invests in the feeders that will receive the highest benefit from the scope of the program. The efficiency of this work is planned through earned value measurements which track the cost and schedule efficiency of the work compared to plan. The planning and tracking of the program use best project management practices.

- The work that will be performed on the program is planned through a thorough engineering analysis and the designs go through a full design review process to ensure that any replacements are prudent and in the best interest of the customer. This prevents work that is out of scope or does not provide adequate benefit from being added to the plan.
- Auditing the completed work ensures that the work performed and charged for was included in the plan or managed and tracked through the approved design change order process.
- Competitive bidding ensures that the work is awarded in a manner that reduces risks and keeps costs lower.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Internal Customers/Stakeholders: Real Estate, Transmission Engineering, Distribution Engineering, Environmental Compliance, Construction Services, Electric Shop, Meter Shop, Area offices, Account Executives, Regional Business Managers, Avista line crews, WPM, Supply Chain, and Vegetation Management.

External Customers/Stakeholders: Electric distribution customers, Municipalities, State DOT's, US Army Corps of Engineers, Public Land Management agencies, Joint Users, Adjacent Utilities, Native Tribes, Community action groups, Contract line crews.

2.8.2 Identify any related Business Cases

Wood Pole Management, Primary URD Cable Replacement, LED Change-Out Program, Wildfire Resiliency, Distribution Transformer Change Out Program, Distribution Minor Rebuild, Segment Reconductor and FDR Tie

3.1 Steering Committee or Advisory Group Information

The steering committee is comprised of the project sponsor, Asset Maintenance Manager, Director of Operations, and the Asset Management Manager. This group meets as needed, usually annually, 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.

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

The Grid Modernization Communication plan details the individuals that receive communication, the type of communication, and the frequency of communication. This document is located at: c01m19:\Feeder Upgrades - Dist Grid Mod\~Program Admin\Admin\Project Management Plan

Distribution Grid Modernization

Documents\03 Communication Management Plan.docx

Program Communication Plan

Stakeholder Group *(From Stakeholder Checklist)*	Communication Method *Communication Artifact*	Frequency	Members
Internal			
Project Team	Project Kickoff Meeting for each feeder	Once	Keystake holders
	Bi-weekly internal team meeting	Bi-weekly	Avista CPCs, Distribution Engineer, APM, PM
	Monthly team meeting	Monthly	David Clark, John Hanna, Seth Rounds, David Garnetti, HDR contract designers, Alicia Gibbs
Key Stakeholders	Stakeholder Report *One Pager document*	Monthly	Ops managers, CPCs, team members, stakeholders
	Key Stakeholder Check-in Meeting	As-needed	
Steering Committee	Steer-Co meeting	Bi-monthly/ad-hoc meetings and Monthly one pager	Glenn Madden, Darrell Soyars, Rod Price, David Howell, Brian Vandenburg, Dave James, Cody Krogh, Shane Pacini, Alicia Gibbs
Project Sponsors	Stakeholder Report *One Pager document*	Monthly	David Howell
Officers	Ops Council Presentation *Slide Deck*	Annually	
Director	Stakeholder Report *One Pager document*	Monthly	David Howell
Manager	Stakeholder Report *One Pager document*	Monthly	Alicia Gibbs
	Check-in Meeting	Bi-weekly	
External Communications	Media Talking Points *Project Talking Points document*	Once	At the beginning of construction for each feeder
	Stakeholder Report *One Pager document*	Monthly	
Departmental Managers (Responsible)	Project Kickoff Meeting *Roles & Responsibilities document*	Once	
	Stakeholder Report *One Pager document*	Monthly	
Departmental Managers (Informed)	Stakeholder Report *One Pager document*	Monthly	
Departmental Rep. (Responsible)	Project Kickoff Meeting *Roles & Responsibilities document*	Once	
	Stakeholder Report *One Pager document*	Monthly	
Departmental Rep. (Informed)	Stakeholder Report *One Pager document*	Monthly	
End Users	Project Requirements Meeting *Project Charter, Functional Requirements document*	Once	Area engineer, Area Manager
	Stakeholder Report *One Pager document*	Monthly	
	Pre-construction Meeting *minutes*	Once	

Distribution Grid Modernization

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

- Decision making is documented in meeting minutes in the Program Onenote folder.
    - c01m19:\Feeder Upgrades - Dist Grid Mod\~Program Admin\Meetings & Presentations\~1Shared Grid Mod Program notebook
- The prioritization of feeder work is managed in the Feeder Selection management tool which is stored in the Grid Modernization drive. The prioritization is updated every one to two years with updated data from the Feeder Status Report. The feeders are then ranked based on equally weighted health, performance, and reliability scores. The top feeders may undergo an engineering analysis and gather feedback from area engineers to determine which order these feeders are selected in.
- Change requests are managed through a change order process. Any proposed changes that occur during construction to the approved designs are first evaluated, then approved, and tracked through the change order process.

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.

Signature:	Heather Webster	Date:	7/31/2020
Print Name:	Heather Webster		
Title:	Asset Maintenance Project Mgr.		
Role:	Business Case Owner		

Signature:	David Howell *David Howell*	Date:	7/31/2020
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

Minor Rebuild

EXECUTIVE SUMMARY

The Distribution Minor Rebuild business provides a solution for the utility to address small unplanned asset failures and customer driven modifications to the distribution system but excludes fixes to the system considered to be maintenance. Distribution Minor Rebuild is an ongoing program that focuses on keeping the distribution system in reliable condition for customers, maintaining safe conditions for the workers, providing response to unplanned damages to distribution assets not related to weather events, as well as responding to 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. This work impacts customers in WA and ID. By not funding, various types of work will need to be absorbed into some 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 failed transformer, and other safety related projects.) Some minor rebuilds left unrepaired may not result in an immediate catastrophic failure. Over time an adverse accumulation of unrepaired assets would greatly put line workers and the general public at risk as minor asset failures begin to deteriorate pockets of the distribution system.

Historically costs for unplanned minor rebuild work have increased 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 $11,900,000 per year. This is expected to continue for the next 5 years. On average, Minor Rebuild spends approximately $1,000,000/month.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Amy Jones*	*Draft of 2020 Business Case Refresh update*	*6/30/2020*	

Minor Rebuild

GENERAL INFORMATION

Requested Spend Amount	$10,000,000 annually
Requested Spend Time Period	Ongoing Program
Requesting Organization/Department	Electric Operations
Business Case Owner | Sponsor	Amy Jones | 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?

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

The work includes; Asset Condition, NESC/Operating Standard Violation, Facility Upgrades, Facility Route Location Modification, Trouble and 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.

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 the work is Asset Condition. This work focuses on keeping the distribution system in reliable condition for customers, maintaining safe conditions for the workers, providing response to unplanned damages to distribution assets not related to weather events, as well as responding to 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 is deferred

Distribution Minor Rebuild work is one of the many components that support the overall reliability of the distribution system as well as responsiveness to customer requested service demands and system safety. Safety is of utmost concern for linemen and the general public and 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 other safety related projects. In addition, if the business case is not funded, this will also affect the ability to respond to customers' needs for modifications to their electrical service. It is acknowledged some minor rebuilds left unrepaired will not result in immediate catastrophic failures to the distribution system, but over time an adverse accumulation of unrepaired assets would greatly put line workers and the general public at risk as minor asset failures begin to deteriorate within areas of the distribution system.

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.

Historical information and the continuance of tracking spend by categories will be useful in determining the effectiveness of the program and meeting its original objectives.

In 2020, Distribution Minor Rebuild transitioned to an activity-based structure that divided the business case into six general activities, which embody the major types of work performed. This division will allow for improved reporting on spend. Below is a categorical breakdown for the six general activities.

- **Customer Requested Rebuilds** – Work is initiated by an existing customer or property owner, and the costs associated with the work are typically reimbursed by the requesting party. Examples could be a customer requested reroute, overhead to underground line conversion, or customer load increase.
- **Trouble Related Rebuilds** – Emergency work required to repair damaged facilities related to 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 a chart of the estimated spend by general activity. The new general activities were implemented in January 2020.

Minor Rebuild

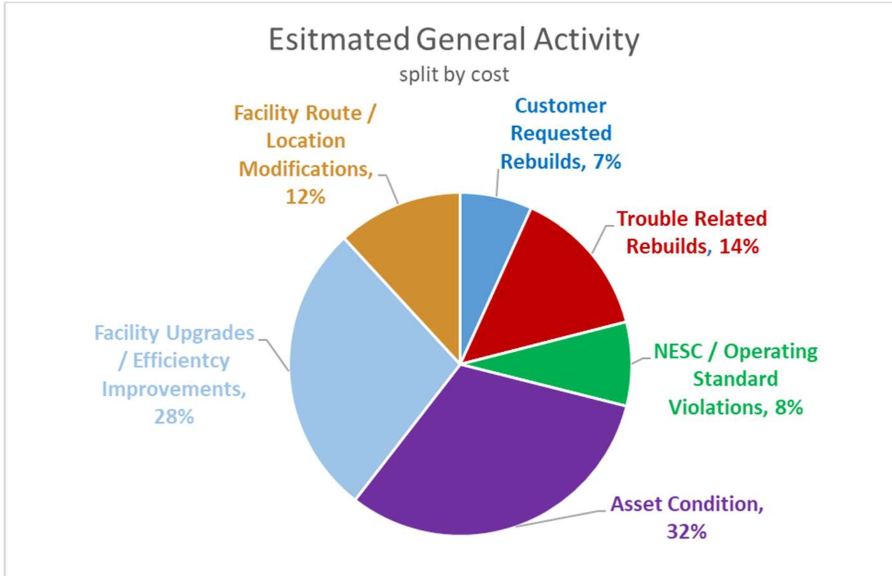


Figure 1: Estimated General Activity split by cost

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

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.

NA

Option	Capital Cost	Start	Complete
Fund Unplanned Work (based on historical quantities)	$10,000,000	Continuous Program	
Some other Program covers the needed work.	$10,000,000	Continuous Program	
Unfunded	$0	NA	

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

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 $11.9MM per year. This is expected to continue for the next 5 years. Minor Rebuild spends approximately $1MM per month. Figure 3 shows the historical spend amount by year. Starting in 2020, the Joint Use spend is no longer included in the Minor Blanket Business Case as it now has its own business case.

Minor Rebuild

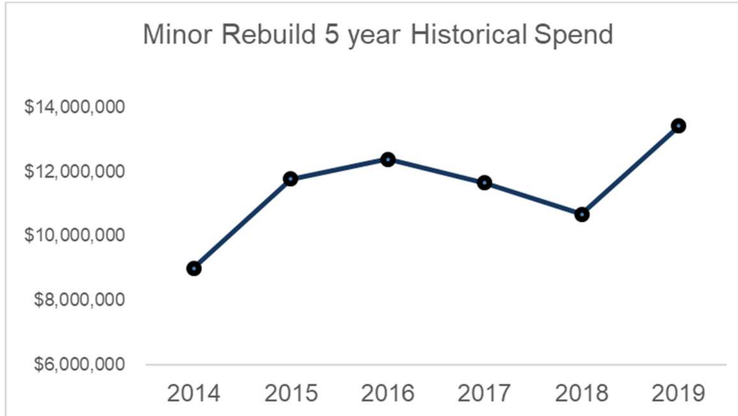


Figure 2: Minor Rebuild Historical Spend

In 2019 2,481 work orders were created with the average cost equaling $4,398, which demonstrates the work is made up of thousands of small dollars, critical non-discretionary jobs. Occasionally, larger rebuild projects such as small reconductor projects, are undertaken as a Distribution Minor Rebuild project if prioritized by the Area Operations Engineer. Only 53 of the 2,481 work orders created in 2019 were over $25,000. Those 53 work orders averaged $52,662.

Figure 2 displays a breakdown of the different types of charges that occur in the Minor Rebuild business case. The majority of charges are from specific work orders. Distribution Minor Rebuild work often 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.

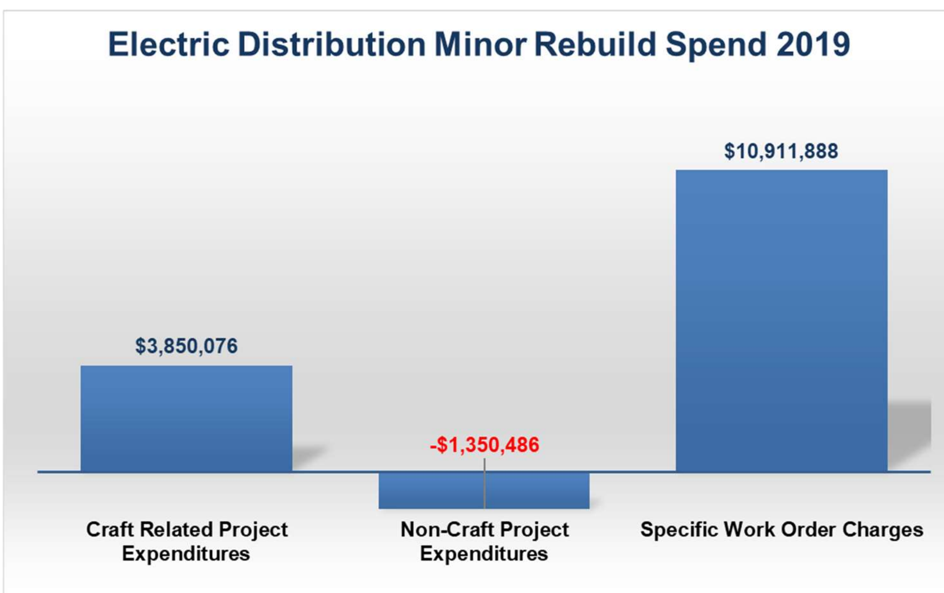


Figure 3: Types of Charges to Minor Rebuild (2019)

The following is a brief description of each type of charge.

Minor Rebuild

- **Craft Related Project Expenditures**: Craft labor (servicemen, general foremen, local rep), associated vehicle usage, trouble related work charges
- **Non-Craft Related Project Expenditures**: Non-craft labor, associated vehicle usage, contribution reimbursables (credits), and material issues/returns
- **Specific Work Order Charges**: The work order number is referenced on timesheets, material requests, invoices, and vehicle charges/loadings

The Non-Craft Project expenditures show a negative value due to customer contributions being greater than charges.

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.

Distribution Minor Rebuild is an ongoing program that focuses on keeping the distribution system in reliable condition for customers, maintaining safe conditions for the workers, provides providing responsiveness response to unplanned damages to distribution assets not related to weather events, as well as responding to small customer driven rebuilds. Throughout the entire distribution system, minor rebuilds, or replacement of asset units need to be completed to maintain system reliability and safety. Spend will continue as it has in previous years.

The work includes**;** failed asset replacements, small mandatory and compliance work, slight 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.

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 Distribution Minor Rebuild business case has been in operation for several years so there will be minimal impact to other business functions and processes with funding this business case. Distribution Minor Rebuild reaches across multiple departments in Engineering and Operations. The business involves operation area engineers, local customer project coordinators, and construction technicians who work directly with customers and perform all the designs for the business. Once the minor projects are designed and ready for construction, field personnel such as a Foremen, Journeyman Linemen, Line Servicemen, Meter men, Equipment Operators execute the work.

Not funding would have a significant impact on business functions and processes as other areas would be responsible for the work and it would also impact the ability to respond to customers' needs for modifications to their electrical service.

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

The other alternative that was considered is not funding the business case however, the needed work will continue to occur. These costs would be covered under other business cases. The body of work within the Distribution Minor Rebuild business case consists of very small unplanned projects across the entire distribution system in response to a variety factors (customer requested, trouble related work, deteriorated pole replacements, and general rebuilds), therefore the alternatives are generally not available to analyze. Typically, as each project arises, any alternatives available for individual rebuild projects are evaluated during the design phase by the designer.

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.

The Distribution Minor Rebuild business case is an on-going program, and assets typically go into service at the time the project (service order/ job) is completed and does not have a final cost. The program has an average annual cost around $11.5MM. The minor rebuild projects are so small in nature they almost always go into service the same day as constructed

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

The Distribution Minor Rebuild business aligns with the company's focus of Our Customers, Our People, and Perform by investing in our infrastructure to achieve optimum life-cycle performance – safely, reliably and affordably. This business case provides a solution to address those small unplanned asset failures and customer driven modifications to the distribution system.

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 Distribution Minor Rebuild business maintains flexibility for the utility to address small, unplanned asset failures and customer driven modifications to the distribution system but, excludes fixes to the system considered to be maintenance. While the work is unplanned, minor rebuilds to the distribution system occur on a regular basis every year to maintain system reliability and safety. The Distribution Minor Rebuild business case provides a solution for the utility to address those small unplanned asset failures and customer driven modifications to the distribution system. Safety is of utmost concern for linemen and the general public and the minor rebuild business case provides the funding for work. Some minor rebuilds left unrepaired may not result in an immediate catastrophic failure. Over time an adverse accumulation of unrepaired assets would greatly put line workers and the general public at risk as minor asset failures begin to deteriorate pockets of the distribution system.

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

Stakeholders that interface with the Distribution Minor Rebuild work are the local area operations engineers, general foremen, and area construction managers.

2.8.2 Identify any related Business Cases

None

3.1 Steering Committee or Advisory Group Information

The Operations Roundtable (ORT) acts as the Advisory Group for this business case. The Distribution Minor Rebuild work is managed by the local area operations engineers, general foremen, and area construction managers.

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 proposes annual budgets, monitors the incurred costs and submits any additional funds requests as needed**.**

The work done under Minor Rebuild, by way of projects, is overseen by Area Engineers. Area Engineers receive a weekly report on all active work orders under the business and managed which projects get done according to current needs and priorities. The local customer project coordinators (CPCs), who design the projects, are required to seek Area Engineer approval for projects above a $10,000 threshold before performing the work.

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 ***Minor Rebuild*** and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	
Print Name:	Amy Jones		
Title:	Asset Maintenance Business Analyst		
Role:	Business Case Owner		

Minor Rebuild

Signature:	David Howell	Date:	8/2/20
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

Rattlesnake Flat Wind 115kV Integration Project

1 GENERAL INFORMATION

Requested Spend Amount	$19,789,874
Requesting Organization/Department	Transmission Services
Business Case Owner	Josh DiLuciano
Business Case Sponsor	Heather Rosentrater
Sponsor Organization/Department	T&D
Category	Project
Driver	Customer Requested

1.1 Steering Committee or Advisory Group Information

- Ken Sweigart – Manager, Transmission Line Design Engineering
- Glenn Madden – Manager, Substation Engineering
- Project Engineer/Project Manager – Aaron Tremayne and Adam Newhouse
- Randy Gnaedinger – Transmission Contracts Analyst

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.

2 BUSINESS PROBLEM

The Interconnection Customer representing the Rattlesnake Flat Wind Farm Development (Avista Interconnection Project #49) has proposed construction of a new 144MW nameplate capacity wind generation facility, and has chosen an interconnection to Avista's Lind-Washtucna 115kV Transmission Line at a point approximately 4.5 miles southeast of Avista's Lind Substation. The Point of Interconnection (POI) will be the new 3-position ring bus Neilson Substation with a line position dedicated to the Interconnection Customer. The Interconnection Customer chose the POI from a number of options developed by Avista's Transmission Planning Group during the FERC-mandated interconnection study process. Per the FERC process, the Interconnection Customer and Avista have signed an Interconnection Agreement that include required milestones for completion of this project.

These milestones include, the Interconnection Customer providing deposits totaling $1,041,500 (equivalent to the project's associated Direct Assigned Costs) in the 2018-2019 time frame, and Avista's completion of the project with an in service date prior to September 30, 2020.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Alt 1: Status Quo: Do nothing.			
Alt 2: Build Network Upgrade Facilities required to support the Rattlesnake Flat Wind Farm nameplate output of 144MW.	*$19,789,874*	*2018*	*2020*

Rattlesnake Flat Wind 115kV Integration Project

Due to the nature of the rules governing the Interconnection Process the POI location is selected by the Interconnection Customer, therefore only one alternative is shown.

Alternative 1:

This alternative is not recommended because it does not comply with rules set forth by FERC governing interconnection requests. Options are available for funding, design, and construction, but not as to whether the project can be avoided.

Alternative 2:

This alternative meets the requirements of the Interconnection Customer's request, and best satisfies the integration requirements of the wind project. This alternative also addresses a Transmission Line Asset Condition project (Lind-Warden) previously identified and prioritized to construct in the 2018-2019 time frame. This alternative is the best solution for the long term.

Solution:

Alternative 2: The scope recommended consists of the following:

Transmission Provider Network Upgrades	
Rebuild 22 miles of 115 kV transmission with OPGW from Lind-Warden – permitting, engineering, design, procurement and construction (includes Distribution Underbuild)	$11,150,000
Rebuild 4.5 miles of 115 kV transmission with Optical Ground Wire (OPGW) from Neilson to Lind – permitting, engineering, design, procurement and construction (includes Distribution Underbuild)	$ 2,900,000
Point of Interconnection 115 kV Substation (Neilson) – engineering, design, procurement and construction of (2) line positions, protection and control of a 3-position ring bus station	$ 2,500,000
Construct Communications Path(s) for Operation of the (POI) 115 kV Neilson switching station, Lind Substation, and Warden Substation – engineering, design, licensing, land acquisition, building construction, and installation	$ 689,874
Lind Substation capacity upgrades 115 kV substation –engineering, design, procurement and installation of protection and control (two relay upgrades and mobile installation)	$ 550,000
Replacement of the Roxboro circuit switcher - engineering, design, procurement and installation of protection and control (includes mobile installation)	$ 250,000
Warden Substation capacity upgrades - engineering, design, procurement and installation of protection and control (two breaker replacements, two relay upgrades, and one relay modification)	$ 1,250,000
Othello Switching Station capacity upgrades - engineering, design, procurement and installation of protection and control construction (two relay upgrades)	$ 500,000

Subtotal Network Upgrades	**$ 19,789,874**

IN SERVICE: 8/31/2020

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Rattlesnake Flat Wind 115kV Integration Project* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: [signature] Date: 4/22/19
Print Name: Josh DiLuciano
Title: Director
Role: Business Case Owner

Signature: [signature] Date: 4-22-19
Print Name: Heather Rosentrater
Title: VP, Energy Delivery
Role: Business Case Sponsor

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

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	*<Author name>*	*mm/dd/yy*	*<name>*	*mm/dd/yy*	*Initial version*

Template Version: 03/07/2017

South Region Voltage Control (N. Lewiston Reactor) Project

1. GENERAL INFORMATION

Requested Spend Amount	$8,000,000
Requesting Organization/Department	Transmission Planning
Business Case Owner	Ken Sweigart
Business Case Sponsor	David Howell/Scott Waples
Sponsor Organization/Department	T&D
Category	Project
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

- Ken Sweigart – Manager, Substation Engineering
- Project Engineer/Project Manager (PE/PM) – Adam Newhouse

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.

2. BUSINESS PROBLEM

There is an ongoing issue with high voltage on the 230 kV transmission system in the Lewiston/Clarkston area. The high voltage problem is persistent most months of the year (the exception is heavy summer loading months) and the high voltage peaks during the overnight hours. This high voltage condition is a result of the expansion of Avista's 230 kV transmission network. Although there are many benefits to a large networked transmission system, one negative outcome is that long, lightly loaded transmission lines produce large amounts of line charging current (leading reactive MVAR), which increases system voltage. Currently, there is no practical way to correct this high voltage issue with the existing 230 kV transmission system beyond taking lines out of service.

3. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Alt 1: Do nothing			
Alt 2: North Lewiston Reactors	*$8M*	*2016*	*2019*

Alternative 1:

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

Alternative 2:

Install two 50 MVAR shunt reactors at the North Lewiston Station on the 230 kV bus. The reactors allow for adequate voltage control to maintain voltage below applicable facility ratings during normal and contingency scenarios.

South Region Voltage Control (N. Lewiston Reactor) Project

Solution:

Alternative 2: North Lewiston Reactors. Project scope includes the following:

Install two 50 MVAR shunt reactors to the existing 230 kV bus at North Lewiston Station. The project has already been initiated including procurement of the reactors.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *South Region Voltage Control Business Case* and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: [signature] Date: 4/18/2017
Print Name: KENNETH SWEIGART
Title: MANAGER SUBSTATION ENGINEERING
Role: Business Case Owner

Signature: [signature] Date: 4/17/17.
Print Name: David Howell
Title: Director Electrical Engineering
Role: Business Case Sponsor

Signature: [signature] Date: 4/19/2017
Print Name: Scott A Waples
Title: Director, Planning & Asset Mgmt
Role: Business Case Sponsor

VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	*Ken Sweigart*		*Above signatures*	*4/14/17*	*Initial version*

Template Version: 03/07/2017

New Saddle Mountain 230/115kV Station Phase 1 Integration

1 GENERAL INFORMATION

Requested Spend Amount	$38,000,000
Requesting Organization/Department	Transmission Planning
Business Case Owner	Scott Waples
Business Case Sponsor	Heather Rosentrater
Sponsor Organization/Department	T&D
Category	Project
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

- Ken Sweigart – Manager, Substation Engineering
- Project Engineer/Project Manager – Brian Chain

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.

2 BUSINESS PROBLEM

In the fall of 2013, Grant employees contacted Avista System Planning about performance issues within Grant's system that are exacerbated by Avista's load in the Othello area. The issue was escalated to Columbia Grid through the Regional Planning process. It was identified through this process and Avista System Planning that the system performance analysis indeed indicates an inability of the System to meet the performance requirements P1, P2 and P6 categories in Table 1 of NERC TPL-001-4 in current heavy summer scenarios, and P6 categories in heavy winter scenarios.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Alt 1: Status Quo			
Alt 2: Build new 115kV Transmission Line			
Alt 3: Close "Star" Points			
Alt 4: Install Generation			
Alt 5: Build Saddle Mountain 230/115kV Substation Phase 1 Project with associated support projects	*$38M*	*2017*	*2021*

Alternative 1:

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

New Saddle Mountain 230/115kV Station Phase 1 Integration

Alternative 2:

This alternative is not recommended as it does not mitigate the low voltage issues in the Othello area.

Alternative 3:

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:

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:

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.

Solution:

Alternative 5: The scope recommended consists of two phases:

PHASE 1:

1) Construct a 3 – position 230 kV double bus double breaker arrangement with space for 2 future positions at the line crossing of the Walla Walla – Wanapum 230 kV and Benton – Othello 115 kV transmission lines.
2) Construct a 3 position 115 kV breaker and a half arrangement with space for 3 future positions.
3) Install 250 MVA Transformer
4) Rebuild entire 8.28 miles of Othello – Warden No.1 115 kV line with minimum 205 MVA capacity
5) Rebuild 2.88 miles of Othello – Warden No. 2 115 kV line with minimum 205 MVA capacity

COST: $38M

IN SERVICE: 12/31/2020

PHASE 2: See Associated Phase 2 BC Narrative

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Saddle Mountain 230/115kV Station (New) Integration 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: 8/11/2017
Print Name: Scott Waples
Title: Director of Planning & AM
Role: Business Case Owner

Signature: Date: 8/14/17
Print Name: Heather Rosentrater
Title: VP Energy Delivery
Role: Business Case Sponsor

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

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	*<Author name>*	*mm/dd/yy*	*<name>*	*mm/dd/yy*	*Initial version*

Template Version: 03/07/2017

Substation – Station Rebuilds Program

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) a synopsis of the problem, 2) the service code and jurisdiction of customers impacted, 3) the recommended solution, 4) the cost of the solution, 5) how the solution will benefit customers identified, 6) the significance of the timeline and 7) the risks of not approving this business case.*
<< Both the Executive Summary and Version History should fit into one page >>

Replacing and upgrading major substation apparatus and equipment as it approaches end of life or becomes obsolete is necessary to maintain safe and reliable operation of Avista's transmission and distribution systems. Rebuilding significant portions of stations may be necessary to accommodate the replacement of failing or obsolete equipment since new standard-use apparatus and equipment is often of higher capacity and newer technology and may need to meet updated equipment spacing and operating standards.

Failure to replace old 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. This Business Case is important for customers because it is critical toward Avista's ability to continue to provide the reliable electrical service that customers have grown accustom to receiving.

Service: ED – Electric Direct

Jurisdiction: Various. Each rebuild project has its own Jurisdiction.

Engineering Roundtable Request Number: Various. Each rebuild project has its own ERT Request.

2020 Expected Spend: $18,900,000

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Ken Sweigart	Initial Version	4/14/2017	
2.0	Jeff Schlect	Consolodation of capital maintenance and major rebuild business cases	5/19/2017	
3.0	Karen Kusel / Glenn Madden	Update to 2020 Template	6/30/2020	

Substation – Station Rebuilds Program

GENERAL INFORMATION

Requested Spend Amount	$20,000,000 per year
Requested Spend Time Period	On Going
Requesting Organization/Department	T&D – Substation Engineering
Business Case Owner | Sponsor	Glenn Madden | Josh DiLuciano
Sponsor Organization/Department	T&D
Phase	Execution
Category	Program
Driver	Asset Condition

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]

Replacing and upgrading major substation apparatus and equipment as it approaches end of life or becomes obsolete is necessary to maintain safe and reliable operation of Avista's transmission and distribution systems. Rebuilding significant portions of stations may be necessary to accommodate the replacement of failing or obsolete equipment since new standard-use apparatus and equipment is often of higher capacity and newer technology and may need to meet updated equipment spacing and operating standards. 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).

Major apparatus include 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.

Failure to replace old 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.

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

Aging apparatus and equipment plus changes in customer needs and compliance requirements.

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 major driver of the business case is Asset Condition. Good asset condition leads to fewer customer outages.

Substation – Station Rebuilds Program

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

This is an on-going program to stay ahead of the curve of asset age and condition.

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.

General age of all major substation equipment.

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]

System Planning Assessments, Maximo Work Orders.

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.

As of July 2020, here are samples of data we use to view asset information used to determine viable options for substation rebuilds.

Equipment Type	Average Manuf Year
Air Switch	2005
Breaker Recloser	2000
Circuit Switcher	1991
HV Circuit Breaker	1996
Power Transformer	1986
Switchgear Breaker	1985
Voltage Regulator	2002

Equipment Type	Oldest Mfg Yr and Substation
Air Switch	1930 - Leon Jct
Breaker Recloser	1924 - South Lewiston
Circuit Switcher	1968 - Osburn
HV Circuit Breaker	1952 - Sunset
Power Transformer	1946 - Garfield
Switchgear Breaker	1963 - Chester
Voltage Regulator	1960 - Bunker Hill

Substation – Station Rebuilds Program

Location	Avg Age of Major Equipment
Coeur Shaft Mine 13kV	1961
Chester 115kV	1974
Rockford 115kV	1975
Post Falls 115kV	1977
Dry Gulch 115kV	1978
Wallace 115kV	1979
Metro 115kV	1979
South Lewiston 115kV	1980
Roxboro 115kV	1981
Leon Jct. 115kV	1981

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)]

The recommended approach is to replace station apparatus and equipment as needed due to asset condition and consider broader station rebuilds when the majority of assets in the impacted area of a station 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 degradation of reliability and mitigating the frequency and duration of outages due to equipment failure.

Option 1: Do nothing - Not recommended

Option 2: Maintain current funding level - Current spending on the Asset Condition risk category is $12.85 million annually. Project prioritization will be supported by Asset Management and substation subject matter experts for prioritization of work within this risk category. Project and funding levels will be reviewed on an annual basis.

Option 3: Reduce current Asset Condition capital improvements. Not recommended. May lead to a reduction in the level of reliability and or operating flexibility that can be achieved by the transmission and distribution systems.

Option	Capital Cost	Start	Complete
Maintain present level of Station Rebuilds	$20M	On Going	On Going
Alternate 1: Do nothing	$0M		
Alternate 2: Maintain minimum level of Station Rebuilds	$0-12M	-	

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*
-

Substation – Station Rebuilds Program

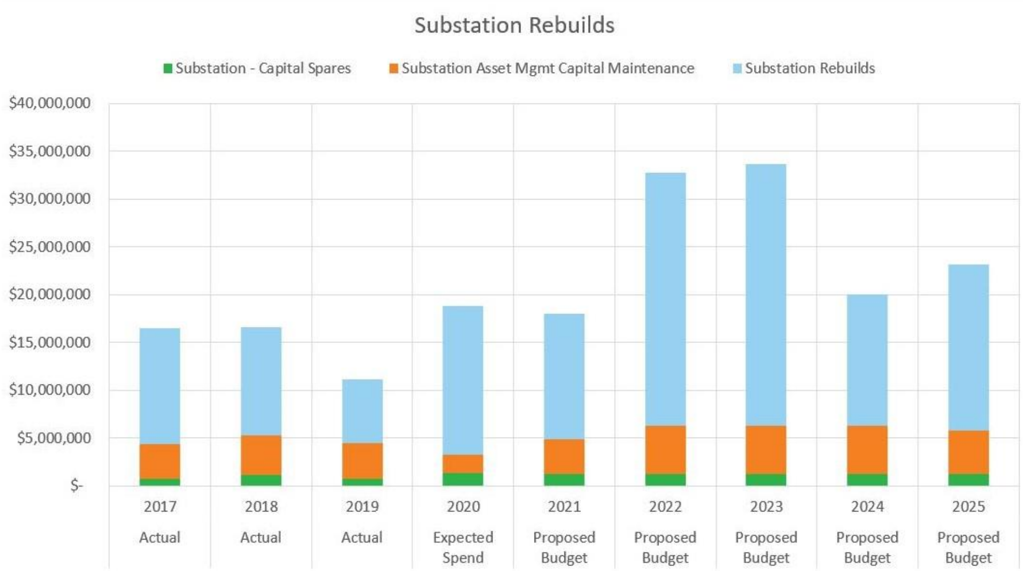
Reference key points from external documentation, list any addendums, attachments etc. System Planning Assessments and Asset Management information.

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.]

Ongoing improvements to the BES via substation rebuilds will result in system reliability, fewer customer outages and smaller O&M costs.



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.

Reduce the numbers of capital improvements or Doing Nothing causes equipment to age and become obsolete and difficult to maintain.

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).]

Ongoing average of two rebuilds per year with multiple projects being in various stages of design, construction and closeout.

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

These projects will help Avista stay ahead of the curve of load growth and equipment age to prevent 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

Customer outages are longer and larger when older equipment fails.

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.]

The Engineering Roundtable manages the prioritization of projects within this business case as supported by Asset Management studies and input from company subject matter experts. The Engineering Roundtable is comprised of representatives from the following departments: Asset Management, Compliance, System Planning, System Operations, Telecommunications, Transmission Contracts, Protection Engineering, Substation Engineering, Transmission Engineering, and Substation Support.

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 Substation - Station Rebuild 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:	Glenn Madden		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:		Date:	
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

Transmission Construction - Compliance

EXECUTIVE SUMMARY

The Transmission Construction – Compliance Business Case covers the Transmission rebuild and reconductor work necessary to maintain compliance with the NERC Reliability Standard TPL-001-4 – Transmission System Planning Performance Requirements ("Standard"). It has 8 requirements and 57 sub-requirements related to planning and analysis, including the requirement for robust system models to determine system stability, voltage levels and system performance under various scenarios. This standard mandates that an annual planning assessment be conducted and corrective actions be identified and implemented to remedy any system performance deficiencies In addition, when Avista's system planning studies indicate any kind of problem that could arise in the transmission system, it must be remedied within specific timeframes. The Transmission Construction - Compliance Program provides funding to mitigate any identified reliability issues in order to remain in compliance with NERC requirements.

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 $5,050,000 is needed to complete the planned 2021-2025 projects . This Program will have a Service Code of Electric Direct and a Rate Jurisdiction of Allocated North.

The Business Case contains four projects:

- *KEC Rimrock Substation Interconnection*
- *Beacon-Ross Park 115kV Rebuild*
- *Beacon-Boulder #1 115kV Rebuild (east of Irvin)*
- *Ninth & Central-Sunset 115kV Partial Rebuild (Upgrade to 795 ACSS)*

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*	*7/10/2020*	
1.0	*Prudent Penny*	*Updated Approval Status*	*6/1/2020*	*Full amount approved*
1.1	*Debbie Downer*	*Budget change*	*10/15/20*	*$50,000 deferred to 2021*
2.0				

Transmission Construction - Compliance

GENERAL INFORMATION

Requested Spend Amount	$5,050,000
Requested Spend Time Period	*5 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

1.1 *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.

1.2 What is the current or potential problem that is being addressed? *NERC Reliability Standards and NESC loading capacities.*

1.3 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.*

1.4 Identify why this work is needed now and what risks there are if not approved or is deferred *Relevant sections of the NERC Sanction Guidelines are cited below:*

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

Transmission Construction - Compliance

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.

.**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.*

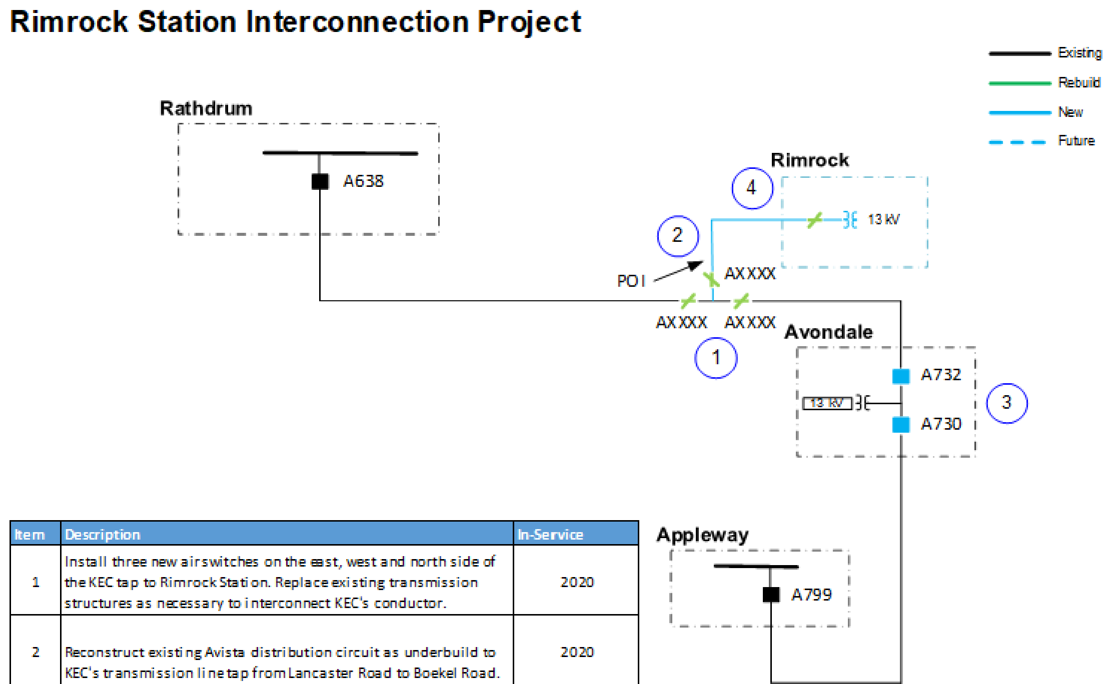
1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

KEC Rimrock System Impact Study.docx
CAI Structure Analysis Results_BEA-BLD.xlsx
CAI Structure Analysis Results_BEA-ROS.xlsx
2019 Avista System Planning Assessment

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.

Transmission Construction - Compliance



Item	Description	In-Service
1	Install three new air switches on the east, west and north side of the KEC tap to Rimrock Station. Replace existing transmission structures as necessary to interconnect KEC's conductor.	2020
2	Reconstruct existing Avista distribution circuit as underbuild to KEC's transmission line tap from Lancaster Road to Boekel Road.	2020
3	Replace switches A732 and A730 within Avondale Station with new circuit breakers and associated station upgrades.	Within 1 year of Rimrock
4	KEC will build, own and maintain their facilities from the POI to the Rimrock Station.	2020

FIGURE 3: RIMROCK INTERCONNECTION PROJECT DIAGRAM

Engineering Project Request

Instructions: If this is a new request, save this template to your local drive, complete the form, then upload it to ENSO Sharepoint.

Project Title *(e.g. "Benewah-Moscow 230kV Rebuild")*	Beacon – Boulder #1 115 kV Rebuild	**Request Number**	ERT_2020-xx
Enterprise Project Driver *Reason for initiating the project*	Mandatory & Compliance	**Primary Asset Class**	Transmission
Requested By *The person filling out this form*	Ken Sweigart	**Project Sponsor** *Director sponsoring the project*	Josh DiLuciano
Proposed In-Service Date *Date that the project should be completed*	12/30/2022	**VROM** *Very Rough Order of Magnitude (Cost Estimate)*	$3.60 million

Transmission Construction - Compliance

Problem Statement *Provide a brief explanation of the problem that needs to be addressed*	Under the present existing circumstances, most of the wood structures along the 3+ mile alignment will not pass the structural analysis requirements outlined in the 2017 National Electric Safety Code (Adopted by Washington Statute).
Alternatives Considered *Provide a list of potential alternatives, including non-wires alternatives*	1. Do Nothing – This alternative would not bring us into compliance with the National Electric Safety Code (NESC). By not complying with the NESC, we would be out of compliance with the State of Washington. 2. Rebuild parts of the Beacon – Ross Park 115 kV transmission line within the existing alignment. Work up a design to top existing transmission structures and leave any distribution or joint use on old wood transmission structures. This may require less overall steel, due to the existing wood that would be left along the alignment, but it may require taller steel structures to provide enough height clearance to extend above existing already topped wood structures. Based on previous experience with the public perception in this area, this may not be the preferred option from the public's perspective. Additionally, this option would forego the opportunity to shift the line outside of railroad r-o-w on to provate easement which would eliminate annual permit fees. Parts of this line section are already on Provate easement. 3. Rebuild the Beacon – Boulder #1 115 kV line between Irvin Substation and to our current high capacity standard of 200 degrees C. This option accommodates the following stakeholders: a. Planning and System Operations: Increased line capacity will add flexibility. b. ET: Structures will be built ready for Network Communications needs. c. Real Estate: One-time easement costs will eliminate annual permit fees and real-time the access permitting process. d. Operations: This project will accommodate and coordinate with Distribution and Grid Mod needs.
Recommendation *Indicate which alternative is recommended and why. List specific project details and assets to be installed or replaced as well as project phasing.*	Rebuild the Beacon – Boulder #1 115 kV line to meet code and comply with rules and regulations outlined in the National Electric Safety Code. During the design, we will ensure all stakeholders' needs are met from the public eye externally to those internally. The Beacon-Boulder #1 and #2 115kV Lines serve Otis Orchard, Spokane Valley, and the City of Spokane at the Distributive Transmission level. This line supports distribution feeders. Rebuilding this line will provide customer benefit through an increase in reliability/resiliency and benefit internal Avista Stakeholder groups.
Supporting Documentation *Provide links to studies, lifecycle analyses, etc. that support this request.*	1. CAI Structure Analysis Results_BEA-BLD.xlsx – A structural analysis report performed by Commonwealth Associates.

Engineering Project Request

Instructions: If this is a new request, save this template to your local drive, complete the form, then upload it to ENSO Sharepoint.

Project Title *(e.g. "Benewah-Moscow 230kV Rebuild")*	Beacon – Ross Park 115 kV Rebuild	**Request Number**	ERT_2018-08
Enterprise Project Driver *Reason for initiating the project*	Mandatory & Compliance	**Primary Asset Class**	Transmission

Transmission Construction - Compliance

Requested By *The person filling out this form*	Ken Sweigart	**Project Sponsor** *Director sponsoring the project*	Josh DiLuciano
Proposed In-Service Date *Date that the project should be completed*	4/2/2021	**VROM** *Very Rough Order of Magnitude (Cost Estimate)*	$1.25 million
Problem Statement *Provide a **brief** explanation of the problem that needs to be addressed*	Under the present existing circumstances, most of the wood structures along the 2 mile alignment will not pass the structural analysis requirements outlined in the 2017 National Electric Safety Code (Adopted by Washington Statute).		
Alternatives Considered *Provide a list of potential alternatives, including non-wires alternatives*	1. Do Nothing – This alternative would not bring us into compliance with the National Electric Safety Code (NESC). By not complying with the NESC, we would be out of compliance with the State of Washington. 2. Rebuild parts of the Beacon – Ross Park 115 kV transmission line. Work up a design to top existing transmission structures and leave any distribution or joint use on old wood transmission structures. This may require less overall steel, due to the existing wood that would be left along the alignment, but it may require taller steel structures to provide enough height clearance to extend above existing already topped wood structures. Based on previous experience with the public perception in this area, this may not be the preferred option from the public's perspective. 3. Rebuild the entire Beacon – Ross Park 115 kV line to accommodate the lines current capacity ratings at 130 degrees C or rebuild the line to our current high capacity standard of 200 degrees C. We will also accommodate the needs of the IT communication folks and install an OPGW communication cable at the top of the structures if deemed necessary.		
Recommendation *Indicate which alternative is recommended and **why**. List specific project details and assets to be installed or replaced as well as project phasing.*	Rebuild the Beacon – Ross Park 115 kV line to meet code and comply with rules and regulations outlined in the National Electric Safety Code. During the design, we will ensure all stakeholders' needs are met from the public eye externally to all operations folks internally. The Beacon-Ross Park 115kV Line is one of the more heavily loaded in the Avista System, as evidenced by an earlier Reconductor to 795 ACSS, and the limitation on available outage windows. Additionally, this line supports two distribution feeders. Rebuilding this line will not only provide customer benefit through an increase in reliability/resiliency, but will also allow the removal (aesthetic improvement) of span guys (3 locations). Lastly, Avista Network Communications will benefit through a newly available fiber communications pathway.		
Supporting Documentation *Provide links to studies, lifecycle analyses, etc. that support this request.*	1. CAI Structure Analysis Results_REV 2_Arbutus and Dahlia AAC_UB.xlsx – A structural analysis report performed by Commonwealth Associates. 2. beacon-ross park 115 1-23-19.kmz – A preliminary Google Earth KMZ file of the line design.		

Engineering Project Request

***Instructions:** If this is a new request, save this template to your local drive, complete the form, then upload it to ENSO Sharepoint.*

Project Title *(e.g. "Benewah-Moscow 230kV Rebuild")*	Ninth and Central - Sunset Transmission Line Rebuild	**Request Number**	ERT_2017-49

Transmission Construction - Compliance

Enterprise Project Driver *Reason for initiating the project*	Performance & Capacity	**Primary Asset Class**	Transmission
Requested By *The person filling out this form*	Transmission Planning	**Project Sponsor** *Director sponsoring the project*	Scott Waples
Proposed In-Service Date *Date that the project should be completed*	12/31/2023	**VROM** *Very Rough Order of Magnitude (Cost Estimate)*	$1,300,000

Problem Statement *Provide a brief explanation of the problem that needs to be addressed*	An outage of the Garden Springs – Westside 115 kV Transmission Line (created with completion of the 115 kV phase of the Garden Springs 230 kV Station Integration project) combined with another outage of Metro – Post Street, Metro – Sunset, or Post Street – Third & Hatch 115 kV transmission lines causes the Ninth & Central – Sunset 115 kV Transmission Line to exceed its applicable facility rating. 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 2021 Heavy Summer scenarios for the P6 events.
Alternatives Considered *Provide a list of potential alternatives*	**Alt1: Status Quo** This alternative is not recommended because it does not mitigate the expected capacity constraints, and does not adhere to NERC Compliance regulations. Operating Procedures can be used to defer the System Deficiencies. **Alt2: Ninth & Central – Sunset 115 kV Transmission Line Rebuild** Replace the 795 AAC conductor on the Ninth & Central – Sunset 115kV Transmission Line with 795 ACSS with E3X coating to match the rest of the line. All System deficiencies are mitigated. **Alt3: Garden Springs 230 kV Station Integration** The proposed Garden Springs 230 kV Station Integration project could be advanced in the schedule. The project has its own Engineering Round Table project request. All System deficiencies are mitigated.
Recommendation *Indicate which alternative is recommended and why. List specific project details and assets to be installed or replaced as well as project phasing.*	Alternative 2, replace the 795 AAC conductor on the Ninth & Central – Sunset 115kV Transmission Line with 795 ACSS with E3X coating to match the rest of the line is the recommended alternative. $800,000 – Transmission
Supporting Documentation *Provide links to studies, lifecycle analyses, etc. that support this request.*	Under development.

Transmission Construction - Compliance

This is the continuation of a Program first started in 2012 (execution phase), and requires the mitigation of clearances violations.

Option	Capital Cost	Start	Complete
Maintain Compliance	*$5.05M*	*01-2021*	*12-2025*
[Alternative #1] See 1.5.2	*$M*	*MM YYYY*	*MM YYYY*
[Alternative #2] See 1.5.2	*$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.

See 1.5.2

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 various stages based on individual project.

[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 Spokane area jobs.

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

See 1.5.2.

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.

KEC Rimrock Substation Interconnection: 2020-2022
Beacon-Ross Park 115kV Rebuild: 2020-2021
Beacon-Boulder #1 115kV Rebuild (east of Irvin): 2020-2022
Ninth & Central-Sunset 115kV Partial Rebuild (Upgrade to 795 ACSS): 2022-2023

Transmission Construction - Compliance

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

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.

3.1 Steering Committee or Advisory Group Information

The Engineering Roundtable functions as the Vetting Platform, Steering Committee, and Advisory Group.

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.

3.2 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.

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: ______________________________ Date: ______________

Print Name: ______________________________

Title: ______________________________

Transmission Construction - Compliance

Role:	Business Case Owner		
Signature:		Date:	
Print Name:			
Title:			
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

Transmission Major Rebuild – Asset Condition

1 GENERAL INFORMATION

Requested Spend Amount	$9,450,000
Requesting Organization/Department	T&D – TLD Engineering
Business Case Owner	Lamont Miles
Business Case Sponsor	David Howell/Scott Waples
Sponsor Organization/Department	Electrical Engineering
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The Engineering Roundtable manages the prioritization of projects within this business case as supported by Asset Management studies and input from company subject matter experts. It is comprised of representatives from the following departments: Asset Maintenance, Asset Management, Compliance, System Planning, System Operations, Telecommunications, Transmission Contracts, Protection Engineering, Substation Engineering, Transmission Engineering, and Substation Support.

2 BUSINESS PROBLEM

The Transmission Major Rebuild – Asset Condition Business Case covers major rebuilds of transmission lines due to overall asset condition. Factors such as operational issues, ease of access during outages, and potential for communications build-out are also considered in prioritizing this work.

A relevant metric to this business case is the Probability, Consequence, and Risk Summary developed by the Asset Management group, which indicates which transmission lines are most in need of replacement due to end-of-life indicators. This list changes on an annual basis based on the work performed under this business case in the previous year. Another relevant metric is the System Operator's Log with a focus on tracking the number of outages related to asset failures.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Requested Start	Requested Complete	Risk Mitigation
Do nothing	$0	N/A		
Implement Transmission Major Rebuild – Asset Condition program at recommended spending levels	$21.1M	2017	N/A (Program)	• Lower Operating Risk • Transmission Outages caused by Asset Failures, and

Transmission Major Rebuild – Asset Condition

Option	Capital Cost	Requested Start	Requested Complete	Risk Mitigation
				associated risk of fires
Implement Transmission Major Rebuild – Asset Condition program at current spending levels	$9.45M	2017	N/A (Program)	• Higher Operating Risk • Transmission Outages caused by Asset Failures, and associated risk of fires

The recommended solution is to replace poles, cross-arms, and other assets where the majority of assets have been determined to have reached their end of life.

There are no expected business impacts (such as staffing, etc.) to continue the program in place as it was split off of an existing business case.

Without replacing old and worn-out poles and cross-arms, our system will be increasing in risk for more failures and more risk of a major fire caused by a failure. As time moves forward, the number of failures and risk of a major fire will increase the difference in costs between doing nothing and continuing the Transmission Major Rebuild – Asset Condition program. 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.

Transfers to plant will typically occur lightly over a May-June timeframe for work that can be completed in the spring, and heavily in the October-December timeframe for work that has to be completed in the fall. Most of the work is typically completed in fall months due to access conditions and availability of outage windows.

This business case aligns with the organization's mission to deliver reliable energy service to customers by preventing the degradation of reliability of transmission service to the substations that serve them.

Internal stakeholders in this business case include all of the departments listed in the Steering Committee section.

Option 1: Do nothing – Not recommended

Option 2: According to Avista's Transmission System Asset Management Plan, "The 30-year replacement period is recommended at $21.1 million per year, split between $11.3 million for 115kV and $9.8 million for 230kV. This policy, when coupled with an ongoing, annual risk assessment and targeting of funds, over the long term will effectively reduce risks and minimize total lifecycle costs".

Option 3: Current funding level – Current spending on the Asset Condition risk category is $9.45 million annually. Funding levels will be reviewed on an annual basis.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Transmission Major Rebuild - Asset Condition 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: Lamont A. Miles Date: 4/18/17
Print Name: Lamont A Miles
Title: Transmission Design Manager
Role: Business Case Owner

Signature: David Howell Date: 4/17/17
Print Name: David Howell
Title: Dir. Electrical Engineering
Role: Business Case Sponsor

Signature: Scott Waples Date: 4/19/2017
Print Name: Scott Waples
Title: Director Planning + Asset Mgmt
Role: Business Case Sponsor

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Lamont Miles		Above Signatures	4/17/17	Initial version

Template Version: 02/24/2017

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) a synopsis of the problem, 2) the service code and jurisdiction of customers impacted, 3) the recommended solution, 4) the cost of the solution, 5) how the solution will benefit customers identified, 6) the significance of the timeline and 7) the risks of not approving this business case.*

<< 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).

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: $32,000,000

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	$32,000,000
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.

Westside 230/115kV Station Rebuild

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

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.

Westside 230/115kV Station Rebuild

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.

Westside 230/115kV Station Rebuild

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:		Date:	
Print Name:	Glenn Madden		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:		Date:	
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

Wood Pole Management

EXECUTIVE SUMMARY

Asset Management and Distribution Engineering provide ongoing analysis of 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. The operating guidelines are documented in the Structure Specific Distribution Feeder Management Plan. Asset Maintenance collaborates with Electric Operations and contractors to coordinate and complete the work. Asset Maintenance manages and tracks the work, budget, scope, and schedule. Starting in 2020, WPM is integrating the Wildfire Urban Interface (WUI) program scope into its work plan. The goal is to complete the WUI work by 2030. The major drivers for the program are system reliability, improved cost performance, reduced customer outages, and reduction in fire risk. These drivers are achieved by replacing defective poles, associated hardware, and equipment at the end of its useful life or if the condition of the asset requires replacement. The National Electrical 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 214A details documentation and correction of the pole inspection results.

WPM work encompasses Avista's electric distribution overhead facilities in Washington, Idaho, and Montana. In order to maintain a twenty-year cycle, approximately 11,400 poles need to be inspected annually. The work plan is developed to complete 66% of the poles in the state of Washington and 34% of the poles in Idaho each year. For the past three years, the spend has been approximately $10.5M; however, the anticipated spending level needs to be increased to the $17M range due to inclusion of the WUI program into the WPM work plan. This increase accelerates the twenty-year WPM inspection cycle in order to meet the required ten-year WUI cycle. In addition, with current costs, the historical $10.5M funding level does not support completing the identified component replacements on a twenty-year cycle. In 2019, the average cost to mitigate defective items identified during the inspection process was $1,093.49 per pole. As utilities become more susceptible to wildfire litigation it is imperative that the system is inspected, and the defective assets mitigated in a timely fashion. Keeping WPM on a $10.5M annual budget will push work further into the future which increases safety and fire risks to the community and the reliability to our customers.

Version	Author	Description	Date	Notes
1.0	*Mark Gabert*	*Initial draft of original business case*	*7/1/2020*	
2.0	*Mark Gabert*	*Final draft of the original business case*	*7/31/2020*	

Wood Pole Management

GENERAL INFORMATION

Requested Spend Amount	$88,871,382
Requested Spend Time Period	*5 years*
Requesting Organization/Department	Asset Maintenance/WPM
Business Case Owner | Sponsor	Mark S. Gabert | Alicia Gibbs | David Howell
Sponsor Organization/Department	M51/WPM
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

The current Wood Pole Management (WPM) program inspects and maintains the existing distribution wood poles on a twenty-year cycle and the transmission poles on a fifteen-year cycle. Avista has 7,702 overhead distribution circuit miles. According to the 2017 Wood Pole Management Review and Recommendations the average age of a wood pole is twenty-eight years with a standard deviation of twenty-one years. Nearly 20% of all poles are over fifty years old and there are an estimated 230,000 distribution poles in the system. This means approximately 46,000 poles are currently over fifty years old. Our current inspection cycle allows us to reach approximately 11,400 poles each year. Starting in 2021, 14,854 poles need to be inspected each year because the Wildfire Urban Interface (WUI) program is being integrated into the inspections. This increase in inspections will ensure the poles are inspected and maintained on a twenty-year cycle. Along with inspecting the poles, WPM inspects distribution transformers, cutouts, insulators, wildlife guards, lightning arresters, crossarms, pole 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 work is required to be replaced, and assets that are damaged or near their failure point. The asset condition is observed and documented during the pole inspection process as indicated in both the S-622 Specification for the Inspection of Poles, and the Structure Specific Distribution Feeder Management Plan (DFMP) located on the Asset Maintenance Sharepoint Site Designs and work plans are then created to replace the aging infrastructure. 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?

This program addresses issues such as outages, safety risks, fire risks, and unplanned maintenance. This is accomplished by inspecting, documenting, and maintaining our overhead facilities in a useful condition on a twenty-year cycle. This keeps our poles safe for employees and the general public while maintaining a high level of customer satisfaction. As of 2020, WPM is tracking on a twenty-year cycle, however, as the Grid Modernization Program (GMP) budget is reduced, there is an impact on the recommended twenty-year cycle. GMP contributes to WPM's ability to maintain the required poles needed to remain on the twenty-year cycle. The WUI Program is another impact to maintaining the twenty-year cycle. With the addition of the WUI program, WPM will need to re-inspect some poles in the system sooner than the twenty-year cycle so the required WUI work can be completed. If unfunded to expedite the plan, poles will be pushed past the twenty-year cycle in order to meet the demand from the WUI program and with the reduction of GMP budget.

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

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. These drivers are addressed by replacing defective poles, associated hardware, and equipment at its end of life or as required by asset condition. 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 this 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 is deferred

The work is required now to keep pace with the aging assets and expected failure rate. Figure 1 below shows the increased rate at which the poles are reaching the seventy-five 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 in a planned program.

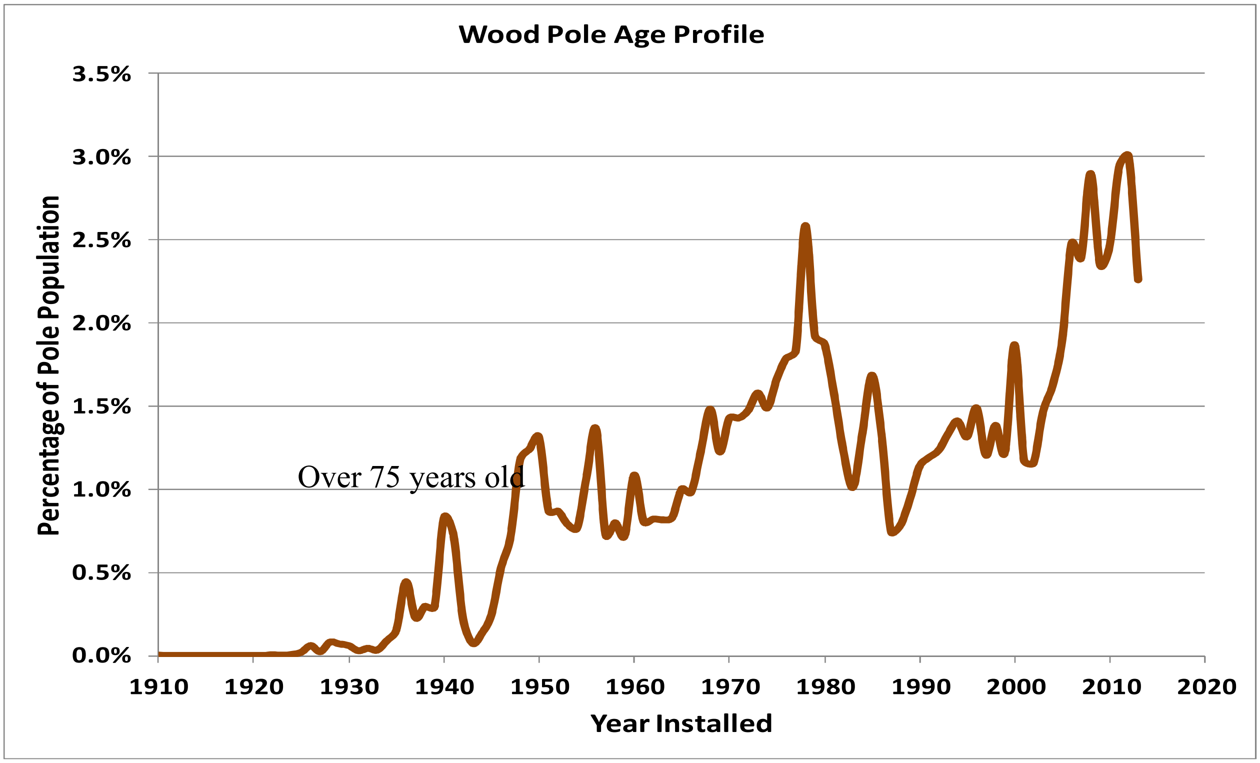
In addition to the risks of fires, outages, and failures with the aging equipment, the additional risks associated with this program pertain to the following:

Environmental: Risks include potential large volume transformer oil spill, 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 a potential for serious injury for crews or the public, significant damage to equipment, property or businesses, public health infrastructure impact 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.

Wood Pole Management

Figure 1- Pole Age Profile



The Outage Management Tool (OMT) is used by Asset Management to track asset conditions and show trends of failures 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 over 36% from 2009 through 2017. This reduction in outage events results in significant customer benefit. This 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.

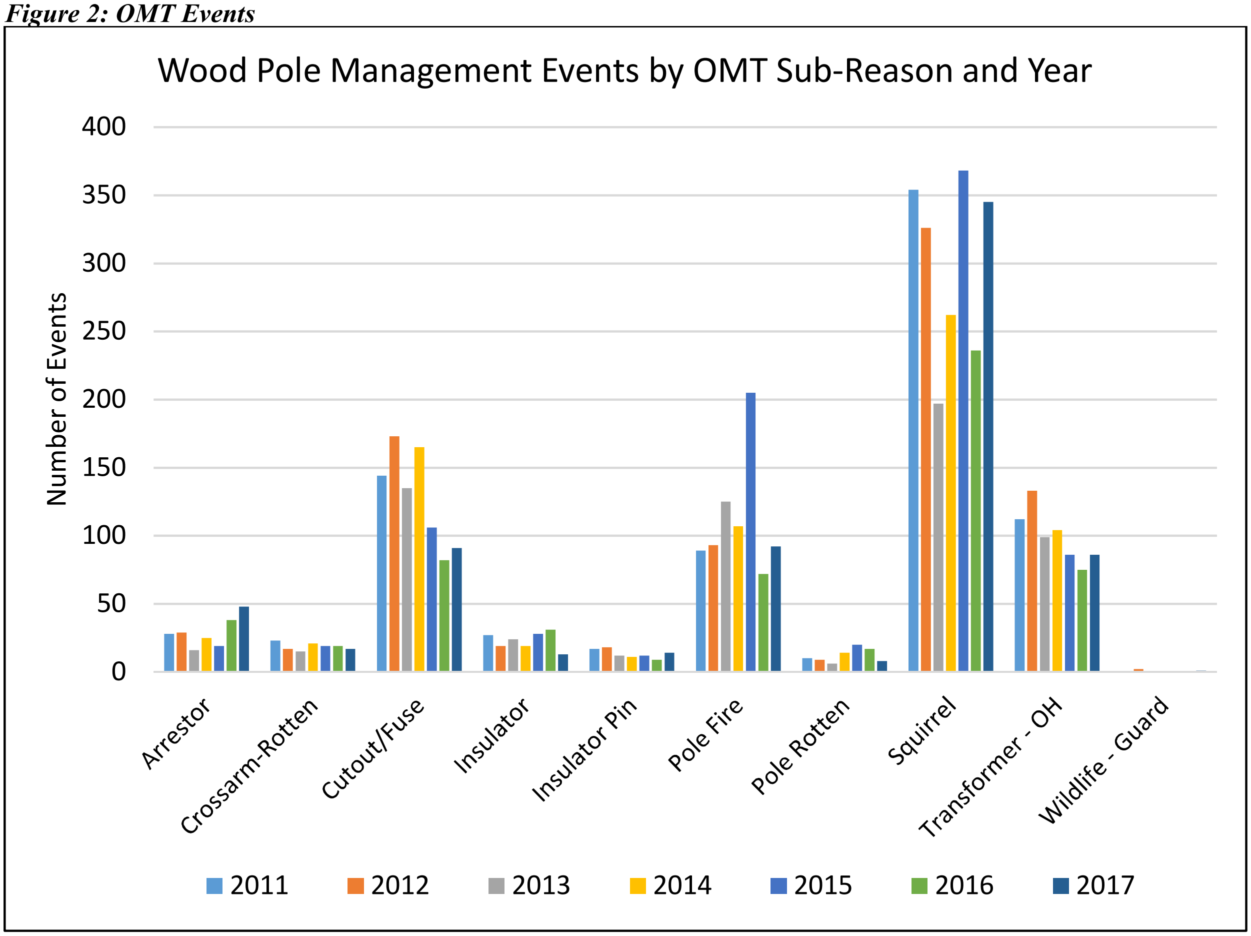
Table 1: Event Reduction Results

	WPM Goal Related Number of OMT Events	Actual WPM Related Number of OMT Events	Projected Miles Follow-Up Work	Actual Miles Follow-Up Work
2009	1460	1320	500	372
2010	1460	1004	450	435
2011	1460	1004	459	333
2012	1460	1013	416	435
2013	1460	816	445	329
2014	1460	905	412	385
2015	1460	760	390	364
2016	1460	717	389	423
2017	1460	888	389	492

Wood Pole Management

The type of OMT events are broken down into more detail in Figure 2. Note there are significant improvements to some events such as annual squirrel events being reduced from nearly 750 to around 240 events. This improvement has been realized by adding wildlife guards to the top of transformer bushings in order 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. Figure 2 also reveals a concerning upward trend of pole-rotten events that indicate the impact of the aging poles. Note that the calculated cost to customers for a pole failure is $24,400 based on an average duration of 4.8 hours for 80 customers[1]. Other key OMT events that have been significantly reduced from 2009 to 2016 include Transformer, Cutout/Fuse, and Squirrel. The combined cost impact to customers in 2015 alone for those events was $2,265,600. See Figure 2.

Figure 2: OMT Events



[1] Source: 2017 Wood Pole Management Review and Recommendation)

Wood Pole Management

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.

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 without WPM 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 SAIDI would be 1.27 (hours).

Table 2: SAIFI Metrics

Projected Metric Description	Projected WPM Contribution To The Annual SAIFI Number	Projected Number of Dist Poles Inspected	Model Predicted Material Use for WPM Follow-up Work	Projected Number of Pole Rotten OMT Events	Projected Number of Crossarm OMT Events
2009	0.214024996	12,600	4,792	137	32
2010	0.208489356	12,600	4,932	137	32
2011	0.211022023	12,600	5,010	137	32
2012	0.211022023	12,600	6,770	137	32
2013	0.211022023	12,600	8,592	137	32
2014	0.211022023	12,600	10,566	137	32
2015	0.211022023	12,600	12,606	137	32
Actual Metric Description	**Actual WPM Contribution To The Annual SAIFI Number**	**Actual Number of Dist Poles Inspected**	**Actual Material Use for WPM Follow-up Work**	**Actual Number of Pole Rotten OMT Events**	**Actual Number of Crossarm OMT Events**
2009	0.1863468	13,161	7,538	44	25
2010	0.19916836	15,553	7,904	37	23
2011	0.202462739	13,324	28,011	35	28
2012	0.16613099	17,318	28,120	52	19
2013	0.15640942	14,364	15,214	34	18
2014	0.241571914*	11,879	14,901	55	26
2015	0.225273848*	8,157	12,072	43	23

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

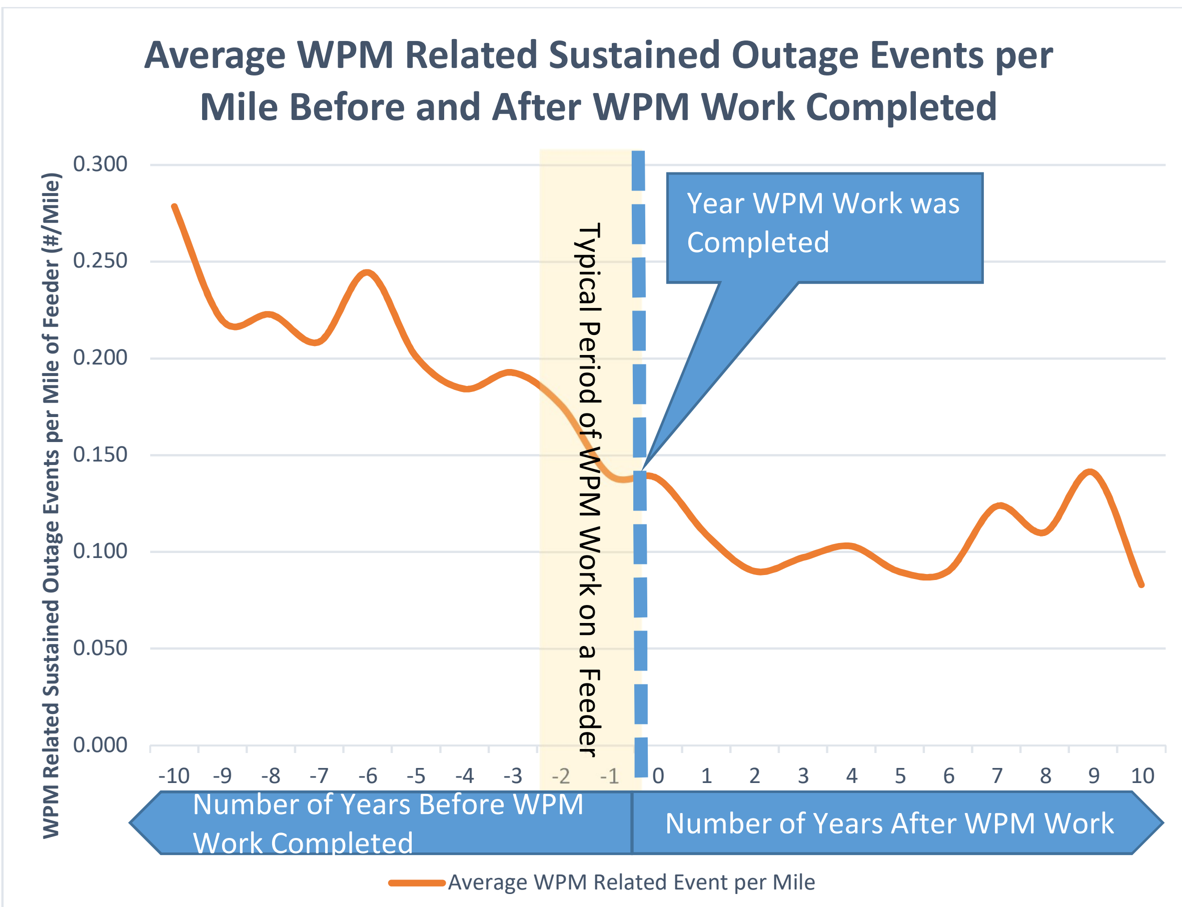
The 2017 Wood Pole Management Program and Review which is located in the c01m570 drive.

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.

Based on the analysis in 2017, the current twenty-year WPM cycle delivers the best life cycle value for the funding level. Asset Management and Distribution Engineering monitor system reliability to determine if adjustments are needed in the future. For perspective the industry average for inspecting and maintaining distribution assets is ten years.

WPM is an ongoing cyclical program that proactively replaces aging assets. By replacing assets before they fail, outage risks are reduced, and replacement costs are reduced through planned work. Investing in the infrastructure increases 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. The peak of events per mile shown in the graph is from approximately six years ago when there were nearly 1.5 events per mile. The results after the program show performance as low as .3 events per mile of feeder, a significant improvement.

If funding were to be reduced, expected outages would increase. The team would need to prioritize which components would be replaced and which would be left. This would increase the likelihood that crews would need to revisit the same pole later if a remaining component were to fail. While the five-year cycle does provide a better Customer Internal Rate of Return of 8.85%, the five-year cycle O&M costs exceeded our historical spending constraint. The internal rate of return for a twenty-year cycle is 8.00%.



Option	Capital Cost	Start	Complete

[Recommended Solution]: Distribution Wood Pole Management Program inspects all feeders on a twenty year cycle and replaces wood poles, crossarms, missing lightning arresters, missing/stolen grounds, bad cutouts, bad insulators, leaking transformers, replace guy wires not meeting current code requirements when the pole is replaced. This includes increasing the pole inspections and replacement work for the next ten years to meet the requirements of the WUI program.	$16,739,331	01 2021	12 2030
[Alternative #1] Distribution Wood Pole Management Program inspects all feeders on a twenty year cycle and repairs and replaces wood poles, crossarms, missing lightning arresters, missing/stolen grounds, bad cutouts, bad insulators, leaking transformers, replace guy wires not meeting current code requirements when the pole is replaced. This alternative will push the WPM cycle out to twenty-three years until 2030 as WUI will compete for the same inspection and replacement costs for the next ten years.	$12,847,800	01 2021	Annually/indefinite
[Alternative #2] Do nothing-increase OMT events by 1,700 per year and increased fire risk.	$0	MMYYYY	MM YYYY

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

In Asset Management's 2017 Wood Pole Management Review and Recommendations several alternatives were examined that included a five-year, ten-year, twenty year, and twenty-five year inspection cycle time as well as the impact of GMP work on the related WPM work. While the five-year cycle did provide a better Customer Internal Rate of Return of 8.85%, the five-year cycle O&M costs exceeded our historical spending constraint.

Alternative	CIRR	NPV of Life-Cycle Costs	NPV of Risk	Benefit/ Cost Ratio	Risk Reduction Ratio
Base Case	6.03%	$1,016,381,966	$509,538,239	0.804	-0.156
WPM 20 Year Cycle without Transformer Changeout Program (TCOP)	8.00%	$817,592,755	$351,165,376	1.243	0.194
WPM 20 Year Cycle with TCOP	7.94%	$799,251,117	$304,232,511	1.272	0.257
WPM 5 Year Cycle with TCOP	8.85%	$650,557,189	$104,155,317	1.562	0.623
WPM 10 Year Cycle with TCOP	7.85%	$812,124,615	$279,737,157	1.252	0.283
WPM 25 Year Cycle with TCOP	7.46%	$894,569,506	$389,231,116	1.136	0.134
WPM 20 Year Cycle with TCOP and Grid Mod	7.10%	$922,761,015	$481,637,684	1.101	0.030

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 WPM program is an ongoing process of inspecting, designing, and completing replacement work of assets identified for replacement during the inspection process. The poles on the feeders in the work plan are at various phases of the process throughout the year. The goal is to complete any identified work on a feeder within eighteen months of inspection, and we currently average about one year from start to finish. This work is incorporated into workplans and allows the company to efficiently utilize resources.

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

Additional WUI design demand, plus increasing the work to meet the twenty-year cycle goal increases the need for additional WPM design, tech, and construction resources. Material availability can also impact the ability to execute on the plan.

Additional departments the WPM program interfaces with will also see some increase in workload which includes: Distribution Engineering, Supply Chain, Environmental, Real Estate, and out-of-cycle Vegetation Management response. There is also a strong need for Asset Management to continue reviewing and analyzing the data that supports this program.

Wood Pole Management

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

In Asset Management's 2017 Wood Pole Management Review and Recommendations:

"Asset Management examined several alternatives that included a 5-year, 10-year, 20 year, and 25-year inspection cycle time as well as the impact of Grid Modernization work on the related Wood Pole Management work. While the 5-year cycle did provide a better Customer Internal Rate of Return of 8.85%, the 5-year cycle Operations and Maintenance costs exceeded our historical spending constraint. The 20-year inspection cycle provided the best Customer Internal Rate of return and our current practice of replacing transformers that functionally have failed while meeting the Operating and Maintenance budget constraints.

Any delays in implementing the Wood Pole Management program strategy as envisioned will delay the immediate benefits and take 20 years based on the current inspection cycle to recover the long-range value of the strategy.

We recommend continuing the Wood Pole Management program on its 20-year inspection cycle and follow-up work strategy. Any delays in the work will impact reliability and system performance. "

Choosing the recommended solution keeps WPM and WUI on track to be completed on time. Choosing Alternative #1 pushes the cycle out further to twenty-three years which increases the risk of more OMT events, increased O&M costs, increased possibility of a fire, and reduces the overall effectiveness of how we manage our aging assets. We also add risk by underfunding our commitment of providing safe, reliable, electric service to our customers. This work has been approved and validated in previous commission responses.

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.

WPM is an ongoing program. The work is a continuous process of inspecting Avista's poles on a feeder basis. Each feeder represents a project within the program. There are several phases to complete each feeder including inspecting, designing, and capital follow-up. As soon as any capital follow-up work is completed, the asset can become used and useful. The transfers to plant occur on a monthly basis. In addition, our Finance Department preps the AVA_Plan system periodically for a spend and transfer to plant forecast update for the remainder of the year.

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

This business case improves safety for our customers, employees, and the general public by responsibly mitigating safety hazards. This will also improve reliability, reduce fire risk, and decrease the number of unplanned O&M outage responses. Our company's vision is supported by building reliable infrastructure and then maintaining the assets in a safe reliable condition that improves our customers lives. The public utility commissions and our customers hold us to the highest standard of care. When we act prudently and follow through with our commitments, we demonstrate our trustworthiness.

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 requested amount is a prudent investment to maintain Avista's overhead electric system on a twenty-year cycle, which is also in alignment with the NESC requirement to inspect and maintain our facilities in a timely manner. This work reduces the company's risk.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Electric customers, Distribution Engineering, Environmental, Wildland Urban Interface, area offices, line crews, Asset Management, and Grid Modernization. Please note that with the sunsetting of the TCOP program the internal crews incorporate WPM as part of their workplan.

2.8.2 Identify any related Business Cases

Grid Modernization Program, WSDOT Control Zone Mitigation, and WUI-Wildfire Urban Interface Program.

3.1 Steering Committee or Advisory Group Information

Asset Management and Distribution Engineering provide ongoing analysis of distribution asset condition. The analysis is used to direct the WPM work that includes inspecting and 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 are documented in the Structure Specific DMFP.

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

The governance process is a collaborative process that includes leadership from: Asset Management Asset Maintenance, Distribution Engineering, the Director of Operations, and the WPM Program Manager and WPM inspectors . The operating guidelines are documented in the Structure Specific Distribution Feeder Management Plan. The yearly goals are documented and updated on the annual one pager.

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

WPM is a long-standing program that is well established. There are few change orders, but they are documented by the inspectors during the audit process. All significant change requests are reviewed by the Program Manager for approval. In cases where scope is re-evaluated, changes are agreed to prior to construction.

The undersigned acknowledge they have reviewed the *Wood Pole Management Business Case* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	7/30/20
Print Name:	Mark S Gabert		
Title:	WPM/WSDOT Program Manager		
Role:	Business Case Owner		

Signature:	David Howell	Date:	8/2/20
Print Name:	David Howell		
Title:	Director of Operations		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:	Alicia Gibbs		
Title:	Asset Maintenance Manager		
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

Campus Repurposing Phase 2

1 GENERAL INFORMATION

Requested Spend Amount	$28,000,000
Requesting Organization/Department	Facilities
Business Case Owner	Vance Ruppert / Eric Bowles, Facilities
Business Case Sponsor	Anna Scarlett, Manager, Shared Services
Sponsor Organization/Department	Shared Services
Category	Project
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

The Campus Repurposing Phase 2 Steering Committee is made up of a cross section of directors that represent groups impacted by the projects, as well as a couple members not directly affected to add an outside view. The current group is as follows:

- Director of Environmental Affairs
- Director of Shared Services
- Director of IT and Security
- Director of Natural Gas
- Director of Financial Planning and Analysis
- Director of Operations

Advisors may contribute input, approvals, or information as needed, and include:

- Vice President of Energy Delivery
- Executive Officers
- End Users

Each project within this business case is reviewed and approved by the Steering Committee group, and regular updates are provided during project execution.

2 BUSINESS PROBLEM

The Campus Re-Purposing Plan is a multiyear plan (Phase 1 and Phase 2) that address the following issues:

- Employee space needs
- Improving safety and efficiency of campus traffic flow
- Outdated fleet maintenance space and processes
- Lack of materials storage yards, no short-term flexibility

Campus Repurposing Phase 2

- Alignment of campus parking and number of employees based at main campus

The Avista corporate campus comprises 28 acres located next to the Spokane River in heart of the Logan Neighborhood. The campus in just north of the downtown Spokane corridor. Avista also owns eight additional acres of property directly adjacent to the campus at the north end. This parcel is separated from the main campus by North Center Street (a main city arterial).

Avista's corporate campus footprint is currently bound to the east by the Spokane River, and to the west and south by the Mission Park and Burlington Northern Railroad, leaving minimal flexibility to manage company parking, employee and materials space needs.

The Avista corporate campus was built in 1958 to consolidate and house all utility operations that were at that time spread throughout the community. As business needs changed over time, one-off expansion projects were to reactively address changes in business need. Employee growth and materials storage increases through the years have created the need to locate employees and materials at offsite locations, requiring space leases and other non-optimal solutions to meet growing company space needs.

Campus Repurposing Phase 2

Strategic property purchases to the North of the campus have been ongoing since 1988 as they become available to help address the issue and grow the campus to give us future flexibility. The final properties between Avista and the neighboring Riverview Retirement Community were purchased in 2014, now allowing us to develop them for company use.

The decision was made in 2011 to take a holistic approach to these issues and create a single proposed solution for the Corporate Campus that would address current issues, and future needs. The campus repurposing planning group began working in 2011 to find a way to address the growing employee space needs, parking issues, campus materials storage issues, safety and traffic flow issues (Operations traffic and employee traffic mixing), as well as look into addressing the changing business needs of our vehicle fleet and operational processes.

The result of this approach is a total campus plan that repurposes the existing campus for the next 50 years, minimizing our reactive approach and ensuring the best long term results for the Company and Ratepayers.

3. PROPOSAL AND RECOMMENDED SOLUTION

Campus Repurposing Phase 2 includes three major projects:

1. **North Center Re-Route**
2. **Construct New Fleet Building**
3. **Construct Parking Garage**

These three projects are connected and largely dependent on each other because of location, timing and the overall campus design. The projects will ultimately allow us to:

- Expand and consolidate the campus footprint while establishing a formal boundary between the Avista campus and the Riverview campus.
- Modernize the aged Fleet Building and address Fleet queuing needs.
- Expand and locate campus parking to align the available number of parking spaces with the number of employees working onsite, improving employee and public safety by reducing parking sprawl.
- Separate operations traffic from pedestrian traffic to improve safety and increase workflow efficiencies.

Campus Repurposing Phase 2

Project 1: North Center Street Re-Route

Avista-owned properties separated from campus by North Center Street

North Center Street currently divides us from the eight acres of property owned to the north on Ross Court. Re-routing North Center Street will allow us to consolidate our campus to include these properties. As North Center Street is a major city arterial that connects Indiana Street to Upriver Drive, a considerable amount of traffic uses the street daily. This traffic creates an ongoing safety risk to employees moving back and forth between the properties. It also creates challenges with securing the lots during business hours (gates, entrances, etc.).

Beginning in 2013, Avista began discussion with Riverview to plan the future development of each of our campuses. Riverview management expressed concern with future development on our adjacent properties due to the proximity of these properties to their resident housing. With no formal separation between our campuses, they were concerned with the height of proposed buildings as well as idling diesel trucks next to their resident properties.

Several options were considered (see options listed below). After many discussions, there was interest on both sides to explore rerouting North Center Street to the north in order to: 1) consolidate our properties into our secured campus; and 2) give Riverview a formal separation between our campuses.

Campus Repurposing Phase 2

Ross Court Property Options (re-route of North Center Street)	Capital Cost	Start	Complete	Risk Mitigation
Option 1 (Recommended): North Center rerouted around our Ross Court properties, adding eight acres to the Campus	$6M	2016	2017	Riverview prefers this option due to formal separation.
Option 2: no reroute (minimum development required to make Ross Court property usable). North Center Street remains in place creating a separated campus to the North, accessed by crossing North Center. Fencing, gates, and lot development still required.	$3,000,000	2016	2017	Risk involved in transporting materials across a major City Arterial. Strong opposition from Riverview on any development other than basic storage.
Option 3: no reroute, with tunnel or bridge connection to Ross Court North Center Street would remain and a tunnel or bridge would be created to safely access Ross Court and create a single secured Campus.	$8,000,000	2016	2017	Higher maintenance costs for bridge or tunnel. Strong opposition from Riverview on any development other than basic storage
Option 4: Do nothing	$0	Basic storage use only with no development. Property does require basic Civil and site work to be usable though.		

Option 1 (recommended): Reroute North Center Street to consolidate Ross Court properties with the main campus.

The re-route of North Center Street would allow us to create a new operations entrance to our campus, separating operations traffic from pedestrian traffic and resulting in operations workflow efficiencies and improved safety of the company and employees.

Campus Repurposing Phase 2

Recommended Option	
Positive Benefits	**Negatives**
Allows the creation of a new Operations entrance	Issues with City permitting?
Riverview's preferred option due to formal separation. No opposition to future developments options	Closure of North Crescent Street to access apartments behind Riverview
Single connected/secured Campus	
Better Operations traffic flow from entry, drop off, and parking	
Create a formal separation between Avista and Riverview	
Better separation of employee and Operations traffic would dramatically lessen safety risk to the company	

Campus Repurposing Phase 2

Options 2 and 3: No reroute, leave North Center Street in place and secure as separate campus.

A minimum of Option 2 or 3 would be required to make the Ross Court properties usable; however, these options would not allow separate operations entrance to be added.

Options1 and 2	
Positive Benefits	**Negatives**
Lower cost options (Option 1 lower cost, Option 2 similar cost)	Development options we are considering would be strongly opposed by Riverview due to direct adjacency of our operations to their resident properties
Slightly larger usable area vs Option 1	Two separate campuses requiring constant traffic across North Center Street creates safety risk (Alternative 2 only).
Alternative 2 would create a single Campus access	Alternative 2 would require higher O&M cost for tunnel or bridge
Quicker project execution	These 2 alternatives will not allow for a new Operations entrance

Campus Repurposing Phase 2

Project 2: Construct New Fleet Operations Facility

Avista's existing fleet operations building is located in the heart of the main campus and was originally built in 1958 to centralize all Avista fleet maintenance operations.

Vehicle and Building Size

The original fleet building was built to house smaller half-ton pick-ups and has been expanded twice through the years to accommodate the increased size of the new service trucks, once in 1978 and again in 1999. The size of vehicles in today's fleet have continue to increase since 1999 and some of the current fleet is difficult to service in the existing building. The current building is much smaller than City of Spokane and Waste Management facilities, which utilize similar-sized vehicles. Many of our larger trucks cannot be worked on in the existing space without leaving the doors open.

Existing Fleet Building Location

Campus Repurposing Phase 2

CNG

Avista has added vehicles fueled by compressed natural gas (CNG) to our fleet over the past four years. The existing fleet building is not CNG rated and all CNG-fueled vehicles must be taken offsite for repairs. To make the building CNG compliant would require the addition of a new emergency exhaust system. The estimated cost to make the building CNG compliant is around $1.3 Million

Environmental

The hydraulic lift system installed in the existing building did not include secondary containment when originally installed, and testing has indicated possible leakage of hydraulic oil in the soil under the building. Relocation of the building will allow us to completely encase all new hydraulic systems and mitigate any current or potential leakage.

Safety

The existing fleet staging and queuing area is also in the heart of the campus and is directly adjacent to multiple parking canopies and surface parking areas. This staging area is small and requires multiple trips in and out of the area for day-to-day operations. A main employee walkway also goes through this major traffic area and brings considerable safety risk to the company as some of the pedestrian traffic can be hidden by the parking canopies. Moving the fleet building to the north will allow for increased queuing area and lessen the employee and operations traffic risk considerably.

Building Conditions

In addition to compliance, environmental and safety issues, the existing building has a number of conditions that affect operations and employee safety and health, including the issues below (see attachment *Corp Fleet Building Issues* for complete list).

- Current facilities have bays less than 14' wide. Current trucks are 103" wide at the mirrors, leaving limited space for maneuvering and working on vehicles.
- We cannot lift rear tandem axle trucks with in ground lifts. We utilize wheel lifts which add 38" to the width of the vehicle. This leaves less than 2' for the technician to move himself and his tools into position. Tandem axle trucks make up 35% of the Avista Fleet. This effects productivity.
- Roof leaks at multiple points.

Options and Alternatives

Fleet Operations Options	Capital Cost	Start	Complete	Risk Mitigation
Option 1 (Recommended): Build a new CNG-compliant Fleet Operations building at the north end of the property and address the existing issues. • This options would allow us to use the existing fleet footprint for the Parking Garage and move all	$10,000,000	2017	2018	Major safety risk mitigated with employee and Ops traffic mixing.

Operations traffic to the North end of the Campus.				
Option 2: Address the major issues in the existing building separately. • Replace Hydraulic systems, replace the constantly leaking roof, and install a CNG compliant exhausting system. • Increase the building in the future if needed.	$4,000,000	2017	2018	• Location not optimal in regards to safety and risk • Environmental and compliance issues • Continued rising of maintenance costs due to age of the building and systems
Option 3: Do nothing	$0	Still need to address the future impact of larger fleet vehicle sizes, aging hydraulic systems, non-compliant CNG space, and most importantly the safety risk due to the constant traffic and employee mixing.		

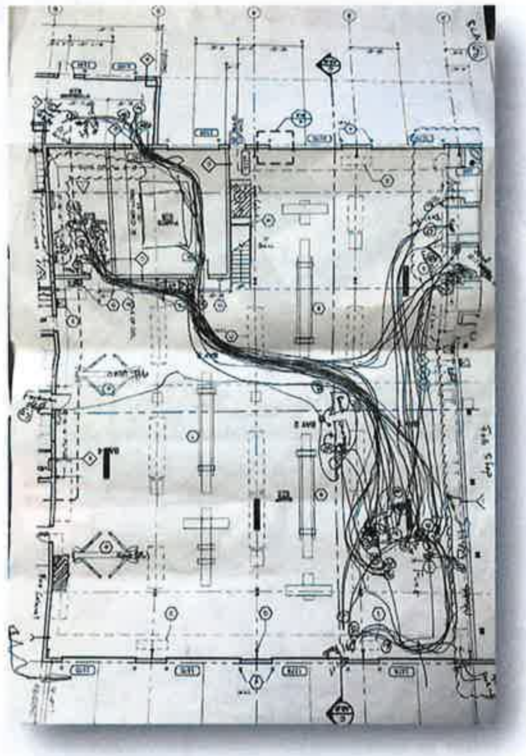
Option 1 (recommended): Construct a new fleet operations facility at the north end of the campus.

Constructing a new fleet operations center operations building strategically located at the north end of the campus would achieve a number of objectives:

- Enable us to increase the size of bays to accommodate larger fleet vehicles
- Address CNG compliance requirements and environmental issues related to the aging current facility
- Increase efficiency and safety of pedestrians and operations traffic on campus
- Increase efficiency of fleet operations

A pre-design BPI process was undertaken in early 2016 to look at efficiencies that would be created by a new building and new processes. It was discovered that the poor layout of the existing building resulted in numerous extra steps taken each day resulting in wasted time and resources. The new building was designed using industry best practices, and observed employee workflow.

Campus Repurposing Phase 2

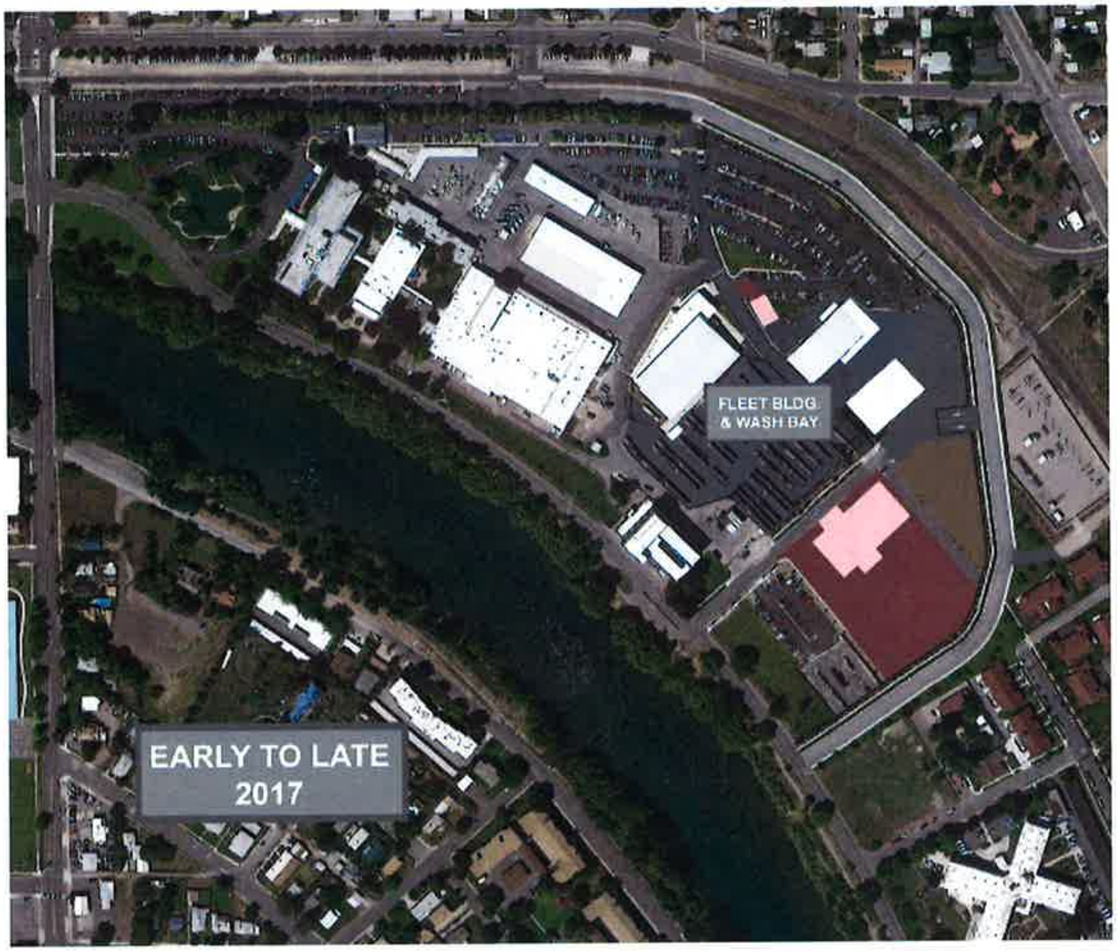


BPI Spaghetti workflow diagram

See attached bullet points for a comprehensive list of issues that a new building would address.

Recommended Option: New Fleet Building on Ross Court

Campus Repurposing Phase 2



Option 2: Address individual issues with existing building

Remodeling the existing building to accommodate fleet vehicles that no longer fit the current facility is not possible within the current footprint's size. In addition, this option does not address environmental, compliance or safety concerns described above. To make the building CNG compliant would require the addition of a new emergency exhaust system. The estimated cost to make the building CNG compliant is around $1.3 Million

Option 3: Do Nothing:

Doing nothing is not a viable option. New hydraulic lifts would be required soon, and basic space, environmental and compliance issues would still need to be addressed. We would need to reevaluate how to continue servicing CNG vehicles.

Campus Repurposing Phase 2

Project 3: Parking Garage

As of June 2016, Avista has a headcount of approximately 1,280, including company and contracted employees, reporting to the main campus facility. The number of parking spaces available for employees is approximately 728 (not including visitor and disabled parking). Assuming not all employees are on the property at any one time, a minimum of 400 additional parking spaces are required each day to address the current existing need as well as additional spaces for future flexibility. Avista leases parking space along Perry Street from Burlington Northern Railroad (BNR), in an open-ended lease that can be cancelled by BNR with 30 days written notice. Employees walk across railroad tracks to get to and from the buildings and these parking areas. Additionally, loss of this lease would result in the loss of almost 200 parking spaces.

Aligning campus parking with employee count has been addressed through the years by relocating materials storage yards from the campus footprint and adding surface parking lots (see below).

Action Taken	Year	Parking Spaces
Mission Campus Parking Space Count	2008	538
Added Spaces South Mission Lot	2009	+ 57
Added Spaces Transformer Storage Lot	2009	+ 55
Expanded North Pole Yard	2012	+124
Added North Ross Court	2012	+ 49
Total Current Parking Spaces (including Disability and Visitor Parking)		**823**
Total Parking Spaces Available (excluding Disability and Visitor Parking)		**728**
Estimated Employees/Contractors Assigned to Mission Campus as of June 2016*		1282
Estimated Employee/Contractors e not at Mission Campus on any one day (15%)		-129
Shortage of Parking Spaces to Meet Current Need for Employees/ Contractors Assigned to Mission Campus**		**425****

Campus Repurposing Phase 2

Using valuable campus real estate for parking lots has required us to take our operations vehicles and materials storage offsite to our Beacon substation property more than a mile away, increasing crew time and resources to access materials and vehicles each day.

This daily deficit in parking is currently absorbed in gravel lots on Ross Court and along the railroad tracks on Burlington Northern Railroad land. This parking is not in compliance with City of Spokane parking code, and we could be required to cease at any time. Additional parking overflow beyond these locations usually takes place in the immediate neighborhoods around Avista, and has resulted in frustrated calls, threats, and visits from our residential neighbors.

The proposed parking garage is intended as a long-term solution to the employee and visitor parking deficiency and related safety concerns.

Safety

With our current parking conditions, employees and visitors face a number of ongoing safety risks:

Campus Repurposing Phase 2

- The main building and service center, where the majority of regular and contract employees are located, is separated from parking areas by railroad tracks, busy arterials (Mission and Perry Streets), and operations areas, forcing pedestrians to cross these areas throughout the day.
- Operations traffic peaks in the mornings and afternoons, when employees are often walking to or from their vehicles.
- Parking areas are open and must be maintained throughout year to keep lots safe and clear of seasonal conditions. Even with ongoing maintenance, lost work days due to slipping and falls on the main campus (both inside and outside) is estimated at 11,000 days since 1997. In the first quarter of 2017, Avista experienced a record number of slips, trips and falls related to icy conditions.
- While we have full-time security on campus with cameras and patrol staff, there is no security off campus to protect employees, visitors and their vehicles.

Options and Alternatives

We analyzed three primary options for adding up to 500 parking spaces to fully solve the parking issue and give protection against the loss of the BNR leased space:

- **Option 1 (recommended)** – Construct a parking garage in the location of the original fleet building. The garage would be a four-story structure with five levels of parking.

Campus Repurposing Phase 2

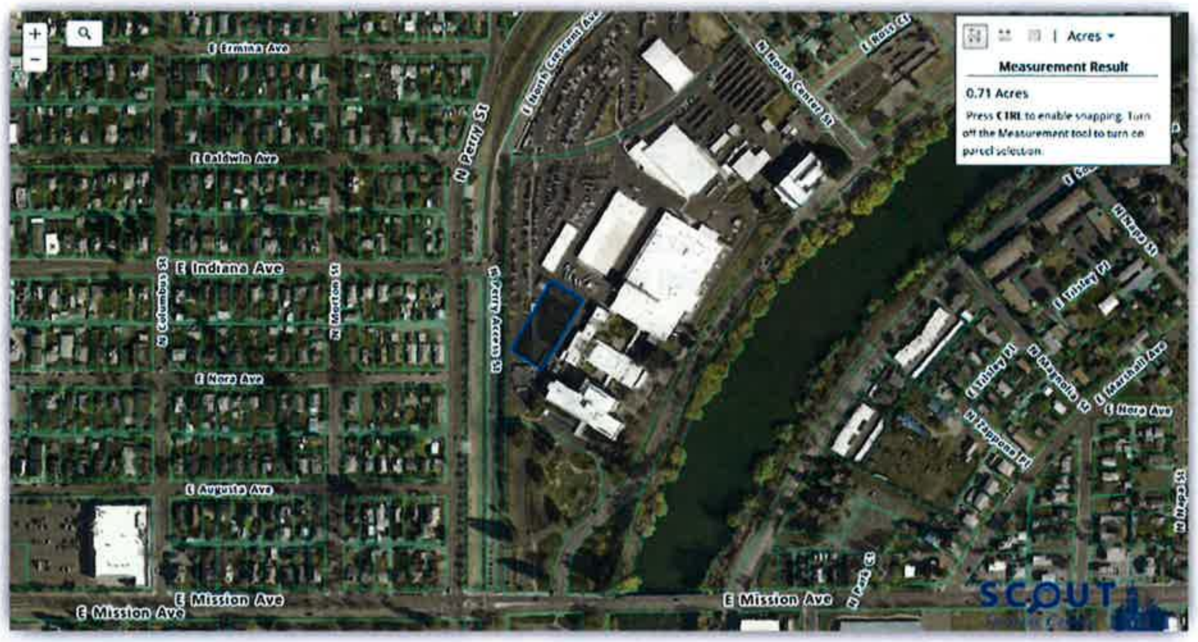
- **Option 2** – Convert property at the north end of campus (Ross Court) into parking lots.
- **Option 3** – Purchase properties to the east of campus, across Perry Street, and develop parking lots.

Ross Court Property Options (re-route of North Center Street)	Capital Cost	Start	Complete	Risk Mitigation
Option 1 (Recommended): Build Parking Garage Build a 4-story 500-space parking garage in the location of the existing Fleet Building.	$12,000,000	2018	2018	• Coverage in the event of the loss of BNR leased space. • Employees would not need to park in the neighborhood.
Option 2: Convert Ross Court property into parking to address current deficit Pave the remaining four acres of undeveloped Ross Court property and make a parking lot. Would need to include drainage swales, parking island vegetation, and sidewalks to be comply with city code.	$3,000,000	2017	2018	• Not highest and best use of existing property. Will only net ~175. spaces. • Would impact Fleet construction project as this space is earmarked for the new building. • Risk of impact from losing BNR lease still possible.
Option 3: Purchase properties to the east of Avista to build 500 parking spaces (10 acres required) Purchase 10 acres of property along Perry to the east and develop to create 500 parking spaces.	$16.2M	2016	2017	• Risk of not getting all properties. • Highest maintenance costs (snow removal, crack seal, seal coat, 15-year average asphalt replacement).
Option 4: Do nothing	$0	• Risk of City of Spokane compliance issues with using Ross Park in its current form. This can be called out at any time. • Negative perception from local neighbors due to parking overflow in front of their houses. • Loss of BNR lease would be catastrophic to employee parking with no immediate resolution.		

Option 1 (recommended): Build a 4 story Parking Garage

This option will minimize the physical footprint required (only 0.71 acres). Constructing it in the location of the original Fleet Building will locate parking density next to employee workspace density, maximizing safety and operations efficiency.

Campus Repurposing Phase 2



Parking Garage Footprint

Option 1 (Recommended): Building a four-story parking garage with five levels of parking	
Positive Benefits	**Negatives**
Locates parking density near employee density.	Customer perception of structure
Will drastically reduce slips, trips and falls experienced by employees walking through 20 acres of existing parking lots each day, reducing risk and L&I claims to the Company.	Possible environmental issues under existing fleet footprint
Majority of parking would now be secured within the Campus.	
Will dramatically reduce the risk to the company from employee and Operations traffic mixing in the north lot areas.	
Lowest O&M maintenance costs, and longest life vs. asphalt lot.	
Lowest snow removal cost vs.10 acres of traditional blacktop.	
Could allow us to repurpose campus real estate back to materials storage.	

Option 2: Convert Ross Court property into parking to address current deficit

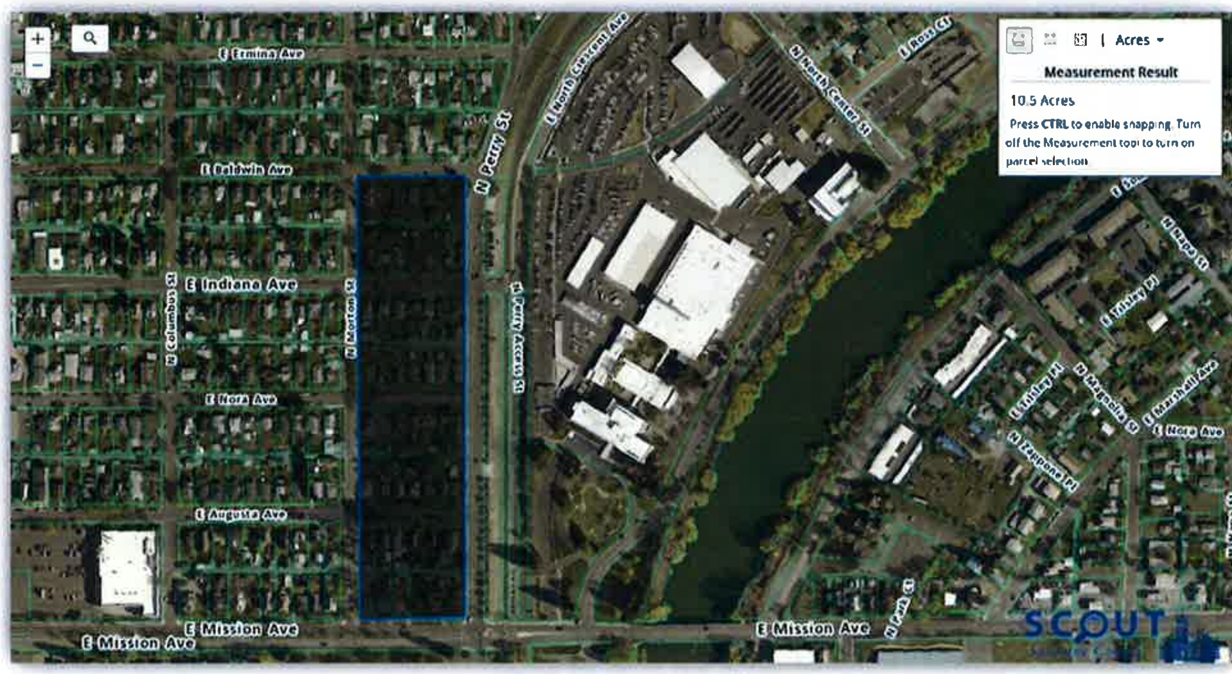
Converting property on the north side of Campus (Ross Court), would only address part of the current parking deficit, with a net of approx. 175 spaces. This solution doesn't address a potential BNR lease loss and would impact plans for the new fleet facility.

Option 2: Pave existing Ross Court properties to be used for parking	
Positive Benefits	**Negatives**
Lower cost vs. recommended	Not highest and best use of purchased properties on Ross Court. High cost vs strategic value (when including property purchases). No option for a new Fleet Building.
Quickest Solution	Solution would only address the current parking deficit, (only net approx. 175 spaces) Doesn't address BNR lease loss.

Campus Repurposing Phase 2

Option 3: Purchase properties to the east of Avista to build 500 parking spaces

Traditional parking lot construction for 500 spaces would require 10 acres of land to accommodate 208 drainage swales, vegetation for heat island mitigation, and other items required by the City of Spokane. The only available option for adding additional land to the campus would be the properties to the east, on the other side of Perry Street. These would be difficult and costly to acquire, and add additional challenges of expanding the campus into a residential area separated by a major arterial.



500 spots using surface parking construction

Option 3: Purchase 10 acres to the east and build 500 spaces	
Positive Benefits	**Negatives**
Would net the full 500 spaces	Highest cost option
	High risk of not getting all properties required to build. Risk of street vacations not being approved.
	Increased risk of injury with 500 employees crossing Perry Street daily.
	Highest cost maintenance option, (snow removal, crack seal, sealcoat, complete asphalt replacement every 15-20 years).

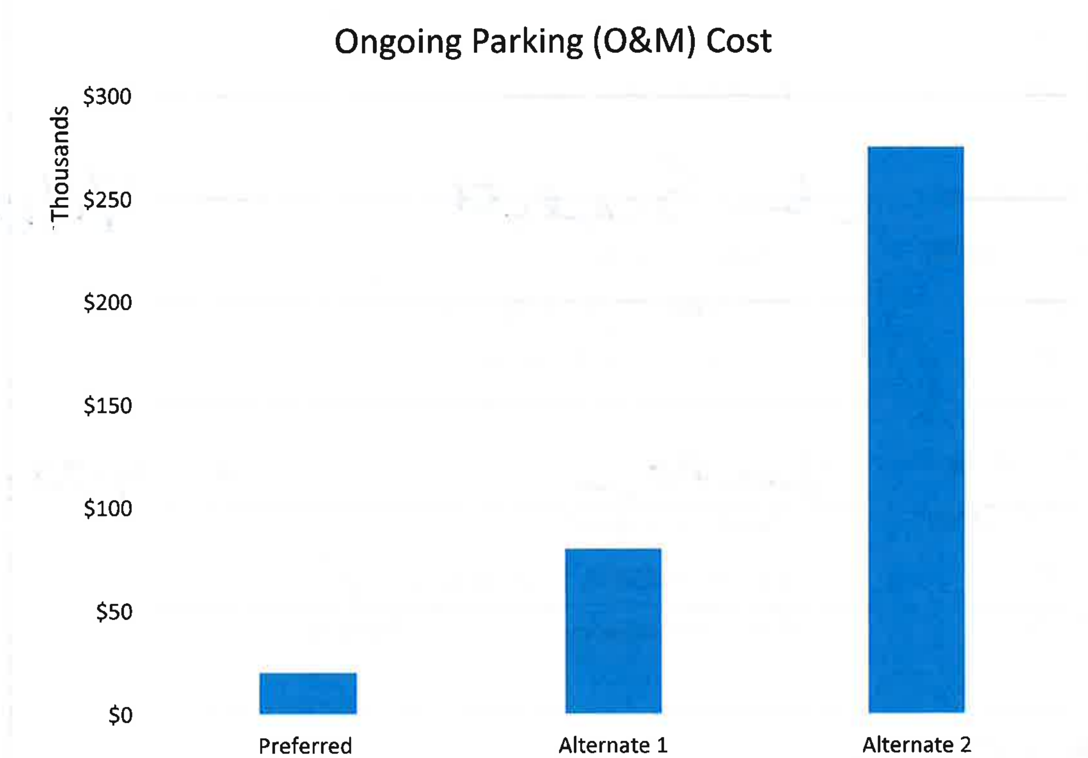
Option 4: Do Nothing

This option would not solve the parking deficiency or the problems it has created:

- Operations vehicles and materials storage offsite at Beacon substation property
- Non-compliant parking
- Neighborhood impacts

Campus Repurposing Phase 2

Do Nothing	
Positive Benefits	**Negatives**
Lowest Cost	Does not address the current parking deficit
	Still out of compliance with current City of Spokane parking code
	Frustration from neighbors due to employees parking in front of their houses.
	At risk if BNR lease is ever lost.



Ongoing O&M costs include snow removal, crack seal, seal coat, and asphalt renewal at 15 years. Parking Garage useful life based on 45 years.

See attached PowerPoint Presentations for high level explanations.

Campus Repurposing Phase 2

APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Campus Repurposing Phase 2 plan and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: [signature] Date: 5/1/17
Print Name: Eric Bowles
Title: Manager, Facilities
Role: Business Case Owner

Signature: [signature] Date: 5/1/17
Print Name: Anna Scarlett
Title: Manager, Shared Services
Role: Business Case Sponsor

Signature: [signature] Date: 4-28-17
Print Name: Heather Rosentrater
Title: Vice President, Energy Delivery
Role: Steering/Advisory Committee Review

VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1	Eric Bowles	04/24/17	Heather Rosentrater	04/25/17	New template

Template Version: 02/24/2017

Downtown Campus

1 GENERAL INFORMATION

Requested Spend Amount	$13,785,000
Requesting Organization/Department	Facilities
Business Case Owner	Eric Bowles / Vance Ruppert, Facilities
Business Case Sponsor	Anna Scarlett, Manager, Shared Services
Sponsor Organization/Department	Shared Services
Category	Project
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

The Downtown Campus Business Case includes several different, but related projects that will address the needs of several different user groups. The first phase included the purchase of a new 2.32 acre property in mid-2015. The second phase was the early 2016 tenant improvement renovation of an existing 22,000 square foot office building on the newly purchased property, to provide office space and employee parking for two new Avista special projects. The third and final phase is to build a 32,000 square foot operations building for our Downtown Network Operations group (DTNW), with an estimated completion in late 2017.

The Steering Committee is made up of a cross section of directors that represent groups impacted by the projects, as well as a couple members not directly affected to add an outside view. The current group is as follows:

- Director of Environmental Affairs
- Director of Shared Services
- Director of IT and Security
- Director of Natural Gas
- Director of Financial Planning and Analysis
- Director of Operations

The Advisory Group that assisted in shaping the "Business Problem" and the "Proposal and Recommended Solution" consisted of the following stakeholders:

- Downtown Network Operations (DTNW): Ryan Bradeen. Previous stakeholders included Bryan Cox, John McClain, Ron Doran, and Don Schrader.
- Avista Facilities Management (AFM): Laura Vickers, Peggy Blowers.
- Advanced Metering Infrastructure (AMI): Laura Vickers, Vern Malensky.
- Finance: Ryan Krasselt.
- Real Estate: Rod Price.
- Generation & Production / Substation Support: Alexis Alexander, Michael Day. Previous stakeholders included Mike Gonnella and Jerry Cox.
- Substation Engineering: Ken Sweigart, Aaron Henson. Former stakeholder Mike Magruder.
- Enterprise Technology: Jim Corder, Mike Lang.

- Facilities: Eric Bowles, Anna Scarlett, Vance Ruppert, Lindsay Miller. Previous stakeholders included Laura Vickers and Mike Broemeling.

Other advisors may contribute input, approvals, or information as needed, and include:

- Vice President of Energy Delivery
- Executive Officers
- End Users

2 BUSINESS PROBLEM

Business Problem #1

Avista Facilities Management replacement project (AFM) and Advanced Metering Infrastructure project (AMI)

In 2015, Avista announced two new special projects would begin at the company. The first was the AFM project, which will update our gas and electric infrastructure mapping system throughout our entire service territory. The second project was the AMI project, which will replace electric and gas meter sets with fully automated reading technology and eliminate the need for manual readings of the majority of meter sets. Both of these projects are slated to last until approximately 2019. The leadership for both of those projects provided an estimate of approximately 100 employees total during its execution phase. To complicate matters, several current Avista employees would be solely assigned to these projects, and their regular job positions would be backfilled or rotated by others. Facilities would have to conservatively assume that 100 project employees PLUS 25 backfilled employees would need to be accommodated.

Avista was renting office space at 18825 Mirabeau Parkway, Spokane Valley, WA, for a special project that was nearing completion called Project Compass (for implementation of the CC&B/Maximo Management system). The office space could accommodate about 70-80 employees, not enough for the expected 100+ employee headcount for AFM and AMI. The shortfall would have to be made up by leasing additional office space elsewhere, or placing those employees at the Mission Campus Central Operating Facility (main campus). However, 20-30 additioanl employees at the main campus would further strain the limited office and parking space resources. There are no other Avista-owned office properties that could make up the shortfall.

Business Problem #2

Downtown Network Operations group (DTNW)

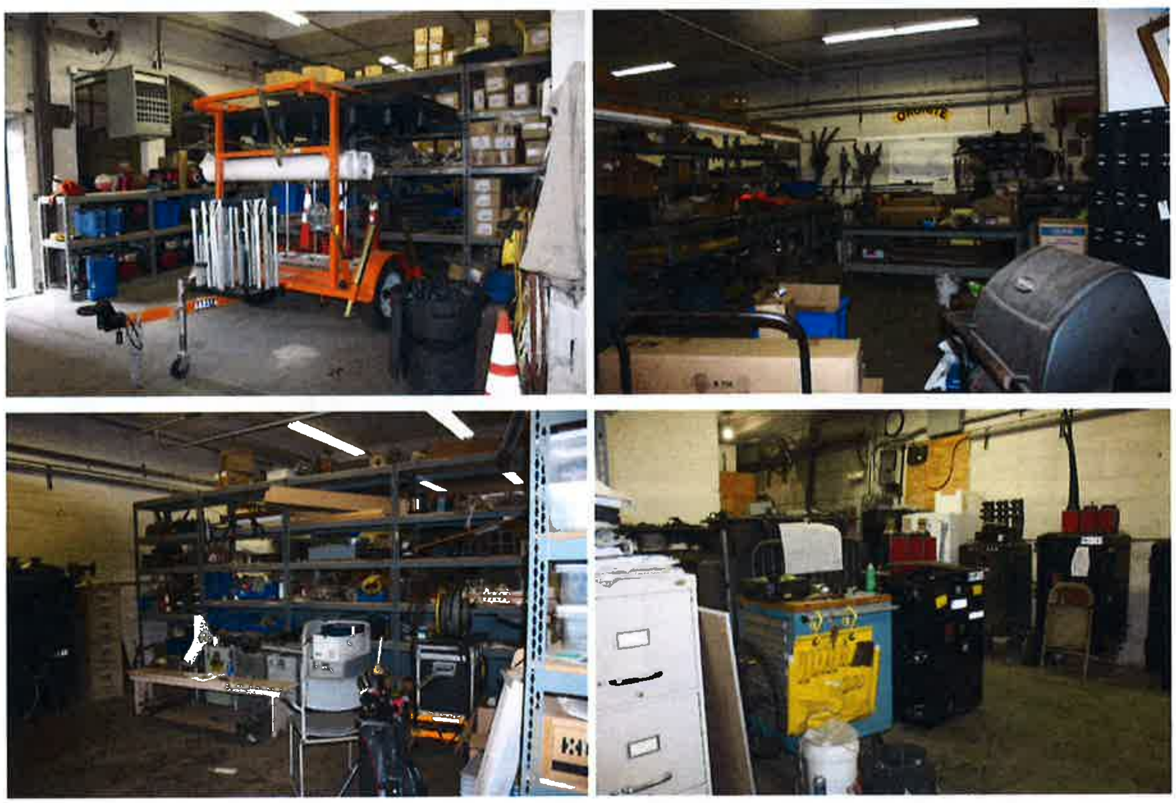
The DTNW serves as the main electrical line crew for approximately 1,550 customers within the downtown core of the city of Spokane. The majority of their electrical line work is done in tunnels, vaults, and crawlspaces underneath the sidewalks and streets of downtown. As such, their equipment, tools, and methods are similar to our overhead aerial line crews, but they have distinct differences due to their work environment. Approximately 15 Avista field crew and administrative support employees make up the DTNW.

Downtown Campus

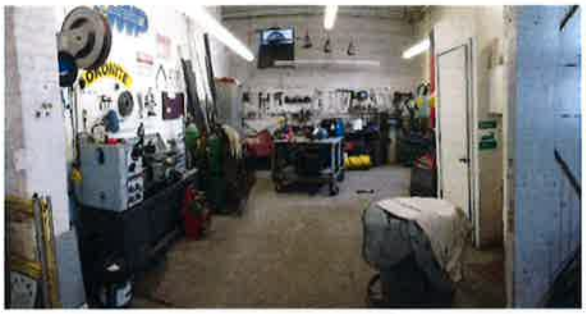
The DTNW currently are housed and work out of the Post Street Annex at 331 N. Post Street, built in approximately 1910. The building was an addition to the Post St. Substation building constructed circa 1895. Due to its age, many of the building components, systems, and equipment have deteriorated over time. In addition, its placement on historic watch lists and limited site access does not lend it to modifications or additions that would be an improvement to conditions. The DTNW has used all available space in the Annex for their operations, vehicle parking, and stores and materials. In fact, they use three other sites where they keep overflow materials and equipment. One is a Wire Warehouse Building located at 601 E. Riverside Ave. Another is an exterior storage yard next to Avista's substation at 620 E. Third Ave. Finally, they store underground transformers at the Mission COF. The DTNW is often traveling to these multiple sites to gather materials and equipment to perform their work, and consolidation of all these sites will be an advantage in future operations.

The following images are representative of the DTNW's current conditions:

Post St. Annex:



Downtown Campus



<u>620 E. Third Ave:</u>

Downtown Campus

Wire Warehouse Building:

Central Operating Facility:

Downtown Campus

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 (Recommended) – Purchase 1717 W. 4th Street for permanent office space and construct a new DTNW Operations Building	$13,785,000	05/2015	10/2017
Option 2 – Purchase alternate lot and build new / expand as needed for office space and a DTNW Operations Building	$15,000,000 - $20,000,000 (approx.)	05/2015	12/2018
Option 3 – Do nothing for DTNW. Obtain a rental for office space.	$222K yearly (O&M misc. costs AND $17,000/mo rental lease costs) (approx.)	05/2015	2020, or indefinitely

The three above options were produced with input from the Advisory Group listed above in Section 1, Item 1.1. Please note, individual stakeholders from the Advisory Group may not have been involved in producing all three options.

Option 1 (Recommended) – Purchase 1717 W. 4th Ave. for permanent office space and a new DTNW Operations Building

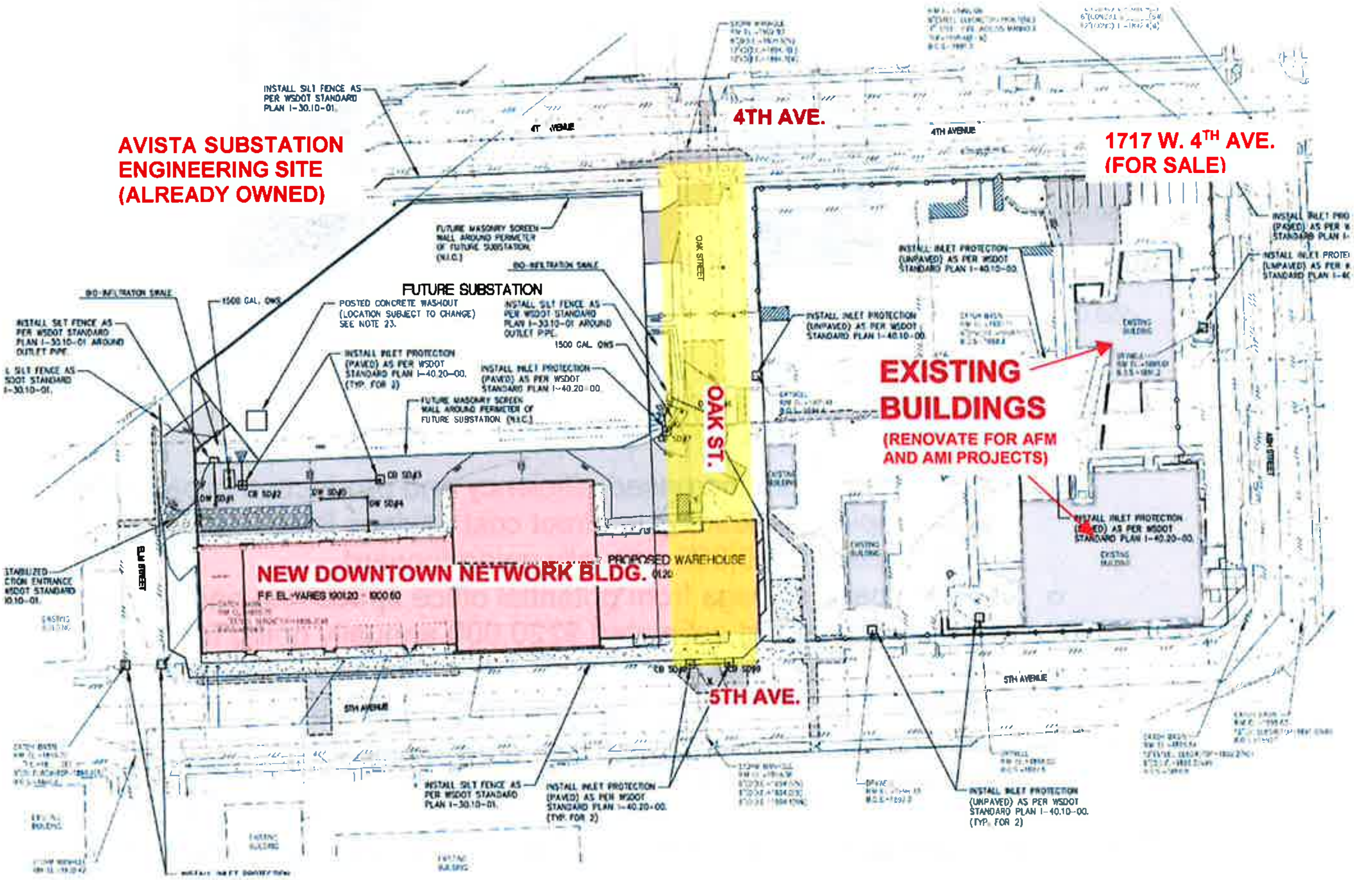
The preferred option is to purchase a 2.32 acre lot located at 1717 W. 4th Street, with two existing 22,000 SF and 6,700 SF office buildings, and parking lots. The 22,000 SF building shall be renovated for office space to accommodate the AFM and AMI projects, instead of leasing space elsewhere for the 100+ employees. The buildings can house further special office / project needs past the life span of AFM and AMI, which would help reduce employee and parking loads at the Mission main campus.

During the search for this site, it was discovered that Avista currently owns the land to the west of this lot. It was previously purchased by our Substation Engineering group as a future new substation site. Due to this, Avista could gain additional site acreage by vacating the public street between both lots, as well as create one contiguous campus that would allow for easier security fencing and features. The campus can then be developed to accommodate a new 32,000 SF operations building for the DTNW. This building would be able to consolidate the crews and

Downtown Campus

equipment onto one site rather than the several scattered around downtown. The new building will also include equipment meant to make the DTNW work processes more efficient, such as state of the art overhead cranes and welding shops.

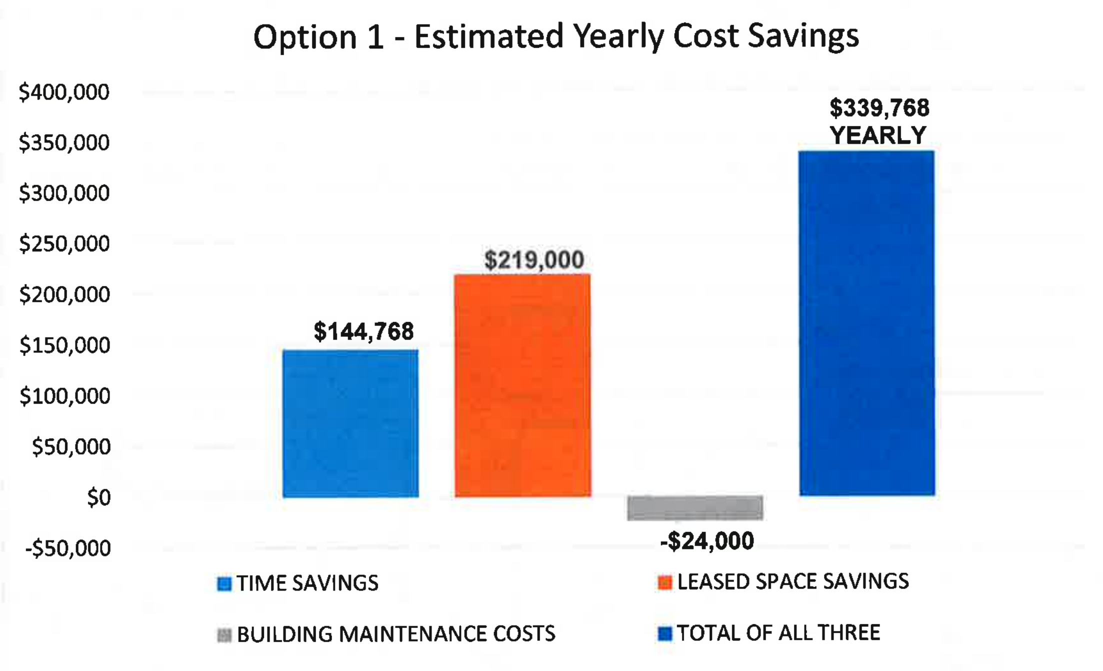
The drawing below shows the recommended project. The proposed vacated street is shown in yellow.



Amongst the benefits this proposed design will provide include the following Items 1 through 4.

1. Estimated Cost Savings. The chart below outlines estimated annual cost savings going forward.

Downtown Campus



- Time savings from increased efficiency and production capabilities of Avista employees leading to direct cost savings is estimated at approximately $145,000 annually going forward.
- Leased space savings from potential office space and parking required for the customers is estimated $220,000 annually going forward
- Building maintenance costs refers to the increase in building, site, electrical, plumbing, or HVAC systems that will need repair and or maintenance once the project is completed. The direct costs are estimated at $24,000 annually going forward.

2. Non-quantifiable improvements in safety of Avista employees includes:

   - Reduced risk of service truck backing accidents due to pull-through parking bays.
   - Improved air quality for welding and work that produces possible harmful vapors or particles.
   - Clearly articulated paths of service vehicle traffic on site.
   - Gantry and jib cranes to reduce the risk of lost time accidents resulting from manual lifting and moving of equipment and materials.
   - Covering for main pedestrian pathways and service vehicle parking areas to reduce the risk of snow and ice slips, trips, and falls.
   - An underground training vault to simulate working conditions within the downtown core. Allows for practice of confined space techniques and air monitoring.
   - Clear separation of office employee personal vehicles and DTNW service vehicles and equipment.

3. Non-Quantifiable Equipment Savings

- Potential increased longevity of service vehicles/trucks due to being covered and/or in heated parking.

4. Customer benefits are outlined throughout the items above, but some clarifications and items to consider also include:
    - Faster response time of field crews due to increased efficiencies.
    - Increased reliability of DTNW crews.
    - Increased customer safety due to the above two items, especially during a safety event such as an electrical outage.
    - Accommodating future customers within the downtown Spokane area. Between the 2000 and 2010 census Spokane population grew approximately 6%.

Option 2 – Purchase alternate lot and build new / expand as needed for office space and a DTNW Operations Building

The Advisory Group explored relocating the Downtown Campus to available alternate sites. It was determined with DTNW leadership that based on service territory and travel, the new site must be roughly in the same downtown Spokane vicinity that it is now, which ruled out lots elsewhere in Spokane County. Avista's Real Estate Department contacts with local broker Kiemle & Hagood produced two alternative sites.

The first was located at 627 E. Sprague Ave. However, this site's asking price of \$2,975,000 was \$725,000 more than the recommended solution's price. In addition, 1717 W. 4th Ave. had been on the market for over a year and the final price could be (and was) reduced even further than the \$725,000 difference.

The AFM / AMI space needs could possibly have been accommodated in this alternate building, however, there were two existing tenants with pre-existing, multi-year leases in place, taking up 75 percent of the office space in the building. One, or possibly both, of the tenants would have to be bought out of their lease in order for AFM, AMI, and the DTNW to fit into the building.

In addition, after a walk-through of 627 E. Sprague Ave., it was less advantageous and had more risk of potential planning layout issues for the DTNW. The recommended site in Option 1 allowed for construction of a new building that would provide greater flexibility for the sizes of equipment and materials that the DTNW uses. In comparison, 627 E. Sprague would force the DTNW to "make due" with heights, parking, storage, and layout limitations of the existing structure.

The second site that was evaluated was located at 821 W. Mallon Ave. (a.k.a. the Wonder Bread Building – former Continental Bakery Company). According to a Spokesman Review article it was built in 1909, and the bakery component closed in 2000. Upon walk-through, it appeared that the building was in such a state of disrepair that it would have needed significant capital investment to bring the space to a usable status. There were gaping holes between floors, pigeon excrement and pest contamination, and obvious signs of squatting and vagrant tenancy. In addition, the asking price was the highest of all lots considered –in the \$3 to \$3.5 million range. According to county records, it sold for \$3.025 million in September 2016.

Downtown Campus

Unfortunately, no other feasible lots materialized in the search.

Option 3 – Do nothing for DTNW. Obtain a rental for AFM / AMI

The third option will see ongoing yearly average costs at about $222,000 per year ($18,000 in O&M maintenance costs and $204,000 in rent). Both costs would expect to grow uniformly over time as the DTNW must be minimally maintained to remain in usable condition, and rental rates for AFM / AMI office space would uniformly increase over time. Using a conservative uniform increase rate of 5% yearly it could be expected that within 10 years the yearly costs would approach $344,000. At the same time, over that 10 years a total of approximately $2.8 million would be spent on maintenance and rental costs.

In regards to future capital costs, in the short term, it is expected to remain static and inconsequential. This is due to minimal, if any, past capital funding put into DTNW facilities due to building ages. However, catastrophic failures of the building, site, or any of its systems would require an immediate, and potentially costly, replacement from capital budget resources. It could potentially create a spike in any given year of capital spending.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Downtown Campus ~~Campus Repurposing Phase 2~~ plan and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	5/1/17
Print Name:	Eric Bowles		
Title:	Manager, Facilities		
Role:	Business Case Owner		

Signature:		Date:	5/1/17
Print Name:	Anna Scarlett		
Title:	Manager, Shared Services		
Role:	Business Case Sponsor		

Signature:		Date:	4-28-17
Print Name:	Heather Rosentrater		
Title:	Vice President, Energy Delivery		
Role:	Steering/Advisory Committee Review		

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1	Eric Bowles	04/25/17	Heather Rosentrater	04/25/17	New template

Template Version: 03/07/2017

New Dollar Road Service Center

1 GENERAL INFORMATION

Requested Spend Amount	$24,000,000
Requesting Organization/Department	Facilities
Business Case Owner	Eric Bowles / Vance Ruppert, Facilities
Business Case Sponsor	Anna Scarlett, Manager, Shared Services
Sponsor Organization/Department	Shared Services
Category	Project
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The Steering Committee is made up of a cross section of directors that represent groups impacted by the projects, as well as a couple members not directly affected to add an outside view. The current group is as follows:

- Director of Environmental Affairs
- Director of Shared Services
- Director of IT and Security
- Director of Natural Gas
- Director of Financial Planning and Analysis
- Director of Operations

The Advisory Group that assisted in shaping the "Business Problem and the "Proposal and Recommended Solution" consisted of the following stakeholders:

- Gas Operations: Mike Faulkenberry, Tim Mair, Craig Buchanan, Seth Shaffer, Jeff Webb, Fred Valentine. Previous stakeholders included David Howell and John Schwendener.
- Warehouse: Laurie Heagle, Gary Knight, Mike Cavallaro.
- Fleet Maintenance: Greg Loew.
- Facilities: Eric Bowles, Anna Scarlett, Vance Ruppert. Previous stakeholders included Laura Vickers and Mike Broemeling.

Other advisors may contribute input, approvals, or information as needed, and include:

- Vice President of Energy Delivery
- Executive Officers
- End Users

New Dollar Road Service Center

2 BUSINESS PROBLEM

The Dollar Road Service Center serves as the main gas operations facility for approximately 300,000 customers within the greater Spokane area. Approximately 70 Avista field crew and administrative support employees are based out of the site. This facility also supports our local gas crews in the Ritzville, Colville, and Davenport regions to help serve an additional approximately 50,000 customers.

The existing Dollar Road Service Center was constructed in 1956, at a size of approximately 22,000 square feet. Over the decades, previous capital projects included asphalting exterior yards for gas pipe lay down and material and equipment storage, as well as purchasing adjacent properties to increase our storage acreage. In the early 2010's, a vehicle storage and fleet maintenance building was constructed to support the gas operations functions.

This narrative is meant to address the 22,000 square foot main building that has been in service for nearly 70 years. Due to its long history, many of the main building components, systems, and equipment have deteriorated over time.

In 2011, Facilities prepared a survey of several of our existing sites that created an Asset Condition score. The Dollar Road Service Center scored the second lowest in terms of Asset Condition (see attached survey results).

As part of the survey, the following images were captured to represent current conditions:

New Dollar Road Service Center

3 PROPOSAL AND RECOMMENDED SOLUTION

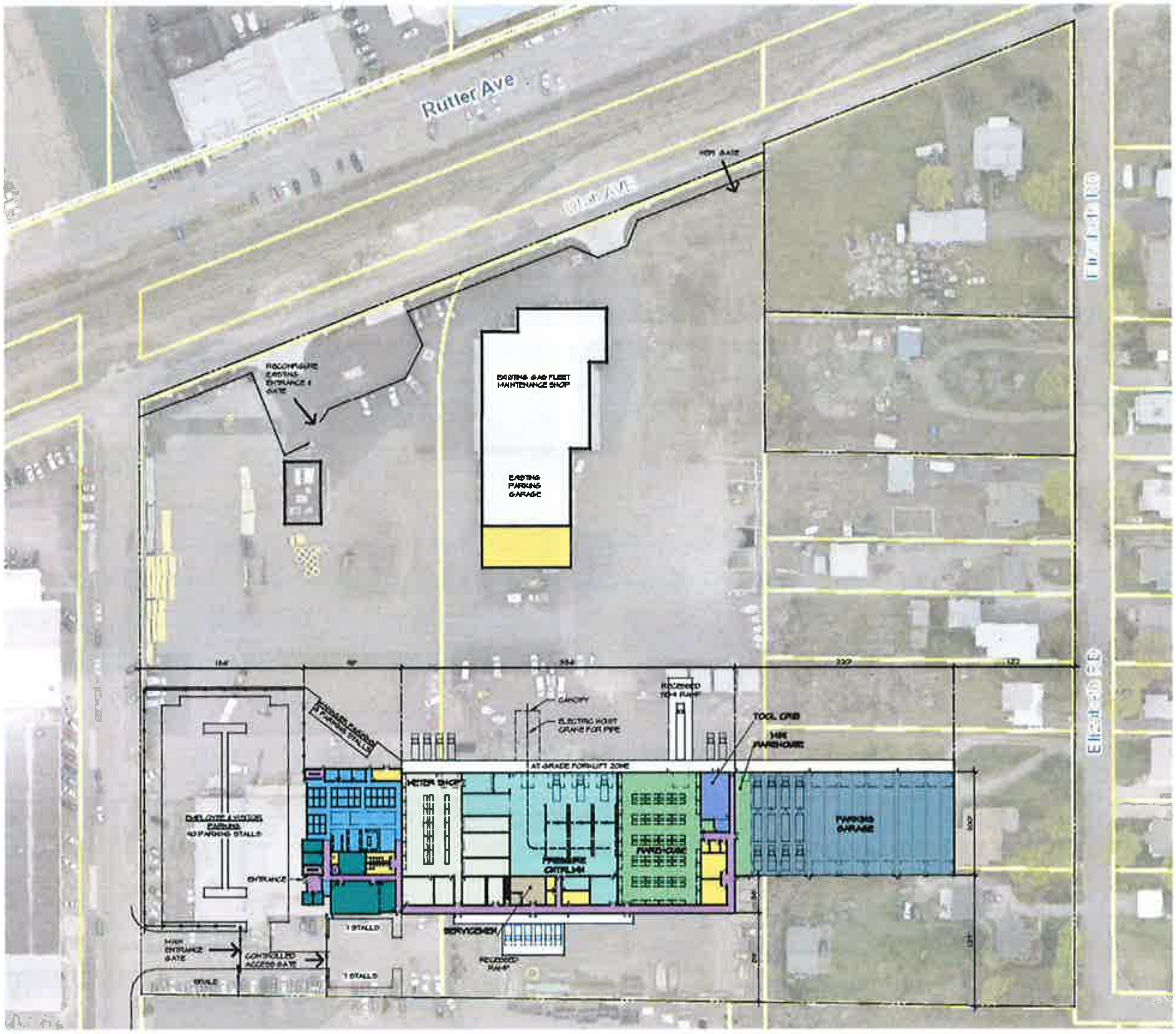
Option	Capital Cost	Start	Complete
Option 1 (Recommended) – Demolish existing building and build new Service Center on existing property.	$24,000,000	01/2016	12/2018
Option 2 – Purchase new property/site and build new Service Center.	$37,000,000 (approx.)	01/2016	12/2018
Option 3 – Do nothing, keep using existing building.	$21K capital yearly. $169K O&M yearly. (Both values are approximate averages from the last 5 years)	N/A	N/A

The three above options were produced with input from the Advisory Group listed above in Section 1, Item 1.1. Please note, individual stakeholders from the Advisory Group may not have been involved in producing all three options.

Option 1 – Demolish existing building and build new Service Center on existing property

The recommended design solution is shown below. The existing building to be demolished is at the lower left of the image, shown underneath the new proposed parking lot. The vehicle storage and fleet maintenance building was constructed in 2011 and 2013 and is shown in white in the upper middle portion of the image. This option is proposed to begin construction in 2017 and end in late 2018.

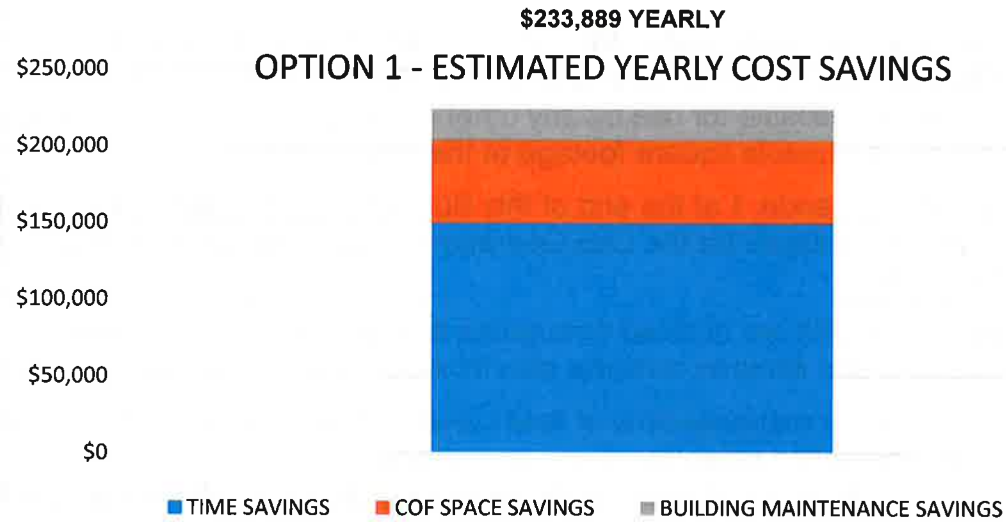
New Dollar Road Service Center



New Dollar Road Service Center

The benefits this proposed design will provide include the following items 1 through 7.

1. Estimated Cost Savings. The chart below summarizes estimated yearly cost savings going forward.



- Time savings from increased efficiency and production capabilities of Avista employees leading to direct cost savings, is estimated at approximately $150,000 annually.
- Space savings for potential office space and parking uses will occur once the project is completed due to the relocation of approximately 10 gas meter shop employees from the main campus, and the capacity for relocating up to 30 more as needed, resulting in decreased pressure on the limited employee and parking space at the main campus.
- Building maintenance savings refers to the reduction in building, site, electrical, plumbing, or HVAC systems that will need repair and or maintenance once a new building is completed. The direct cost savings are conservatively estimated to be ($20,000) yearly going forward.

2. Non-quantifiable improvements in safety of Avista employees, including but not limited to:

- Service truck backing accidents.
- Air quality for welding and work that produces possible harmful vapors or particles.
- Providing clearly articulated paths of service vehicle traffic on site.
- Separating employee parking from service yard traffic and parking.
- Providing necessary clearances for employees that work with interior shelving and forklifts, build natural gas control gates, and pick materials such as 60 foot sticks of gas pipe in the storage yard.
- Providing gantry, trolley, and jib cranes as needed to prevent lost time accidents resulting from manual lifting and moving of equipment and materials.
- Providing canopies or covers for main forklift and pedestrian pathways

to prevent snow and ice slips, trips, and falls.

3. Non-Quantifiable Equipment Savings
   - Potential increased longevity of service vehicles/trucks due to being covered and/or in heated parking.
4. Create temporary office space for current Dollar Road employees during construction that will be become permanent after the project is completed. The space will be available for use by any other Avista group, which in turn will free up parking and usable square footage at the main campus.
5. Please see Appendix 1 at the end of this Business Case Justification Narrative for further advantages for the Gas Operations, Gas Meter Shop and Warehouse business units.
6. Customer benefits are outlined throughout the items above, but some clarifications and items to consider also include:
   - Faster response time of field crews due to increased efficiencies.
   - Increased reliability of gas operations.
   - Increased customer safety, especially during a safety event such as a broken gas line.
   - Accommodating future customers within the Spokane area. Between the 2000 and 2010 census Spokane population grew approximately 6%.
   - Ability to accommodate and assist customers outside the greater Spokane area, but within our overall service territory.

Option 2 – Purchase new property/site and build new Service Center

Facilities explored relocating the gas operations to an alternate sites, with the intent to build a facility similar to Option 1 above. In addition, the new site would have to build a new Fleet Maintenance Building and Vehicle Storage Building to replace their uses currently on the existing site. The estimated cost of this option would be $7 million for an alternate site, $24 million for the Option 1 facility above, and $6 million to replace the Fleet Maintenance and Vehicle Storage Buildings (total $37 million).

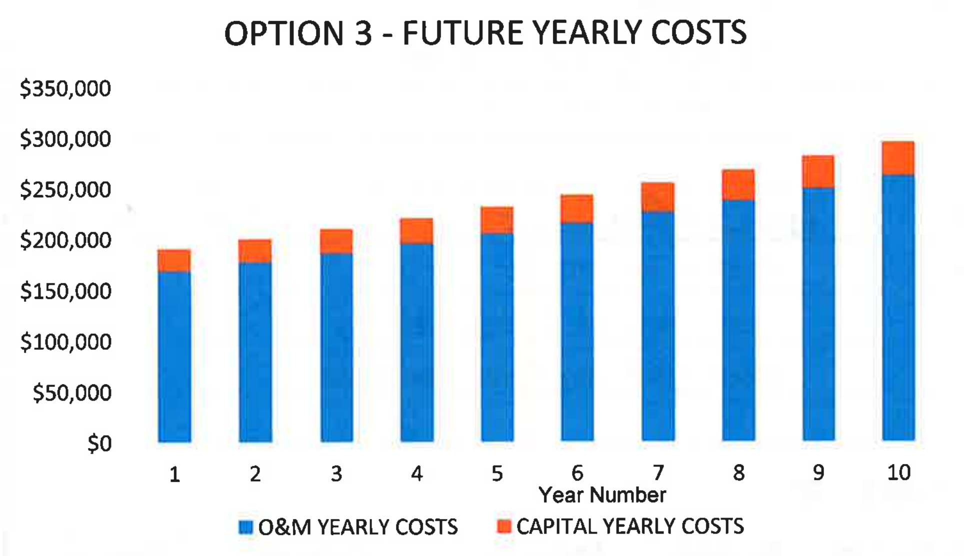
During the search for an alternate site, it was determined with David Howell and Tim Mair that based on service territory and travel, the new site must be roughly in the same centralized position of Spokane that it is now, which ruled out any lots on the north side or South Hill of Spokane, west towards the Airport, or east towards the Valley. We did find a lot of suitable size near Playfair Commerce Park, however it was a build-to-suit lease option only, not a purchase option. The central location desired resulted in no lots on the market (at that time) large enough for the Gas Operations team. It was thus decided to stay and expand upon the current site by purchasing residential properties to the east and re-zone them into LI Light Industrial Zoning.

New Dollar Road Service Center

Option 3 – Do nothing, keep using existing building

The third option will see ongoing yearly average costs at about $190,000 per year ($21,000 in capital and $169,000 in O&M costs). It should be noted that the O&M costs should expect to grow uniformly over time as the building must be maintained to remain in usable condition. Using a conservative uniform increase rate of 5% yearly it could be expected that within 10 years the O&M yearly costs would at least approach $265,000. At the same time, over that 10 years a total of approximately $2.1 million would be spent on O&M maintenance costs.

In regards to future capital costs, it should be expected that it will rise at a uniform increase rate of 10% yearly as building, site, and building systems are systematically replaced due to age or condition. Using this figure it could be expected that within 10 years the capital yearly costs would at least approach $33,000. At the same time, over that 10 years a total of approximately $270,000 would be spent on capital costs. However, catastrophic failures of the building, site, or any of its systems would require an immediate, and potentially costly, replacement from capital budget resources. It could create a spike in any given year of the capital cost spending due to the failure.



4 APPROVAL AND AUTHORIZATION

Dollar Rd Service Center

The undersigned acknowledge they have reviewed the ~~Campus Repurposing Phase 2~~ plan and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 5/1/17

Print Name: Eric Bowles

Title: Manager, Facilities

Role: Business Case Owner

Signature: Anna Scarlett Date: 5/1/17

Print Name: Anna Scarlett

Title: Manager, Shared Services

Role: Business Case Sponsor

Signature: Date: 4-28-17

Print Name: Heather Rosentrater

Title: Vice President, Energy Delivery

Role: Steering/Advisory Committee Review

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1	Eric Bowles	04/25/17	Heather Rosentrater	04/25/17	New template

Template Version: 03/07/2017

New Dollar Road Service Center

Appendix 1

1. Gas Operations additional efficiencies obtained and justifications for Option 1, as per Tim Mair:

Heated Truck Parking Stalls:

- Protects the trucks from winter weather – shortens the time that it takes to get ready for use.
- Increases the life span of tools that are no longer in the elements.
- Dry's tools, equipment, and the trucks out for the next day's work.
- Eliminates the need for engine power cord connections, and snow removal of trucks.
- Mini warehouse will be in this area for loading trucks.

Pressure Control-men work area:

- At this time the area is over crowded with not enough area to work and walk.
- Improves the overall safety of employees working in the area.
- Large diameter pipe is being moved around by employees without full use of cranes. The new cranes will enable the employees to do the work with a crane.
- The new area will be better ventilated for clearing the area out when welding.

Covered Crane / Pipe Cleaning Area:

- Preparation of pipe needs to be outside for health and safety reason.
- Cleaning of this pipe outside will help keep the PC area inside clean and avoid trip hazards.
- Crane will be used to transport large diameter pipe into PC area for final prep and build of Regulator Stations.
- The crane and covered area will improve the overall safety for this area and the employees.

Welding Training Room:

- This room will have 3 training weld stations that are enclosed out of the weather.
- We have only 2 stations now that are outside on the dock.
- Improves safety, out of weather, and better training environment.

Tool Crib Area:

- Improved storage racks – safer to work around, more organized.
- More open area for the tools to be repaired.
- Locked area for storing of high cost items.

Gas Serviceman Area:

- Area is used to build meter sets and house out of stores parts for field work.
- Test equipment required in this area which is required to meet compliance regulations.

New Dollar Road Service Center

Main Office Area:

- Two conference rooms will facilitate the meeting requests for five different departments working out of the service center.
- Foreman's work area is consistent with other service centers. It will allow the foreman to complete paper work, check emails, follow up on training, and complete time sheets online.
- Cubicle space for field workers – this area will be used for computer based, training, checking emails, and field paper work.
- Existing office space for 26 employees new space for 31 employees allow for some growth.
- Large classroom – used for Quarterly, safety, training meetings and for emergencies.
- Break Room will be used for early AM crew meetings.

Covered Spoils Area:

- Sand, cold mix, and gravel that is left uncovered creates problems with dust, freezing of materials, additional weight for loading and hauling. This adds cost and time to the work that has to be done with this material.

2. Gas Meter Shop additional efficiencies obtained and justifications for Option 1, as per Fred Valentine:

The bullets points below help show how things will be improved (compared to current state) when the Dollar Road Service Center gets completed. To summarize:

1 – Material will be managed and distributed by one group. Currently, two different groups are doing this work.

2 – Material will be consolidated under one roof. Currently, there are at least 6 locations meters and regulators are being stored.

3 – Inventory will be easier to record when all material is in one warehouse.

4 – Shop size increase will allow more functional space.

5 – Work benches will be in each specific room and not in pedestrian areas as per current layout.

6 – Noise and debris will be confined to the specific room and not throughout the entire area, or adjoining neighbors.

7 – Material and equipment specific to each room will have a "destination" rather than a random placement for future attention.

8 – Shelves can be placed more appropriately to increase spacing for safer movement and use of units.

3. Warehouse additional efficiencies obtained and justifications for Option 1, as per Laurie Heagle:

- Increased number of stores inventory items from 670 in 2011 to 1200 in 2016. A 79% increase.
- Changes in gas standards and increased emphasis on gas growth continue to **increase both** the ***number of new items*** and the ***quantity of material needed*** to serve the company's needs. (Dollar Road is the distribution center for all of Washington and Idaho and some of Oregon.)

New Dollar Road Service Center

- Pallets of materials must be routinely placed in the aisles as there is not enough space to stage, put away or store materials on shelves/racking. This makes the storekeepers job to pull materials more challenging and time consuming.
- With the added number of items it is challenging to place frequently needed materials in locations to provide efficient and ergonomic access.
- The warehouse is not currently secured resulting in unexpected material shortages.

Gas Cheney HP Reinforcement Project, ER 3311

1 GENERAL INFORMATION

Requested Spend Amount	$5,000,000 (2019)
Requesting Organization/Department	Gas Engineering
Business Case Owner	Jeff Webb
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 - Gas Engineering
Category	Project
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

The Gas Planning department routinely 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 (Avista defines design day as the projected system demand for a "coldest day on record" weather event). These deficient areas are given a priority level based on the severity of the risk associated with insufficient system capacity. 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.

2 BUSINESS PROBLEM

Load studies performed by the Gas Planning department as well as pressure monitoring during cold weather events has shown that there is insufficient pressure at the south end of the Cheney High Pressure (HP) pipeline that feeds the town of Cheney, Washington. During the most recent winter, cold weather drove the pressures at the end of the supply line to 136 pounds per square inch (psig). The line starts out at 240 psig at the source approximately 12 miles away. Sufficient capacity is defined as pressures at or above 15 psig in the distribution system and 90 psig on the HP system on a design day analysis. Without a reinforcement project, Avista will not have sufficient capacity to serve Firm customer load in the Cheney area on a design day scenario. In addition, there is a large industrial customer (Firm rate) that has expressed interest in increasing their load. Avista would not be able to meet the new request unless a reinforcement was completed.

The first segment of the Cheney HP pipeline supplies the Medical Lake area and was built in 1957, the second part that continues to Cheney was built in 1965. For years, Avista and a large gas user in Cheney have operated under a "gentlemen's agreement" where the customer switches from natural gas to an alternate fuel for periods of cold weather during the winter. Avista paid the incremental difference in fuel costs if the customer was asked to curtail natural gas use. The customer did

Gas Cheney HP Reinforcement Project, ER 3311

this voluntarily and so enabled Avista to defer this reinforcement project for many years. The customer is now considering adding additional Firm load and possibly a cogeneration plant as well. This will further exasperate the gap between system capacity and customer demand, and forces the need to complete this reinforcement project.

Depending on the route chosen, the gas main could cross through areas not yet served by gas, providing the additional benefit of new growth. This project is still in the planning stage, additional load information needs to be firmed up before proceeding further with design and alternative analysis. Cheney has approximately 1400 gas customers.

Gas Planning is unable to properly model this area because the HP system does not have sufficient capacity to reach design day conditions of 82 HDD (Heating Degree Day, average daily temperature of -17 deg F). 62 HDD is as low as the model can go. As shown in Image 1, at 62 HDD the HP system is below 90 psig and many parts of the distribution system are below 15 psig. This model scenario assumes the large customer in Cheney is only using 20 thousand cubic feet per hours (Mcfh), well below their typical winter load of 60 Mcfh. This customer is requesting 150-250 Mcfh in the future, all Firm load.

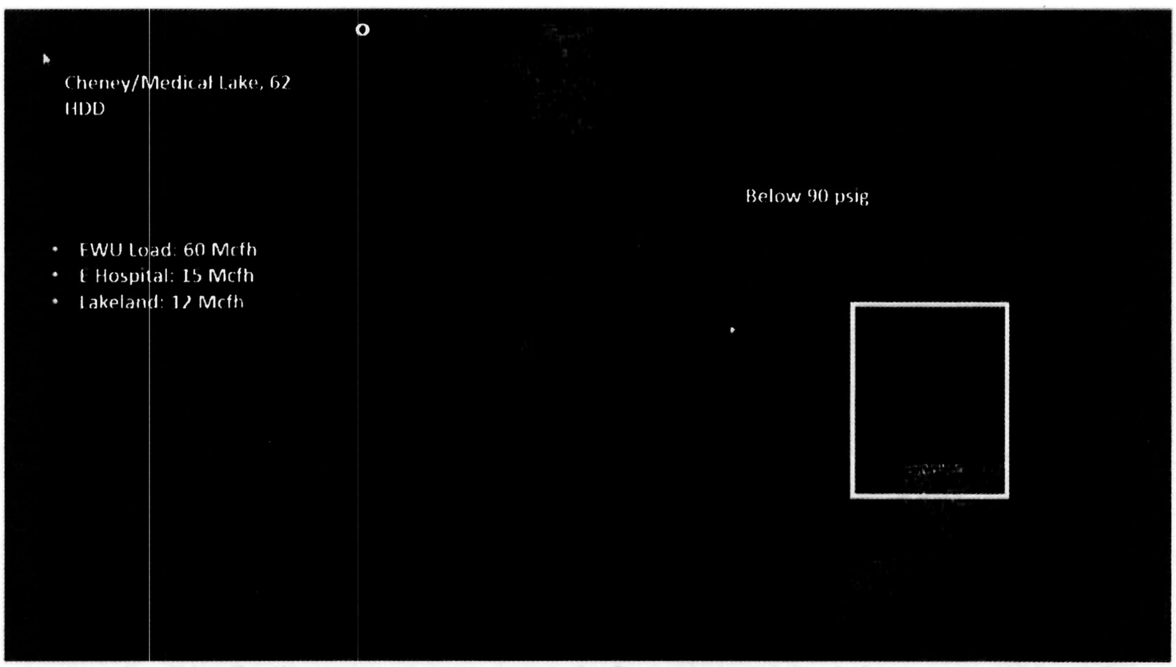


Image 1 – Distribution system pressures before proposed reinforcement (62 HDD is shown, design is 82 HDD)

Gas Cheney HP Reinforcement Project, ER 3311

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete	Risk Mitigation
Option 1 - Do nothing	$0	N/A		
Option 2 – Preferred Solution, Install new Gate Station and HP supply line from Spangle area	TBD	6/2018	12/2019	
Option 3 – Alternative #1, Upsize a portion of the existing HP supply line.	$5,000,000	6/2018	12/2019	
Option 4 – Alternative #2, Install new HP supply line from Airway Heights area	TBD	6/2018	12/2019	

These options are still being vetted out by the project team. Just recently Avista received from the large customer in Cheney their projected growth plans. This new information can now be used to determine the best course forward. Here is a high level summary with information known to date.

Option 1 – Do nothing

Without a reinforcement project, Avista does not have sufficient capacity to serve Firm customer loads in the Cheney, WA area on a design day scenario. See Image 1 for a load study analysis showing the Cheney distribution system with insufficient capacity to serve existing customers. Doing nothing would put the company at a high risk of outages starting at approximately 60 HDD. Additionally there would be no capacity available for the large customer in Cheney to expand their operations.

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.

Option 2 – Preferred Solution, Install a new Gate Station and HP supply line from the Spangle area

This option would provide the greatest flexibility by adding a new Gate Station (supply point into Avista's system) and HP supply line. The other two options are somewhat limited because they tap into existing systems, whereas this option creates a new dedicated tap that can be sized appropriately and will have few, if any, capacity limitations. This route will add reliability to the system by bringing in a second independent gas source to the area and will provide additional growth opportunities along the way for individuals without gas service. This reliability will be even greater because the new gas source will be served off another Interstate natural gas provider, GTN TransCanada. All existing lines and the other options are sourced from Williams NW Pipeline.

Option 3 – Alternative #1, Upsize the existing HP supply line (existing route)

This option would replace the existing 6" and 4" diameter supply line from the Medical Lake Gate Station with a larger diameter pipe along the same route. This would ease the workload from the Real Estate department as for most cases, existing permits and easements will cover this type of construction activity.

Option 4 – Alternative #2, Install a new HP supply line from the Airway Heights area (new route)

This option would extend a HP supply line from the existing 8" line that ends just south of the Airway Heights area. This route will add reliability to the system by bringing in a second independent gas source to the area and will provide growth opportunities along the way for customers without gas service. This would require significant work to acquire new permit and easements.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Cheney HP Reinforcement Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	4-17-17
Print Name:	Jeff Webb		
Title:	Manager Gas Engineering		
Role:	Business Case Owner		

Signature:		Date:	4/17/17
Print Name:	Mike Faulkenberry		
Title:	Director of Gas Operations		
Role:	Business Case Sponsor		

Gas Cheney HP Reinforcement Project, ER 3311

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeff Webb	04/17/17	Mike Faulkenberry	04/17/2017	Initial Version

Template Version: 02/24/2017

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 (until the end of 2031). 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 (Idaho, Oregon, and Washington). 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.

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 2015 through 2019 has been $20M-$22M annually and is reflective of the program's most recent cost experience updates. The requested budget amounts consider Avista's regulatory mandate to complete this program and has a goal of investing in its infrastructure to achieve optimum life-cycle performance. Inflation of approximately 2.3% has been planned for by escalating the annual costs.

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.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Michael Whitby*	*Initial draft of original business case*	*2011*	
1	*Michael Whitby*	*Budget Change*	*2015*	*Additional $1.8M approved*
2	*Michael Whitby*	*Budget Change*	*2016*	*Additional $3M approved*
3	*Michael Whitby*	*Budget Change*	*2017*	*$2M deferred to 2018*
4	*Michael Whitby*	*Budget Change*	*2018*	*$1M deferred to 2019*
5	*Michael Whitby*	*Budget Change*	*2019*	*$1.5M deferred to 2020*
6	*Karen Cash*	*Budget Change*	*2020*	*$1,035,000 deferred to 2021*

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

GENERAL INFORMATION

Requested Spend Amount	$22,000,000 - $29,000,000 Annually
Requested Spend Time Period	11 years (2021 through 2031)
Requesting Organization/Department	Natural Gas / Gas Facility Replacement Program
Business Case Owner | Sponsor	Karen Cash / Mike Faulkenberry
Sponsor Organization/Department	Energy Delivery / Natural Gas
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

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.

GFRP was initiated in 2012 and is planned to continue for 20 years (until the end of 2031). 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.

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.

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

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.

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

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 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 **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 is deferred

To ensure Avista fulfills the regulatory mandate to complete this program.

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 acceptable. 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.

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

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 objective of this investment and structured replacement program is to reduce risk by replacing at risk pipe and by rebuilding Service Tee Transitions. Through rigorous Project Management efforts, the GFRP plans and tracks the performance of the projects, and utilizes Earned Value for cost analysis and for upstream reporting. Further, the GFRP tracks and reports Planned vs. Actual quantities by project, by year, by state jurisdiction, and also reports multi-year cumulative statistics.

1.5 Supplemental Information

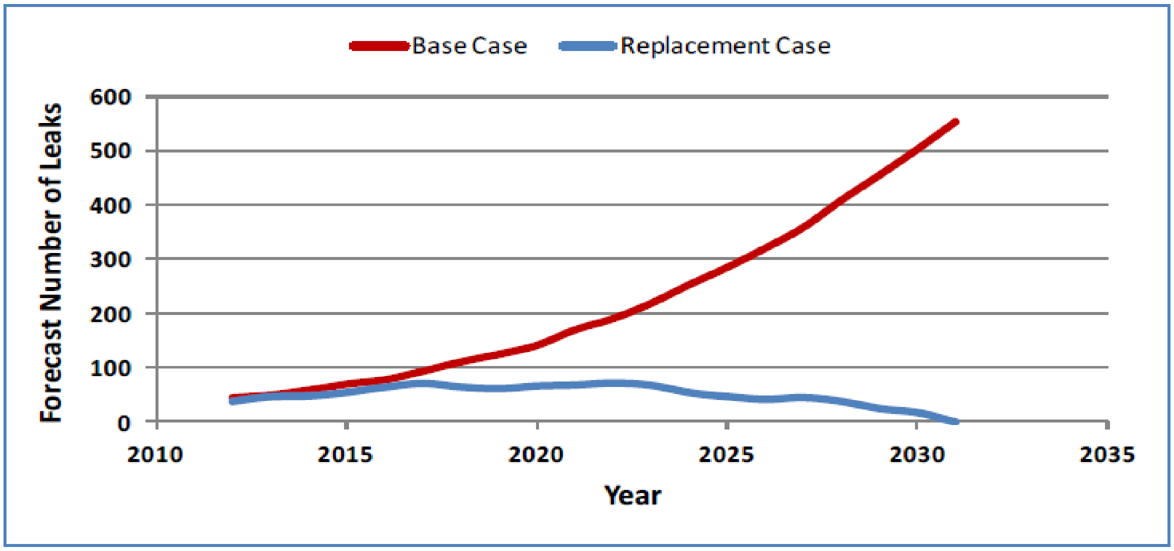
1.5.1 Please reference and summarize any studies that support the problem

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

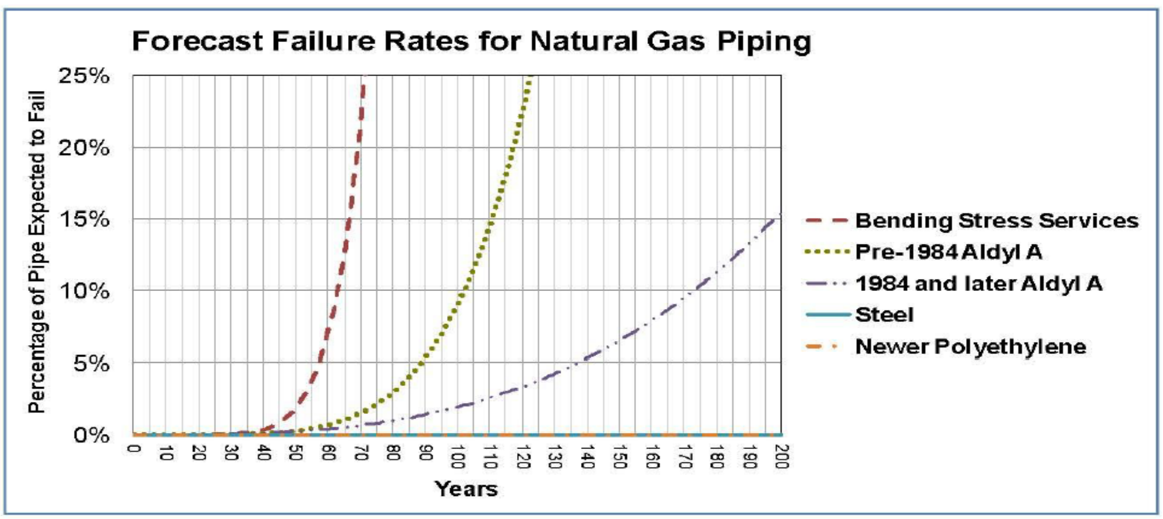
1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

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.

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.



"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 twenty-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 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.

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

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-year timeframe	≈ $443M	January 2012	December 2031

The 2013 Avista Study of Aldyl-A Mainline Pipe Leaks was updated in 2018 based on the upon leaks and replacements through the end of 2017. The original study developed failure distributions that described the likelihood of leaks occurring on the Aldyl-A pipe installed by Avista for natural gas distribution and to evaluate multiple replacement scenarios. According to the table below the baseline scenario remains more cost effective when compared to the replacement strategies.

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

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

The 2013 Avista Study of Aldyl-A Mainline Pipe Leaks was updated in 2018 based on the upon leaks and replacements 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 the worst pipe already replaced. If the 20-year replacement program where all Aldyl-A pipe is removed continues there is a slight reduction in the expected number of leaks, 255 in the original study and 246 in the updated model.

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 20-year 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.

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.

[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.]

Over the duration of the 20-year program, the GFRP will conduct replacement and rebuild work in virtually every gas district across Idaho, Oregon, and Washington, with large concentrations of Aldyl-A pipe occurring in the metropolitan centers of Spokane, Washington, Medford, Oregon, and Coeur d'Alene, Idaho. Based on the scope of work and schedule, the GFRP will plan and manage more than 100 Major Capital Projects as follows:

Category	Type	Quantity	Duration	Project Count
Major	Main Pipe	737 miles	20 years	~ 105
Major	STTR	17,769 service tees	5 years (Completed)	~20

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. Assumptions made during the study were as follows:

- Planned replacement of Aldyl-A Mainline pipe costs $357 per three feet in Washington and Idaho and $360 per three feet in Oregon.
- Unplanned replacement of Aldyl-A Mainline pipe costs $5,071 per three-foot section.

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

- Consequences for a Catastrophic Event, Injury with lost time and injury without lost time are applied per Avista standard practice.

At Avista we forecast Capital Projects/Programs on five-year budget planning cycles which are updated and adjusted annually. In order to provide the most accurate budget forecasts possible it is necessary to draw from the program's most current cost data which is tracked and derived from recently completed projects. The historical spending trend from 2015 through 2019 has been $20M-$22M annually and is reflective of the program's most recent cost experience updates. The requested budget amounts take into account of Avista's regulatory mandate to complete this program with full contractor complement and has a goal of investing in its infrastructure to achieve optimum life-cycle performance. Inflation of approximately 2.3% has been planned for by escalating the annual costs.

Year	System Transfer to Plant (TTP)	Actual vs. Forecasted
2011	$2,683,207	Actual
2012	$187,815	Actual
2013	$17,690,260	Actual
2014	$16,875,629	Actual
2015	$19,709,181	Actual
2016	$19,576,293	Actual
2017	$18,371,496	Actual
2018	$21,914,044	Actual
2019	$22,002,672	Actual
2020	$22,307,086	Forecasted
2021	$22,832,227	Forecasted
2022	$23,357,368	Forecasted
2023	$23,894,587	Forecasted
2024	$24,444,163	Forecasted
2025	$25,006,379	Forecasted
2026	$25,006,379	Forecasted
2027	$26,169,901	Forecasted
2028	$26,771,808	Forecasted
2029	$27,387,560	Forecasted
2030	$28,017,474	Forecasted
2031	$28,661,876	Forecasted
Grand Total	$443,442,553	
Annual Average	$21,116,312	

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

Unplanned leak repairs are an O&M cost and are addressed by the local districts. Through this program, O&M expenses are mitigated. 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.

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

To establish context, Avista's goal is operate a safe & reliable, and cost-effective gas distribution system. Specifically, as related to these goals, § XI of *"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.

To summarize, the primary alternatives modeled are as follows:

- **Do Nothing**

Pipe Replacement Strategies:

Since the "do nothing" option was not an acceptable or prudent approach, the Company evaluated different periods of time for removal of all Priority Aldyl-A pipe, up to a program horizon of 30 years. Avista assessed the prudence of different approaches based on the forecast of likely natural gas leaks due to failed pipe, as well as the rate impact to customers.

- **Less than 20 Year Pipe Replacement Program**
- **Conduct a 20 Year Pipe Replacement Program (Optimal)**
- **Conduct a 25+ Year Pipe Replacement Program**

Based on the time horizon scenarios modeled, it was determined that the optimum timeframe for removing priority Aldyl-A pipe was the 20 years.

RISKS ASSOCIATED WITH ALTERNATIVES CONSIDERED:

To summarize the primary alternatives and associated risks;

- **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.

- **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.

- **Conduct a 20 Year Pipe Replacement Program:**

  The report proposes and suggests that a Systematic Replacement Program conducted over a 20 year timeline is the optimum timeframe to prudently manage this risk, based on the forecast number of leaks and risks, and the rate impact to our customers.

- **Conduct a 25+ Year Pipe Replacement Program:**

  Lengthening the timeframe to 25 years resulted in more than a doubling of the number of leaks expected when compared to a 20-year horizon. Lengthening the timeline beyond 25 years was found to result in a substantial increase in the number of material failures expected.

As outlined above, Asset Management has identified 20 years as the optimum timeframe to prudently manage this risk. Avista's leadership has adopted this recommendation and has funded and staffed the program to achieve this objective. Furthermore, the three state Commissions that regulate Avista's natural gas operations have thoroughly examined this program in several rates proceedings, and in policy proceedings, and have deemed this approach to be prudent, cost effective, and in the interest of our customers.

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.

Start: January 2012

Expected End: December 2031

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".

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

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.

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 objective of this investment and structured replacement program is to reduce risk by replacing at risk pipe and by rebuilding Service Tee Transitions. Through rigorous efforts, the GFRP plans and tacks the performance of each project and utilizes Earned Value for cost analysis and for upstream reporting. Furthermore, the GFRP tracks and report Planned vs. Actual quantities by project, year, state jurisdiction, and also reports multi-year cumulative statistics.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Avista's customers and the general public expect Avista's natural gas system to operate safely and reliably without incidents. Avista is dedicated to and focused on maintaining a safe and reliable system that shields the public from imprudent risks. The proposed pipe replacement programs have been initiated with the purpose of mitigating the known risks within the natural

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

gas distribution system. Given this context, the Gas Facility Replacement Program's portfolio of projects could therefore be considered as a customer-related benefit.

The GFRP's Aldyl-A Pipe Replacement projects touch numerous internal and external stakeholders. A comprehensive list of stakeholders is in the "2019 GFRP Operating Plan & Projects" document.

2.8.2 Identify any related Business Cases

Business cases have been submitted annually and updated as necessary since 2012, the inception of the Gas facility Replacement Program.

3.1 Steering Committee or Advisory Group Information

The Gas Facility Replacement Program (GFRP) Advisory Group consists of the GFRP's Program Manager, Cas Operations Contract Construction Manager, Director of Natura Gas, and the Manager of Gas Design & Measurement. This group meets monthly to review program wide Earned Value results, that 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.

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

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 Program Manager.

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

The Gas Facility Replacement Program (GFRP) Advisory Group consists of the GFRP's Program Manager, Cas Operations Contract Construction Manager, Director of Natura Gas, and the Manager of Gas Design & Measurement. This group meets monthly to review program wide Earned Value results, that 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. The monthly

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

documentation tracks the projects and is the primary device for documenting program decision making.

As projects are completed, the Distribution Integrity Management Program (DIMP) Aldyl-A prioritization list is updated annually. As projects are completed, they are removed from the list and new projects are added and evaluated, as necessary.

Annual spend levels and funds change requests to the Capital Planning Group are maintained as documentation of program funding and funding changes throughout the year.

The undersigned acknowledge they have reviewed the **Gas Facility Replacement Program (GFRP)** 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: Karen Cash   Date: 7/13/20
Print Name: Karen Cash
Title: GFRP Manager
Role: Business Case Owner

Signature: Mike Faulkenberry   Date: 7/13/2020
Print Name: Mike Faulkenberry
Title: Natural Gas Director
Role: Business Case Sponsor

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

Template Version: 05/28/2020

Gas Non-Revenue Program, ER 3005

1 GENERAL INFORMATION

Requested Spend Amount	$9,000,000
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner	Jeff Webb
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 – Gas Engineering
Category	Program
Driver	Failed Plant & Operations

1.1 Steering Committee or Advisory Group Information

This work is typically unplanned and is initiated by customers or Avista maintenance crews and is managed at the Local District level. Gas Engineering establishes the overall budget based largely 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 this ER that require substantial design efforts such as farm tap retirements, highway or river crossings, and steel pipelines.

2 BUSINESS PROBLEM

The work in this annual program is mostly reactionary, unplanned work and is 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, meter barricades (only in Washington State and only through the year 2020), and farm tap elimination. Each of these work types 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. With the exception of the meter barricade work, the business needs and potential solutions identified impact all gas customers in Avista's service territory.

When shallow facilities are discovered, an appropriate response to the situation is determined by Local District Management. If the response to the situation is capital in nature, then the repair is funded from this program. If the scope of the project is large enough to warrant it, the project will be prioritized and risk ranked against other similar type projects. 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,

Gas Non-Revenue Program, ER 3005

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 is in conflict 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 just repairing the leak. The Local District looks at the long term fix when possible, not just addressing the immediate concern, and considers what is the right thing to do in these situations. This type of betterment falls under this program.

The need for meter protection can come from a variety of sources: customer, meter reader, atmospheric corrosion inspectors, or from company personnel. Each report is vetted by the Local District to ensure the need is warranted and then the job is scheduled for installation. Installation of meter barricades or break-away fittings on existing meters sets is capital only in Washington State and only through the year 2020.

A single service farm tap (SSFT) installed on a supply 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.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$0	N/A	
Option 2 – Preferred Solution, Complete programmatic work as described	$6,000,000	01-2017	12-2017
Option 3 – Alternative Solution, Reduced funding	$3,000,000	01-2017	12-2017

Option 1 – Do nothing

Shallow facilities – Higher likelihood of being damaged and causing a gas leak.

Requested by others & leak repair – To miss the opportunity to better the system while already on-site doing work is shortsighted because we increase the chances of having to be back at the site to remedy other maintenance items at a later date. 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, they must be monitored and re-evaluated on a periodic schedule to ensure they are not becoming a greater hazard to the public.

Meter protection – Not installing meter barricades or break-away fittings is against Federal Rules (CFR 192.353) and presents a significant safety risk to the public, especially if the facilities are damaged.

Farm tap elimination – If Avista is not allowed to optimize the gas distribution system by reducing the number of farm taps that are maintenance intensive, then eventually more staff will be required to perform this federally mandated 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.

Option 2 – Preferred Solution, Complete programmatic work as described

Shallow facilities – Lowering gas mains and services is not required by Federal Rules, but it is prudent. It reduces the chances of damage caused by excavation over and around the gas facilities. This is critical because damage from excavation is the highest risk to our gas facilities. Excavators are expecting gas pipes to be at the depths they are first 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.

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 the time once there is the sensible way to operate. Betterments as described in Section 2 are driven by Company Standards and best practices.

Meter protection – Avista is mandated by Federal Rules to protect above ground facilities from damage. Gas meters located where vehicles are normally parked or driven create a hazard if the meter is not properly protected.

Farm tap elimination – When there are many farm taps located in close proximity to each other and when those stations have reason to be rebuilt, then it makes sense to rebuild just one of them and install distribution main to the other sites to provide a new source of gas. This allows the adjacent 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), inability to perform proper maintenance, and capacity constraints.

The customers benefit from these types of projects by having a safer, well maintained distribution system. Also this is a prudent way to spend resources because many deficiencies at stations can be remedied under just one project. Additionally, the new main might be installed in front of structures without gas service, making it easier to serve them with gas in the future should they choose to change their energy source.

Option 3 – Alternative Solution, Reduced funding

<u>Shallow facilities</u> – Likelihood of being damaged and causing a gas leak if fewer facilities were lowered.

<u>Requested by others & leak repair</u> – *This betterment would happen at a reduced rate, causing workload pressure on the maintenance personnel.* To miss the opportunity to better the system while already on-site doing work is shortsighted because we increase the chances of having to be back at the site to remedy other maintenance items at a later date. 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, they must be monitored and re-evaluated on a periodic schedule to ensure they are not becoming a greater hazard to the public.

<u>Meter protection</u> – Not installing meter protection is against Federal Rules and presents a significant safety risk to the public, especially if the facilities are damaged.

<u>Farm tap elimination</u> - *This optimization would happen at a reduced rate, causing workload pressure on the maintenance personnel.* If Avista is not allowed to optimize the gas distribution system by reducing the number of farm taps that are maintenance intensive, then eventually more staff may be required to perform this federally mandated 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.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Non-Revenue 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 Webb	Date:	2-17-20
Print Name:	Jeff Webb		
Title:	Manager of Gas Engineering		
Role:	Business Case Owner		

Signature:	Mike Faulkenberry	Date:	2/17/20
Print Name:	Mike Faulkenberry		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

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

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeff Webb	03/16/2017			Initial version
1.1	Jeff Webb	04/05/2017			
2.0	Jeff Webb	2/17/2020			Revised for Oregon 2020 GRC filing

Template Version: 02/24/2017

Gas N-S Corridor Greene St HP Main Project, ER 3304

1 GENERAL INFORMATION

Requested Spend Amount	$100,000 - 2018
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner	Jeff Webb
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 – Gas Engineering
Category	Mandatory
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

Gas Operations manages this category of work. They are notified of upcoming municipal projects that impact the gas system in their areas. When conflicts are identified that require relocating gas facilities, negotiations with the appropriate entities take place in an attempt to design around the conflict. If negotiations are not successful, and if required per the franchise agreement, then Avista will relocate the gas facility to avoid the conflict. If the relocate project is significant enough, then Gas Engineering will take over the project to design and manage. The overall program budget is managed by Gas Engineering.

2 BUSINESS PROBLEM

Due to the Washington State DOT, North-South Corridor Project, a relocation of the gas facilities may be required. Scope and schedule are currently in flux and Avista is working with both WSDOT, City of Spokane, and Burlington Northern Railroad to minimize impacts to our 20" high pressure (HP) gas main. This work will likely happen in 2018.

See the Business Case entitled "Gas Replacement Street and Highway Program" for further justification of this type of project considered "work in request of others".

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$ TBD		
Option 2 – Preferred Solution, Complete replacements as necessary	$100,000	1-2018	12-2018

Option 1 – Do nothing

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 be in conflict with 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 municipalities.

Option 2 – Preferred Solution, Complete the replacements as necessary

By completing the projects as requested, then Avista meets the obligations under its franchise agreements, remains in good standing with the municipalities, and avoids financial penalties.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas N-S Corridor Greene St HP Main Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Jeff Webb Date: 4-17-17

Print Name: Jeff Webb

Title: Manager Gas Engineering

Role: Business Case Owner

Signature: Date: 4/17/17

Print Name: Mike Faulkenberry

Title: Director of Natural Gas

Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeff Webb	04/17/2017	Mike Faulkenberry	04/17/2017	Initial version

Template Version: 03/07/2017

Gas Replacement Street and Highway Program, ER 3003

1 GENERAL INFORMATION

Requested Spend Amount	$3,000,000
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner	Jeff Webb
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 – Gas Engineering
Category	Program
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

Gas Operations manages this category of work. The work is generated by the various municipalities that Avista has franchise agreements in. The overall program budget is managed by Gas Engineering.

2 BUSINESS PROBLEM

It is very difficult to forecast year-to-year what the cost in this category will be. Virtually all of Avista's pipelines are located in public utility easements (PUEs) which are controlled by local jurisdictional franchise agreements. Avista is mandated under these agreements to relocate its facilities, when local jurisdictional projects necessitate. Often these come without significant lead time by the local jurisdictions. It is often the case that meetings are called in the Spring to notify franchisees (natural gas, electric, cable, phone etc.) that they will need to relocate their facilities. This does not enable ideal planning and often may cause Avista to spend unbudgeted funds and do so in a manner that is not of the utmost efficiency.

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 gas facilities are required, then Avista must 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.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$ TBD		
Option 2 – Preferred Solution, Complete	$3,000,000	January	December

replacements as necessary			

Option 1 – Do nothing

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 be in conflict with 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.

Option 2 – Preferred Solution, Complete the replacements as necessary

By completing the projects as requested, then Avista meets the obligations under its franchise agreements, remains in good standing with the municipalities, and avoids financial penalties.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Replacement Street and Highway 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: [signature] Date: 2-17-20
Print Name: Jeff Webb
Title: Manager Gas Engineering
Role: Business Case Owner

Signature: [signature] Date: 2/17/20
Print Name: Mike Faulkenberry
Title: Director of Natural Gas
Role: Business Case Sponsor

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

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeff Webb	03/17/2017			Initial version
1.1	Jeff Webb	04/07/2017			
2.0	Jeff Webb	2/17/2020			Revised for 2020 Oregon GRC filing

Template Version: 03/07/2017

Index for Business Case Justification Narratives Related to 2020 Pro Forma Plant Group Electric and Natural Gas Energy Delivery Systems, Fleet, and Office and Operations Facilities Plant Additions

Electric Storm Business Case

EXECUTIVE SUMMARY

The Electric Storm Business Case is focused on restoring Avista's transmission, substation, 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 and excludes major event days (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	Notes
Draft	*Amy Jones*	*Initial draft of Business Case refresh 2020*	*7/1/2020*	

Electric Storm Business Case

GENERAL INFORMATION

Requested Spend Amount	$3,200,000 annually
Requested Spend Time Period	Ongoing program
Requesting Organization/Department	Operations
Business Case Owner | Sponsor	David Howell | David Howell
Sponsor Organization/Department	Operations
Phase	Execution
Category	Program
Driver	Failed Plant & Operations

1. BUSINESS PROBLEM

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, 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 *(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 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 SAFI and CAIDI. The secondary driver for this business case is **Customer Service Quality and Reliability**.

<u>Benefits to Customers</u>
This business case allows funding for a rapid response to unexpected damages and service interruptions so customer outage times are minimized. The importance of quickly replacing damaged facilities is vital to providing reliable service to our customers.

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

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 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 primary measure that will be used to determine success is outage duration including other reliability measures such as Avista's reliability indices like SAFI and CAIDI. These measures will demonstrate the impact of the work charged to this business case.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

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

Option	Capital Cost	Start	Complete
Fully Funded	*$3,200,000 annually*	*Continuous Program*	
Unfunded: The work would need to be completed if unfunded and would need to be absorbed by another business case.	*$0*		

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

The annual budget amount is determined based on the historical average rate of capital restoration work.

Figure 1 shows the historical costs (2010 – 2019) for the distribution storm business case. From 2010 to 2013, the average annual cost for distribution storms was $2.1 million dollars, with a range of $1.3MM (2011) to $2.7MM (2013). The years of 2014 and 2015 experienced an anomaly with 2014 having two uncharacteristic major wind events during the summer and November 2015 was a historic 100-year windstorm event. Consequently, 2014 and 2015 realized record spending on storm related distribution work. The year 2016 had a distribution storm spend of nearly $4 million, but much of the work was related to clean up of the historic November 2015 storm event. The proposed funding level does not account for the storm anomalies that occurred in 2014 and 2015 (Major Event Days).

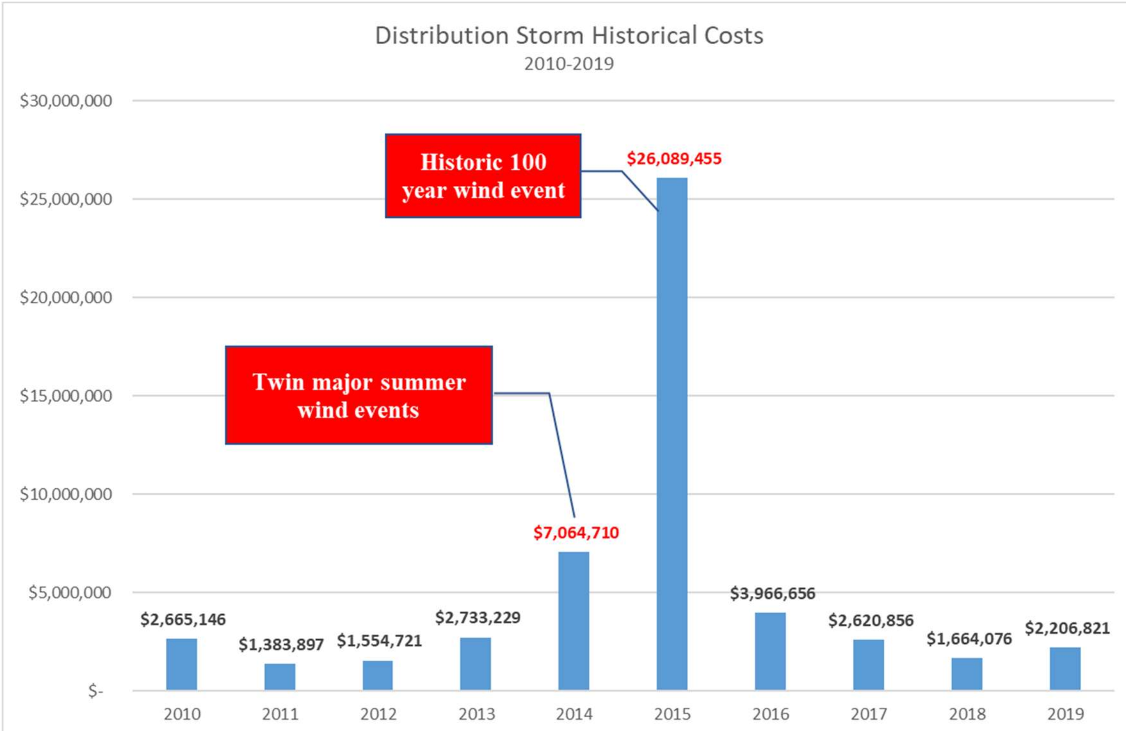


Figure 1: Dx Storm Historical Costs

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 requested capital cost amount will be spent as needed, driven by customer outages as a result of a weather storm or natural disaster event. Historical spend is an indication of future spend.

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

Work under this business case occurs when repair is needed to facilities that are damaged during weather storm events or natural disasters. Depending on the severity and the duration of the specific outages, various business functions and processes may be impacted. Impacted areas can affect one office area or multiple Avista service territories.

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

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 will have to be repaired, regardless of funding.

Electric Storm Business Case

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.

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.

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

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 SAFI and CAIDI.

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 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 caused by weather storm events or natural disasters, so customer outage times are minimized. If this business case is not funded, the costs to restore power to our customers will be absorbed by a different business case, as the work will need to occur.

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 Electric Storm work is overseen by the local area operations engineers and area construction managers. 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. Leaders will declare Emergency Operating Procedures (EOP) and Stakeholders from every area of the company are involved on safely restoring power to our electric customers.

2.8.2 Identify any related Business Cases

N/A

3.1 Steering Committee or Advisory Group Information

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 EOP with the Director of Operations.

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. Electric Storm 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 ***Electric Storms 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: ____________

Electric Storm Business Case

	David Howell		8/2/20
Print Name:	David Howell		
Title:	Director of Operations		
Role:	Business Case Owner		

Signature:	David Howell	Date:	8/2/20
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

Jackson Prairie Joint Project

1 GENERAL INFORMATION

Requested Spend Amount	$ 1,626,667
Requesting Organization/Department	Gas Supply
Business Case Owner	Jody Morehouse
Business Case Sponsor	Jason Thackston
Sponsor Organization/Department	Gas Supply
Category	Project
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

The Risk Management Committee (RMC) oversees decisions to enter into a joint projects such as Jackson Prairie Storage Project (JP). The RMC is comprised of the following:

- Scott Morris, Chairman, President & Chief Executive Officer, Chair of Risk Management Committee
- Dennis Vermillion, Senior Vice President Avista Corporation – President Avista Utilities
- Mark Thies, Senior Vice President & Chief Financial Officer
- Marian Durkin, Senior Vice President, General Counsel, Corporate Secretary & Chief Compliance Officer
- Jason Thackston, Senior Vice President Avista Corporation – Vice President of Energy Resources Avista Utilities
- David Meyer, Vice President & Chief Counsel for Regulatory & Governmental Affairs
- Ryan Krasselt, Vice President, Controller & Principal Accounting Officer
- Patrice Gorton, Director of Finance, Assistant Treasurer
- Tracy Van Orden (non-voting), Director of Internal Audit

Additionally, the JP Management Committee meets quarterly to review and approve the capital budget status for the current year as well as for vetting of any ongoing or future expenses. A business owner representative from each of the 3 partners has final authority on the Committee. Currently, these representatives are

- Lynn Dahlberg of Williams NWP
- Ron Roberts of Puget Sound Energy
- Jody Morehouse of Avista.

2 BUSINESS PROBLEM

Avista must provide solutions for the following gas supply needs:

- A flexible, diverse portfolio with components that enable Avista to serve customers during peak load demand.
- Risk mitigation methods for shielding customers from extreme daily gas price volatility during cold weather or other events affecting the natural gas commodity market.
- A mechanism or methodology for purchasing gas at lower prices during off-peak periods for use during high cost periods.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing – this is not an option			
Package together various solutions to fulfill Gas Supply obligations	*None – See below for expenses that would flow through the PGA*		
Continue with ownership in JP and fund necessary annual capital expenditures	*$ 1,626,667*	*01/01/2017*	*12/31/2017*
Build LNG Storage	*Cost prohibitive*		

No viable singular capital project options exist for replacing JP Storage at this time. Because JP Storage provides benefits/solutions for an array of business problems, it's likely that in its absence, a combination of solutions would be packaged together.

- For meeting peak load requirements, an option is purchasing additional leased pipeline transport on GTN at an estimated cost of $9,900,000 per year for 90,000 dth/day at $0.30/dth. This expense would flow through the PGA.
- Another solution that has been assessed in past Gas IRPs to meet peaking needs and/or transport needs is to build an LNG storage facility. The capital cost estimates have been in the multi-million dollar range and have proven to be cost prohibitive. The timeline to design and build an LNG facility would be 4 or more years.
- Replacing the optimization benefit JP provides to customers with other options would be difficult if not impossible. Over the 2016 – 2017 gas procurement year, the storage optimization saved gas customers an estimated $20,000,000. This benefit currently flows through the PGA.
- Without storage, the flexibility is lost to purchase gas during seasonal periods of lower gas prices (typically summer), to use or sell back into the market when markets are higher (typically winter). The estimated savings for this seasonal buying approach varies, but has been as high as $10,000,000 over a gas procurement year.
- To replace JP storage capacity with leased capacity would be estimated at more than $34,000,000/year plus additional pipeline transport. This is based on storage capacity lease estimates of approximately $4/dth for equivalent

working gas capacity.

The recommended solution is to continue to fund 1/3 of the capital budget for Jackson Prairie (JP) Underground Storage Facility. Avista owns this facility as a 1/3 partner with Puget Sound Energy and Williams' Northwest Pipeline. Puget Sound Energy is the managing partner for the facility which is located in Chehalis, WA. The requested capital represents Avista's 1/3 share of the capital needed to maintain the existing facility and maintain equal ownership status.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Jackson Prairie Storage Project and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: [signature] Date: 4-13-2017

Print Name: Jody Morehouse

Title: Director Gas Supply

Role: Business Case Owner

Signature: [signature] Date: 4/17/17

Print Name: Jason Thackston

Title: SVP & VP Energy Resources

Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jody Morehouse	04/13/2017	Jason Thackston	04/14/2017	Initial version

Template Version: 03/07/2017

Electric Replacement and Relocation

EXECUTIVE SUMMARY

The Electric 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. Within each agreement are provisions for relocation of utilities at the request of the right-of-way (ROW) owner. Under a Franchise Agreement or Permit, Avista is allowed to occupy space within a ROW owned by the respective jurisdiction in order to serve its customers. Electric relocations occur every year 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 costs of electric relocations have very little variance year to year, therefore fully funding the business 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 WA and ID Customers.

The Electric Relocations business case is unplanned and demand driven work, 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 Relocation over five years is $2.7 million (three-year average = $3.1 million). Because electric relocations are directly correlated with the number of highway and street projects, the reason for the upward trend in spend is likely an increase in transportation project spending.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Amy Jones*	*Initial draft of 2020 Business Case Refresh*	*6/30/2020*	
1.0				
1.1				
2.0				

Electric Replacement and Relocation

GENERAL INFORMATION

Requested Spend Amount	$3,000,000 annually
Requested Spend Time Period	Ongoing Program
Requesting Organization/Department	Electric Operations
Business Case Owner | Sponsor	Amy Jones | David Howell
Sponsor Organization/Department	Operations
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

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 ROW's 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 and close to 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 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 costs of electric relocations have very little variance year to year, therefore fully funding the business will likely ensure all electric relocations under Franchise Agreements or Permits will be completed.

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 major driver of this business case is Mandatory & Compliance. Franchise agreements, typical state highway and railroad permits, and DOT prescribe that the utility will relocate at their expense when in conflict with entity activities. 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 is deferred

This program has been funded for several years and ensures compliance with our Franchise agreements and/or railroad permits. If not funded, we would be out of compliance with our Franchise agreements and/or railroad permits. The work would need to occur and would be funded under another business case.

Work under Franchise Agreements or Permits are contractual, agreed upon, and if the terms of the agreement or permit are not executed a breach of contract will likely ensue. Also, state and local government departments which oversee highways, roads, and city streets incorporate the guidelines set forth in the American Association of State Highway Transportation Officials (AASHTO) Roadside Design Guide into the design of the highways and roads. The guidelines are based on the type of roadway and posted speed, but generally do not allow for any fixed objects inside the traveled way or sides of the roadway ("clear zones") for public safety. As a result, nearly all new road projects require utilities to relocate or remove all poles inside and outside the traveled way. The new roadside design guidelines allow for placement of new facility in a location that improves the safety of the driving public, thus reduces risk to Avista. Avista designers coordinate with each state or local road project to ensure the new relocations meet the clear zone standards yet minimize cost. Most Franchise Agreements have provisions to prohibit the ROW owner from requiring the utility to move the same facility more than once over a span of years, usually five.

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 successful delivery on business case objectives include:

- YTD Spend
- Compliance with Franchise agreements and/or railroad permits

Electric Replacement and Relocation

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

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.

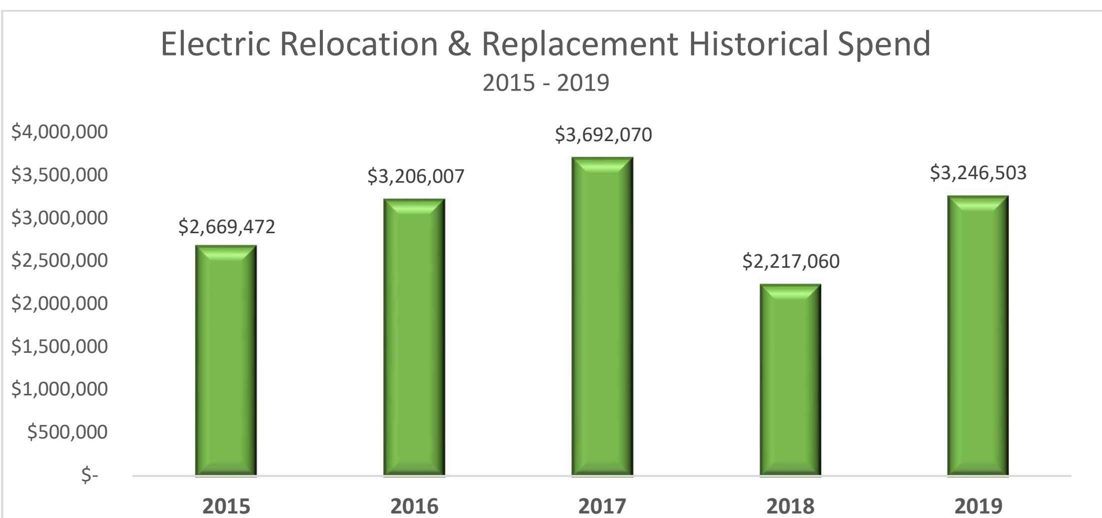
NA

Option	Capital Cost	Start	Complete
Relocate/replace facilities in conflict with street and highway projects where established franchise agreements and/or permits exist.	*$3,000,000 annually*	*Continuous Program*	
UNFUNDED: Avista would be out of compliance with established franchise agreements and/or permits if work is not completed.	*$0*		

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

The Road Moves business is unplanned work, contractually obligated, and adds high risk to the company if not completed, no alternative analysis is considered. This program is demand driven and unplanned work. Funding allocation is based on historical spending trends.

The graph below shows the historical spend for Road Moves (2015 – 2020 YTD - May). The average spend over the five years is $2.7 million. Because electric relocations are directly correlated with the number of highway and street projects, the reason for the upward trend in spend is likely an increase in transportation project spending.



Electric Replacement and Relocation

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 funding will enable us to relocate/replace facilities in conflict with street and highway projects where established franchise agreements and/or permits exist. The funding will ensure we are in compliance with our existing franchise agreements and/or railroad permits.

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

If funded, the outcome of this business case will have minimal impact on existing operations. This funding has been in place for several years to maintain compliance with our franchise agreements and railroad permits. If not funded, the work is required to maintain compliance with our franchise agreements and/or railroad permits and will need to occur.

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

The work covered by this funding is mandatory to maintain compliance with our franchise agreements and/or railroad permitting. Because the Road Moves business is unplanned work, contractually obligated, and adds high risk to the company if not completed, no alternative analysis is considered. This program is demand driven and unplanned work.

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 project. All investments/assets are used and useful at time of install.

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

This work is required to maintain compliance with our franchise agreements and/or railroad permits. This work focuses on our Customers and performance (safety and 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.

The work covered by this funding is mandatory to maintain compliance with our Franchise Agreements and/or railroad permitting.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Internal customers and stakeholders are the local area operation engineers and area construction managers

The primary external stakeholders in the business include all state and local transportation governments as well as customers since they live in the territory governed by these agencies and use the transportation system.

2.8.2 Identify any related Business Cases

NA

3.1 Steering Committee or Advisory Group Information

The Road Move work is overseen by the local area operations engineers and area construction managers.

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

The work is mostly unplanned and non-specific in nature but occurs regularly and historical averages are used to estimate a quantity. Electric Relocations (Road Moves) are agreed to and executed per the jurisdictional Franchise Agreement or Permit.

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. Oversight of the program is provided by the local area operation engineers and area construction managers manage the work as it is identified throughout the given construction season.

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

For the funding: Decision making, prioritization and change requests will be documented and monitored through the Operations Roundtable (ORT).

For the work: Each office will work with their Area Engineer and impacted jurisdiction/Railroad in determining priority.

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

Electric Replacement and Relocation

Signature:		Date:	
Print Name:	Amy Jones		
Title:	Asset Maintenance Business Analyst		
Role:	Business Case Owner		

Signature:	David Howell	Date:	8/2/20
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

Gas Cathodic Protection Program, ER 3004

1 GENERAL INFORMATION

Requested Spend Amount	$715,000
Requesting Organization/Department	B51 - Gas Engineering
Business Case Owner	Jeff Webb / Tim Harding
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 - Gas Engineering
Category	Mandatory
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

The Cathodic Protection (CP) group monitors system performance and recommends replacements and upgrades when corrosion control measures become ineffective. Gas Engineering evaluates the recommendations with the CP group 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. Gas Engineering is responsible for managing this program.

2 BUSINESS PROBLEM

CP system compliance is mandated by Federal Rules within the Department of Transportation code 49 CFR 192, Subpart I. Some of the CP systems have been in service at Avista for extended periods of time and they have exceeded their useful service life. This requires them to be replaced. 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, deteriorate at differing rates, and become ineffective when they are used up. The estimated annual cost for this budget is based on past expenditures. Because of the unpredictable nature of these projects, it is not always know which service territory work will be performed in on any given year.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$0	N/A	
Option 2 – Preferred Solution, Replace end of life cathodic protection systems	$800,000	January	December

Option 1 – Do nothing

CP systems have a finite lifespan and must be replaced when they are at the end of their service life. Failing to replace these facilities will result in inadequate external corrosion protection on Avista's steel piping systems. This would result in non-compliance with State and Federal Rules, as well as increased risk to both employee and public safety.

Option 2 – Preferred Solution, Replace end of life cathodic protection systems

Typical types of projects installed under this work type may include (but are not limited to) CP deep and shallow anode wells, Remote Monitoring Units (RMU), installation of CP rectifiers, shorted casing remediation, replacement of gas mains to improve CP system performance.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Cathodic Protection 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:	[signature]	Date:	2-17-20
Print Name:	Jeff Webb		
Title:	Manager Gas Engineering		
Role:	Business Case Owner		

Signature:	[signature]	Date:	2/17/20
Print Name:	Mike Faulkenberry		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

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

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Tim Harding	04/03/2017			Initial version
1.1	Jeff Webb	04/04/2017			
2.0	Tim Harding	2/12/2020	Jeff Webb		Revised for 2020 Oregon GRC filing

Template Version: 03/07/2017

Gas Isolated Steel Replacement Program, ER 3007

1 GENERAL INFORMATION

Requested Spend Amount	$1,400,000 – Annual Request
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner	Jeff Webb / Jenn Massey
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 – Gas Engineering
Category	Mandatory
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

The Isolated Steel Program Manager works closely with the Operations Managers to identify the work. The work is then dispatched to Gas Operations to complete. The overall program budget is managed by the Program Manager and Gas Engineering.

2 BUSINESS PROBLEM

The Program objective is to identify and document isolated steel sections of pipeline in Avista's system, including isolated risers, and to replace each riser or pipeline section within a specified timeframe after its identification.

The methodology for identifying sections of isolated steel is a programmatic survey, taking pipeline to soil potential measurements of the subject system. The overall program area is divided into subareas based on Avista's established cathodic protection zones. A three-man team conducts the survey; first obtaining "native" measurements with the CP system de-polarized, and then "on/off" measurements with the system polarized and current interrupters installed. Data is obtained digitally by each survey technician using a Trimble handheld device. The data is tracked and processed using an ESRI ArcGIS platform. Based on survey results, replacement job orders are dispatched and the replacements executed.

Isolated portions of pipe including risers, service pipe and main will be replaced as required to meet the requirements of 49 CFR 192.455 & .457 and in accordance with WUTC Docket PG-100049. This program will be conducted in ID and OR also to assure cathodically isolated steel is identified and replaced as needed through 2024.

Once the isolated sections of steel pipe are identified, projects are created to replace them with new pipe. This new pipe could be either steel or plastic.

Gas Isolated Steel Replacement Program, ER 3007

Management of the cathodic protection (CP) zone will drive the decision between steel and plastic pipe. A Generalized Work Flow is provided in Image 1 below.

Per the WUTC agreement, isolated steel risers are being replaced at a rate of at least 10% per year, starting in 2011, and short sections of isolated steel main are replaced within one year of discovery. Work as previously described is also being completed in ID and OR. Work completed under this program results in a safer gas distribution system.

The Program is currently overseen by a Program Manager. Monthly reporting is used to identify budget targets are met and overall completion in each state. Software has been created to identify time constraints based on severity of potential risk. Action codes are listed in below flowchart.

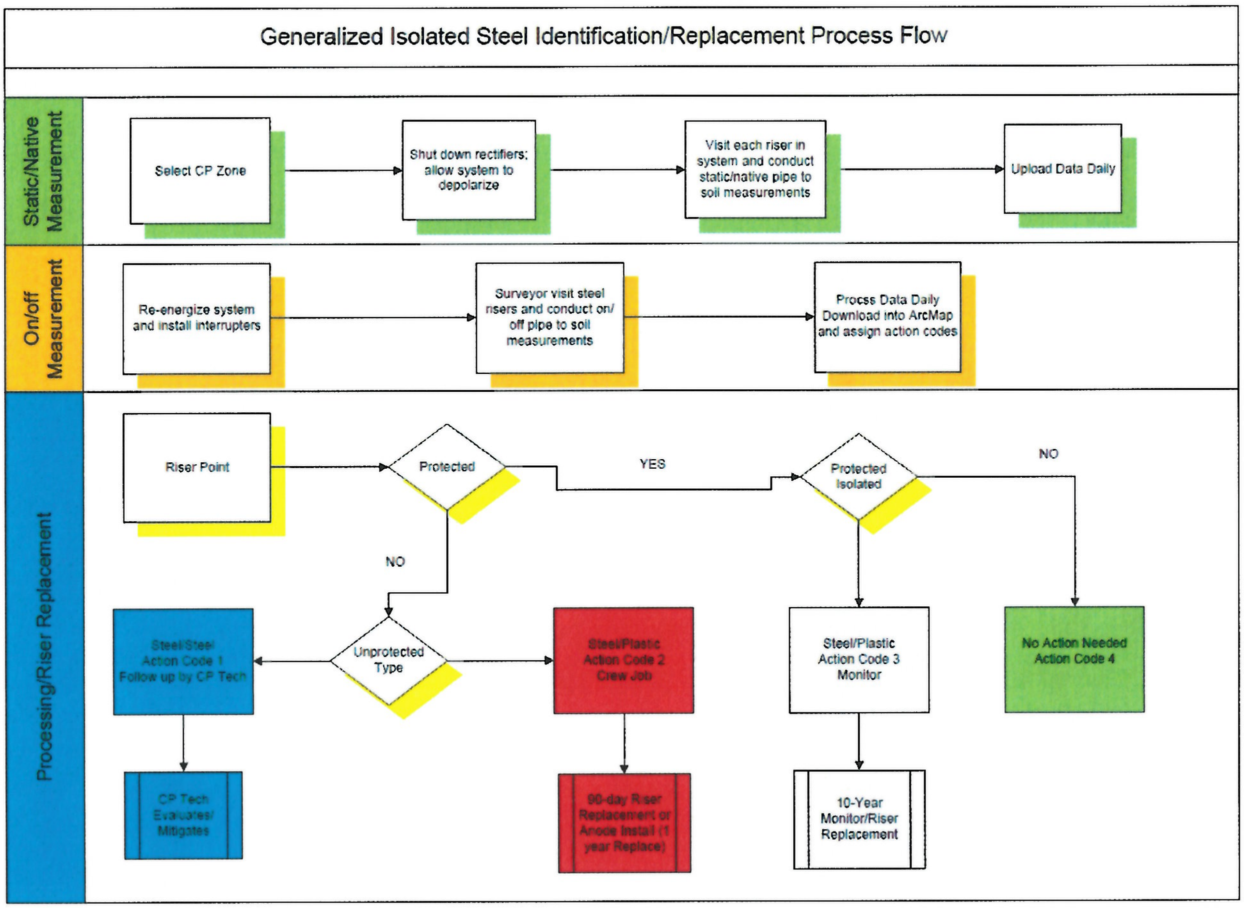


Image 1 – Generalized Work Flow

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$ TBD		
Option 2 – Preferred Solution, Complete the program per the agreement	$2,050,000	2011	11-2021 WA 12-2024 ID and OR

Option 1 – Do nothing

The alternative to completing this program would be to not finish the work within the timeframe mandated by the WUTC. This would be a direct violation of the stipulated agreement between Avista and the WUTC and likely result in financial penalties.

Option 2 – Preferred Solution, Complete the program per agreement as described above

4 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: Jeff Webb Date: 2-17-20

Print Name: Jeff Webb

Title: Manager Gas Engineering

Role: Business Case Owner

Signature: Mike Faulkenberry Date: 2/17/20

Print Name: Mike Faulkenberry

Title: Director of Natural Gas

Role: Business Case Sponsor

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeff Webb	03/16/2017			Initial version
1.1	Jeff Webb	04/07/2017			
2.0	Jennifer Massey	02/05/2020	Jeff Webb	2/17/20	Revised for 2020 Oregon GRC filing

Template Version: 02/24/2017

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 gas measurement for our customers and compliance with the applicable state tariffs.

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 (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.

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 for this program resulting in an average cost of $1,500,000 ($250/meter).

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Jeff Webb	Initial Version	03/16/2017	
1.1	Jeff Webb		04/07/2017	
2.0	Dave Smith	Revised for 2020 Oregon GRC filing	2/17/2020	
2.1	Smith-Webb	Updated to the refreshed 2020 Business Case template	7/10/2020	

Gas PMC Program, ER 3055

GENERAL INFORMATION

Requested Spend Amount	$1,500,000
Requested Spend Time Period	Annually
Requesting Organization/Department	Gas Engineering
Business Case Owner | Sponsor	Jeff Webb/Dave Smith | Mike Faulkenberry
Sponsor Organization/Department	B51 – Gas Engineering
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

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.

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 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

Our customers benefit from this program because it assures that natural gas use is measured accurately in all jurisdictions.

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

Avista would not be in compliance with state commission rules and tariffs in WA, ID, and OR if this program is not completed annually.

Gas PMC Program, ER 3055

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 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 (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.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem.

- Gas PMC Program Standard Operating Procedure
- ANZI Z1.9 "Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming"
- The following state rules regulate the 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

These documents are 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.

The meter accuracy testing results collected annually from the program are documented 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.

Gas PMC Program, ER 3055

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.

Option	Capital Cost	Start	Complete
Recommended Solution, Fully complete the programmatic work described	$1,500,000	January	December

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

Historical program costs are used to determine the average labor costs to remove and test each meter. The number of meters required to be removed varies each year depending on the previous year's testing results. The average cost per meter is then multiplied by the anticipated number of meters to be removed to determine the estimated program cost for the following year.

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 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 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.

Completion of this program may result in a reduction to O&M because there may be less high bill complaints from customers as a result of inaccurate meters.

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 gas meters is not a new process for Avista. Existing processes and technologies will be utilized for this program.

Gas PMC Program, ER 3055

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

The only alternatives are to either partially fund this program or to not fund it at all. If this program were 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. Also, the accuracy of measurement of our customers' natural gas usage could not be assured.

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 program will be completed between January and December of each year. The gas meters are purchased as a pre-capital material item under ER 1050 (Gas Meters). The meter will become used and useful upon installation.

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 must be completed to ensure our customer's meters remain accurate throughout their service life. Accuracy data is obtained and analyzed each year to ensure the program is testing the appropriate number of meters and removing ones that no longer meet Avista's accuracy requirements.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case.

All Avista natural gas customers benefit from this program because it ensures their gas meters remain accurate throughout their service life.

Business case stakeholders include Gas Engineering, Gas Operations, Gas Meter Shop, Technical Services, and state commissions.

2.8.2 Identify any related Business Cases

ER 1050 Gas Meters

Gas PMC Program, ER 3055

3.1 Steering Committee or Advisory Group Information

Gas Engineering is ultimately responsible for the PMC plan and annual reports that are developed and made available to each of the state commissions.

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

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.

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

Meter accuracy testing results are compiled and analyzed in a spreadsheet. An annual report is developed by Gas Engineering and made available to the state commissions upon request. This report defines the program requirements for the following year.

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: Jeffrey A Webb Date: 7/10/2020
Print Name: Jeffrey A Webb
Title: Mgr Gas Engineering
Role: Business Case Owner

Signature: Mike Faulkenberry Date: 7/10/2020
Print Name: Michael J Faulkenberry
Title: Director Natural Gas
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:

Gas PMC Program, ER 3055

Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Joint Use Projects

EXECUTIVE SUMMARY

Joint Use is the regulated use of utility poles and other structures by 3rd party telcommunications companies in order for them to provide their services to the customers we have in common. Avista licenses 76 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	Notes
Draft	*Stephen Schulte*	*Initial draft of original business case*	*6/302020*	

Joint Use Projects

GENERAL INFORMATION

Requested Spend Amount	$2.75m
Requested Spend Time Period	*Year to year*
Requesting Organization/Department	Operations/Joint Use
Business Case Owner | Sponsor	Stephen Schulte | David Howell
Sponsor Organization/Department	Operations/Joint Use
Phase	Execution
Category	Mandatory
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]

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 *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* **and the benefits to the customer.** 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 telecommunicaitons 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 Telecommunicaitons 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 is deferred. 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 whose monetary costs are incalculable.

Joint Use Projects

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.

Avista's joint use team utilizes several systems to track compliance and adherence to Federal, State and local regulations.On physical and practical level, success is more often realized when 2nd and 3rd parties construct their facilities, and follow up quality control is performed. Anectodally the joint use team has been approached by Avista customers who are very happy with their new telecommunication service that was made possible solely by the ability of the provider to attach their cables to Avista utility poles.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem. Tracking, invoicing and budget information is located on the joint use drive located on Avista network drive c01m289.

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.

[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
Replace capital assets when requested	*2.75*	*Ongoing*	*Ongoing*
[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.

Current joint use capital business case amounts were derived from historic spend data coupled with projected activity that is based on trends seen in the joint use request tracking sheet. Avista receives a direct benefit of joint use related capital work by way of receiving a new asset at a decreased cost to rate payers. Due in large part to the dedication of fair and non discriminatory access to utility infrastructure, and the timeliness of completing requested capital make ready work.

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.

Joint Use Projects

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.** Given the current workload, and requests for capital asset replacement in support of joint use, current funding levels will be fully spent by the end of the budget year. Similar funding levels will be required on an ongoing basis with additional funding request sought as conditions warrant. The majority of assets being replaced should not add any additional operating costs beyond current levels such as wood pole test and treat, vegetation management etc.

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.]

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented. Additional workload resulting from increased joint use make ready could be experienced by several workgroups including but not limited to; Distribution Operations, Maximo, Real Estate, GIS, Asset Management, Transmission Operations.

[For example, how will the outcome of this business case impact other parts of the business?]

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative. No realistic alternatives exist nor were discussed. The only alternative would be to cease performing this work which would result in regulatory/legal action and customer dissatisfaction.

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 capital work related to this business case are ongoing and immediate. Transfers to plant occur on a monthly basis and the assets become used and useful immediately following physical construction.

[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).]

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization. The investment that is made in Avista's physical plant to accommodate joint use telecommunications benefits the shared customer base of Avsita and the joint use providers. It places our customer at the center of our focus and helps Avista to provide a safe, reliable and cost effective services. It also helps to provide a safe working environment for all workers who require access to the electric distribution system.

[If this is a program or compilation of discrete projects, explain the importance of the body of work.]

Joint Use 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. Joint Use requested capital make ready work is and will always be a prudent investment as the majority of assets that are being replaced are typically near the end of their life and Avista benefits from a newer, stronger structure. Pole replacements and new assets are typically the solution of last result and are only offered after careful consideration and review. High dollar cost replacements such as transmission pole receive addtitional scrutiny and review for appropriateness and cost effectiveness.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case. Avista Electric rate payers, Distribution operations, Distribution Engineering, Electric Design.

2.8.2 Identify any related Business Cases. The Joint Use business case was carved out of the Miscellaneous Capital Overhead Expense business case so that it could be more closely monitored and tracked.

[Including any business cases that may have been replaced by this business case]

3.1 Steering Committee or Advisory Group Information. The advisory group for this business case is the Operations Resource Team. It consists of the Manager of Operations Analytics (Julie Lee), Operations Analyst (Sherry Bentley), Facilitor of the Operations Round Table (Amy Jones), Manager of Distribution Engineering (Caesar Godinez), Operations Engineers (Brian Chain and Tim Figart), Operations Director (David Howell), and the Joint Use Program Adminstorator (Steve Schulte). Meetings are held at least once per quarter and as needed depending on necessary required changes or requests.

[Please identify and describe the steering committee or advisory group for initial and ongoing vetting, as a part of your departmental prioritization process.]

Joint Use Projects

3.2 Provide and discuss the governance processes and people that will provide oversight. The business case spending levels are tracked and monitored by the Manager of Operations Analytics (Julie Lee) and Operations Analyst (Sherry Bentley) in Utility Accounting with monthly spend reporting to the Operations Director (David Howell).

3.3 How will decision-making, prioritization, and change requests be documented and monitored . Desicision for funding increases will be discussed during the Operations Resource Team meeting. If additional funding is deemed necessary then the business case owner Steve Schulte will complete the necessary documentation which will then be forwarded along to the Capital Planning Group for consideration. All documentation will be kept on file in the joint use server share in a 'budget' folder.

The undersigned acknowledge they have reviewed the Joint Use Projects 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:	*Stephen Schulte*	Date:	7/2/20
Print Name:	Stephen Schulte		
Title:	Joint Use Administrator		
Role:	Business Case Owner		

Signature:	*David Howell*	Date:	7/20/20
Print Name:	David Howell		
Title:	Director of Electric Operations		
Role:	Business Case Sponsor		

Joint Use Projects

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

Template Version: 05/28/2020

Protection System Upgrades for PRC-002

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) a synopsis of the problem, 2) the service code and jurisdiction of customers impacted, 3) the recommended solution, 4) the cost of the solution, 5) how the solution will benefit customers identified, 6) the significance of the timeline and 7) the risks of not approving this business case.*
<< Both the Executive Summary and Version History should fit into one page >>

NERC reliability standard PRC-002-2 defines the disturbance monitoring and reporting requirements to have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances. The methodology of Attachment A of the NERC standard was performed to identify the affected buses within the Avista BES. The Protection Systems must be capable of recording electrical quantities for each BES Elements it owns connected to the BES buses identified.

Non-compliance can carry a fine of up to a million dollars per day based on severity. This business case is important to customers because it allows analysis of system faults for the BES that can lead to continued stability and reliability of the electric system.

Service: ED – Electric Direct

Jurisdiction: AN – Allocated North

Engineering Roundtable Request Number: ERT_2016-07

Cost of Solution: $12,000,000

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Randy Spacek	Initial Version	7/11/2017	Initial Version
2.0	Glenn Madden	Revised to remove DRAFT watermark	5/28/2019	
3.0	Karen Kusel / Glenn Madden	Update to 2020 Template	06/2020	

Protection System Upgrades for PRC-002

GENERAL INFORMATION

Requested Spend Amount	$12,000,000
Requested Spend Time Period	5 Years
Requesting Organization/Department	Substation Engineering
Business Case Owner | Sponsor	Glenn Madden | Josh Diluciano
Sponsor Organization/Department	Electrical Engineering
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]

NERC reliability standard PRC-002-2 defines the disturbance monitoring and reporting requirements to have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances. The methodology of Attachment A of the NERC standard was performed to identify the affected buses within the Avista BES. The Protection Systems must be capable of recording electrical quantities for each BES Elements it owns connected to the BES buses identified.

The present Protection Systems are either electromechanical or first generation relays not capable of meeting the NERC PRC-002-2 standard requirements of fault recording. The scope of the project is to upgrade the existing Protection Systems on various 230 kV and 115kV terminals to Fault Recording (FR) capability per PRC- 002 requirements at Beacon, Boulder, Rathdrum, Cabinet Gorge, North Lewiston, Lolo, Pine Creek, Shawnee, and Westside Substations. Implementation is a phased approach with 50% compliaint within 4 years and fully compliant within 6 years of the effective date 7/1/16. The total number of affected terminals is 49.

Non-compliance can carry a fine of up to a million dollars per day based on severity.

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

PRC-002-2 went into effect on 7/1/2016, we have six years to bring our protection system into compliance with this updated standard.

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 is the main driver for this project. But this will also allow more information to be collected to facilitate analysis of BES disturbances.

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

Avista is required to comply with PRC-002 by July 1, 2022.

Protection System Upgrades for PRC-002

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, Relay & Protection Design Reporting for PRC-002.

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]

NERC Reliability Standard PRC-002-2

NERC Project 200711 Disturbance Monitoring:

DL-2007-11_DM_Imp_Plan_2014Sep01_clean

PRC-002 Bus Fault Summary & Anaylsis 2016.xlsx

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.

The present Protection Systems are either electromechanical or first generation relays not capable of meeting the NERC PRC-002-2 standard requirements of fault recording.

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)]

The Protection System upgrade of 49 terminals impacts the resources of Engineering and GPSS over a 5 year period. The NERC standard requires compliance by specific dates. By missing the compliance date set forth by NERC, Avista not only risks monetary penalties based on severity but reputational damage as well.

Cost estimates per terminal from previous Protection System upgrades at a total installed cost of $150k.

Protection System upgrades is the preffered solution. The relay replacement will not only provide the recording capability but will improve system reliability, reduce maintenance and support other NERC standard requirements (PRC-023, PRC-004).

In the past, Avista has attempted to put in a single digital fault recorder that complicated the wiring and CT circuits within a station. All recorders have since been removed.

Option	Capital Cost	Start	Complete
Upgrade Protection Systems	$4.86M	02 2017	10 2022
Do Nothing	$0M		
Installation of a digital recorder on each BES bus to provide the SER and FR data.			

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

Examples include:

Protection System Upgrades for PRC-002

- *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.

Since this is a compliance mandate, we also looked at other standards and relay options.

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 - $3,200,000

2021 – $5,420,000

2022 – $2,480,000

2023 – $150,000

O&M costs may be reduced with this equipment replacement.

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?]

Delay of the other projects due to resource scarcity.

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).]

Project is currently underway, construction is in progress at multiple sites and will conclude in 2022 and closeout of project will occur in 2023. Transfers to plant are completed when the work at each location is completed.

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

Fault recording at substations enables root cause analysis, which can lead to improved reliability. Additionally the work is mandatory from NERC.

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

NERC required projects are vetted through NERC as to the viability of requiring the work to be done and the associated benefit. The investment is likely to result in improved reliability to the BES.

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.]

The Engineering Roundtable process is used to identify projects requmng Transmission, Substation, or Protection (TS&P) engineering support. The committee is responsible to track TS&P project requests, facilitate prioritization of TS&P capital projects across Engineering, Operations, and Planning), and to ensure projects are completed consistent with the company's mission and corporate strategies.

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 Protection System Upgrades for PRC-002 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:	Glenn Madden		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:		Date:	
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

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 2023.

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 $6,700,000 is needed to complete the mitigations by 2023. 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*	*7/10/2020*	
1.0	*Prudent Penny*	*Updated Approval Status*	*6/1/2020*	*Full amount approved*
1.1	*Debbie Downer*	*Budget change*	*10/15/20*	*$50,000 deferred to 2021*
2.0				

Transmission NERC Low Priority Ratings Mitigation

GENERAL INFORMATION

Requested Spend Amount	$6,700,000
Requested Spend Time Period	*3 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

1.1 *The Transmission NERC Medium 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).*

1.2 What is the current or potential problem that is being addressed? *Clearance violations.*

1.3 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.*

1.4 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 2023 will show us taking ten 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.*

1.5 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.*

Transmission NERC Low Priority Ratings Mitigation

1.6 Supplemental Information

1.6.1 Please reference and summarize any studies that support the problem

CAN-0009_FAC-008 FAC-009.pdf

1.6.2 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.

This is the continuation of a Program first started in 2012 (execution phase), and requires the mitigation of clearances violations.

Option	Capital Cost	Start	Complete
Mitigate Violations	*$6.7M*	*01-2021*	*12-2023*
[Alternative #1]	*$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.

Transmission NERC Low Priority Ratings Mitigation

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. spend, and transfers to plant by year.

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.

3.1 Steering Committee or Advisory Group Information

The Engineering Roundtable functions as the Vetting Platform, Steering Committee, and Advisory Group.

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.

3.2 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.

The undersigned acknowledge they have reviewed the *Transmission NERC Low Priority Ratings 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:		Date:	
Print Name:			
Title:			
Role:	Business Case Owner		

Signature:		Date:	
Print Name:			
Title:			
Role:	Business Case Sponsor		

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

Template Version: 05/28/2020

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 continue to fund these tools at an annual level of $2.4M for 2021 and then escalated for inflation and increase technology ($100k) each year for the five year plan.

Capital tools benefit 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 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	Notes
Draft	*Daisy Drafter*	*Initial draft of original business case*	*4/15/2020*	
1.0	*Prudent Penny*	*Updated Approval Status*	*6/1/2020*	*Full amount approved*
1.1	*Debbie Downer*	*Budget change*	*10/15/20*	*$50,000 deferred to 2021*
2.0	*Cody Krogh*	*Updated plan to new outline*	*7/13/2020*	

GENERAL INFORMATION

Requested Spend Amount	$ 2,400,000
Requested Spend Time Period	5 years
Requesting Organization/Department	Supply Chain
Business Case Owner | Sponsor	Cody Krogh | Dan Johnson
Sponsor Organization/Department	H51 / Supply Chain
Phase	Monitor/Control
Category	Program
Driver	Asset Condition

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?

Each year, the Capital Equipment Program has more requests for tools and equipment than can be funded. 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. These additional tools will require more funding, over time, to support replacement costs, as well as ensure all areas of the company can take advantage of this technology.

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 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 is deferred

This work is needed to ensure that our workers have safe and reliable tools 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 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 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.

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]

Attachment 1: Email from 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

NOTE: All files are stored in the "N-Drive" under "Capital Budget", then "Business Case Folder" and then "2020 Business Case"

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.

Safety project for ergonomic related battery assist tools was widely implemented in 2016 with the addition of 44 battery assist tools. This was followed by 2017 with 75 tools, 2019 with 58 tools. This equipment has a 5 year warranty, so future failures for 5 year old equipment will not be covered by 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.

[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
[Recommended Solution] Option 1 (Recommended)	*$2.4 M*	*01/2018*	*NA*
Partially Fund (based on priority)	*Varies*	*01/2018*	*NA*
Rent 4% of total equipment and purchase the rest	*$2.3 M*	*01/2018*	*12/2020*

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

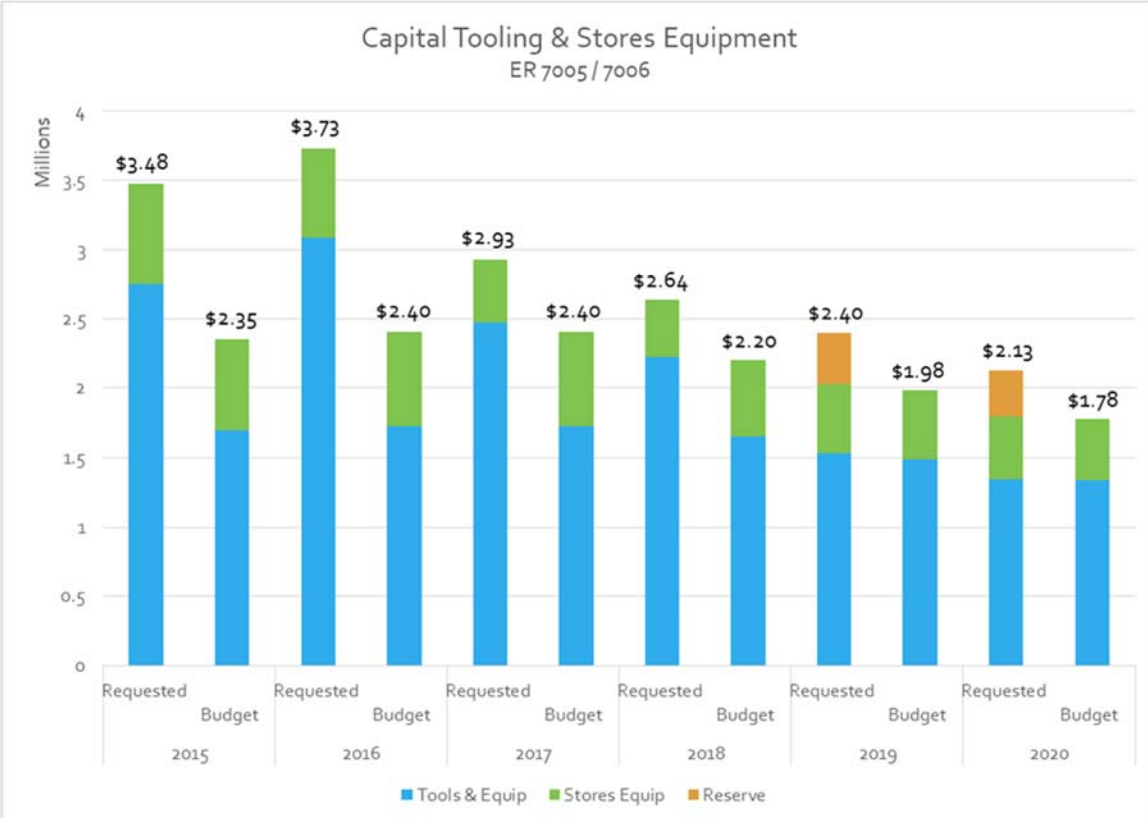
Examples include:

- *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*

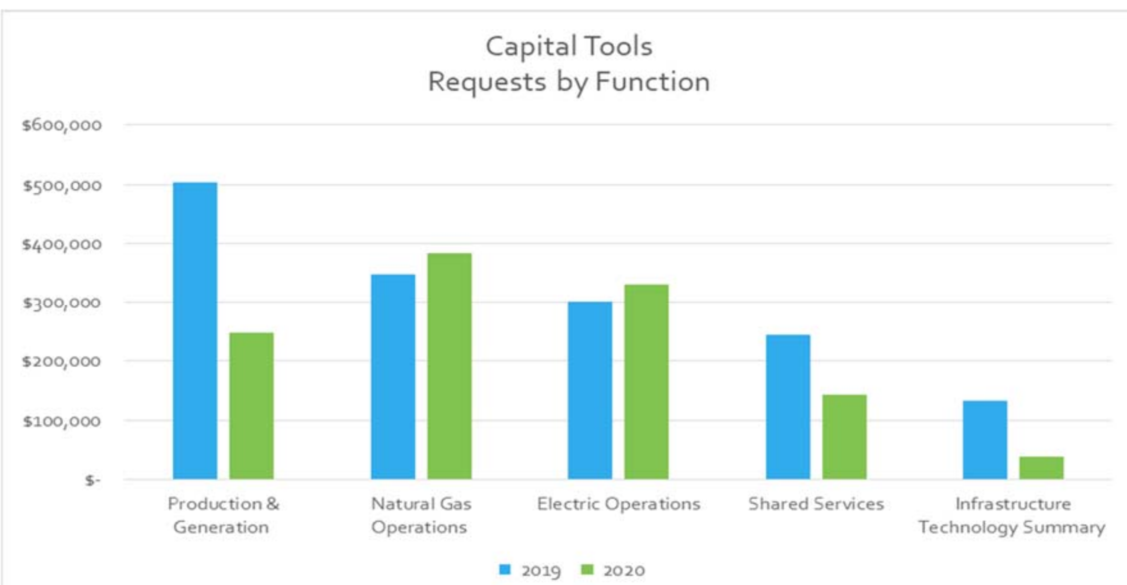
Reference key points from external documentation, list any addendums, attachments etc.

Each year, 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 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 will require more funding, over time, to support replacement costs.

Capital Equipment Program (ER7005/7006)

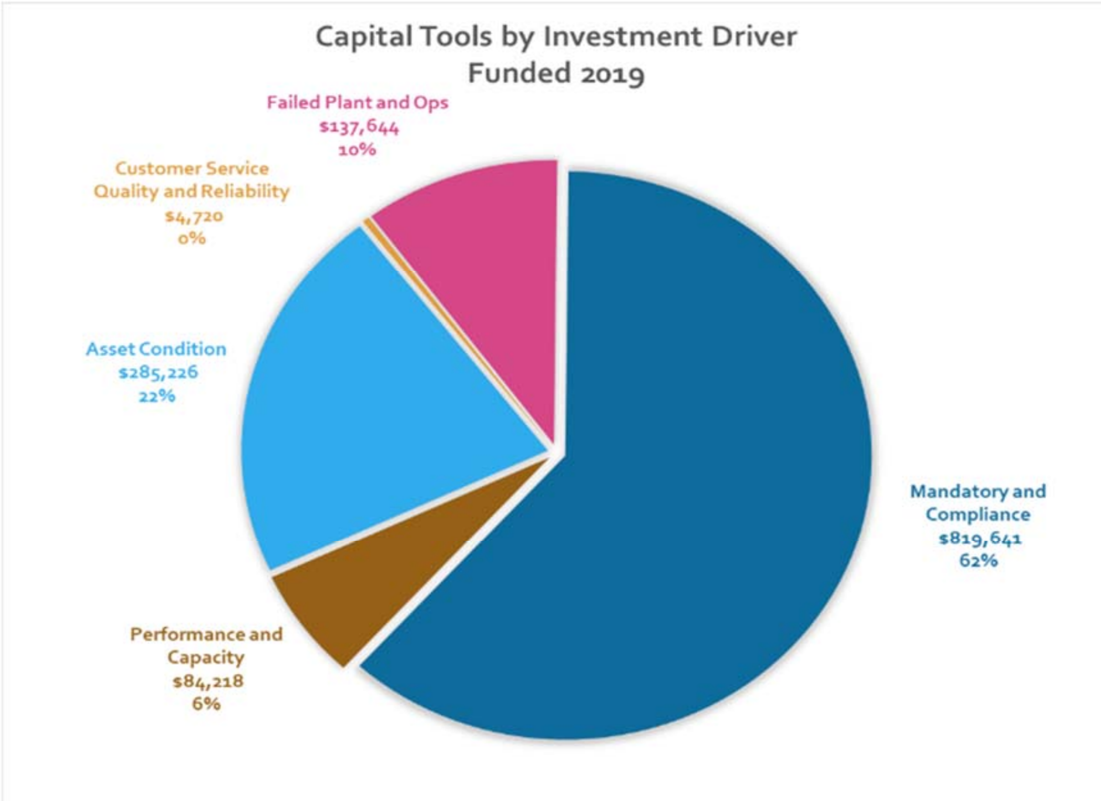


The distribution of Capital Equipment funds by the Business Unit is shown below in Figure 2 (see below). The allocation is based on overall tool ranking and priority rather than a set allotment by department. As a result, there is variation year over year (as noted in the graph) ensuring that the most critical tools are funded.



Capital Equipment Program (ER7005/7006)

The 2019 capital tool breakdown by investment driver is represented below in Figure 3. The highest percent of spend (62%) 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 complinace standards and tools identified to improve safety or ergonomics (improved body posture, reduced exertion of force, and reduction in frequency).



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.]

An updated process was created in 2019 and is being 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" in section 1.5.1.

Capital Equipment Program (ER7005/7006)

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.

2.3 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?]

One of the business functions that will be impacted are those areas using outdated equipment/tools. We need to replace existing tools that have failed or reached the end of their life, or have been deemed unsafe do to current safety or regulatory issues. Avista employees must be able to rely on this equipment while performing hazardous duties, and must be confident that the equipment will perform safely and efficiently. Failed equipment not in compliance with current safety standards can lead to hazardous conditions for the operators, potentially causing injury or death.

Another important priority for tool and equipment purchases is enhanced productivity. Capital equipment is used to perform new construction work or repair work for unplanned failures. Often this work can take less time or be completed quickly with better results by using improved tools.

These processes need to be implemented to not only improve the safety, but also the productivity of employees. These benefits do impact other parts of the business as work will be completed efficiently and safely, reducing delays and injuries. There are also benefits to our external customers in regard to restoration time and reliability.

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

Option 1 – Fund Program at Current Level (Recommended)

It is recommended that this Program be funded, annually, at its current level with a 5% annual increase to ensure Avista has the proper capital equipment necessary to safely and efficiently perform all required work. This 5% increase is to cover inflation of current pricing, support replacement equipment as complement has increase in time, and support increases in technology leading to higher equipment costs. 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 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 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.

Having the ability to test and incorporate equipment that falls within the enhanced productivity category can help support improved processes and lead to enhanced safety and longer equipment lifecycles.

Option 3 – Rent Equipment

Renting a percentage of the capital equipment was considered as a possible alternative. Of the 430 items purchased from 2012 to 2014, 233 can be rented, although 216 out of the 233 items are needed, on hand, at all times for emergency locates and repairs. This leaves 17 possible items, or 4% of the total equipment, which qualifies 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 for a basic cable locator is $450/month, which equates to $5,400/year. The 2017 purchase price of this item is $3,700.

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.

2.5 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).]

An updated process was created in 2019 and is being fully implemented in 2020. 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. The average tool lead-time is 12-14 weeks.

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.

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.

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 funding is managed through a well-defined process with oversight from the CEC the final list from each Business Unit is then reviewed by the CEC to ensure funding is distributed fairly and impartially across the company. This is required to prioritize spending because the total tool requests exceed the allocated budget. Decision records and meeting notes are maintained on the SharePoint site. The Capital Equipment Steering Committee submits the revised list to the CPG for final approval and execution.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Internal customers would be employees such as line workers and other employees who will be using the capital tools to perform their jobs. They are also the stakeholders as some equipment will need to be replaced in order for the employees to effectively and safely complete their jobs. Our external customers also benefit from this program as they will reap the benefits of our workers increased reliability and decreased down time. With more reliability and less down time we are able to fix/repair any issues the customers may have much faster and keep our external customers satisfied with our quick service and reduced down time.

2.8.2 Identify any related Business Cases

[Including any business cases that may have been replaced by this business case]

All business cases need the proper tools in order to best utilize the labor for the completion of work benefiting our employees and customers. Examples of Business cases that utilize these tools are: Wood Pole Management, Grid Modernization and Wild Fire Resiliency.

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 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.

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

The governance process is documented in the Capital Equipment Committee Board Charter (See attachments in section 15.1). 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 of 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

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

The Capital Equipment Committee works to ensure that the funding for capital equipment is fairly distributed, all decision-making, prioritization and change request records along with meeting notes will and are maintained on the SharePoint site as “Capital Committee Notes”. All participants in the process (Directors, managers, requesters) have access to the approvals and addition for their area via the SharePoint site. The members of the CPG are also the Directors approving the requests for their areas prior to the Cap Equipment Committee’s approval session.

Capital Equipment Program (ER7005/7006)

The undersigned acknowledge they have reviewed the Capital Equipment Program and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: DocuSigned by: Cody Krogh 72D171DBE3F04F8... Date: Jul-29-2020 | 11:19 AM PDT

Print Name: Cody Krogh

Title: Supply Chain Manager

Role: Business Case Owner

Signature: DocuSigned by: Dan Johnson 8547E8F9CC5E4E4... Date: Jul-29-2020 | 12:56 PM PDT

Print Name: Dan Johnson

Title: Director, Shared Services

Role: Business Case Sponsor

Signature: Date:

Print Name:

Title:

Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

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 (primarily) older structural equipment comes due for replacement.

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

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.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Brian Chain*	*Initial draft of original business case*	*6/30/2020*	
1.0		*Updated Approval Status*		*Full amount approved*

Downtown Network – Asset Condition

GENERAL INFORMATION

Requested Spend Amount	$2M-4M annually (see Funds Request)
Requested Spend Time Period	5 years
Requesting Organization/Department	C57 Downtown Network
Business Case Owner | Sponsor	Ryan Bradeen | David Howell
Sponsor Organization/Department	Electric Operations
Phase	Execution
Category	Program
Driver	Asset Condition

Downtown Network – Asset Condition

1. BUSINESS PROBLEM

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 budget covers both electrical and structural elements of the Downtown Network system.

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 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 is deferred

Electrically, our network protector fleet is relatively new. However, there remain a few older style “live front” network protectors that are very dangerous to work on while energized. As such, Avista has committed to take outages in order to do any work on these protectors. We are changing these out to newer dead front designs as fast as budget and resources allow. Without replacement we risk either an employee accident (which may also affect the public from a safety perspective), customer outages, or more likely, both.

Our transformer fleet is more 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 fairly 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 STA busses. Structural failures are a significant public

Downtown Network – Asset Condition

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 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

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 BI is seen increasing, then Asset Condition dollars are not being appropriately supported or allocated.

Appropriate use of the Failed Plant BI is critical to utilizing this as a success metric.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

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.

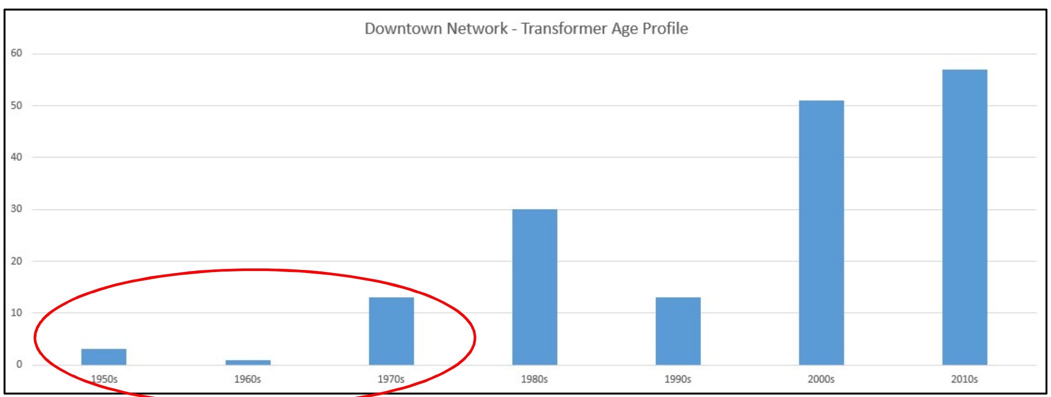


Figure 1: Downtown Network Transformer Age Profile

Downtown Network – Asset Condition

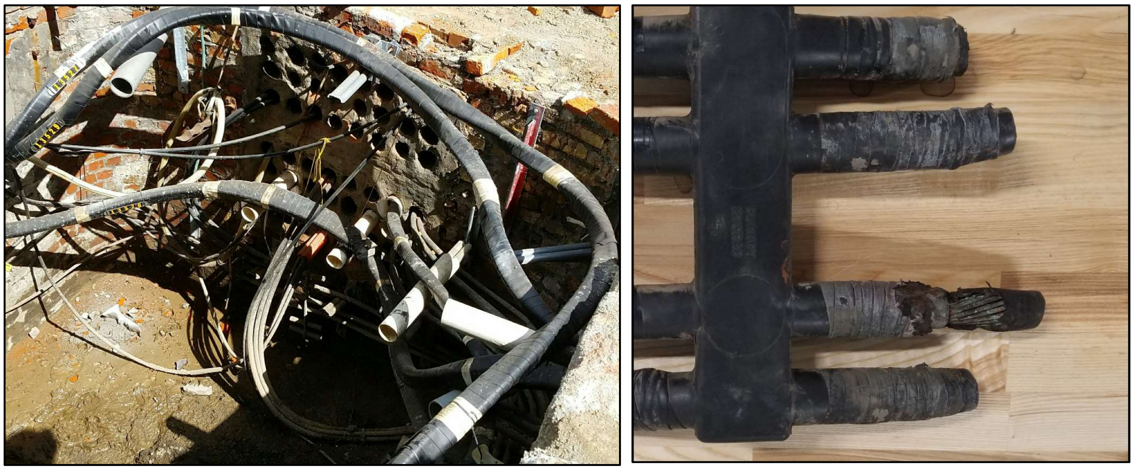


Figure 2: Brick handhole w/assortment of PILC cable / Failed insulation on grid bus (Hotel Ruby Service)

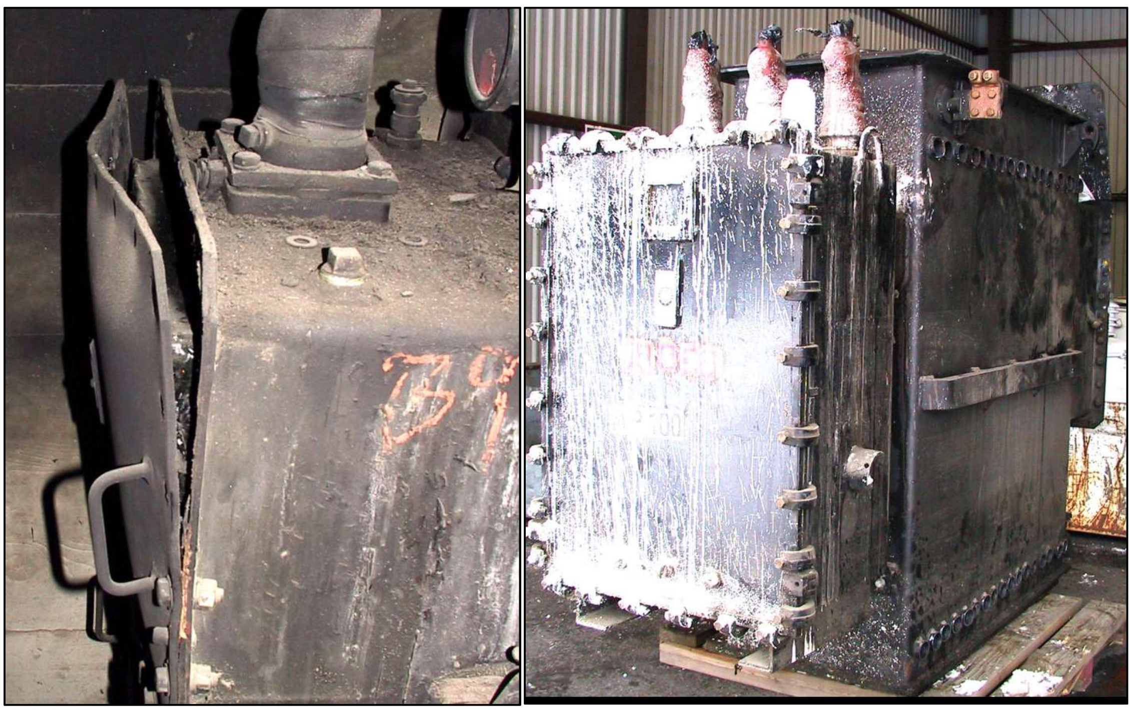
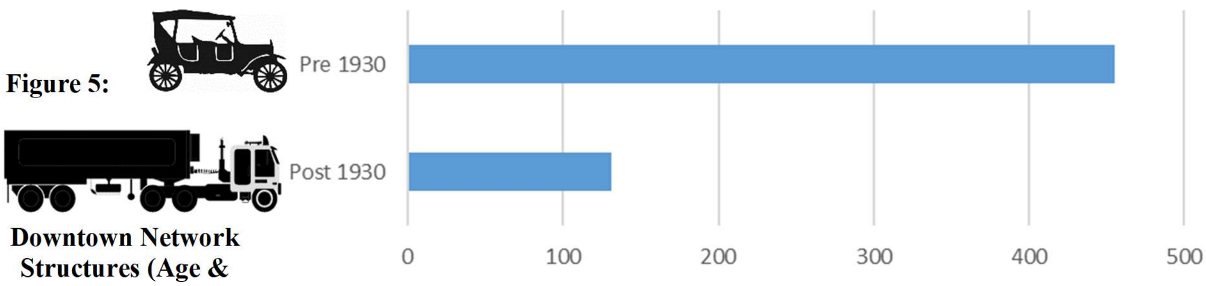


Figure 3: Faulted primary terminations on network transformer / Faulted network transformer

Downtown Network – Asset Condition

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

Figure 5:



Downtown Network Structures (Age & Design Profile)

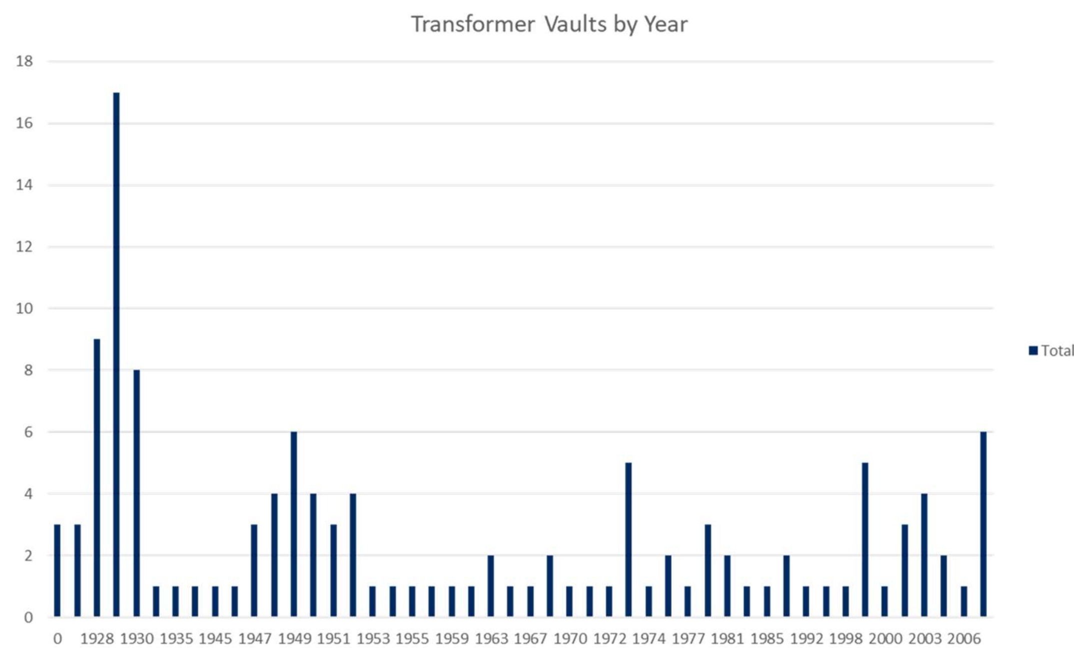


Figure 6: Transformer Vault Age Profile

The following Alternatives are presented as a range of options under which this business case could be funded. Remember that this Asset Condition business

Downtown Network – Asset Condition

case/ER supports a Failed Plant BI, so even the Do Nothing option carries some cost.

Downtown Network's recommendation is to start at the Alternative 2 funding level and systematically increase toward (if not all the way to) the Alternative 3 funding level. This recommendation 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.

Alternative 1: Do Nothing/Reactive Replacements

The do nothing option 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.

Cost: $1M (for 2020, increasing “failed plant” will 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 as a whole.

Cost: $2M (for 2020, increasing “failed plant” will 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 BI	$1M, increasing
Eliminate Worst Known Electrical & Structural Issues	$2M, increasing
Create/Follow Complete Systematic Replacement Programs	$5.7M

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

Our electrical fleet downtown consists of:

- 181 network transformers and 181 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.**

Downtown Network – Asset Condition

- 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 street lights 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 VROM-based 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.
- 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.

Downtown Network – Asset Condition

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 annual amount requested will fund replacements of the following:

- The worst ranked network vault transformers, based on visual and DGA inspections from prior maintenance years, as shown in the Transformer Replacement Program document available on the Downtown Network sharepoint site.
- Live front network protectors (ten remain on the system at this point in time).
- PILC cable splices (refer to the Downtown Network GIS Online system, which identifies every leaky splice location as a manhole unable to be entered, per WAC.
- Services and street lights that are ranked as unsafe per survey results documented in Downtown Network GIS Online system.
- Manholes with known poor structural condition (roofs, walls).
- Transformer vaults with known poor structural condition (roofs, walls, grates).

Annual job planning is performed at the end of each prior year; job estimates are prioritized by Downtown Network management, engineering, and foremen, and cut off when budget runs out. In past years, the Asset Condition budget has been fully allocated at the beginning of the year and fully spent by around September of each year. At that point the budget has been throttled for the remainder of the year; despite knowing about severely deteriorated installations (cracked/spalling manhole roofs in traffic, multiple leaky splices/cable in one hole, live front protectors, etc), no work is performed on them.

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 outcome of this business case affects most especially, Distribution Operations, and Claims. Successful replacement of assets will lessen impacts to Failed Plant emergency responses and subsequent damage claims made by customers and the public.

Downtown Network – Asset Condition

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

See alternatives discussed at beginning of Section 2, for a look at the possibilities considered for Downtown Network's Asset Condition program as a whole.

On a micro level, alternatives for each individual project are discussed by the Downtown Network management, engineering, and foremen, as part of the annual job planning exercise. For some projects further Scoping Documents are developed; these often consider possible alternative solutions. These are available on the Downtown Network shared drive.

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

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

This Business Case invests in the heavily utilized 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 items (live front breakers, manhole/vault roofs and grates) that directly impact anybody who lives, works, or visits downtown Spokane.

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

As discussed earlier in Section 2.1, a simple analysis of the replacement cost of both electrical and structural components of the Downtown Network clearly shows that Avista has underinvested in refreshing equipment. Even with questionably long average lifespans of equipment (e.g. transformer vaults aging past 100 years) there is a bow wave of work to be done in order to catch up. Continued underinvestment will only make the problem worse.

From a big picture standpoint, there will come a time when equipment fleet replacement levels *will* catch up, however. For the most part this does not occur within the 5 year planning horizon. We will need to watch for when it does occur though, and draw down or redirect spending when appropriate. For example, the network protector fleet is relatively new. We have ten live front breakers left to replace and after that, protector replacements are of a questionable priority.

If all other classes of equipment had no bow wave of replacements to be addressed, this should result in a decrease in necessary funding at the end of 2021, when the live front replacements are scheduled to be completed. However, the needs of the structural portion of the system, which are much older and dilapidated, will easily subsume the dollars going toward live front replacements (and then some).

The conversation about shifting dollars from protector replacements to structural replacements is one example of the kind of discussion that goes on as part of Downtown Network's annual job planning exercise. This is the forum that will allow Downtown Network management, engineering, and foremen to continue evaluating prudency. Similar discussions will be ongoing, reflected on both the job planning board and in future request years.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

- Downtown Network
- Claims
- Operations
- Distribution Operations
- System Operations
- Generation Control Center
- Regional Business Managers

2.8.2 Identify any related Business Cases

This business case supersedes ER 2058, which used to encompass both ER 2062 (Asset Condition) and ER 2063 (Performance & Capacity). ER 2058 has been defunct for several years.

Downtown Network – Asset Condition

3.1 Steering Committee or Advisory Group Information

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

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

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 (Ryan Bradeen 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).

Downtown Network – Asset Condition

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

Presently, decisions to add, delete, or modify projects on the job planning board are tracked in versions of the planning board spreadsheet, stored on the Downtown Network shared drive.

Downtown Network – Asset Condition

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:

Print Name:

Title:

Role: Business Case Owner

Signature: David Howell Date: 8/2/20

Print Name: David Howell

Title: Operations Director

Role: Business Case Sponsor

Signature: Date:

Print Name:

Title:

Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

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 is $1.2M based on historical spends.

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.

Delays or cancellations of funding to this business case will result in trends 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	Notes
Draft	*Brian Chain*	*Initial draft of original business case*	*6/30/2020*	
1.0		*Updated Approval Status*		*Full amount approved*

Downtown Network – Performance & Capacity

GENERAL INFORMATION

Requested Spend Amount	$1.3M-2.2M annually (see Funds Request)
Requested Spend Time Period	5 years
Requesting Organization/Department	C57 Downtown Network
Business Case Owner | Sponsor	Ryan Bradeen | David Howell
Sponsor Organization/Department	Electric Operations
Phase	Execution
Category	Program
Driver	Performance & Capacity

Downtown Network – Performance & Capacity

1. BUSINESS PROBLEM

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 ESR, 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 of 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

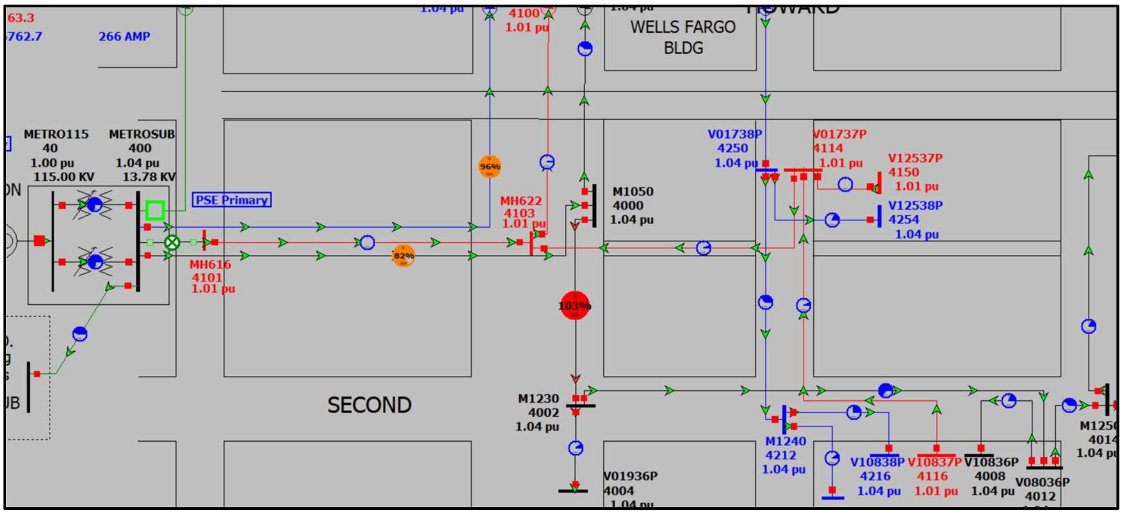
The major driver in this business case is Performance & Capacity; however, with regard to the Vault Integration Project, almost every other business driver also applies.

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 is deferred

Downtown Network – Performance & Capacity

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 is 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 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

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

Capital investment in this business case after the next two years (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 should reduce dramatically as new operational procedures are implemented as part of the Vault Integration Project. These procedures are already in draft format and being reviewed/approved by Safety & Health, L&I, and System/Distribution Operations.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

Refer to the Vault Integration Project Charter and Scoping Memo for more detail around the spending on this project.

https://sp2016.corp.com/sites/sp/DTNetwork/_layouts/15/start.aspx#/SitePages/Home.aspx?RootFolder=%2Fsites%2Fsp%2FDTNetwork%2FShared%20Documents%2FCommunications&FolderCTID=0x0120000A381BA032775F47AF043FFE7EB5DCE1&View=%7BF2BD4327%2D2C21%2D4CDD%2D8022%2D8008F47F9D84%7D

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 business case supports the installation of new assets that support growth on the system or improved operational efficiencies, not asset replacements.

The individual capacity increases that are installed as part of this business case are modeled and driven on an annual basis. Without additional capacity, cable overloads will result and large scale network quadrant outages will occur. Alternatives for each individual small cable or transformer upgrade are considered by Engineering on every single capacity issue.

The Vault Integration Project portion of this Business Case will result in reduced O&M vault visits as described in the attached Charter.

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

Reduced O&M and overtime expenditures were considered in the original Vault Integration Project charter. The improvement to Downtown Network crew safety was also a factor; transformer vault entry in the middle of downtown arterial streets is perhaps the worst traffic control problem that any crew at Avista will ever encounter. The project reduces the amount of "patrol" work that a crew must perform at the end of cutover jobs; these jobs often extend to the end of allowable crew working hours i.e. the network patrol must occur at the end of a very long shift when crews are most likely to have an accident while blocking a manhole entry in the middle of 1st Ave while crawling down a ladder into an energized vault.

See attached project Charter.

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 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 40% installed with one quadrant (Metro West) commissioned and one quadrant (Metro East) partially installed.

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.

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 Vault Integration Project will impact System and Distribution Operations processes. Many issues in the field that would result in a crew callout will now, at a minimum, have remote monitoring operations that precede the callout. In many cases, the results of these remote monitoring steps should mitigate the need for the callout entirely.

Ongoing work with System and Distribution Operations management is producing new procedures to guide operations as it incorporates this new system. Note that it is difficult to implement new procedures across only a portion of the system; full benefits can only be realized after enough funding is provided to finish the project.

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

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.

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.

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

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.

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

Project prudency is explained further in the attached Project Charter, for the Vault Integration Project. The project sunsets as expenditures finish up over the next two years. No review of prudency has been scheduled prior to project completion.

A project offramp could be taken at the end of the Metro quadrant portions of the project, leaving Post Street unfinished. This would severely hamper our ability to implement new procedures that take full advantage of the new communications system.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Customers and stakeholders that interface with the Vault Integration Project are identified in the Attached project charter and scoping memo.

2.8.2 Identify any related Business Cases

This business case supersedes ER 2058, which used to encompass both ER 2062 (Asset Condition) and ER 2063 (Performance & Capacity). ER 2058 has been defunct for several years.

Downtown Network – Performance & Capacity

3.1 Steering Committee or Advisory Group Information

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

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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).

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

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Downtown Network – Performance & Capacity

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: ____________________ Date: ____________

Print Name: ____________________

Title: ____________________

Role: Business Case Owner

Signature: David Howell Date: 8/2/20

Print Name: David Howell

Title: Operations Director

Role: Business Case Sponsor

Signature: ____________________ Date: ____________

Print Name: ____________________

Title: ____________________

Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Fleet Services Capital Plan

1 GENERAL INFORMATION

Requested Spend Amount	$7,700,000
Requesting Organization/Department	Fleet
Business Case Owner	Greg Loew, Manager, Fleet Services
Business Case Sponsor	Dan Johnson, Manager, Shared Services
Sponsor Organization/Department	Shared Services
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The Fleet capital replacement program is based on the Vehicle Replacement Model that is a product of our Utilimarc benchmarking subscription. The model uses benchmark data, purchase and auction data, combined with nationwide vehicle information that Utilimarc uses to build an accurate and robust model. The Fleet Specialist for Capital then takes the results of the model to validate, verify usage and work with operations managers to ensure that the identified unit meets their business needs. Capital projects requests are created for each discrete project (vehicle/equipment) that is approved by the Fleet Manager with notifications to the Manager of Shared Services and the Vice President of Operations.

2 BUSINESS PROBLEM

Fleet equipment as it ages experiences a growth in cost related to its operation. Those costs are driven by the requirement of more parts and more labor required to keep that unit up and running. As your fleet's average age increases you will see a steady but accelerating trajectory of costs servicing hours required. It can be described as more complex repairs requiring more hours and parts to fix. Those increasing costs are not just the burden of Fleet; the users will see the impact in lost productivity/downtime. In a 2011 analysis of Avista's class 46 vehicles and a subsequent analysis done in 2016 saw a 52% reduction in the labor hours required per truck by bringing the classes average age from 9.5 years to the industry average of 5.5 years.

	2010	*2011*	*2012*	*2013*	*2014*	*2015*	*2016*	*2017*	*2018*
AVA Avg Age	*8.03*	*7.81*	*7.59*	*6.81*	*6.55*	*6.23*	*5.94*	*6.13*	*6.32*
Industry Avg Age	*6.11*	*6.27*	*6.27*	*6.56*	*6.37*	*6.49*	*6.10*	*6.46*	*6.35*
Avg Op Cost / Unit	*$10,924*	*$11,558*	*$11,534*	*$10,845*	*$9,739*	*$9,285*	*$8,665*	*$9,571*	*$10,065*

Fleet Services Capital Plan

		2016	2017	2018
OR Avg Age	[redacted]	*5.5*	*5.3*	*5.8*
OR Avg Cost/Mile	[redacted]	*$1.01*	*$1.16*	*$1.18*

2020 and 2021 Oregon Capital Replacements

2020 Capital Expenditures in Oregon Jurisdiction	*2021 Capital Expenditures in Oregon Jurisdiction*
$326,431	*$289,549*

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	**Capital Cost**	**Start**	**Complete**
Option 1 (Recommended): Fully fund replacement program	*$7,700,000*		
Option 2: Partially fund program	*$3,700,000*		
Option 3: No funding	*0*		

Option 1 (Recommended) – Fully Fund Replacement Program

The Fleet asset model is optimized for the lowest total cost of ownership. Our life cycle model seeks the goal of balancing risk and limited investment dollars. The model allows Fleet to provide users with a reliable and safe tool that is ready for work at any given moment. The fully funded option allows our capital purchasing model of equipment to continue replacing aging equipment in a predictive manner that keeps technician staffing levels constant to the predictive number of repair work orders generated. The program does not include additions to the existing fleet. The analysis of the data by Utilimarc shows that this fully funded model over time will yield the lowest cost per vehicle.

The recent large outages from the summer of 2014 and November 2015 show the strength of our fleet. During those thousands of hours of combined operation we only had two minor breakdowns that we were able to quickly repair and return to service before the start of the operator's next shift.

The customer benefits from this in two distinct ways. One, that crews are quicker to respond to issues because they operate reliable equipment that can be ready for duty. Two, that costs for customers remain steady from a fleet cost perspective because we have a constant investment in the equipment along with a progressive maintenance that has a monthly average over 95% of vehicles ready for duty. By pursing the recommended investment path we avoid rising maintenance costs, outside of economic inflationary trends, and increasing down time due to mounting demand repair work orders. Additionally, this investments allows us to purchase equipment that has modern emissions controls or alternative energy sources allowing us reduce carbon emissions from our fleet vehicles.

Option 2 – Partially Fund Replacement Program

The partially funded, option 2 continues to replace vehicles but at reduced amount when compared to the recommended option. The combined ownership and maintenance costs to appear to be nominally less in costs over the time of the model. However what you see is a rapidly aging fleet in the last two thirds of the model which have increasing work order counts for repairs and significant impacts to reliability/uptime not shown in the total fleet costs.

Option 3 – Do Not Fund Replacement Program

Option 3 is a plan designed to replace a unit only at failure. This model has rapidly increasing costs due to significant repairs required. This model will require increasing numbers of repair work orders to be assigned to outside vendors since company technicians will be able to handle only incrementally more work than today. This outside work has a higher price per hour and higher parts costs due to vendor markups. This model will lead to increasing down time of equipment as it ages. The repairs will become more costly and consume more technician time. Increasingly, even with the best preventative maintenance plan, there will be unplanned failures in the field downing a crew while the issue is addressed. This model was practiced at Avista for over 20 years and led to clusters of vehicles failing at approximately the same time and creating capital constraint issues.

Vehicle Replacement Analysis

The following information demonstrates the effect of three different replacement strategies on Avista's Fleet performance. Three projections were built using Utilimarc Vehicle Replacement Model (VRM) to show the effect of different levels of capital commitment on fleet maintenance cost, ownership cost, average age, and demand repairs. In the Full Budget (Option 1) scenario, vehicles are replaced in line with each vehicle's calculated, optimal, lifecycles with an annual capital cost starting at approximately $8,000,000. The Half Budget (Option 2) scenario cuts the annual replacement budget in half to start at approximately $3,700,000. The No Budget (Option 3) scenario restricts the annual capital cost to $0.

Summary

The table below shows the effects of each budget on annual vehicle ownership and maintenance cost for Avista's fleet. The full projections are provided on the pages to follow.

Annual Vehicle Ownership and Maintenance Cost	2016	2020	2025	2030
Full Budget	$9,588,817	$9,735,956	$10,604,849	$11,700,794

Fleet Services Capital Plan

Half Budget	$9,439,904	$9,274,112	$10,197,151	$11,658,431
No Budget	$9,350,935	$9,145,384	$10,854,088	$13,913,603

Avista's fleet is currently ahead of its ideal lifecycle. This is shown by the increase in average age we see under even the Full Budget scenario. Because of this, the No Budget scenario is marginally cheaper in the first few years of the projection (<2%). However, by the 15th year, the No Budget scenario is 19% higher than the two alternative scenarios. Avista would also see average age increase from 9.0 years to over 20 years under this worst-case scenario.

The Full Budget scenario is marginally more expensive then the Half Budget scenario in these projections, but will begin to outperform the Half Budget scenario beyond the 15th year. While their total costs are comparable, the Full and Half Budget scenarios differ in how money is being spent. Under the Full Budget scenario, capital investment is larger each year, but maintenance costs are significantly lower. The Full Budget scenario also offers younger units for the crews to operate (average age of 9.22 in the 15th year) vs 14.74 in 15th year) and fewer demand repairs (7,082 work order in the 15th year). Conversely, The Half Budget scenario sees a smaller capital investment each year, but the unit for the crews to operate will be older (average age of 14.74 in year 15) and will see more demand repair (9,671 work orders in the 15th year).

Vehicle condition, availability and downtime should also be considered in these scenarios. In order to maximize safety, reliability and responsiveness for customer needs, including emergency outage restoration, vehicles should be equitable in terms of standards and in optimal working condition.

Assumptions

- Inflation: All capital, ownership and maintenance costs are increase annually be 2% to account for inflation.
- Consistent Replacement: The replacement model is programed to replace a consistent number of unit each year to achieve more predictable capital requirements and avoid replacement bubbles. When many vehicles are concentrated in relatively few vintages, these "bubbles" can cause sudden increases in parts and labor cost, vehicle downtime, and technician requirements. Replacing a constant number of unit each year avoids this problem, but consequently the model will occasionally replace a unit before it reaches in lifecycle or let a unit run beyond its lifecycle.
- Maintenance: Maintenance cost includes the cost of all parts and labor needed to maintain the asset over the course of its lifetime. Note that maintenance cost does not include the cost of fuel or any administrative or corporate overheads. While there will be some fuel efficiencies associated with running younger vehicles, the unpredictable nature of the price fuel make it difficult to quantify the savings associated with these efficiencies.
- Maintenance Savings: The replacement model maintains a constant cost per wrench-turning hour of technician labor. This means that when maintenance cost increase or decrease, the model adjusts staffing levels to meet the increased or

decreased demand for labor. This should be considered alongside historic overtime and contract labor practices when interpreting these results.

Fleet Services Capital Plan

Cost Tables

Full Budget	2016	2017	2018	2019	2020
Annual Maintenance (Parts, Labor, Vendor) Cost	$4,742,786	$4,856,108	$4,976,085	$5,129,998	$5,303,926
Annual Ownership Cost	$6,559,724	$6,390,102	$6,363,332	$6,262,211	$6,210,697
Annual Capital Budget	$8,010,456	$7,625,997	$8,550,766	$7,983,602	$8,457,832
Units Replaced Annually	112	106	106	103	104
Average Age	8.47	8.38	8.36	8.42	8.51
Units Out of Lifecycle	134	110	74	57	41
Annual Demand Repair Work Orders	6,609	6,637	6,660	6,711	6,768

3.7M Budget	2016	2017	2018	2019	2020
Annual Maintenance (Parts, Labor, Vendor) Cost	$4,945,378	$5,262,213	$5,553,296	$5,876,138	$6,194,199
Annual Ownership Cost	$6,130,531	$5,589,192	$5,260,460	$4,914,123	$4,665,065
Annual Capital Budget	$3,719,912	$2,905,936	$4,096,366	$3,574,700	$3,664,350
Units Replaced Annually	50	44	50	46	47
Average Age	9.11	9.59	10.01	10.47	10.92
Units Out of Lifecycle	186	203	202	238	247
Annual Demand Repair Work Orders	6,899	7,191	7,434	7,694	7,942

No Replacement	2016	2017	2018	2019	2020
Annual Maintenance (Parts, Labor, Vendor) Cost	$5,236,220	$5,756,008	$6,296,020	$6,859,429	$7,436,489
Annual Ownership Cost	$5,735,049	$4,936,895	$4,259,317	$3,682,958	$3,191,696
Annual Capital Budget	$-	$-	$-	$-	$-
Units Replaced Annually	-	-	-	-	-
Average Age	9.77	10.76	11.74	12.71	13.69
Units Out of Lifecycle	281	322	403	457	572
Annual Demand Repair Work Orders	7,276	7,828	8,380	8,932	9,485

Fleet Services Capital Plan

Full Budget	2021	2022	2023	2024	2025
Annual Maintenance (Parts, Labor, Vendor) Cost	$5,469,634	$5,626,095	$5,806,710	$5,936,489	$6,088,050
Annual Ownership Cost	$6,231,649	$6,252,235	$6,244,883	$6,383,525	$6,422,122
Annual Capital Budget	$8,744,956	$8,763,990	$8,633,034	$9,629,551	$8,990,833
Units Replaced Annually	103	111	101	106	103
Average Age	8.62	8.65	8.77	8.83	8.93
Units Out of Lifecycle	34	40	41	38	32
Annual Demand Repair Work Orders	6,834	6,880	6,945	6,956	6,990

3.7M Budget	2021	2022	2023	2024	2025
Annual Maintenance (Parts, Labor, Vendor) Cost	$6,505,655	$6,847,961	$7,168,380	$7,465,391	$7,801,053
Annual Ownership Cost	$4,509,902	$4,243,790	$4,133,092	$4,111,033	$4,009,498
Annual Capital Budget	$4,301,788	$3,281,927	$3,841,499	$4,613,173	$4,025,692
Units Replaced Annually	49	45	46	50	46
Average Age	11.35	11.80	12.23	12.60	13.01
Units Out of Lifecycle	307	330	366	400	418
Annual Demand Repair Work Orders	8,169	8,404	8,618	8,790	8,985

No Replacement	2021	2022	2023	2024	2025
Annual Maintenance (Parts, Labor, Vendor) Cost	$8,036,849	$8,660,759	$9,299,771	$9,958,388	$10,638,865
Annual Ownership Cost	$2,772,141	$2,413,132	$2,105,273	$1,840,887	$1,613,357
Annual Capital Budget	$-	$-	$-	$-	$-
Units Replaced Annually	-	-	-	-	-
Average Age	14.66	15.63	16.59	17.55	18.50
Units Out of Lifecycle	620	681	734	769	793
Annual Demand Repair Work Orders	10,037	10,588	11,140	11,691	12,242

Fleet Services Capital Plan

Full Budget	2026	2027	2028	2029	2030
Annual Maintenance (Parts, Labor, Vendor) Cost	$6,226,667	$6,411,144	$6,535,809	$6,698,371	$6,853,080
Annual Ownership Cost	$6,549,886	$6,593,568	$6,783,330	$6,851,754	$6,967,321
Annual Capital Budget	$9,764,701	$9,296,048	$10,423,336	$9,731,966	$10,310,050
Units Replaced Annually	112	106	106	103	104
Average Age	8.93	8.95	9.02	9.13	9.22
Units Out of Lifecycle	23	20	16	17	19
Annual Demand Repair Work Orders	6,995	7,048	7,045	7,074	7,082

3.7M Budget	2026	2027	2028	2029	2030
Annual Maintenance (Parts, Labor, Vendor) Cost	$8,099,925	$8,432,876	$8,704,428	$9,019,315	$9,318,223
Annual Ownership Cost	$3,998,122	$3,899,631	$3,982,001	$3,957,415	$3,994,430
Annual Capital Budget	$4,534,552	$3,542,320	$4,993,447	$4,357,539	$4,466,822
Units Replaced Annually	50	44	50	46	47
Average Age	13.34	13.75	14.06	14.41	14.74
Units Out of Lifecycle	422	443	459	477	497
Annual Demand Repair Work Orders	9,136	9,314	9,419	9,555	9,671

No Replacement	2026	2027	2028	2029	2030
Annual Maintenance (Parts, Labor, Vendor) Cost	$11,342,717	$12,068,385	$12,823,413	$13,603,405	$14,412,019
Annual Ownership Cost	$1,417,138	$1,247,603	$1,100,859	$973,611	$863,098
Annual Capital Budget	$-	$-	$-	$-	$-
Units Replaced Annually	-	-	-	-	-
Average Age	19.46	20.41	21.36	22.31	23.25
Units Out of Lifecycle	828	860	889	921	940
Annual Demand Repair Work Orders	12,793	13,343	13,894	14,444	14,994

Methodology

Annualized Total Cost

For each class, Utilimarc's Vehicle Replacement Module (VRM) determines what lifecycle achieves the lowest cost to own and maintain an average asset over its lifetime. This done by calculating the *annualized total cost* for each potential lifecycle. Annualized cost total is the sum of all ownership and maintenance cost a unit obtains over the course of its life, divided by the number of years the unit is in service. Minimizing annualized total cost guarantees the lowest total cost over the life of the asset. As an example, the table below shows the annualized cost for the possible lifecycles of a light duty pickup truck.

Replacement Age	Annualized Total Cost	Deviation
1	$5,964	12.3%
2	$5,759	8.4%
3	$5,598	5.4%
4	$5,476	3.1%
5	$5,390	1.5%
6	$5,337	0.5%
7	$5,313	0.0%
8	$5,316	0.1%
9	$5,345	0.6%
10	$5,397	1.6%
11	$5,472	3.0%
12	$5,567	4.8%
13	$5,682	7.0%
14	$5,816	9.5%

Consider the following three replacement scenarios over a 14-year financial period:

Scenario 1: A fleet manager plans to replace this vehicle every year. The annualized cost of this replacement strategy is $5,946. Over the 14-year period, this replacement strategy will cost fleet 14 x $5,946 = $83,244.

Scenario 2: A fleet manager plans to replace this vehicle every seven years. The annualized cost of this replacement strategy is $5,313. Over the 14-year period, this replacement strategy will cost fleet 14 x $5,313 = $74,382.

Scenario 3: A fleet manager plans to replace this vehicle every fourteen years. The annualized cost of this replacement strategy is $5,816. Over the 14-year period, this strategy will cost fleet 14 x $5,816 = $81,424

Fleet Services Capital Plan

The table below summarizes the calculations in the previous example.

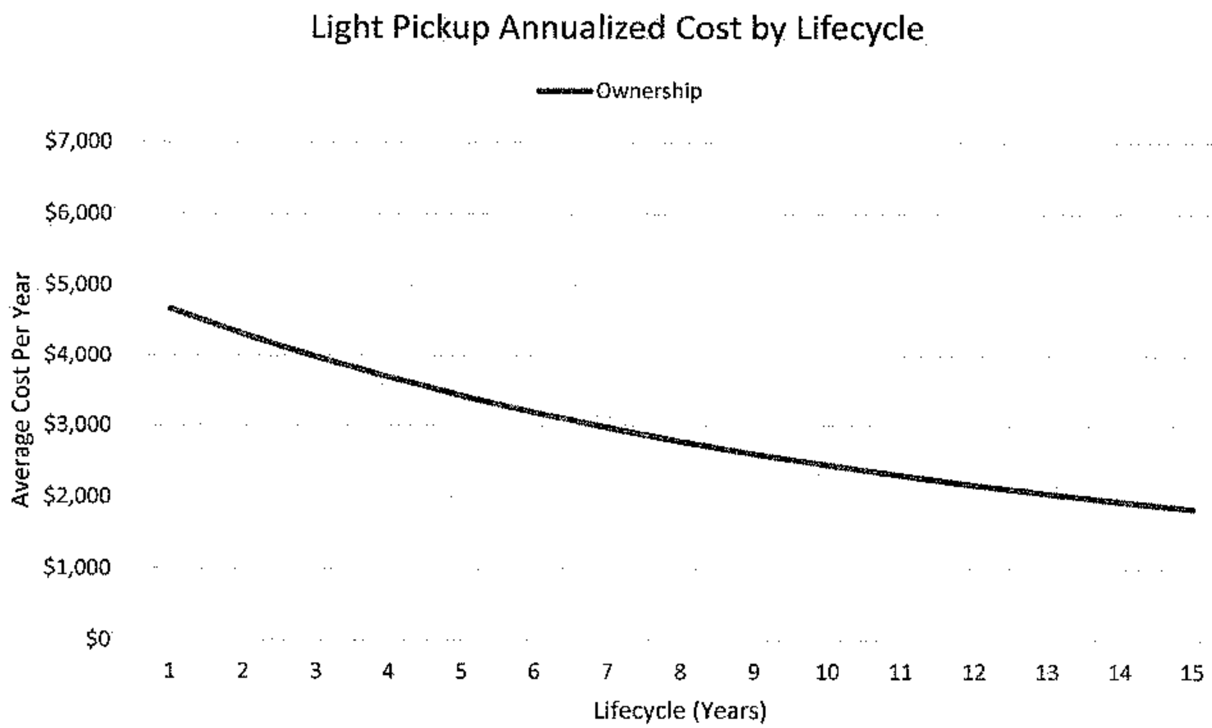
	Chosen Replacement Age	Financial Period (Years)	Annualized Cost	Total Cost for Financial Period
Scenario 1	1	14	$5,946	$83,244
Scenario 2	7	14	$5,382	$74,382
Scenario 3	14	14	$5,816	$81,424

This example illustrates that by minimizing annualized total cost achieves the lowest total cost of ownership over the life of the vehicle. Utilimarc recommends replacing units within 1.0% of the true lowest cost of ownership. This generally provides a three-year range for replacement, which allows for flexibility when planning replacement without dramatically affecting overall cost.

Fleet Services Capital Plan

Modeling Ownership Cost

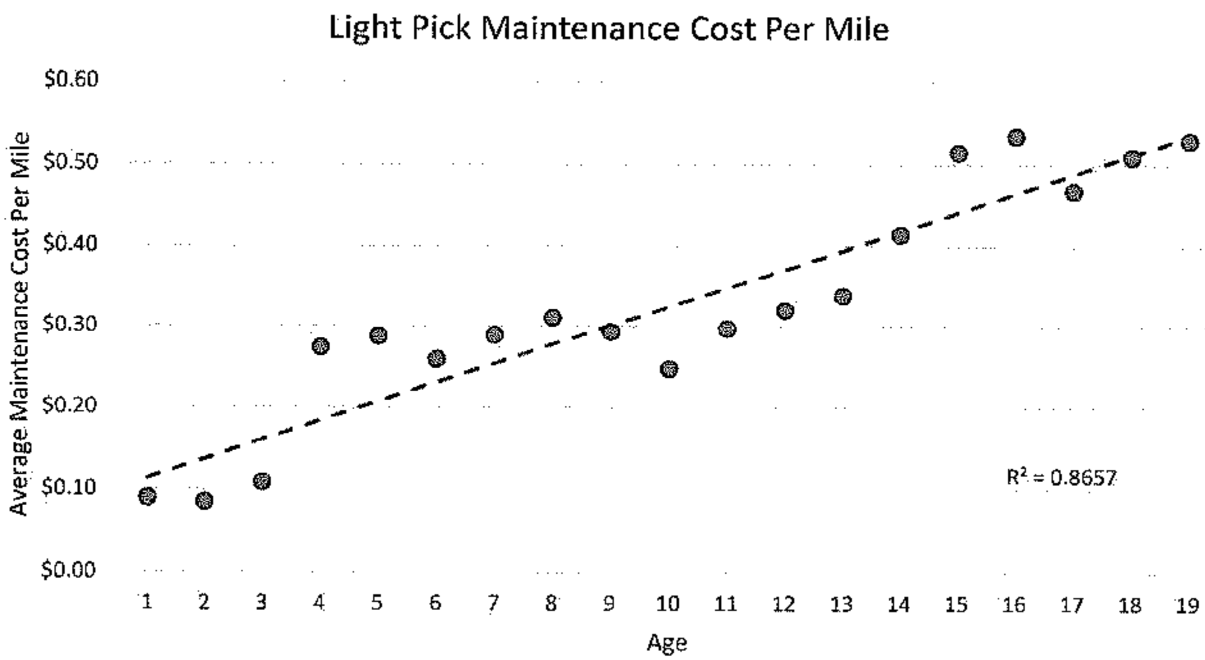
The Vehicle Replacement Model uses an exponential decay model to project the ownership cost of an asset over its lifetime. Each asset is assumed to lose 18% of its current book value every year as a cost of depreciation. This decay rate of 18% is established based on historical auction information from companies across the industry. *Annualized Ownership Cost* is calculated by taking the cumulative sum of each year of depreciation for the asset and dividing by the number of years the asset is in service. Continuing the example from the previous section, the graph below shows the annualized ownership cost for a light pickup truck for each potential lifecycle.



Fleet Services Capital Plan

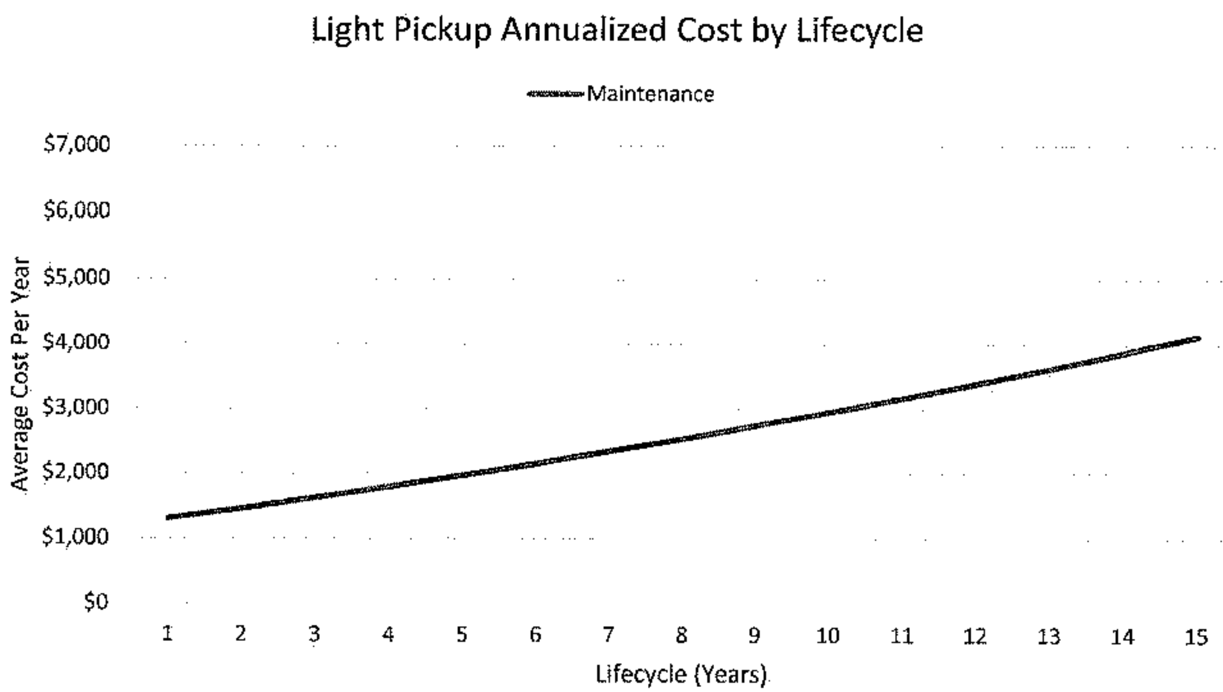
Modeling Maintenance Cost

The Vehicle Replacement Model uses a linear regression model to project the maintenance cost of an asset over its lifetime. These class specific models are built using historical, maintenance cost per mile data taken from the Utilimarc data. In the graph below, the red dots represent the average historical maintenance cost per mile for a light pickup truck of each age. The red, dashed line represents the linear regression model used to estimate the maintenance cost of an average pickup. The linear regression model helps predict the increase cost of maintenance associated with running older vehicles.



Fleet Services Capital Plan

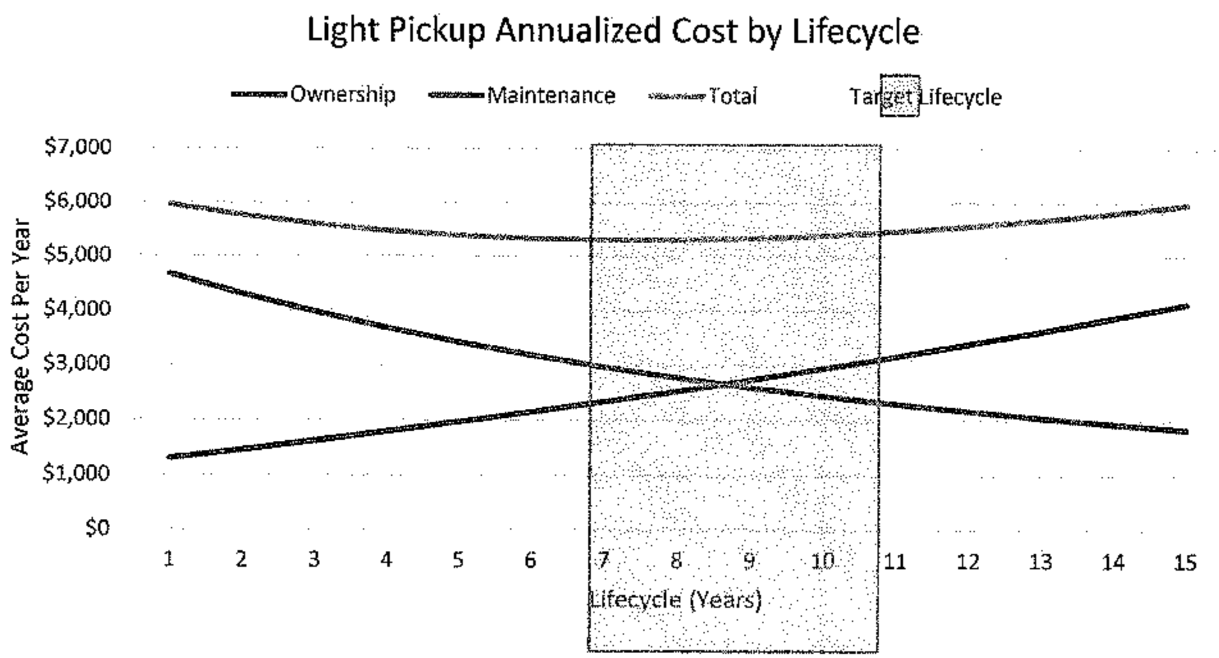
Annualized Maintenance Cost is calculated by taking the cumulative sum of each year of maintenance cost for the asset and dividing by the number of years the asset is in service. The graph below shows the annualized maintenance cost for light pickup trucks, based on the linear regression model and a calculated average annual mileage.



Fleet Services Capital Plan

Modeling Annualized Total Cost

Annualized total cost is calculated by taking the sum of annualized maintenance and ownership cost. The graph below shows the annualized total cost for a light duty pickup truck. The target lifecycle is indicated by a green shaded zone. This is a visual representation of the table from pg. 7 and demonstrates how the model identifies each lifecycle.



4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Fleet Services plan and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 2/20/20
Print Name: Greg Loew
Title: Manager, Fleet Services
Role: Business Case Owner

Signature: Date: 2/20/2020
Print Name: Dan Johnson
Title: Manager, Shared Services
Role: Business Case Sponsor

Signature: Date: 2-21-2020
Print Name: Heather Rosentrater
Title: Vice President, Energy Delivery
Role: Steering/Advisory Committee Review

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1	*Greg Loew*	*04/25/17*	*Heather Rosentrater*	*04/25/17*	*New template*
2	Greg Loew	2/19/20			Oregon 2020 update

Template Version: 03/07/2017

Gas Regulator Station Replacement Program, ER 3002

EXECUTIVE SUMMARY

This annual program will replace or upgrade existing at-risk Gate Stations, Regulator Stations 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, enhance safety, replace inadequate or antiquated equipment that is no longer supported, and ensure the reliable operation of metering and regulating equipment.

These stations require annual maintenance per 49 CFR 192.739 and 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 and be exposed to fines from the various state utility commissions.

Avista's gas customers from all jurisdictions benefit from these types of projects by having a safer, more reliable, well maintained distribution system. Also, this is a prudent way to spend resources because many deficiencies at a station can be remedied under just one project.

Annual cost to fund this program is $1,000,000.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Jeff Webb	Initial version	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	Smith-Webb	Updated to the refreshed 2020 Business Case template	7/10/2020	

Gas Regulator Station Replacement Program, ER 3002

GENERAL INFORMATION

Requested Spend Amount	$1,000,000
Requested Spend Time Period	Annually
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Jeff Webb/Dave Smith | Mike Faulkenberry
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?

Existing stations located throughout Avista's gas territory in WA, ID, and OR have a finite service life and will eventually no longer meet Avista's current design standards, may feature obsolete equipment, or may develop operational or safety issues that need addressed in order to delivery safe and reliable gas service to customers.

Another category of work in this program is moving regulator stations located underground in a vault to a more traditional above ground configuration. Stations located in vaults are difficult to maintain because of the limited working room for tools and workers. Additionally, water in the vault can make maintenance more difficult. Regulator Stations in a vault are also a safety concern as they are confined spaces and can trap harmful levels of natural gas should a leak be present.

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's primary driver is asset condition. By replacing obsolete stations, we will continue to deliver safe and reliable gas service to customers.

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

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.

Gas Regulator Station Replacement Program, ER 3002

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 success of the program can be measured by the completion of station replacement projects. These stations are a vital link to providing gas service and replacing obsolete stations will help Avista continue to deliver safe and reliable gas service to customers.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem.

A master list of stations with reported deficiencies is maintained by Gas Engineering and is shown below.

Project List/Capital Plannin					Next Projec	20	1							
3002	2007-95	Rebuild	Rebuild - Reg Station #562 Gold Creek, Colville WA	Colville, WA	Ken Sampson	9/7/2007				High	D Smith		In Const.	Replace outlet valve on bypass and station. Existing Kerotest valves are difficult to throttle. Consider a regulated bypass. Need to also look at the system capacity. An asphalt plant is down stream. According the Ken S it is necessary to operated the regs @ 55 psig to ensure adequate pressure to the asphalt plant. Valves need replaced, they are older kerotest valves and mixed ANSI class. Need regulated bypass due to fast acting load downstream. Possible Summer Student project. (11/21/08 - Add a regulated Bypass). Targeting First week of June 2018 if possible.
3002	2007-129	Rebuild	Rebuild - Reg Station #1-2, Mead Gate Kaiser Run, Spokane WA	Spokane, WA	Rich I	12/14/2007	TBD			High	D Smith	1/9/2015	In Design	Replace Axial flows w/ Mooney's to improve maintenance. Project goes hand in hand with Mead Gate Rebuild. On Hold until we determine an overall plan to increase capacity of the 174 psig system.
3002	2008-6	Rebuild	Rebuild - Reg Station #316, Colton WA	Colton, WA	Trevor S	1/17/2008	TBD			High	T Harding	9/21/2012	In Const.	Current reg station has 2" Fisher 630 w/ 1/2" Orifice and 2" Axial Flow. Trevor would like a Reg/Monitor w/ 2x1" Mooney's.
3002	2008-60	Rebuild	Rebuild - Reg Station #27, Liberty Lake WA (Golf Course)	Liberty Lake, WA	David H	7/14/2008	TBD			High	D Smith		In Design	Full relief station installed directly under power lines. Need to convert to a Reg /Monitor station. In addition, HP inlet line should be replaced as it has a MAOP of 250 and is a limiting factor on the Liberty Lake HP Feeder which has a MAOP of 440 PSIG.
3002	2008-86	Rebuild	Rebuild - CDA East Reg Station #221, CDA ID	CDA, ID	Steve F	9/10/2008	TBD			High	R Anderson	10/8/2012	In Design	Turbine Meter Redundant, Pulse for YZ Odorizer from Meter, Hard to turn plug valves. Build in 2013, install in 2014. Delayed until HP reinforcement complete 2017.
3002	2008-87	Rebuild	Rebuild - Reg Station 206, Sandpoint ID	Sandpoint, ID	Steve F	9/10/2008	TBD			High	R Anderson	1/9/2015	In Design	Top run of side of Regs is 2" (May be to small), Station has settled, No outlet vavle for station. (Reviewed 9/18 w/ Steve F, needsoutlet isolation valve, Raise station approx. 12", replace fence. Need to bypass station during construction. - DRH)
3002	2008-88	Rebuild	Rebuild - Reg Station 213, Odorizer, **Post Falls, ID**	Post Falls, ID	Steve F	9/10/2008	TBD			High	R Anderson	10/8/2012	In Design	Odorizer Float Sticks (Pearless Bypass Odorizer), Clean up header, some threaded valves. Build in 2013, install in 2014. Total Rebuild
3002	2009-146	Upgrade	Upgrade - Odorizer #315, replace four valves, Colton, WA	Colton, WA	Jenny B	9/4/2009	TBD			High	T Harding		In Design	Here are four valves (differential valves) at Odorizer Station #315 on Rimrock Rd, Colton, WA being used as Emergency Valves in case of a problem and being turned yearly as maintenance. #PUM711, #PUM721, #PUM722, #PUM852.
3002	2009-160	Rebuild	Rebuild - Reg Stn #31, Nine Mile Rd & Royal, **Spokane WA**	Spokane, WA	Rich I	11/12/2009				High	D Smith		In Const.	Clean up Rockwell Strainer, Axial Flow Relief, only 2' off ground, bypass valves stuck, cobbled up sense lines.

Image 1 – Master List of Stations with Deficiencies

This list 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.

The master list of stations with reported deficiencies referenced in section 1.5.1 summarizes the issues at each station.

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. At this pace, the number of stations remediated will slowly outpace the number added each year. 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 well without requiring additional headcount.

Since these stations are a vital link to providing customers with reliable gas, planned work is better than unplanned work. Unplanned work during times of high gas use (normally the winter) can be more difficult to perform and have negative impacts to customers if it fails to operate properly.

Gas Regulator Station Replacement Program, ER 3002

Option	Capital Cost	Start	Complete
Recommended Solution, Replace at risk stations at requested funding level	$1,000,000	January	December
Alternative Solution, Replace at risk stations at a reduced funding level	$500,000	January	December

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

A master list of stations with reported deficiencies is maintained by Gas Engineering. Each year this list is evaluated by subject matter experts in Gas Engineering and Gas Operations and the stations are prioritized by risk level. Stations with the highest risk level are selected for completion while others are deferred to future years. The workforce available to do this type of work is responsible for both maintenance of these stations and the rebuild efforts. The

Gas Regulator Station Replacement Program, ER 3002

requested level of spend in the Recommended Solution complements their available time well without requiring additional headcount.

Stn #	Priority	2020 Cost	Comments	State	Budgeted for 2020	Deferred to 2021
722	1	$ 6,000	Eastern St Hosp MSA	WA	$ 6,000	
4406	1	$ 10,000	Interstate Conrete MSA, Rathdrum	ID	$ 10,000	
316	1	$ 25,000	Colton DR, materials already ordered	WA	$ 25,000	
201	1	$ 30,000	Bonners Ferry DR, materials ordered already	ID	$ 30,000	
0801	1	$ 50,000	Cove Ave, La Grande	OR	$ 50,000	
0812	1	$ 25,000	Hilgard, La Grande w/ Heater Maintenance	OR	$ 25,000	
2713	1	$ 280,000	Keno Gate Rebuild	OR	$ 280,000	
562	1	$ 50,000	Gold Creek Loop Rd	WA	$ 50,000	
7701	1	$ 25,000	Lakeland Village MSA	WA	$ 25,000	
2404	2	$ 57,000	Ave G, White City	OR	$ -	$ 57,000
213	2	$ 80,000	McGuire GS	ID	$ 80,000	
307	2	$ 15,000	Moscow DR, reg change only	ID	$ -	$ 15,000
375	2	$ 20,000	Spangle Odorizer	WA	$ 20,000	
24c18	3	$ 100,000	Eastman Kodak - Kirtland Road	OR	$ -	$ 100,000
206	3	$ 60,000	Sandpoint DR	ID	$ -	$ 60,000
303	3	$ 10,000	High pressure DR, change to FT station	WA	$ -	$ 10,000
36	3	$ 95,000	Airport Road	WA	$ -	$ 95,000
221	4	$ 50,000	CDA East GS & RS 2210	ID	$ -	$ 50,000
Various	4	$ 10,000	Misc FT replacement, one is likely to happen	ID	$ -	$ 10,000
24P23	4	$ 55,000	Payne Road Rebuild	OR	$ -	$ 55,000
31	4	$ 30,000	Nine Mile & Royal	WA	$ -	$ 30,000
23	5	$ 30,000	Trent & Woodlawn	WA	$ -	$ 30,000
260	5	$ 30,000	Silverton Reg Station	ID	$ -	$ 30,000
315	5	$ 30,000	Colton Gate Station	WA	$ -	$ 30,000
420	5	$ 60,000	Lewiston DR	ID	$ -	$ 60,000
2412	5	$ 125,000	Siskiyou & Willamette Rebuild/Relocate	OR	$ -	$ 125,000
4577	6	$ 40,000	Trent & Harvard	WA	$ -	$ 40,000
115	7	$ 35,000	Odorizer Station Rebuild	WA	$ -	$ 35,000

Image 2 – Partial list of of stations ranked by priority

(only 2020-2021 are shown)

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.**

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 may reduce unplanned O&M costs because obsolete stations are being removed from the system resulting in an increase in the overall reliability of the gas distribution system.

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

Gas Operations rely on station replacement projects as a vital part of their work. The current level of spend complements their available time to do this work without requiring additional headcount.

Gas Regulator Station Replacement Program, ER 3002

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

There are two outcomes if this program is funded at a reduced rate. One is to replace fewer regulator stations and industrial meter sets. There is already a backlog of high-risk stations to be replaced, so this approach would take an even longer time to get through that backlog while new stations are continually added to the list every year. Secondly, 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. This option is not recommended.

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. 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.

2.5 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.

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.

2.6 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 requested funding level is prudent to continue to serve safe and reliable gas service to customers. A master list of stations with reported deficiencies is maintained by Gas Engineering. Each year this list is evaluated by subject matter experts in Gas Engineering and Gas Operations and the stations are prioritized by risk level. Stations with the highest risk level are selected for completion while others are deferred to future years. 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 well without requiring additional headcount.

2.8 Supplemental Information

Gas Regulator Station Replacement Program, ER 3002

2.8.1 Identify customers and stakeholders that interface with the business case.

Avista gas customers in WA, ID, and OR benefit from this program as these stations are utilized in all territories to deliver safe and reliable gas service.

Stakeholders including Gas Engineering, Gas Operations, and the Gas Meter Shop work together to ensure a successful program execution.

2.8.2 Identify any related Business Cases.

N/A.

Steering Committee or Advisory Group Information

Gas Engineering is ultimately responsible for prioritizing the projects and reporting out financial updates to the Capital Project Group.

2.10 Provide and discuss the governance processes and people that will provide oversight.

Gas Engineering, Gas Operations, and the Gas Meter Shop work together to administer this program. 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.

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

A master list of Regulator Stations and Industrial Meter Sets with reported deficiencies is maintained by Gas Engineering. Gas Operations and the Gas Meter Shop report concerns while performing regular maintenance and these deficiencies are collected on the master list. Annually, subject matter experts from Gas Operations and Gas Engineering review the master list and risk rank the work for the following year. Stations with the highest risk (typically due to multiple different concerns) are prioritized over stations with only minor issues. Prioritizing this work annually with the subject matter experts provides a consistent approach. Through this process, the highest risk projects are selected to be funded. The spend for each individual project that falls under this ER is monitored on a monthly basis by the Project Engineers. Changes to the total annual spend for this ER is monitored by the business case owner.

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: Date: 7/10/2020

Print Name: Jeffrey A Webb

Gas Regulator Station Replacement Program, ER 3002

Title:	Mgr Gas Engineering		
Role:	Business Case Owner		
Signature:	Mike Faulkenberry	Date:	7/10/2020
Print Name:	Michael J Faulkenberry		
Title:	Director Natural Gas		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

Gas Reinforcement Program, ER 3000

EXECUTIVE SUMMARY

This annual program will identify and provide for necessary capacity reinforcements to the existing natural gas distribution systems in WA, ID, and OR. Avista has an obligation to serve existing firm gas customers by providing adequate capacity on design day conditions. Sufficient capacity is defined as pressures at or above 15 pounds per square inch (psig) in the distribution system on a design day analysis. 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.

Typical projects completed under this Business Case may include (but are not limited to) upsizing existing gas mains, looping existing gas mains (bringing in a second source to an area), and installing new regulator stations (pressure reduction 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 lower cost (smaller scope) projects may be completed under the blanket project numbers set up for each district.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Jeff Webb	Initial draft version	03/17/2017	
1.1	Jeff Webb	Business Case Refresh PH 1	04/06/2017	
1.2	Jeff Webb	Revised for 2020 Oregon GRC filing	2/17/2020	
2.0	Harding-Webb	Revised V2 Business Case Refresh PH 2	7/10/2020	

Gas Reinforcement Program, ER 3000

GENERAL INFORMATION

Requested Spend Amount	$1,300,000
Requested Spend Time Period	1 Year / Perpetual Annual Request
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Tim Harding - Jeff Webb | Mike Faulkenberry
Sponsor Organization/Department	B51 – Gas Engineering
Phase	Execution
Category	Program
Driver	Performance & Capacity

1. BUSINESS PROBLEM

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

Avista's gas distribution systems are constantly changing as new customers are added to the system and other construction activities occur. It is expected that these systems are able to supply gas to all firm customers during high demand, including cold 'Design Day' conditions. There are certain systems that currently do not have adequate capacity to meet these needs. Reasons for this can include increased customer loads, new gas customers being added to the system, undersized piping, long piping lengths, and undersized valves and regulators.

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 is Performance & Capacity related. These reinforcements improve system capacity and allow un-interrupted service to firm customers. Additionally, these reinforcements reduce the likelihood of low-pressure outages for all customers in effected areas.

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

One of Gas Planning's responsibilities include the identification of low pressure areas on our distribution system, low pressure is synonamous with insufficient capacity. Insufficient capacity can result in a gas outage during a cold weather event. The impacts of a gas outage is very different than an electric outage. Even after temperatures warm and pressures have recovered in a gas system, it can take several days to restore service to customers, because each meter must be first shut off and then individually turned back on by a serviceman performing a safety check. To make matters worse, an outage will occur during extremely low temperature conditions – a very serious safety concern when customers may not have heat for days. This is a customer safety issue.

Gas Reinforcement Program, ER 3000

Additionally, according to tariff language, firm customers are paying for a reliable fuel source at all times short of a "Force Majure". Therefore it would be unfair to have customers paying for firm service while Avista is intentionally operating a system that cannot meet the intent of the tariff.

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.

Seasonal pressure recorders are placed at key locations in our distribution systems each winter. These devices record and regularly transmit pressure data that is reviewed remotely. This monitoring allows the Gas Planning department to cross-check and calibrate the computer model data with actual system pressures. By doing this, they are better able to suggest new reinforcements, while also verifying improved performance from previously installed reinforcements.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem.

Load studies, using computer models are run annually. Their findings are best reviewed graphically and are too numerous to display in this document. Gas Planning stores copies of load study results.

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.

Sample Reinforcement Priority List:

Gas Reinforcement Program, ER 3000

OBJECTID	SIZE	MATERIAL CODE	NOTES	SHAPE.LEN	STATUS	LOCATION	CITY
23417	6"	Plastic	High	2561.08	Proposed	Reinforcement for Medford	Medford
21178	4"	Plastic	High	2476.81	New	Install new 4" and replace section of 2" with 4", Load study resu	Medford
21179	2"	Plastic	High	28.98	New	2" Tie-In	Medford
17977	6"	Plastic	High	4028.42	Replacemen	Load Study Result (currently ADL)	Medford
16377	4"	Plastic	High	1882.30	New	IP Connection to feed end of 55 psig system	Medford
20858	2"	Plastic	High	257.28	<Null>	2" Tie-In, E 6 psig system	Medford
20860	2"	Plastic	High	350.30	<Null>	2" Tie-In, W Medford	Medford
18301	4"	Plastic	High	3516.67	Replacemen	3500' of 2" to 4" Replacement	Spokane Valley
18300	8"	Steel	High	27535.87	New	*HP 27,700' 8" parallel to existing 4"*	Cheney
17981	6"	Plastic	High	4218.98	Replacemen	ADL Replacement Bellinger Rd	Jacksonville
20866	6"	Plastic	High	4808.68	New	Additional Jacksonville feed	Jacksonville
16068	4"	Plastic	High	3072.72	Replacemen	Palouse 2" Main Replacement	Palouse
16057	6"	Plastic	High	9418.36	Replacemen	South Hill	Spokane
17337	4"	Plastic	High	271.27	Replacemen	Along E St, 280'	Riddle
11577	6"	Steel	High	19572.92	Proposed	*HP Warden*	Warden
19901	6"	Plastic	High	5265.93	<Null>	6" main upsize for new development	Spokane
6777	2"	Plastic	High	407.66	Proposed	Loomis and Railroad	St John
21177	4"	Plastic	Medium	2796.64	Replacemen	Replace 2" with 4", low pressure area reinforcement	Spokane Valley
20861	6"	Plastic	Medium	2426.55	<Null>	Replace 4" with 6"	Colfax
20862	4"	Plastic	Medium	150.82	<Null>	Replace 2" with 4"	Roseburg
20863	4"	Plastic	Medium	3356.39	<Null>	Replace and install 4"	Roseburg
20864	4"	Plastic	Medium	523.10	<Null>	Replace 2" with 4"	Roseburg
20865	2"	Plastic	Medium	207.30	<Null>	2" Tie-in	Spokane
20857	2"	Plastic	Medium	157.07	<Null>	2" Tie-In, W 6 psig system	Medford
20859	4"	Plastic	Medium	724.85	<Null>	Replace 2" with 4", W 6 psig system	Medford
20537	2"	Plastic	Medium	167.22	New	Tie-in to eliminate AOI	Spokane
20218	6"	Steel	Medium	1395.06	Replacemen	ADL replacement	Spokane
18620	4"	Plastic	Medium	459.75	Replacemen	ADL Replacement, 500' of 2" to 4"	Medford
18618	4"	Plastic	Medium	5756.67	Replacemen	ADL Replacement	Spokane
18617	4"	Plastic	Medium	1768.88	Replacemen	ADL Replacement, 1800' of 2" to 4"	Medford
18297	4"	Plastic	Medium	6655.04	Replacemen	6700' of 2" to 4" Replacement	Rogue River
18298	4"	Plastic	Medium	1414.99	Replacemen	1500' of 2" to 4" Replacement	Spokane
17984	2"	Plastic	Medium	222.96	New	2" Tie-In Ashland 8 psig System 250'	Ashland
17985	4"	Plastic	Medium	529.18	Replacemen	Ashland 8 psig system 530' along Meade St	Ashland
17986	4"	Plastic	Medium	492.56	Replacemen	Ashland 8 psig system 500' along Harrison St	Ashland
17982	4"	Plastic	Medium	1268.93	Replacemen	1300' 2" to 4" along Keasey St	Roseburg
17983	4"	Plastic	Medium	2470.64	Replacemen	ADL Replacement 2400' Kline St 2400'	Roseburg
16065	2"	Plastic	Medium	143.52	Proposed	14th and Eastern	Spokane
15737	2"	Plastic	Medium	610.08	Proposed	Intersection of Lenter and Lathen	Moscow
15738	6"	Steel	Medium	4152.18	Replacemen	6" Main Replacement	Moscow
15106	6"	Steel	Medium	20412.47	Replacemen	Klamath Main Replacement	Klamath Falls
14779	2"	Plastic	Medium	414.46	Proposed	Plum and Winchester Tie-In	Medford
14780	2"	Plastic	Medium	410.38	Proposed	Plum and Winchester Tie-Ins	Medford
4542	2"	Plastic	Medium	136.73	New	Alderwood Tie-in	Spokane

Option	Capital Cost	Start	Complete
Proposal / Recommended Solution – Strategically install assets	$1,300,000	01 2020	12 2020
Alternative Solution – Reduced funding option: Strategically install assets with reduced funding level	$800,000	01 2020	12 2020

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

The current budget request is based on past historical spending. This is a reasonable amount of construction work to divide between Engineering and Operations resources. There continues to be about a 6 year backlog of high

Gas Reinforcement Program, ER 3000

and medioum priority projects within this program. A reduced budget will increase the backlog and increase the risk of low-pressure outages.

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 money spent for this budget goes directly to the design and installation of new assets. Installations typically happen in Q2, Q3 and Q4 across all three states.

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

N/A

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

Alternatives include halting reinforcement efforts, or reducing program funding. Failing to meet firm customer demand, resulting in customer outages due to low pressure conditions are circumstances that Avista needs to avoid. These situations can have financial implications for the Company, reduced levels of Customer Experience, and legitimate safety concerns for vulnerable customers.

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.

These projects typically take place in Q2, Q3, and Q4. The assets become used and useful upon installation and are transferred to plant soon after completion.

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

Reinforcement projects allow the natural gas system to operate safely and reliably, meeting customer demands during all reasonable conditions.

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.

As the gas systems expand and customer growth continues, there continues to be a need for capacity reinforcements. Projects will be reviewed and prioritized on an annual basis by Gas Planning.

When reinforcements are successfully installed, the risk for customer outages due to low pressure conditions are greatly reduced. This positively impacts the Pressure Controlmen and Servicemen groups because of the reduced number of incidents they must respond to.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case.

This program touches on all service territories that Avista serves. Construction of these projects is done by both contractors, as well as in-house crews. Design duties are split between Gas Engineering and local CPCs. All Avista gas customer are stakeholders in these projects.

2.8.2 Identify any related Business Cases.

N/A

3.1 Steering Committee or Advisory Group Information.

The Steering Committee/Advisory Group for this program consists of Gas Planning and Gas Engineering.

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

The Gas Planning department annually 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 (Avista is consistent with other utilities in the industry and defines design day as the projected system demand for a "coldest day on record" weather event). These deficient areas are given a priority level based on the severity of the risk associated with insufficient system capacity. 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.

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.

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

The Gas Planning department formally sends a list of proposed reinforcements to the Gas Engineering group each year. As described above, the highest priority projects are assigned to Gas Engineering to be completed that year. Any proposals for re-prioritization is reviewed by Gas Planning. In a typical year there is a backlog of several years' worth of work (from a budget perspective). Top priority projects, that fit within the annual budget, are assigned to specific engineers to manage.

The undersigned acknowledge they have reviewed the Gas Reinforcement 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:	Jeffrey A Webb	Date:	7/10/2020
Print Name:	Jeffrey A Webb		
Title:	Manager Gas Engineering		
Role:	Business Case Owner		

Signature:	Mike Faulkenberry	Date:	7/10/2020
Print Name:	Michael J Faulkenberry		
Title:	Director Natural Gas		
Role:	Business Case Sponsor		

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

Template Version: 05/28/2020

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, federal gas standards, system growth, and external projects (e.g. Smart Grid). The customers who benefit are all electric and gas residential, commercial, and industrial customers (CD.AA).

The estimated costs for the upcoming five years are $4.3M. The amount requested is based partially upon historical spending needs, and partially on known upcoming major projects. Within the program's yearly authorized spend amount, specific budgetary items to be implemented are determined based upon requests by affected stakeholders including System Operations, Distribution Operations, and Power Supply, and are documented in the Director of Transmission & Distribution System Operations' annual goals and priorities list.

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 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.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Craig Figart	Initial draft of original business case	07.1.2020	
1.0	Craig N Figart	Final version of 2020 business case	07.17.2020	Updated Executive Summary

SCADA - SOO and BuCC

GENERAL INFORMATION

Requested Spend Amount	$4.3M
Requested Spend Time Period	*5 years*
Requesting Organization/Department	T&D - SCADA/EMS/DMS - System Operations
Business Case Owner | Sponsor	Craig N Figart | Mike Magruder
Sponsor Organization/Department	Energy Delivery
Phase	Execution
Category	Program
Driver	Asset Condition

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.

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

Asset Condition is the major driver of the business case. Another driver is Customer Service quality and reliability. This business case is crucial in a key aspect of Our Vision; "Delivering reliable energy service…" It is essential in providing sufficient control center technology tools, situational awareness, and monitor/control capabilities to achieve reliable energy service.

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

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 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.

SCADA - SOO and BuCC

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 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

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]

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.

[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
Fully Funded "SCADA – SOO and BuCC" business case	*$1.3M*	*01/2021*	*12/2021*
Cancel Dispatcher Training Simulator (DTS) replacement	*$1.15M*	*01/2021*	*12/2021*
Do not complete EMS Upgrade project, nor DTS	*$0.65M*	*01/2021*	*12/2021*

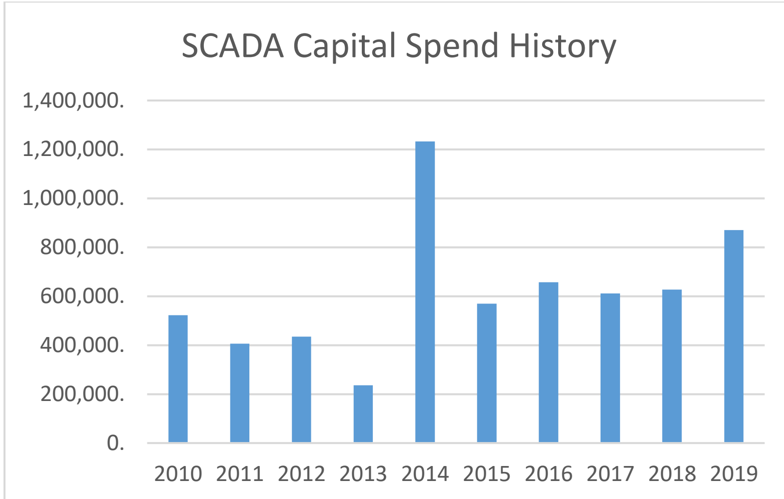
2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

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.

SCADA - SOO and BuCC



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.]

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 EMS upgrade project is required to be completed in order to upgrade hardware and software that is no longer supported. The EMS upgrade project will also better accommodate operation under the Energy Imbalance Market.

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

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).]

This is a continuous program. Work is started and completed throughout each year, and in some cases, such as major upgrades, spans multiple years. Technology continues to change and T&D Systems continue to incorporate improved technology.

SCADA - SOO and BuCC

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.]

This business case is crucial in a key aspect of Our Vision; "Delivering reliable energy service…" It is essential in providing sufficient control center technology tools, situational awareness, and monitor/control capabilities to achieve reliable energy service.

This business case is key in accomplishing the Our Focus item of "Safe & Reliable Infrastructure." Providing remote monitor and control capabilities to operators is essential in achieving "optimum life-cycle performance - safely, reliably, and at a fair price."

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

- Our Stakeholders include:
  - Operations
    - System Operators
    - Power Schedulers
    - Distribution Dispatchers
    - Gas Controllers
    - Energy Accounting & Risk Management
    - Neighboring utility control centers
    - Peak Reliability Coordinator
  - Technicians
    - Protection/Control/Metering Technicians
    - Telecommunication Technicians
  - Engineering
    - Protection/Integration Engineering
    - Substation Engineering
    - Generation Engineering
    - Distribution System Operations
  - Enterprise Technology
    - Oracle Database Administrators
    - Security Engineering
    - Network Engineering
    - Network Operations

SCADA - SOO and BuCC

2.8.2 Identify any related Business Cases

[Including any business cases that may have been replaced by this business case]

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.]

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

Within the program's yearly authorized spend amount, specific budgetary items to be implemented are determined based upon requests by affected stakeholders including System Operations, Distribution Dispatch, and Power Supply, and are documented in the Director of Transmission & Distribution System Operations' annual goals and priorities list.

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

The undersigned acknowledge they have reviewed the *Business Case Justification Narrative – SCADA -SOO and BuCC – 2020* 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:	July 17, 2020
Print Name:	Craig N Figart		
Title:	Manager of SCADA/EMS		
Role:	Business Case Owner		

Signature:		Date:	
Print Name:	Mike Magruder		
Title:	Energy Delivery Director, Transmission & Distribution System Operations		

SCADA - SOO and BuCC

Role: Business Case Sponsor

Signature: ______________________ Date: ______________

Print Name: ______________________

Title: ______________________

Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Segment Reconductor and FDR Tie

1 GENERAL INFORMATION

Requested Spend Amount	$7,500,000 / year (on-going)
Requesting Organization/Department	Distribution Engineering – C51
Business Case Owner	Cesar Godinez
Business Case Sponsors	David Howell, Josh DiLuciano, Heather Rosentrater
Sponsor Organization/Department	Energy Delivery / Distribution Engineering
Category	Program
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

Distribution Area Engineers and Distribution System Planning.

Tim Figart & Jon Gilrein – Spokane

Marshall Law – East Region

Dan Knutson – Othello, Davenport

Marc Lippincott – Colville

Chris Dux – South Region

Damon Fisher – Distribution System Planning

Cesar Godinez – Distribution Engineering Manager

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

2 BUSINESS PROBLEM

Avista's electric distribution system consists of three hundred and forty seven (347) discrete primary electric circuits encompassing over 19,000 miles of overhead conductors and underground cables. The distribution grid is managed by division or 'area engineers' and centralized distribution planning.

Load Demands on the grid are dynamic with load patterns changing as a result of many factors including weather, temperature, economic conditions, conservation efforts, and seasonal variations. 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

Segment Reconductor and FDR Tie

overloading. In the near future AMI load data will be exported to Synergi and used in the computer simulation.

Avista's 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 Distribution System Planning (Damon Fisher).
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 maintain 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. Distribution FDR Management Plan – a design guide to assist the CPC/Engineer when making decisions related to reinforcements or reconstruction of distribution assets (Asset Management).
6. Feeder Automation Strategy – a design guide to assist the CPC/Engineer when making decisions involving automated devices (Distribution Engineering).
7. 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.
8. 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.
9. 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.

Segment Reconductor and FDR Tie

A typical distribution circuit is illustrated below. Similar to 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).

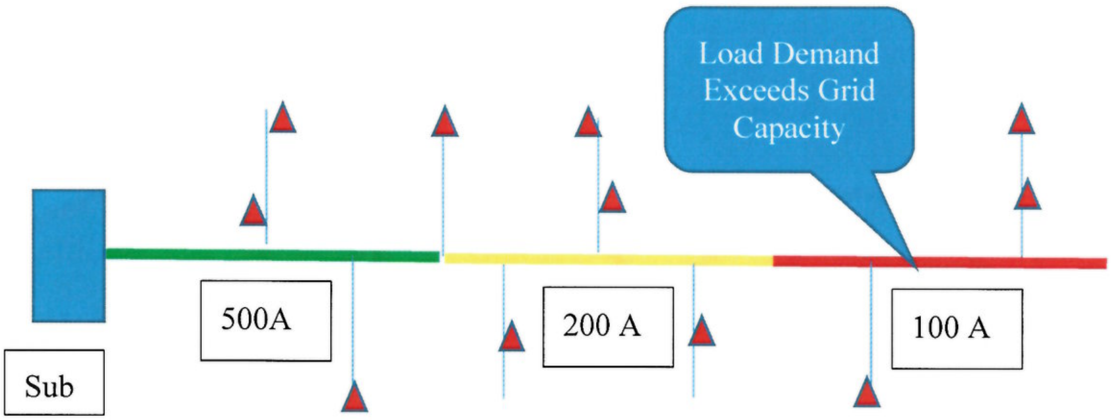


Illustration of Distribution Grid Capacity Constraint

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

2017 Avista Standard OH Primary Conductors

556 All-Aluminum (AAC) – 557 Amps (main trunk, urban)

336 All-Aluminum (AAC) – 405 Amps (main trunk, rural)

2/0 Aluminum Conductor, Steel Reinforced (ACSR) – 221 Amps (gen purposes, rural)

#4 Aluminum Conductor, Steel Reinforced (ACSR) – 112 Amps (lateral circuit)

Legacy Conductors

2/0-3/0 Copper – 291-336 Amps (main trunk)

#2 Copper – 185 Amps (main trunk)

#6 Copper - 65 Amps (lateral circuit)

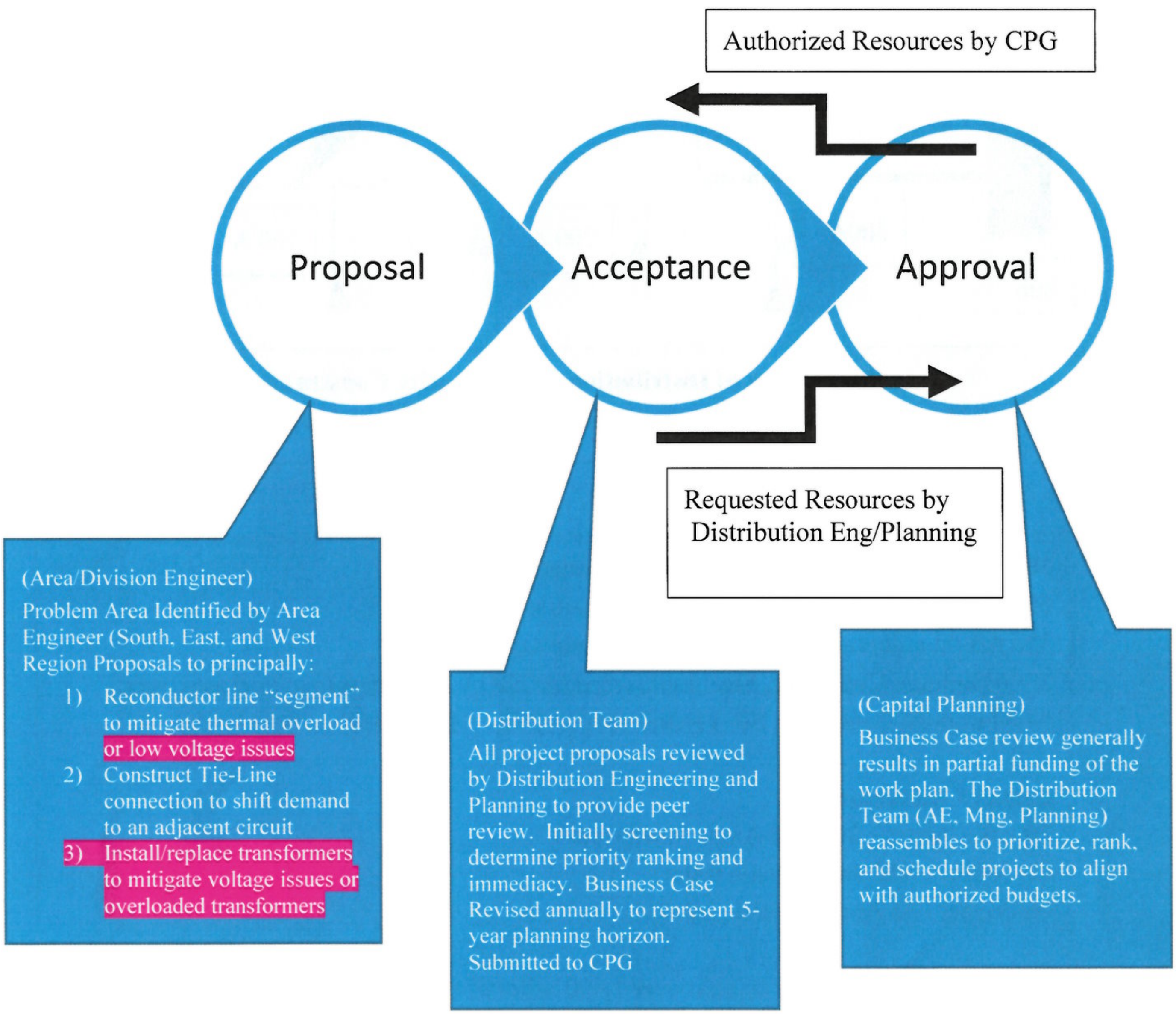
Avista's distribution grid contain over 1,000 miles of conductor equivalent or smaller than #6 Copper.

Segment Reconductor and FDR Tie

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 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" with the exception of distribution substations.*

The Segment Reconductor & FDR Tie decision model is illustrated below.



3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Description	Consequence
Do-Nothing	No Action to mitigate thermal overloads	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.
Select DSM treatment	Target homes and businesses with demand side management solutions to effect peak load demand reduction.	This option would be a viable, however, State Commissions do not allow DSM treatment in localized areas.
Load Shifting	FDR Tie	This action is represented in the Segment Reconductor program. By extending lines to adjacent circuits, load can be shifted to underutilized circuits and mitigate overloads. This action requires capital investment.
Capacity Increase	Reconductor overloaded 'segments' to increase line capacity or to mitigate identified low voltage issues. Install transformers to mitigate low voltage issues. Replace Transformers to mitigate overloaded transformers.	All electric components all thermally limited. Reconductoring is the most direct approach to mitigating overloaded circuits and low voltage issues.

Recommendation:

1. Do Nothing is unacceptable. Violates NESC/WAC regulations and represents an unacceptable level of risk to public safety and infrastructure.
2. Targeted DSM is not allowed.
3. FDR Tie – represented in the program (indirect solution)
4. Segment Reconductor – represented in the program (direct solution)

Segment Reconductor and FDR Tie

Projects listed in the current 5-year "Segment Reconductor and FDR-Tie" program are summarized on the Distribution Engineering SharePoint site. The following is a summary of those projects listings as of May 30, 2018.

https://sp2016.corp.com/sites/sp/enso/dist/_layouts/15/start.aspx

Region	2020	2021	2022	2023	2024
West	3,750,000	3,750,000	3,750,000	3,750,000	3,750,000
East	1,875,000	1,875,000	1,875,000	1,875,000	1,875,000
South	1,875,000	1,875,000	1,875,000	1,875,000	1,875,000
Total	**7,500,000**	**7,500,000**	**7,500,000**	**7,500,000**	**7,500,000**

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.

Distribution assets are fixed resources and therefore, project alternatives are generally dominated by supply side solutions. Operating limitations are codified in Avista internal standards (as listed) but derived through industry and regulatory policies including: Washington Administrative Code (WAC), National Electric Safety Code (NESC), National Electric Code (NEC), and IEEE/ANSI standards & manufacturer recommendations specific to equipment ratings and operating limits.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Segment Reconductor and FDR Tie business case* and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 7/17/19
Print Name: Cesar Godinez
Title: Distribution Engineering Manager
Role: Business Case Owner

Signature: Date: 7/17/19
Print Name: Josh DiLuciano
Title: Director of Electrical Engineering
Role: Business Case Sponsor

Signature: Date: 7/19/19
Print Name: Heather Rosentrater
Title: VP, Energy Delivery
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.1	David James		Above signatures	04/07/17	Initial version
1.2	Cesar Godinez	06/28/19	Above signatures		Addition of Voltage/Transformer Mitigation Work Identified by AMI Data

Template Version: 03/07/2017

Segment Reconductor and FDR Tie

EXAMPLES SHOWN FOR ILLUSTRATION:

FDR Status Report (provides baseline circuit performance and logistics information) Warning Level (yellow highlight),

Third & Hatch

3HT12F1

Service Area	Spokane		
Trunk [Mi]	2.11		
Lat. [Mi]	7.12		
Predom. Conductor	556AAC		
Nom. Volt. [kV]	13.2	**Per Phase KVA**	
# Customers	642	A:	9956
Conn. kVA	29173	B:	9219
Peak KVA	11411	C:	9998
Utilization factor	0.391		
Scada Status	3-Phase		
Pri. Meter Customer			

Notes

2015	Feeder Demand (A) AΦmax	BΦmax	CΦmax	BΦavg	Imbal. (%)	Peak Reactive (KVAR)	Station Regs (Buck Boost) AΦ		BΦ		CΦ	
Winter	326	272	292	199.2	7.5%	-35.50	-9	-2	-10	-2	-9	-1
Spring	318	294	322	142.7	7.9%	110.46	-10	-1	-10	0	-9	-1
Summer	387	380	394	212.8	7.7%	753.85	-9	4	-9	2	-9	4
Fall	395	347	377	215.6	9.1%	351.60	-10	3	-10	2	-9	3

Historical Demand (A)

Year	Summer	Winter
13	336	272
14	372	302
15	380	298

Capacitor Information

Cap ID	KVAR Rating	Status	Smart ID	Location
71378	600	ON	2906F	(126 - 146) S Scott
82259	600	ON	2907F	(1 - 99) E Main

Reliability

Year	SAIFI	CAIDI
10	0.18	1:10:09
11	1.23	1:22:32
12	2.11	1:34:54
13	0.06	6:10:04
14	0.09	3:31:01
15	0.45	6:47:31

(Reliability data disregards major event days)

Feeder Health Check

	Value	Cond.	Section ID
Max Loading (%)	62.02	556AAC	389-445931-0
Location:	Pacific-2nd and Scott		
Min. Volts (V)	123.08	1CN15	394-2660217-0
Location :	Under the WSU Riverpoint Campus		

2015 5 Worst Outages

Incident ID	Date	Cust. Hrs.	# Eff Cus.	Dur.	Cause	Location
866563	7-Dec	1014:46:08	152	6:40	Pole Fire	1036 E DESMET AVE UNIT 8
867075	8-Dec	593:50:08	53	11:12	Car Hit Pole	523 E 3RD AVE
868558	15-Dec	222:48:45	25	8:54	Maint/Upgrade	902 E BOONE AVE
790350	8-May	54:22:14	22	2:28	Maint/Upgrade	(1000 - 1098) E Sharp-Sinto
786456	19-Mar	24:11:30	5	4:50	Maint/Upgrade	(800 - 929) E Sprague

Segment Reconductor and FDR Tie

Distribution "500 Amp" Plan (System Planning)

Company standard for the operation and load service planning associated with Avista's electric distribution grid.

Key elements-- Urban "FRD Tie" system. Requires that reserve capacity margins be maintained so that adjacent circuits can restore service to customers in the event of a planned or forced outage. In summary, no urban circuit should be loaded above its 67% capacity limit.

System Limits - Operating & Design

The following set of proposed service limits are based on traditional company service reliability and practices, as well as appropriate state and federal rules and regulations. These are guidelines only, specific situations will arise where these limits must be exceeded because of physical or economic problems.

1. Maximum Outage - 3 hrs.

   This is an approximate number heavily weighted by the political influence of "Keeping the Customer Happy". Avista urban customer service record has been quite good in the past and should be maintained at a high level.

2. Maximum Portion of Customers Served to See Full Length of Outage - 50%

   For example: Feeder outage - 50% of customers on that feeder)
   Substation outage - 50% of customers served by that substation)

   This again is an arbitrary number. However, it is the worst case possibility using the substation connections and feeder sectionalizing practice that is being recommended as General Design Criteria for the future. Most cases would result in a smaller number of customers seeing full outage duration.

Excerpt from "500 Amp" Plan. Source: Distribution SharePoint (3/15/17)

Segment Reconductor and FDR Tie

Avista's SCADA monitoring system incorporates a temperature compensated thermal, ampacity rating system known internally as SVL (Scada Variable Limit). SVL has been in use since 1993. The following indicates a summary screen indicating the top ten most heavily loaded (by % capacity) transmission lines, substation power transformers, and distribution circuits. This screen is continuously monitored by System Operators but also used by Area Engineers to capture data during peak load conditions. It provides additional data to aid with project planning for the segment reconductor program.

SCADA Variable Limits

Top 10 Lists

Note 1: It may be necessary to manually refresh this display to update the sort order.

Last Ran: 02-Jul-2013 15:39:49

BEACON Temperature Was: 98.1 F

Recalc

				Reading At Last Run	Rated Limit	% Of Rated
Top 10 (% Of Rated) Transmission Breakers						
1	OROFINO	CB	A343	451.0	563.2	80.1
2	STRATFRD	CB	A46	435.1	571.5	76.1
3	STRATFRD	CB	A50	455.4	600.0	75.9
4	WARDEN	CB	A310	521.0	711.1	73.3
5	WARDEN	CB	A253	212.0	291.6	72.7
6	PINE_PUD	CB	RATHDRUM_LINE	424.0	596.4	71.1
7	CLEARWTR	CB	A217	383.6	575.5	66.7
8	NLEWISTN	CB	A588	382.5	575.5	66.5
9	NOXON	CB	R316	674.4	1177.2	57.3
10	RATHDRUM	CB	CAB_LINE	676.5	1183.5	57.2
Top 10 (% Of Rated) Transformers						
1	NRTHEAST	XFMR	#2	834.7	983.5	84.9
2	CDALENE	XFMR	#2	1221.0	1467.7	83.2
3	10TH_STW	XFMR	#1	773.7	960.9	80.5
4	BARKERRD	XFMR	#1	780.6	983.5	79.4
5	COLBERT	XFMR	BPAT_COLBERT	767.0	983.5	78.0
6	DALTON	XFMR	#2	754.3	978.5	77.1
7	AIRWYHGT	XFMR	#2	752.4	983.5	76.5
8	PRAIRIE	XFMR	#2	669.1	875.6	76.4
9	WAIKIKI	XFMR	#1	746.7	983.5	75.9
10	POUNDLN	XFMR	#1	709.7	960.9	73.9
Top 10 (% Of Rated) Feeders						
1	MILLWOOD	CB	12F4	471.0	537.6	87.6
2	CDALENE	CB	124	457.2	532.9	85.8
3	POUNDLN	CB	1201	420.8	516.5	81.5
4	WAIKIKI	CB	12F2	430.0	537.6	80.0
5	ROSSPARK	CB	12F5	429.0	537.6	79.8
6	WAIKIKI	CB	12F3	422.8	537.6	78.7
7	9TH_CENT	CB	12F4	340.0	435.0	78.2
8	SANDPNT	CB	4S23	238.0	307.7	77.4
9	CRTCHFLD	CB	1210	396.0	516.5	76.7
10	10TH_STW	CB	1256	392.4	516.5	76.0

Segment Reconductor and FDR Tie

FDR by Area. Shown only to illustrate the scale of the effort to monitor our distribution system.

	A	B	C	D	E	F	G	H	I	J	K	L
1	REV	######		FDR BY AREA ENGINEER -- DISTRIBUTION ENG. SHAREPOINT								
2	im Figart, Marshall Law (temp			Liz Frederiksen			Scott Weber, Marshall Law			Marc Lippincot	Dan Knutson	
3	Spokane	Spokane	Deer Park	Mar/Pull	L/C	Grangeville	CDA	Kell/St. M	Sandpoint	Colville	Davenport	Othello
4	3HT12F1	L&S12F1	CLA56	DER651	CFD1210	COT2401	APW111	BIG411	BLA311	ARD12F2	DVP12F1	L&R511
5	3HT12F2	L&S12F2	COB12F1	DER652	CFD1211	COT2402	APW112	BIG412	CGC331	CHW12F2	DVP12F2	L&R512
6	3HT12F3	L&S12F3	COB12F2	DIA231	DRY1208	CRG1260	APW113	BIG413	CKF711	CHW12F3	FOR12F1	LIN711
7	3HT12F4	L&S12F4	DEE12F1	DIA232	DRY1209	CRG1261	APW114	BUN422	CLF712	CHW12F4	FOR2.3	OTH501
8	3HT12F5	L&S12F5	DEE12F2	ECL221	HOL1205	CRG1263	APW115	BUN423	NRC351	CLV12F1	HAR12F1	OTH502
9	3HT12F6	LIB12F1	LOO12F1	ECL222	HOL1206	GRV1271	APW116	BUN424	ODN731	CLV12F2	HAR12F2	OTH503
10	3HT12F7	LIB12F2	LOO12F2	EWN241	HOL1207	GRV1272	AVD151	BUN426	ODN732	CLV12F3	LF34F1	OTH505
11	3HT12F8	LIB12F3	MLN12F1	GAR461	LMR1530	GRV1273	AVD152	LKY551	OLD721	CLV12F4	LL12F1	RIT731
12	9CE12F1	LIB12F4	MLN12F2	JUL661	LMR1531	GRV1274	BLU321	LKY552	OLD722	CLV34F1	ODS12F1	RIT732
13	9CE12F2	MEA12F1		JUL662	LMR1532	JPE1287	BLU322	MIS431	PRV4S40	*GIF34F1	RDN12F1	ROX751
14	9CE12F3	MEA12F2		LAT421	LOL1266	KAM1291	CDA121	OGA611	SAG741	GIF34F2	RDN12F2	SOT521
15	9CE12F4	MIL12F1		LAT422	LOL1359	KAM1292	CDA122	OSB521	SAG742	GRN12F1	WIL12F1	SOT522
16	AIR12F1	MIL12F2		LEO611	NLW1222	KAM1293	CDA123	OSB522	SPT4S21	GRN12F2	WIL12F2	SOT523
17	AIR12F2	MIL12F3		LEO612	NLW1321	KOO1298	CDA124	PIN441	SPT4S22	GRN12F3		SPR761
18	AIR12F3	MIL12F4		M15511	PDL1201	KOO1299	CDA125	PIN442	SPT4S23	KET12F1		WAS781
19	BEA12F1	NE12F1		M15512	PDL1202	NEZ1267	DAL131	PIN443	SPT4S30	KET12F2		
20	BEA12F2	NE12F2		M15513	PDL1203	ORO1280	DAL132	STM631		ORI12F1		
21	BEA12F3	NE12F3		M15514	PDL1204	ORO1281	DAL133	STM632		ORI12F2		
22	BEA12F4	NE12F4		M15515	SLW1316	ORO1282	DAL134	STM633		ORI12F3		
23	BEA12F5	NE12F5		M23621	SLW1348	WEI1289	HERN	WAL542		SPI12F1		
24	BEA12F6	NW12F1		NMO521	SLW1358	WIK1278	HUE141	WAL543		SPI12F2		
25	BEA13T09	NW12F2		NMO522	SLW1368	WIK1279	HUE142	WAL544		*VAL12F1		
26	BKR12F1	NW12F3		PAL311	SWT2403		LKV341	WAL545		VAL12F2		
27	BKR12F2	NW12F4		PAL312	TEN1253		LKV342			VAL12F3		
28	BKR12F3	NW13T23		POT321	TEN1254		LKV343					
29	C&W12F1	OPT12F1		POT322	TEN1255		IDR251					
30	C&W12F2	OPT12F2		TUR111	TEN1256		IDR252					
31	C&W12F3	PST12F1		TUR112	TEN1257		IDR253					
32	C&W12F4	PST12F2		TUR113			PF211					
33	C&W12F5	ROS12F1		TUR115			PF212					
34	C&W12F6	ROS12F2		TUR116			PF213					
35	CHE12F1	ROS12F3		TUR117			PRA221					
36	CHE12F2	ROS12F4		ROK451			PRA222					
37	CHE12F3	ROS12F5		RSA431			PVW241					
38	CHE12F4	ROS12F6		SPA442			PVW243					
39	EFM12F1	SE12F1		SPU121			RAT231					
40	EFM12F2	SE12F2		SPU122			RAT233					
41	F&C12F1	SE12F3		SPU123			SPL361					
42	F&C12F2	SE12F4		SPU124								
43	F&C12F3	SE12F5		SPU125								
44	F&C12F4	SIP12F1		TKO411								
45	F&C12F5	SIP12F2		TKO412								
46	F&C12F6	SIP12F3		TVW131								
47	FWT12F1	SIP12F4		TVW132								
48	FWT12F2	SIP12F5		WOR471								
49	FWT12F3	SLK12F1										
50	FWT12F4	SLK12F2										
51	GRA12F1	SLK12F3										
52	GRA12F2	SUN12F1										
53	GRA12F3	SUN12F2										
54	GLN12F1	SUN12F3										
55	GLN12F2	SUN12F4										
56	H&W12F1	SUN12F5										
57	H&W12F2	SUN12F6										
58	INT12F1	WAK12F1										
59	INT12F2	WAK12F2										
60		WAK12F3										
61		WAK12F4										
62												
63												

*VAL12F1 & GIF34F1 are shared by Colville and Davenport offices

Non-Avista & select customer dedicated FDRs omitted

# by Area Engr	FDR Count	Dist Mngt System (SG)
Spokane	123	3PH SCADA
South	95	1PH SCADA
East	77	
North	24	
Big Bend	28	
Total	**347**	

REV NOTES

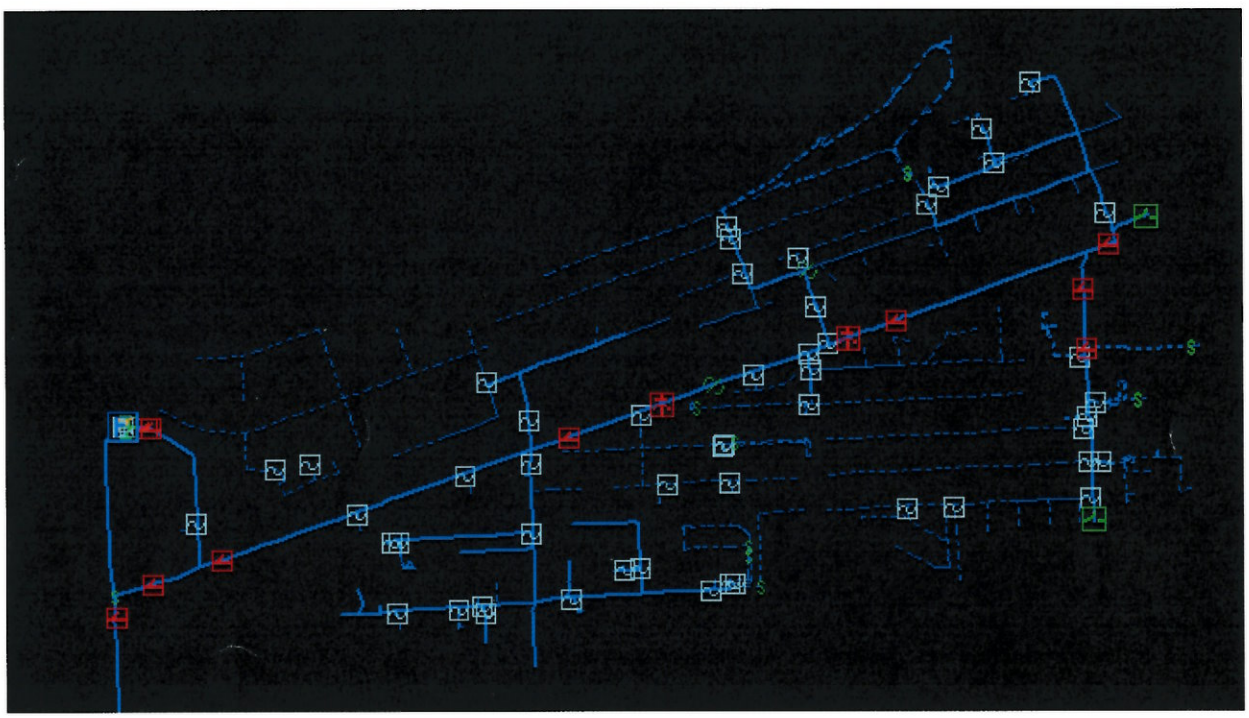
12/10/2013	LMR	LEWISTON MILL ROAD ENERGIZATION FALL 2014
12/10/2013	NLW	N LEW 13 KV SUB MOVED TO N LEWISTON 230 KV 2014
9/23/2014	GRA	NEW GREENACRES SUB 2015
9/24/2014	GIF	ADD 13 KV AT GIFFORD IN 2015
7/20/2016	RAT	231 and 233 DMS
8/26/2016	HAR	4KV CONVERSION, ASSIGN DAV TO BB

Segment Reconductor and FDR Tie

Synergi Computer Modeling (Millwood 12F4 screen shot)

Computer simulation is the primary tool used to identify and develop strategies to mitigate a thermal overload condition. Note, that Avista's electric distribution system has been developed over the full course of the Company's operating history and infrastructure installed near the turn of the century (1900) is still in-service. Though current Avista construction standards limit the number of overhead primary wires to four (4): #4 ASCR, 2/0 ACSR, 336 AAC, 556 AAC; Avista maintains a fleet of seventy five (75) different primary wires and cables. Many are no longer available commercially and we maintain 'hand coils' salvaged from project work in order to effect maintenance repairs on those conductor segments. We ceased to install overhead copper conductors in the 1950's though today, thousands of miles of #6A, #6CW, and other copper conductors remain in service.

Synergi Computer System: Millwood 12F4 Circuit



ER 7001/ 7003 Structures and Improvements

EXECUTIVE SUMMARY

This program is be responsible for the capital maintenance, site improvement, and furniture budgets at over 40 Avista offices, storage buildings, and service centers (over 900,000 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 (Terracon), 30% is set aside for Manager Requested projects, and 20% is kept aside for unexpected capital needs and furniture replacements. There is currently a $7M Asset Condition backlog identified using Paragon Asset Condition software. A funding of $3.5M will allow us to maintain a flat backlog over the next 5 years.

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 their 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.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Lindsay Miller	Initial Version	07/10/2018	Initial Version
2.0	Lindsay Miller	Executive Summary Only	07/07/2020	Revised Template

ER 7001/ 7003 Structures and Improvements

GENERAL INFORMATION

Requested Spend Amount	$3,500,000
Requested Spend Time Period	Yearly
Requesting Organization/Department	Facilities
Business Case Owner | Sponsor	Eric Bowles | Dan Johnson
Sponsor Organization/Department	Shared Services
Phase	Planning
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

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 our building systems are also 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 optimal today due to changes in our vehicle sizes, materials storage, and operations flow. These changes have required the need for project funding to address changing business and site requirements as well.

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

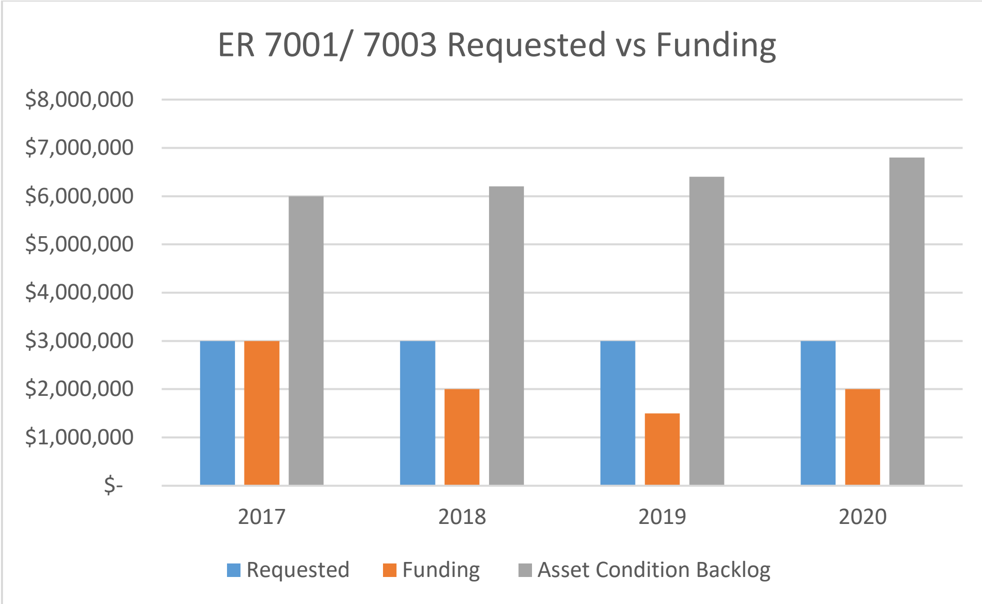
ER 7001/ 7003 Structures and Improvements

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
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

ER 7001/ 7003 Structures and Improvements

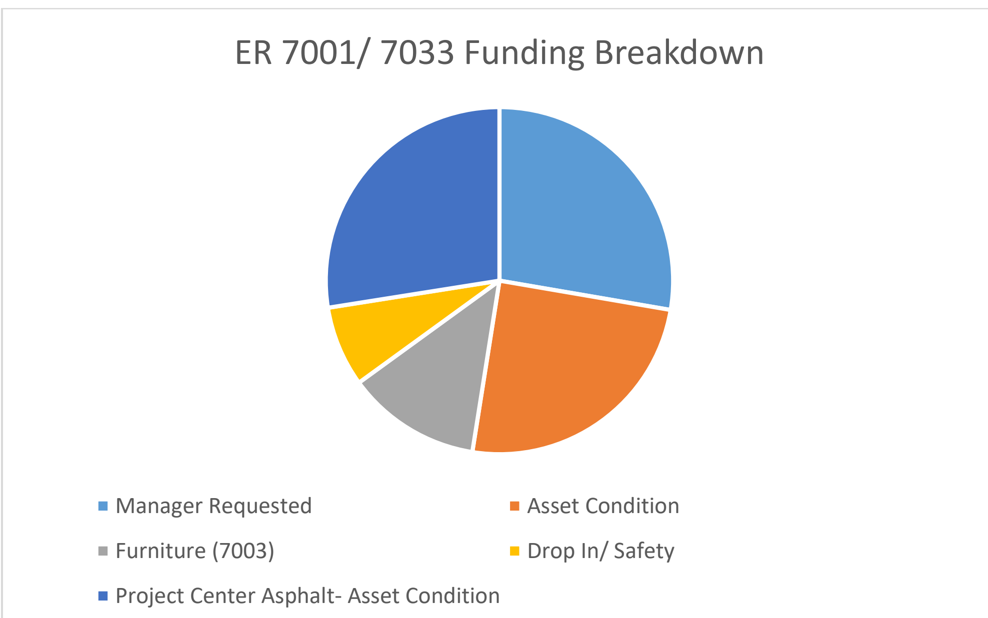
Main Campus Parking Garage	2019	1411 E. Mission Ave.	Spokane	WA
Main Campus Ross Park Building	1903	1411 E. Mission Ave.	Spokane	WA
Main Campus Service Building	1959	1411 E. Mission Ave.	Spokane	WA
Main Campus Warehouse Building	1959	1411 E. Mission Ave.	Spokane	WA
Main Campus Waste and Asset Recovery	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

ER 7001/ 7003 Structures and Improvements



Funding backlog

There is currently an identified backlog of $6.8M 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.

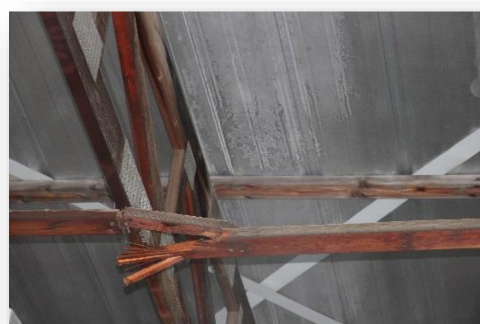


ER 7001/ 7003 Structures and Improvements

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 take into account 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

This portion of the program is for furniture replacements based on industry standard lifecycles, condition, and availability of parts. The program is also meant to support new furniture additions required on approved building projects.

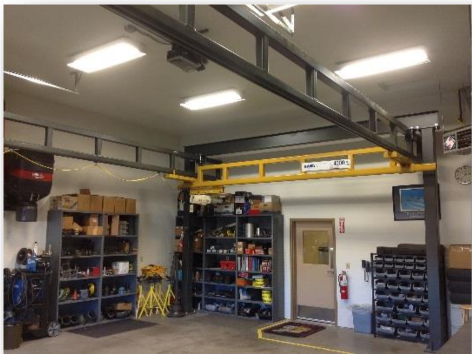
ER 7001/ 7003 Structures and Improvements

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 Operations site managers in June the year before. The list is then vetted for validity and business need by director-level management. Approved projects are then 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 will be 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.

ER 7001/ 7003 Structures and Improvements

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 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.

Customers benefit from this project by Facilities providing a 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 is deferred

As previously stated there is an identified backlog of Asset Condition work of $6.8M. This list is growing every year as our buildings age and new items are identified that need replacement. Deferring this work will cause a large bowel 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 one time capital investment.

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 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
2) Environmental/ Compliance: Ensure that the building and site meets with Avistas environmental standards
3) Employee/ Customer Impacts: Room for employee or operations growth
4) Operational Efficiency: Ensure that operational needs of employees are being met
5) Asset Condition: Provide systems and materials that meet with Avista standards

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

The Asset Condition Study and Asset Condition Report for all of Avista's Assets is used to help determine the best options to resolve the various Asset Condition needs.

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.

The Asset Condition Study and Asset Condition Report for all of Avista's Assets 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.

Recommended Solution – Fund Program at full amount

This will allow us 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.

Option	Capital Cost	Start	Complete
Fund Program at Full Amount	$3.5M	01 2021	12 2021
Alternative #1- Partially Fund Program	Less than $3.5M	01 2021	12 2021
Alternative #2- Do Nothing	$0	-	-

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

There is currently an identified backlog of $6.8M 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.

ER 7001/ 7003 Structures and Improvements

Even funding this program at the $3M level we will never be able to completely reduce the backlog. Providing more than the $3M 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.

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.**

Average funding splits based on project priorities

This program is be responsible for the capital maintenance, site improvement, and furniture budgets at over 40 Avista offices, storage buildings, and service centers (over 900,000 total square feet) Companywide. This program is intended to systematically address the following needs:

- Lifecycle asset replacements (examples: roofing, asphalt, electrical, plumbing)
- Lifecycle furniture replacements and new furniture additions (to support growth)
- 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.)

This program would encompass capital projects in all construction disciplines (roofing, asphalt, electrical, plumbing, HVAC, landscaping, expansions, remodels, energy efficiency projects). 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.

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

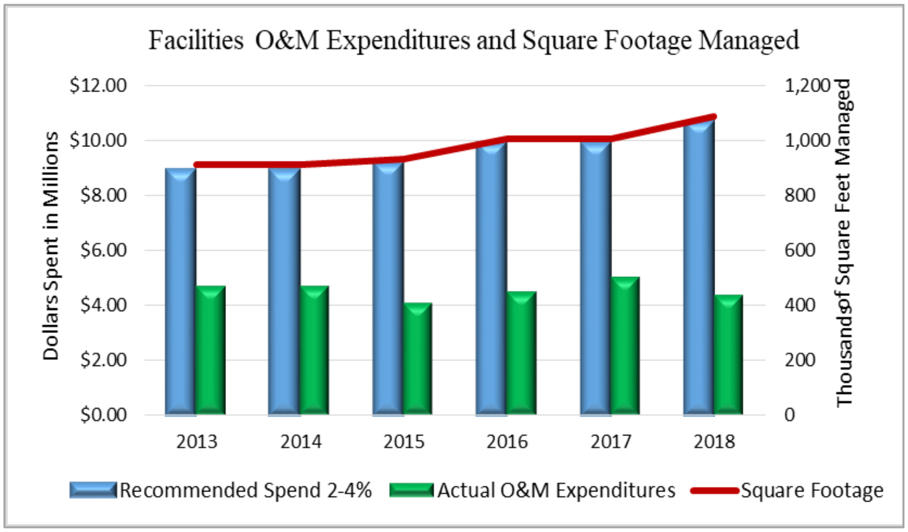
This Business Case will impact the employees that work out of the offices and locations where projects are completed. Other teams that may be impacted are: ET, ET Security, Radio Relay, Environmental and Stores/ Warehouse.

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

<u>Alternative #1 – Partially Fund Program based on priority</u>

ER 7001/ 7003 Structures and Improvements

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 over the long-term. 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 maintenance and replacement requirements based on the Terracon report of $8,800,640 *per year*, which equals 3.64% of the current replacement value of the assets. 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.

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.

<u>Alternative #2 – Do nothing</u>

This option is not recommended. Building improvements are capital events that materially extend the useful life of a building and/or increase the value of a building. Building improvements are capitalized and recorded as an addition of value to the existing building. Sites will continue to decline due to normal wear and tear. The failure of certain systems, such as roofing or HVAC, can cause major damage to other areas of the building. Walkways and structural issues not being addressed could have safety impacts to employees, visitors and customers.

When failures occur the capital investment must be made, regardless of funding. This program provides an avenue to PLAN these capital investments.

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.

The majority of 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.

2.6 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 customer performance and reliability. Being able to provide service to our customers safely and efficiently is a cornerstone of Avista and the current Pullman Operations office does not allow employees to meet those goals.

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

Hopefully the business problems described earlier makes a strong case that this investment makes sense, as to avoid significant operational, reliability, and performance risks. As the project progresses, the scope and budget will be re-baselined as required. And hopefully the project can come in possibly under budget and ahead of schedule. Full oversight of the scope and budget will be provided to the Facilities Steering Committee (see Section 3.1 (A)) for their review and evaluation as described in Section 3.2 and 3.3.

2.8 Supplemental Information

ER 7001/ 7003 Structures and Improvements

2.8.1 Identify customers and stakeholders that interface with the business case

The project within this business case will impact the Pullman Service Center Team. The team will be able to work out of the current service center during construction but we will be reaching out to the team during the design and construction phases.

2.8.2 Identify any related Business Cases

None

3.1 Steering Committee or Advisory Group Information

ER7001 Facilities Structures and Improvements is a 5-year program created to address the capital lifecycle asset replacements and business/site improvements at all of 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 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 981,000 square feet. These facilities were constructed between 1903 and 2016. Terracon estimated the value of this infrastructure at approximately $242 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.

ER 7001/ 7003 Structures and Improvements

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.

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

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.

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.

The undersigned acknowledge they have reviewed the ER 7001/ 7003 Structures and Improvements and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Eric Bowles Date: 8/3/2020

Print Name: Eric Bowles

ER 7001/ 7003 Structures and Improvements

Title:	Corporate Facilities Manager		
Role:	Business Case Owner		
Signature:	Dan Johnson	Date:	8/3/2020
Print Name:	Dan Johnson		
Title:	Director Shared Services		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

Substation – New Distribution Station Capacity Program

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) a synopsis of the problem, 2) the service code and jurisdiction of customers impacted, 3) the recommended solution, 4) the cost of the solution, 5) how the solution will benefit customers identified, 6) the significance of the timeline and 7) the risks of not approving this business case.*
<< Both the Executive Summary and Version History should fit into one page >>

New distribution substations added to the system for load growth and reliability are critical to the long term operation of the system. As load demands, increase and customer expectations rise regarding reliability, incremental distribution substation capacity is required. This allows for improved operational flexibility, better system reliability, and easier routine maintenance scheduling as equipment is more easily taken out of service because load can be transferred.

Capacity on the electric system to be able to take components out of service on a planned basis so that maintenance or replacements can be made has reduced as load demands have increased. Having the right amount of backup capacity in each area is critical for the continued appropriate management of the electric system. This business case is important because through it, customers can likely continue to receive electric service at a level that they have grown accustom to receiving.

Service: ED – Electric Direct

Jurisdiction: Various. Each rebuild project has its own Jurisdiction.

Engineering Roundtable Request Number: Various. Each rebuild project has its own ERT Request.

2020 Expected Spend: $7,600,000

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Ken Sweigart	Initial Version	04/14/2017	Initial Version
2.0	Karen Kusel / Glenn Madden	Update to 2020 Template	06/30/2020	

Substation – New Distribution Station Capacity Program

GENERAL INFORMATION

Requested Spend Amount	$6,000,000 per year
Requested Spend Time Period	On Going
Requesting Organization/Department	T&D
Business Case Owner | Sponsor	Glenn Madden | Josh DiLuciano
Sponsor Organization/Department	T&D
Phase	Execution
Category	Program
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]

New distribution substations added to the system for load growth and reliability are critical to the long term operation of the system. As load demands, increase and customer expectations rise regarding reliability, incremental distribution substation capacity is required. This allows for improved operational flexibility, better system reliability, and easier routine maintenance scheduling as equipment is more easily taken out of service because load can be transferred.

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

As load demands, increase and customer expectations rise regarding reliability, incremental distribution substation capacity is required.

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

Performance and Capacity – Increasing load on an aging electrical system. And the better the asset condition, the fewer equipment failures and possible customer outages there are.

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

This is a continuing effort to stay ahead of the curve to avoid reliability issues.

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 and Studies.

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 on System Planning Sharepoint site.

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)]

This program adds new distribution substations to the system in order to serve new and growing load as well as for increased system reliability and operational flexibility. New substations under this program will require planning and operational studies, justifications, and approved Project Diagrams prior to funding.

Alternatives considered include:

Do Nothing: Maintain (to the best of our ability) all obsolete or end-of-life apparatus. Repair or replace equipment on emergency basis only. Some repairs would not be possible due to obsolescence. Considerably more, and longer, customer outages would result. Although there is zero Capital cost connected with keeping the status quo there are some associated O&M and other system sustainment costs.

Extension of distribution feeders from neighboring substations and increased capacity at those substations would be required at a minimum. The negative impact is most certainly reduced reliability and difficulty in long term maintenance and system operation. Increased liability would result.

Solution: Anticipated load growth requires the addition of two new substations per year over the 2017-2026 horizon

Option	Capital Cost	Start	Complete
Recommended Solution	$6M	Annually	Annually
Alternative #1: Do Nothing	$0		
Extend Existing Distribution Feeders			

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.

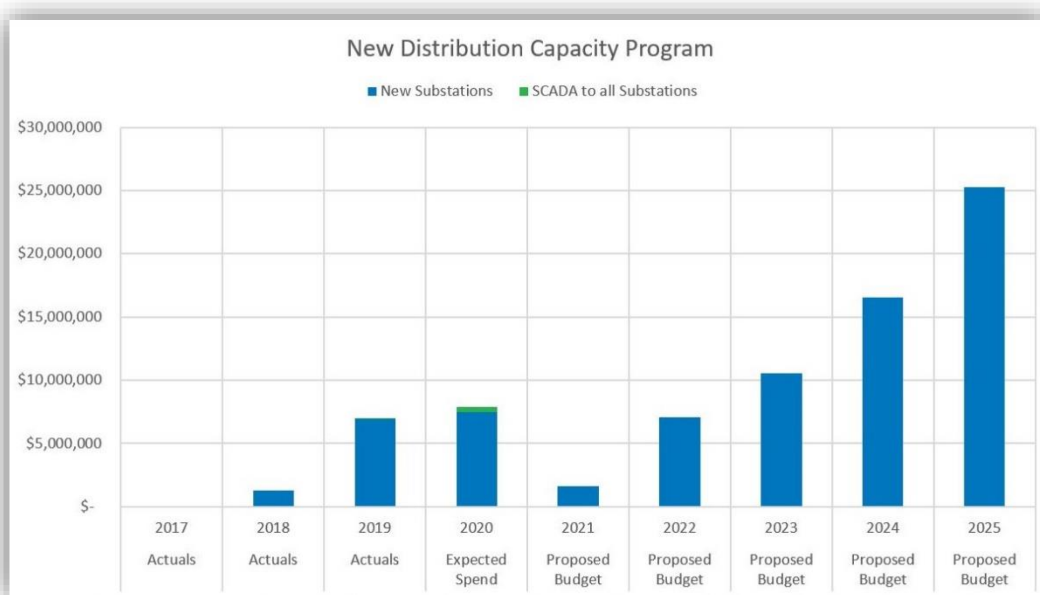
Substation – New Distribution Station Capacity Program

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.]

Below is a graph showing previous years actual spend on this Business Case, the Expected Spend for 2020 and budget requests for the future.



O&M will increase due to the addition of electric substation and associated transmission and distribution lines. This will include inspections and maintenance of equipment.

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.

Status Quo – Obsolete equipment drives up maintenance costs and outage risks. Extending Distribution Feeders – higher risk of load issues and customer outages.

Substation – New Distribution Station Capacity Program

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).]

See graph above, Section 2.2. Transfers to plant will occur when a substation is in-service or energized. Adhering to project timelines will save capital carrying costs.

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

These projects will help Avista stay ahead of the curve of load growth and equipment age to prevent 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

Failure to adjust to load changes and customer needs will lead to equipment failures, customer outages and expensive emergency projects.

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.]

- Glenn Madden - Manager, Substation Engineering
- Project Engineer/Project Manager (PE/PM) – Various

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.

The Engineering Roundtable manages the prioritization of projects within this business case as supported by Asset Management studies and input from company subject matter experts. The Engineering Roundtable is comprised of representatives from the following departments: Asset Management, Compliance, System Planning, System Operations, Telecommunications, Transmission Contracts, Protection Engineering, Substation Engineering, Transmission Engineering, and Substation Support.

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 Substation – New Distribution Station Capacity 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:	Glenn Madden		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:		Date:	
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		

Transmission Minor Rebuild

EXECUTIVE SUMMARY

The Transmission Minor 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 Failed Plant and Asset Condition.

The implementation of this business case will be considered successful if these projects are all completed on an annual basis or the dates identified in the Engineering Roundtable Project List.

The Transmission Minor Rebuild Business Case covers the follow-up work to Wood Pole Inspections, Aerial Patrol inspections, and Ad Hoc ground inspections and Air Switch Replacements.

During routinely scheduled inspections, issues are discovered regarding the condition of assets, including items such as rotten poles, broken/split/rotten crossarms, broken conductor or ground/shield wire, and air switches that no longer operate safely or reliably.

The recommended solution is to correct the issues found by these inspections either in the same year, or within 1-2 years afterwards. There are no expected business impacts to continuing this program in place. If Avista does not fully implement this business case, it runs an increased risk of system failures, customers outages, and wildfires. This Program will have a Service Code of Electric Direct and a Rate Jurisdiction of Allocated North. An annual spend of $3,343,420 is needed to complete the mitigations as follows:

- *ER 2057, BI AMT12 and AMT13 ($1,613,420): Wood and Steel Pole Inspections (FAC-501-WECC-1, TMIP)*
- *ER 2057, BI XT902 ($1,500,000): Aerial and ground inspections (FAC-501-WECC-1, TMIP, and Ad Hoc)*
- *ER 2254, BI AMT10 ($230,000): Planned/unplanned replacements based on failure or upgrade needs*

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*	*7/10/2020*	
1.0	*Prudent Penny*	*Updated Approval Status*	*6/1/2020*	*Full amount approved*
1.1	*Debbie Downer*	*Budget change*	*10/15/20*	*$50,000 deferred to 2021*
2.0				

Transmission Minor Rebuild

GENERAL INFORMATION

Requested Spend Amount	$16,717,100
Requested Spend Time Period	*5 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	Multiple (see Executive Summary)

1. BUSINESS PROBLEM

1.1 *The Transmission Minor 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 Failed Plant and Asset Condition.*

The Business Case also covers aerial, ground and Ad Hoc patrols intended to pro-actively replace structures and structure components as riak on near term failure. This work (BI XT902: $1.5M) in previous years was funded through the Operations Storms blanket Business Case.

1.2 What is the current or potential problem that is being addressed? *. Avoidance of failure conditions; that, if left unaddressed in the near-term (<1-2 years) will result in an increased risk of system failures, customers outages, and wildfires.*

1.3 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, combined with Failed Plant and Asset Condition: Customer benefits by having a Transmission System in compliance with Federal Standards, and one where identified near-term failure risks are proacitively addressed.*

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

Transmission Minor Rebuild

1.5 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.*

1.6 Supplemental Information

1.6.1 Please reference and summarize any studies that support the problem

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

1.6.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Below are a few examples of the metric documents developed for this Business Case.

	A	B	C	D	E	F	G	H	I
1	STRUCTURENUM	FEEDERID	Severity	STATUS	Condition 1	Condition	DESCRIPTION	PATROLLEDBY	DATEPATROLLED
2	11/4	Pine St.-Rathdrum	No defect	OK	Bird Nest	-		wss3058	6/26/2019
3	5/6	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Crossarm - Split	-		wss3058	6/26/2019
4	3/4	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Pole - Woodpecker Holes	-		wss3058	6/26/2019
5	22/3	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Pole - Woodpecker Holes	-		wss3058	6/26/2019
6	20/6	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Crossarm - Split	-		wss3058	6/26/2019
7	19/3	Pine St.-Rathdrum	Moderate defect to be monitored	OK	Phase Insulator - Broken	-	Repair next outage on the line	wz74pk	5/3/2018
8	19/2	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Phase Insulator - Broken	-	Repair next outage on the line - both	wss3058	6/26/2019
9	15/2	Pine St.-Rathdrum	Serious defect, repair inside 6 mo	Remediation Required	Crossarm - Split	-		wss3058	6/26/2019
11	18/2	Pine St.-Rathdrum	Serious defect, repair immediately	Remediation Required	Crossarm - Broken	-	south arm busted open pretty good	wss3058	6/26/2019
12	27/3	Pine St.-Rathdrum	Serious defect, repair inside 6 mo	Remediation Required	Crossarm - Split	-		wss3058	6/26/2019
13	26/4	Pine St.-Rathdrum	Serious defect, repair inside 6 mo	Remediation Required	Crossarm - Split	-		wss3058	6/26/2019
14	26/2	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Pole - Woodpecker Holes	-		wss3058	6/26/2019
15	25/3	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Pole - Woodpecker Holes	-		wss3058	6/26/2019
17	24/3	Eighth & Fancher-Latah	Moderate defect to be monitored	Remediation Required	Pole - Split	-	roadside pole hollow top	wss3058	6/17/2019
18	27/10	Eighth & Fancher-Latah	Minor defect to be noted	OK	Phase Insulator - Broken	-	Repair next outage on the line	wz74pk	5/11/2017
19	28/2	Eighth & Fancher-Latah	Minor defect to be noted	OK	Phase Insulator - Broken	-	Repair next outage on the line	wz74pk	5/11/2017
20	14/12	Eighth & Fancher-Latah	Serious defect, repair inside 6 mo	Remediation Required	crossarm - HW loose	Pole - Split	guy need insulation	wss3058	6/17/2019
21	18/9	Eighth & Fancher-Latah	No defect	Remediation Required	Pole - Split	-		wss3058	5/24/2018
22	17/8	Eighth & Fancher-Latah	Serious defect, repair inside 6 mo	Needs Inspection	Pole - Split	-	rotten pole top	wss3058	6/17/2019
23	10/7	Eighth & Fancher-Latah	Moderate defect to be monitored	Remediation Required	Crossarm - Broken	-	split on north side	wss3058	6/17/2019
24	10/12	Eighth & Fancher-Latah	Minor defect to be noted	OK	Phase Insulator - Broken	-	Repair next outage on the line	wz74pk	5/11/2017
25	4/9	Eighth & Fancher-Latah	No defect	OK	Crossarm - Split	-		wss3058	6/17/2019
26	4/10	Eighth & Fancher-Latah	Moderate defect to be monitored	Needs Inspection	Crossarm - Split	-		wss3058	6/17/2019
27	5/5	Eighth & Fancher-Latah	Moderate defect to be monitored	Remediation Required	Crossarm - Split	-		wss3058	6/17/2019
28	8/10	Beacon-Boulder #1	Moderate defect to be monitored	OK	Phase Insulator - Broken	-	Repair next outage on the line	wz74pk	5/11/2017
30	10/7	Beacon-Boulder #2	No defect	Remediation Required	Pole - Split	-		wss3058	5/24/2018
31	5/7	Beacon-Boulder #1	Moderate defect to be monitored	OK	Phase Insulator - Broken	-	Repair next outage on the line	wz74pk	5/11/2017
32	3/5	Beacon-Boulder #1	Serious defect, repair inside 6 mo	Remediation Required	Crossarm - Broken	-		wss3058	6/17/2019
35	18/2	Lind-Warden	No defect	OK	Misc	-	REPLACE BEAR ONPOLE	wz74pk	6/13/2017
36	20/11	Lind-Warden	Moderate defect to be monitored	OK	Pole - Split	-		wz74pk	6/13/2017

	A	B	C	D	E	F	G
1	PM Work						
2	0	6	Replace		Confirmed, G Str 2 DG, 2 SG	3	str
3	0	8	Replace		Confirmed, H w 1 SG	3	str
4	9	5	PM Xarm	PM 2020	Replace arm	3	arm
5	11	3	Split Xarm	PM 2020	Replace arm, 11/4 restaple gnd	3	arm
6	11	6	Split Xarm	PM 2020	Dbl arm, wise to replace str	3	str
7	12	5	replace		confirmed	3	str
8	18	2	split Xarm	PM 2020	Confirmed, high priority	3	arm
9	19	4	stub + PM Xarm	PM 2020	H str	3	str
10	39	4	bad xarm	PM 2020	Y - high priority	3	arm
11	40	3	PM Xarm	PM 2020	confirmed, str	3	str
12	43	8	bad xarm	PM 2020	confirmed	3	arm
13	43	10	stub both		confirmed, bad shape str	3	str
14	53	10	stub both		confirmed, str this year	3	str
15	55	1	stub both, bad top		Confirmed, str, move 60' ahead to get out of creek?	3	str
16	56	5	replace, broken guy wire	guy, PM 20	confirmed - GDA, w side guy	3	str
17	62	11	addded		in bad shape	3	str
18	65	7	Low band, restub, and stub R	Xarm PM 2	yep, rough	3	str
19	65	10	replace		yep, rough	3	str
20	66	12	stub both, bad xarm, broken guy		hot mess, easy access though	3	str
21							
22	Reinforcement						
23	1	9	Stub/PWT - stub/replace	1		60 locations, 72 stubs	

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This is the continuation of an ongoing Program, and requires the mitigation of structure deficiencies.

Option	Capital Cost	Start	Complete
Mitigate Deficiencies	*$16.7M*	*01-2021*	*12-2025*
[Alternative #1]	*$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.

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.

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 and structure component change-outs resulting in facility failure avoidance.

[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.

Replacing structures and structure components is presently the only alternative considered.

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.

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 Novemeber time frame.

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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. This Business Case directly impacts our customer, and places them as its focus.

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 solutions 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.

3.1 Steering Committee or Advisory Group Information

The Engineering Roundtable functions as the Vetting Platform, Steering Committee, and Advisory Group.

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.

3.2 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.

Transmission Minor Rebuild

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:		Date:	
Print Name:			
Title:			
Role:	Business Case Owner		

Signature:		Date:	
Print Name:			
Title:			
Role:	Business Case Sponsor		

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

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