BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-17________

DOCKET NO. UG-17________

EXH. HLR-6

HEATHER L. ROSENTRATER

REPRESENTING AVISTA CORPORATION

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Index of Business Case Justification Narratives

* The transfers to plant associated with this business case represent investment of fifty-two thousand dollars ($52,000), on a system basis, in 2017. Given the relatively low investment amount and near-term completion of the project (i.e., in 2017), a business case justification narrative in the new format was not completed for this project.

Distribution Grid Modernization

1 GENERAL INFORMATION

Requested Spend Amount	$17,500,000
Requesting Organization/Department	Asset Maintenance
Business Case Owner	Laine Lambarth
Business Case Sponsor	Bryan Cox
Sponsor Organization/Department	Asset Maintenance
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

- The program scope is defined by an analytical study done by the Program Engineer for each feeder and by the Distribution Feeder Management Plan which was created and is updated by consulting The Distribution Engineering Standards Engineer and Asset Management Manager.
- Reliability, avoided costs, and capital offset of future O&M expense data is collected and analyzed by Asset Management. This information is normalized and entered into a selection tool which then ranks the feeders.
- The regional distribution engineers for the East, South, North, West and Spokane regions are consulted regarding the feeder ranking and feeder prioritization within their respective regions.
- The program manager then balances the prioritized feeders between the states, rural/urban split, and regions.
- The program manager then collaborates with Electric Operations and Contractors to coordinate the work and track the budget, scope, and schedule.

2 BUSINESS PROBLEM

The Distribution Grid Modernization Program provides value to customers and shareholders through the following objectives of improving:

- <u>Grid Reliability</u> - Replacing aging and failed infrastructure that has a high likelihood of creating customer outages and a need of an unplanned crew call-out which costs more than planned work and would filter into higher rates for customers.
  - o Without programs like Grid Modernization and Wood Pole Management there would be an average 40 pole failure events per year effecting an average of 80 customers for 4.8 hours per event. Totaling a customer impact value of approximately $24,000 per event totaling to $960,000 per year.

- Energy Efficiency - Replace equipment such as old conductor and transformers that have high energy losses with new equipment that is more energy efficient and improve the overall feeder energy performance. This creates the need for less power generation or acquisition and equates to lower rates for customers.
- Operational Ability - Replace conductor and equipment that hinders outage detection and install automation devices that enable isolation of outages.
  - This means shorter outrages for customers because the areas that failed can be identified faster and possibly reroute power automatically. Currently the Grid Modernization Program in the only company initiative installing these devices.
  - The installation of automated line devices on a feeder of 1600 customers reduces an average outage duration from 3 hours to 5 minutes per event for 1200 of those customers.
- Safety - Focus on public and employee safety through smart design and work practices.
  - Replacing aging and failed infrastructure that puts employees and customers at risk of property damage and injury.
  - Bringing infrastructure up to current National Electric Safety Code.
  - Eliminate PCB risk to the public by eliminating transformers containing known PCB's.
  - The Grid Modernization program lowers the risk of high severity safety (S4) events, defined below, as follows:
    - S4 events are categorized as having potential for multiple serious injuries or loss of an individual life; major damage to property or business, and a public health infrastructure impact up to 72 hours.
    - Base Case (do nothing) has the risk of 10 S4 events every 50 years with a total cost of $52.3M.
    - The Grid Modernization Program brings this risk down to 2 events in 50 years with a total cost of $10.4M.

Another Safety objective of The Distribution Grid Modernization Program is to address Washington State's Department of Transportation (WSDOT) Target Zero requirements, which states that utilities move all non-breakaway structures, such as power poles and pad mount transformers, out of highway clear zone as defined in the 10/2005 AASHTO "A Guide for Accommodating Utilities Within Highway Right-of-Way," which is attached for reference. Washington State law requires that we complete this task by year 2030. Currently this is the only program within Avista actively addressing this mandate. Additional Control Zone justifications include the following Washington Administrative Codes (WAC) and Revised Codes of Washington (RCW):

- WAC 468-34-350 - Control Zone Guidelines
- WAC 468-34-300 - Overhead Lines Location
- RCW 47.32.130 Dangerous Objects and Structures as Nuisances
- RCW 47.44.010 Wire and Pipeline and Tram and Railway Franchises - Application - Rules on Hearing and Notice
- RCW 47.44.020 Grant of Franchise - Condition - Hearing

- Selected Metrics include:
  - Energy savings provided by completed work
  - Number of circuit miles of work completed
  - Number of sustained outages (anything longer than 5 minutes) recorded in Avista's Outage Management Tool (OMT).

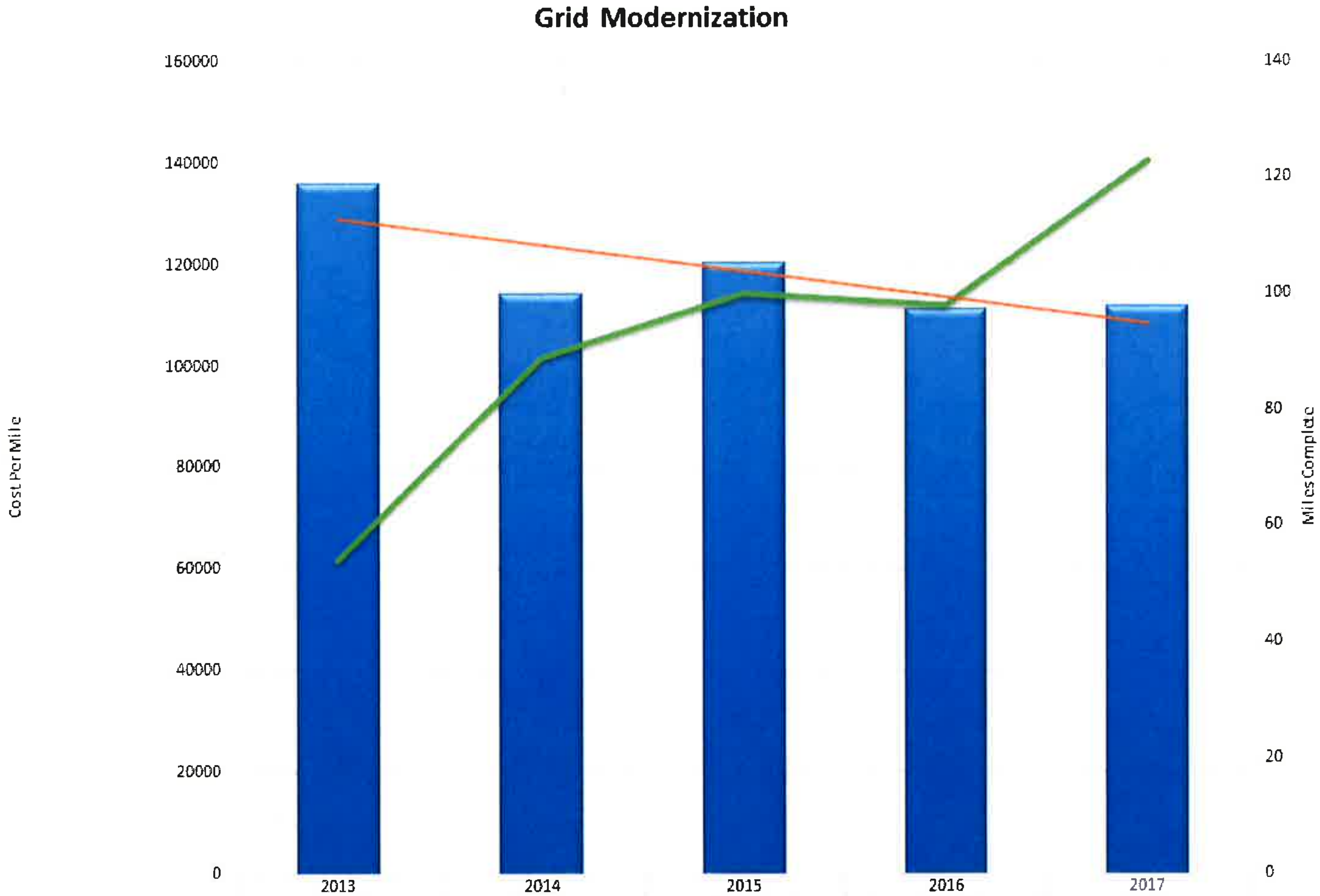
Based on Avista's 2015 Integrated Resource Plan dated August 31st, 2015, the realized and anticipated energy savings by identified feeders is shown in Table 1.

Table 1, Energy Savings based on Integrated Resource Plan

Feeder	Service Area	Year Complete	Annual Energy Savings (MWh)
9CE12F4	Spokane, WA (9th & Central)	2009	601
BEA12F1	Spokane, WA (Beacon)	2012	972
F&C12F2	Spokane, WA (Francis & Cedar)	2012	570
BEA12F5	Spokane, WA (Beacon)	2013	885
CDA121	Coeur d'Alene, ID	2013	438
OTH502	Othello, WA	2014	21
RAT231	Rathdrum, ID	2014	0
M23621	Moscow, ID	2015	413
WIL12F2	Wilbur, WA	2015	1,403
WAK12F2	Spokane, WA (Waikiki)	2016	175
RAT233	Rathdrum, ID	2019	471
SPI12F1	Northport, WA (Spirit)	2019	127
Total			**6,076**

In order to address Avista's entire system and every customer in a 60 year cycle, the program would need to address an average of 190 miles per year of Avista's 11,300 total overhead and underground circuit miles. The miles of work planned is ultimately driven by the approved budget and generally can only be projected for 5 years. At the current funding level and average cost per circuit mile, represented in Table 2 below, it will take us approximately 90 years to address the entire system and every customer.

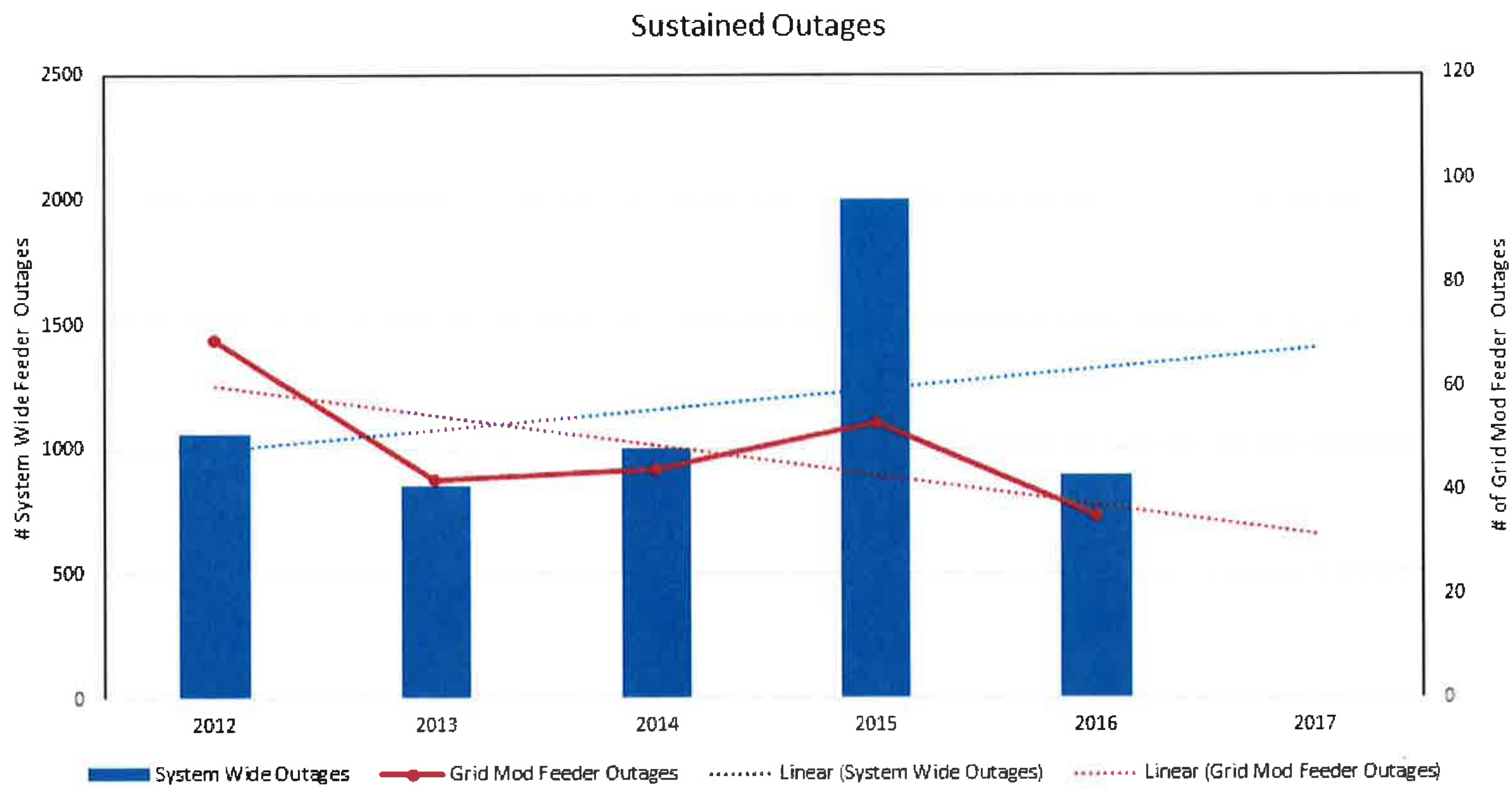
Table2, Grid Modernization Circuit Miles Addressed and Associated Cost



	2013	2014	2015	2016	2017
Cost Per Mile	135770	114232	120171	111172	111682
Circuit Miles Complete	54	89	100	98	123

For tracking the impacts of the programs effect on sustained outages we monitor the OMT sub-reasons identified as potentially avoidable and most directly impacted by The Grid Modernization Program work. Through the end of 2015 there has been a reduction of 0.1 outages per mile of overhead work completed. Table 3, below, illustrates these reduction of outages and therefore the reliability advantages and reasons for the program. The red line represents the reduction of outages of these sub-reasons on the feeders that the Grid Modernization program has completed to date. You will see the Grid Modernization addressed feeder outages are trending down whereas the system wide outages are trending up. If 2015, which is when Avista experienced a large wind storm, was excluded the system wide outages would be trending slightly downward but the Grid Modernization addressed feeders are trending downward at a faster rate.

Table 3, OMT Sustained Outages related to Grid Modernization



3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing - Address issues as the infrastructure fails. This is the most risky as injury or property damage may occur and is estimated to increase the risk cost by $6.1M. It is also the most costly as usually it is done during off hours and ends up in overtime and is estimated to increase O&M by $2.5M. It is also unplanned and therefore takes longer to do. This option would also lead to higher and longer number of customer outages.	$9,000,000 per year		

[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. 2017 request is for $17.5M as we continue to ramp up to the full recommendation.	*$21,000,000 per year*	*01 2012*	*12 2072*
[Alternative #1] Address issues through the different specific company initiatives, such as Wood Pole Management, Transformer Change Out, 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 and travel time, flagging, etc. which means higher rates for customers. This also means the customer could have multiple different planned outages and have multiple different street closers while the crews did specific work at multiple different times. The risk reduction is also cut in half compared to the comprehensive work completed by the Grid Modernization program.	*Per year*	*MM YYYY*	*MM YYYY*

The Grid Modernization Program combines the recommendations from two Avista system performance studies into its work activities to provide refreshed system feeders with new automation capabilities across Avista's distribution system. The first of these studies was performed in 2009 and had a system efficiencies team evaluate the potential energy savings for distribution system upgrades and analyzed the value of selective rebuild with "right sized" conductor replacements for reducing energy losses, improve reliability, and meeting future load growth demand. A second study was conducted in 2013 to assess the benefits of distribution feeder automation for increased reliability, operability, and load loss savings.

The reliability, energy losses, reductions in operations and maintenance (O&M) costs and capital investment from the individual efficiency programs under consideration were combined on a per feeder basis. This approach provided a means to rank and compare optimal feeder modernizing and net resource costs to achieve the desired benefits.

The system efficiencies team evaluated several efficiency programs to improve both urban and rural distribution feeders. The programs consisted of the following system enhancements:

- Conductor losses;

- Distribution transformer losses and PCB mitigation;
- Secondary district losses;
- Conservation Voltage Reduction (CVR);
- Integrated Volt/Var Control (IVVC), and;
- Fault Detection Isolation and Restoration (FDIR) opportunities;

The Grid Modernization Program's charter criterion has grown to include a more holistic approach to the way Avista addresses each project. This vital program integrates work performed under various operational initiatives at Avista including the Wood Pole Management Program, the Transformer Change-out Program, the Vegetation Management Program, various budgeted maintenance programs and the Feeder Upgrade Program.

The ancillary work of the Grid Modernization Program includes the replacement of undersized and deteriorating conductors, replacement of failed and end-of-life infrastructure materials including wood poles, cross arms, fuses and insulators. Inaccessible pole re-alignment, right-away, undergrounding, joint use coordination and clear zone compliance issues are addressed for each feeder section. This systematic overview enables Avista to cost-effectively deliver a modernized and robust electric distribution system that is more efficient, easier to maintain and more reliable for our customers.

The long-term plan aims to upgrade 190 circuit miles per year to cover the whole distribution system in a 60 year cycle. According to Avista's Asset Management subject matter experts a 60 year cycle is optimal due to the average mean time to failure and age profiles of our systems assets. It also coordinates well with the Wood Pole Management's (WPM) program 20 year cycle. The average cost for the Grid Modernization program to rebuild a circuit mile is $110,000. In order to meet the 60 year cycle $21M would be needed each year. Alternatively we could complete the entire system in 80 years for $15.5M each year, but that means we would not address the entire system until approximately the year 2093. This would not be prudent at Asset Management shows a bow wave of infrastructure reaching end of life by the year 2060. Currently the program is still ramping up to its fully desired resource needs and therefore has only requested $17.5M for 2017. The plan is to have enough resources, design, and funding in place to be able to construct the 190 circuit mile per year goal by 2019.

The Grid Modernization Program consists of the following fully allocated resources: Project Manager, Associate Project Manager, Distribution Engineer, six internal designers (customer project coordinators/CPC), and five contract designers and has the following part time shared resources: analyst, and two in-house and two contract field inspector/auditors. Construction labor usually consists of a mix of in-house and contract line crews totaling around eight to twelve five man crews. The program also interfaces with and relies on assistance from the following departments which might require additional resources; Real

Estate, Environmental, Contracts, Substation Engineering, Relay Shop, Electric Shop, SCADA, Network Systems, and Protection Engineering.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Distribution Grid Modernization 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: Laine Lambarth — Date: 4/17/17

Print Name: Laine Lambarth

Title: Grid Modernization Project Mgr

Role: Business Case Owner

Signature: B Cox — Date: 4/17/17

Print Name: Bryan Cox

Title: Sr Dir of HR Operations

Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Laine Lambarth	4/14/2017	Bryan Cox	4/14/2017	Initial version

Template Version: 02/13/2017

Distribution Transformer Change Out Program 2017

1 GENERAL INFORMATION

Requested Spend Amount	$3,000,000
Requesting Organization/Department	Asset Maintenance
Business Case Owner	Cody Krogh
Business Case Sponsor	Bryan Cox
Sponsor Organization/Department	Asset Maintenance
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

Transformer condition, outage information, and energy savings is collected and analyzed by Asset Management. The environmental team tests and tracks PCB level of each transformer by location. This information is reviewed with Asset Maintenance to establish an effective replacement program that prioritizes work based on environmental risk and reliability. Asset Maintenance manages the program and collaborates with Electric Operations and contractors to coordinate the work. Asset Maintenance tracks the work budget, scope, and schedule.

2 BUSINESS PROBLEM

The Transformer Change-Out Program (TCOP) work has three primary drivers. First, the pre-1981 distribution transformers that are targeted for replacement average 44 years of age. Their replacement will increase the reliability and availability of the system. Secondly, the transformers to be replaced are inefficient compared to current standards and their replacement will result in energy savings. Thirdly, pre-1981 transformers have the potential to have Polychlorinated Biphenyls (PCB) containing oil.

The TCOP Program was implemented in 2011. The Program has focused on eliminating all transformers containing or potentially containing PCBs. The initial target was on areas near the Spokane and Pend Oreille River watersheds and has now moved to all transformers containing PCBs. These transformers have specific work plans for removing them from the system. These PCB targeted transformers are on schedule to be replaced by 2019. The second phase of the Program is to replace all remaining pre-1981 transformers through the use of the Wood Pole Management Program. This work is planned to be complete by 2040 based on the current funding request.

PCBs and PCB wastes are regulated by both the Washington Department of Ecology (Ecology), through the Dangerous Waste Regulations, Chapter 173-303 WAC, and by the U.S. Environmental Protection Agency (EPA) under 40 CFR Part 761, the Toxic Substances Control Act (TSCA). The transformers to be removed early in the program are those that are most likely to have PCB containing oil and their replacement will reduce the risk of PCB containing oil spills which are a safety, environmental, and a public relations concern.

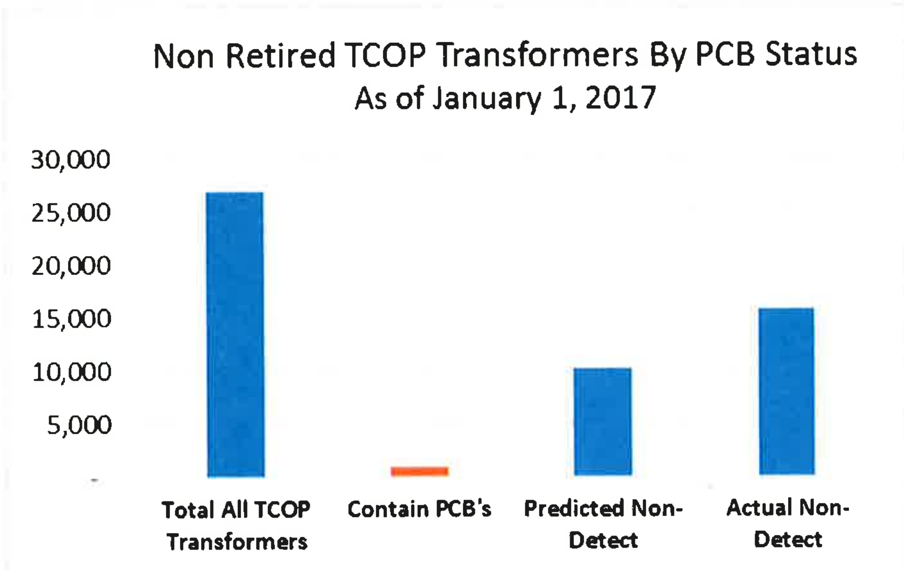
There has also been an increased focus on PCBs and similar contaminants by local, regional, and national initiatives. On April 10, 2010, the EPA had issued an Advanced Notice of Proposed Rulemaking (ANPR) on new PCB regulations. Washington State Ecology created an "urban waters initiative" to investigate persistent and bio-accumulative toxics; this initiative included the Spokane River watershed. The Spokane River is listed on the Clean Water Act "impaired" list for PCB contamination. The City of Spokane began a storm water study to find and reduce sources of PCBs in its storm water system. In addition, PCB cleanup is very difficult in any environment and nearly impossible in aqueous environments. These and other efforts reflect how important it is to keep PCBs from entering the environment. As a result, Avista is determined to aggressively remove PCBs from its electrical distribution system in a disciplined manner.

Currently, there are 906 transformers remaining in our system that are known or predicted to contain a PCB level greater than 1 part per million. In addition, there are 1,098 underground transformers that have been predicted to not contain PCBs (predicted non-detect) however, no actual tests have been conducted on these transformers. These transformers were analyzed using Serial Number Sequencing (SNS) where transformers with similar serial numbers were assumed to have similar PCB levels. Serial Number Sequencing is more cost effective versus PCB testing the pre-1981 transformers in the field. The predicted non-detect transformers do run a risk of containing some level of PCBs. The table below reveals the replacement plans for the targeted transformers in the immediate future.

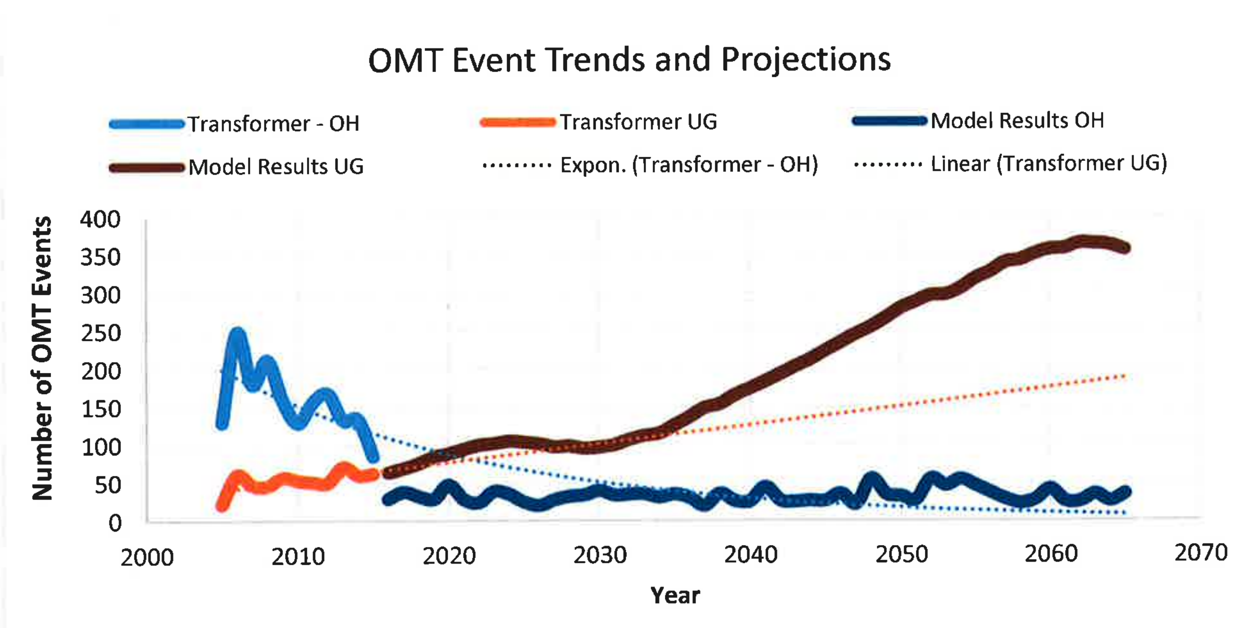
Distribution Transformers Containing PCB's					
	2011-2016		2017	2018	2019
Total	12342	Planned for TCOP Only	815	73	18
Retired	11436				
Remaining	906				
Distribution Underground Transformers Predicted Non Detect (Predicted No PCB's)					
Predicted Non-Detect	1098	Planned for TCOP Only	535	568	0

This is the sixth year of replacing the targeted (PCB containing) distribution transformers. When the program began in 2011, there were over 12,000 targeted transformers. Currently, 7% of the 12,000 are remaining. This program has been successful in converting targeted transformers to a retired asset. The chart below shows remaining transformers year to date.

Distribution Transformer Change Out Program 2017



Another compelling reason to replace the pre-1981 transformers is due to the decreasing reliability caused from a population of transformers that average 44 years old. The optimal replacement age of a transformer is 44 years old. The failure of an aging transformer results in an outage for the downstream customers. The chart below shows the positive reduction in outages as a result of this Program. Note that overhead transformer outages have been reduced nearly 60% between 2007 (approximately 250 outage events) and 2016 (approximately 100 outage events). There is a customer impact value of $5,600 per event according to the U.S. Department of Energy's Interruption Cost Estimate (ICE) Calculator. This reduction in outage events equates to about $840,000 in customer value for 2016.



Distribution Transformer Change Out Program 2017

Another significant driver for the TCOP program is energy efficiency and cost savings. A component of Washington State Initiative I-937 is to undertake cost-effective energy conservation. To fulfill this requirement, sources of efficiency were identified. Distribution transformers are one of the identified groups of assets where efficiency can be gained by replacing dated models with newer models that do not lose as much energy while in an unloaded state. Upon replacement of all pre-1981 transformers, there is an expected energy savings of 5.6 MW per hour. According to Asset Management this represents a savings of $215 per hour and contributes to an estimated Internal Rate of Return (IRR) of 8.24%.

The key metrics of the program are to replace the targeted transformers and achieve energy savings, which results in increased reliability. The table below reflects the results tracked for the program.

Table 2: TCOP Metrics

Year	Planned Number of Transformers Changed Out	Actual Number of Transformers Changed Out	Planned Energy Savings from Transformers (MWh)	Actual Energy Savings from Transformers (MWh)
2012	2,687	2,529	2,304	2,430
2013	2,555	2,599	2,304	2,671
2014	2,930	2,625	2,304	3,002
2015	2,335	2,899	1,746	3,150
2016	1,419	2,310	1,265	2,428
2017	1,283		*	
2018	347		*	

*Not calculated

References:

“Distribution Transformer PCBs” report, February 2010

Electric Distribution System, 2016 Asset Management Plan

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing: No planned replacement program for distribution transformers. Substantially higher risk of a PCB containing oil spill occurring.	$0	N/A	
Continue to replace high risk PCB transformers, then remaining pre-1981's.	*$3,000,000*	*01 2017*	*12 2017*
[Alternative #1] Planned replacement of PCB transformers only through programmatic work.	Cost and timing dependent on when programs address feeders with PCB transformers		

In order for the Distribution Transformer Change-Out Program to be successful, design resources are needed to complete field assessments and designs. Contract construction crews are also necessary to supplement Avista's Electric Operation resources. Pole inspection support from the Wood Pole Management group is also required to ensure the safety of the pole prior to any construction work.

This Program has been funded since 2011. The current approach is considered the best solution for mitigating environmental risk and for dollar efficiency. There are alternatives that consider different implementation schedules. One alternative is to remove overhead PCB containing and other pre-1981 transformers through the Wood Pole Management program. This alternatives does have some efficiencies because it involves a crew visiting a pole one time to address multiple issues. Additional funding would be required for Wood Pole Management to conduct this increase in scope. Another program to address the underground transformers would also be needed. The time to replace all, would be approximately 20 years. Underground transformers run a greater risk of leaking and not detecting those leaks. This is motivation to replace those transformers in a shorter time period.

Another alternative discussed was to replace the targeted transformers "as we get there". In other words, if work is occurring at a site where a targeted transformer is located, the transformer would be replaced at that time. This method could be considered efficient by the same reasons as using the Wood Pole Management approach with a crew visiting a location one time however, this approach would take a minimum of 120 years to replace all targeted transformers. This increases the risks of spills and/or failures.

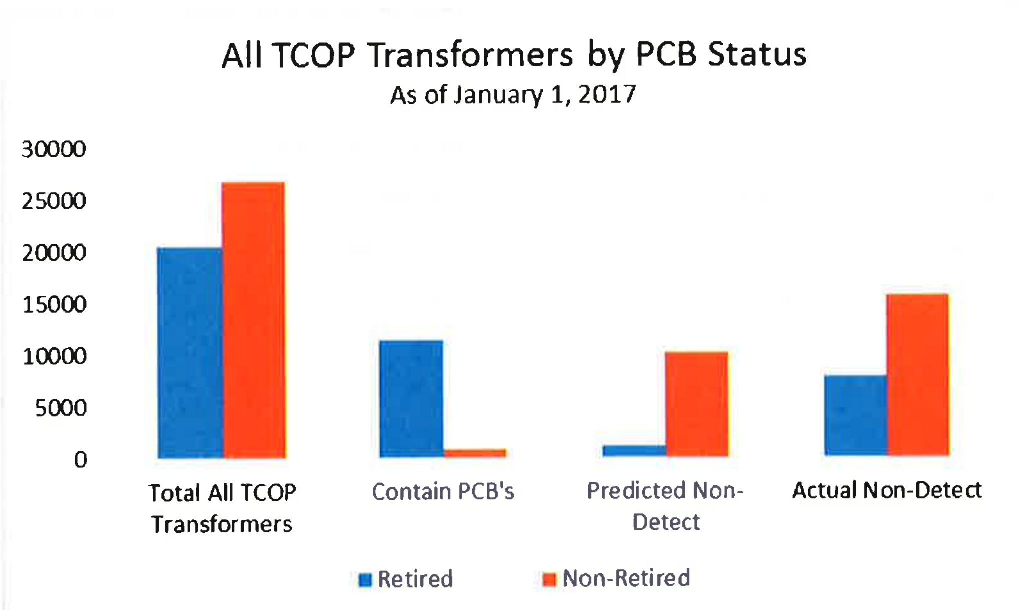
Distribution Transformer Change Out Program 2017

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

Environmental: Risks include; large volume transformer oil spill, difficult hazardous waste cleanup, moderate to low volume or level of PCBs, minimal impact to waterways, repeated or moderate air emission exceedance. If the program is unfunded the potential occurrence is greater than 4 spills per year. If funded, the potential occurrence is less than 1 per 50 years.

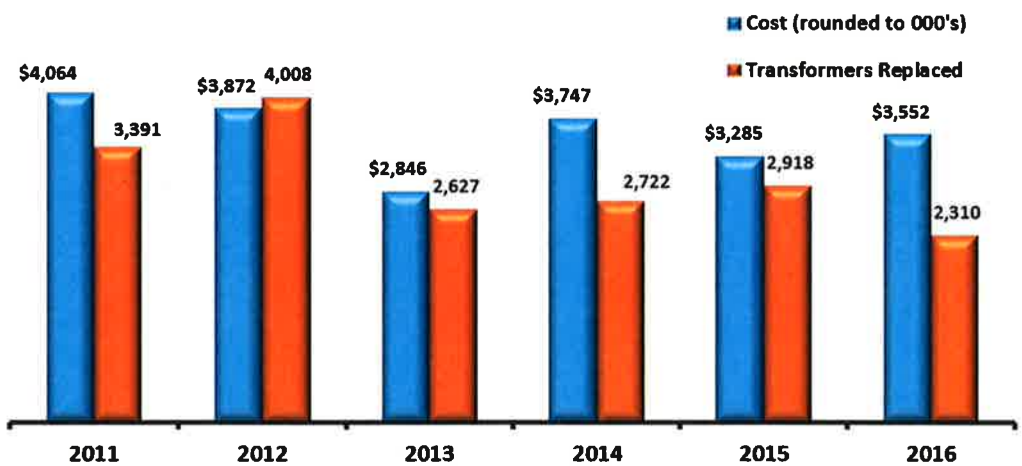
Public Safety and Health: Risks include: a potential for serious injury for crews or the public, significant damage to equipment, property or business, public health infrastructure impact up to 48 hours. If the program is unfunded, the potential occurrence is less than 1 per 10 years. If funded the potential occurrence is less than 1 per 50 years.

The entire population of pre-1981 transformers total nearly 47,000 units. The first phase of targeted PCB transformers (approximately 12,000) is expected to be complete by 2019. The second phase of the program is to replace the remaining pre-1981 transformers (Predicted Non-Detect and Actual Non-Detect). This work is expected to extend to 2040. The chart below shows the comparison of targeted transformers by retired status (blue = retired, orange = remaining to work)



The Distribution Transformer Change-Out Program aligns with Avista's strategic vision by ensuring transformers deliver safe and reliable energy to our customers. As older transformers are replaced for more modern equipment, the result is an increase in reliability, efficiency and energy savings. The other impact for replacing the pre-1981 transformers containing PCB oil, demonstrate that we are diligent in protecting our waterways and the environment as a whole, mindful of our environmental footprint and meet compliance requirements. As a result, Avista customers will be positively impacted by this program with the increased efficiencies, reliability, and environmentally safe equipment. The risk of not doing the work exposes Avista not only to environmental risks but reliability risk as well.

The requested amount of spend is in alignment with the program plan. The chart below shows the historic spend levels and efficiency of dollars spent versus transformers installed.



Avista stakeholders for this program include:

- Asset Maintenance department; responsible for the work.
- Environmental department; responsible for our environmental footprint in our service territory.
- Electric Operations; performs the construction work.
- Asset Management for tracking system reliability and risk.
- Avista customers who benefit from increased system reliability and efficiencies.
- The general community within our service territory who are impacted by environmental issues.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Distribution Transformer Change-Out Program 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:	4-14-2017
Print Name:	Cody Krogh		
Title:	Mgr Asset Maintenance		
Role:	Business Case Owner		

Signature:		Date:	4-17-17
Print Name:	Bryan Cox		
Title:	Sr Dir of HR Operations		
Role:	Business Case Sponsor		

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Cody Krogh	4/14/2017	Bryan Cox	4/14/2017	Initial version

Template Version: 02/24/2017

Wood Pole Management

1 GENERAL INFORMATION

Requested Spend Amount	$9,000,001
Requesting Organization/Department	Asset Maintenance/Wood Pole Management
Business Case Owner	Mark Gabert
Business Case Sponsor	Bryan Cox
Sponsor Organization/Department	M51/WPM
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

Asset Management and Distribution Engineering provide ongoing analysis of distribution asset condition. This analysis is used to direct the Wood Pole Management work that includes inspecting and maintaining Avista's poles, hardware and equipment on a twenty year cycle. The operating guidelines are documented in the Distribution Feeder Management Plan (DFMP). The analysis is documented in the Electric Distribution System 2016 Asset Management Plan. Asset Maintenance then collaborates with Electric Operations and contractors to coordinate the work. Asset Maintenance tracks the work budget, scope, and schedule.

2 BUSINESS PROBLEM

The major drivers for the program are system reliability, improved cost performance, and reduced customer outages. These drivers are obtained by replacing defective poles, associated hardware, and equipment at its end of life. The National Electric Safety Code (NESC) is adopted as Washington State Law under WAC 296-45-045. More specifically Part 013 describes the application, Part 121 describes the inspection interval, and Part 212A describes documentation and correction of the pole inspection results.

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. 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 we have an estimated 240,000 Distribution poles in the system. This means approximately 48,000 poles are currently over fifty years old. Our current inspection cycle allows us to reach approximately 12,000 poles each year. Along with inspecting the poles, we inspect 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 asset condition and indicate what work is required to replace assets that are damaged or near 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 Distribution Feeder Management Plan (DFMP). Designs and work plans are then created to replace the aging infrastructure. The construction work to replace the assets is part of this program.

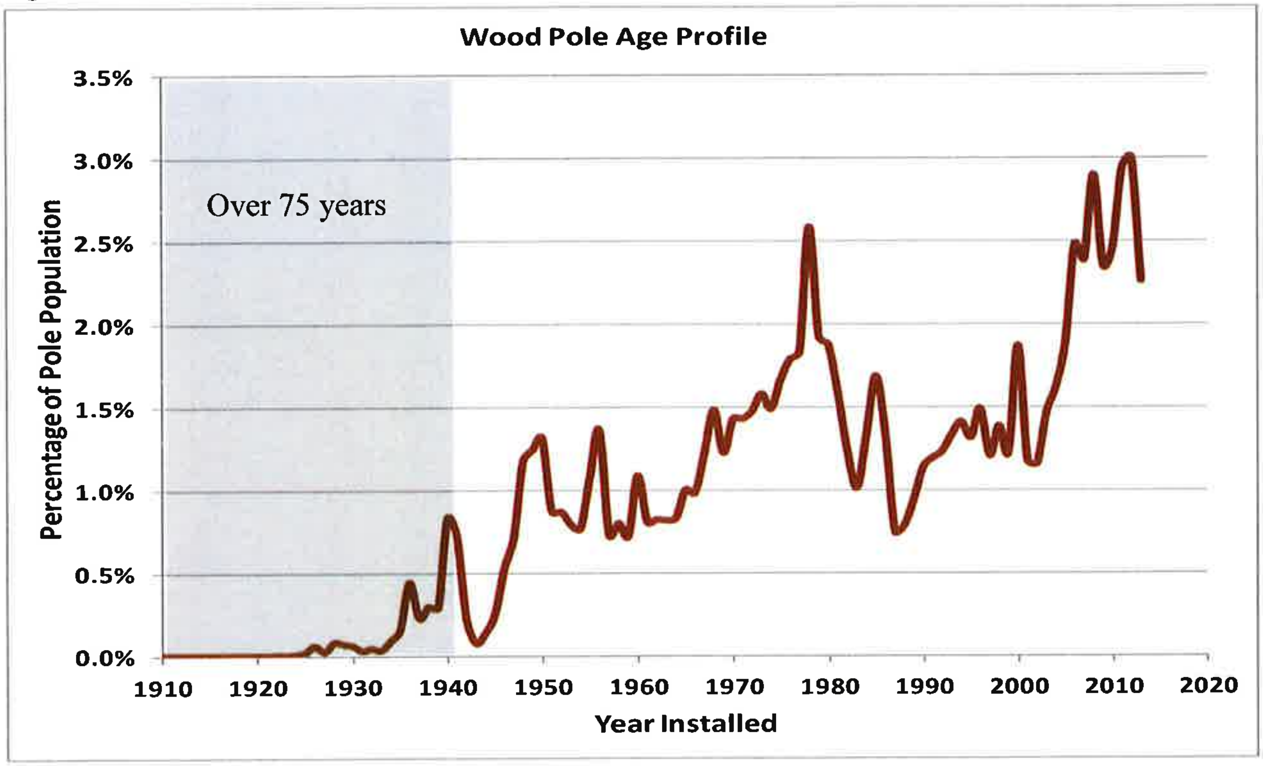
The work is required now to keep pace with the aging assets and expected failure rate. Figure 1 below shows the increased rate at which the poles are reaching the seventy-five year end of life. If this work is not maintained the aging infrastructure will cause an increasing rate of failures leading to increased outages and higher construction costs.

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

> **Environmental:** Risks include; large volume transformer oil spill, difficult hazardous waste cleanup, moderate to low volume or level of PCBs, minimal impact to waterways, repeated or moderate air emission exceedance. If the program is unfunded the potential occurrence is greater than 4 spills per year. If funded, the potential occurrence is less than 1 per 50 years.
>
> **Public Safety and Health**: Risks include: a potential for serious injury for crews or the public, significant damage to equipment, property or business, public health infrastructure impact up to 48 hours. If the program is unfunded, the potential occurrence is less than 1 per 10 years. If funded the potential occurrence is less than 1 per 50 years.

Wood Pole Management

Figure 1- Pole Age Profile



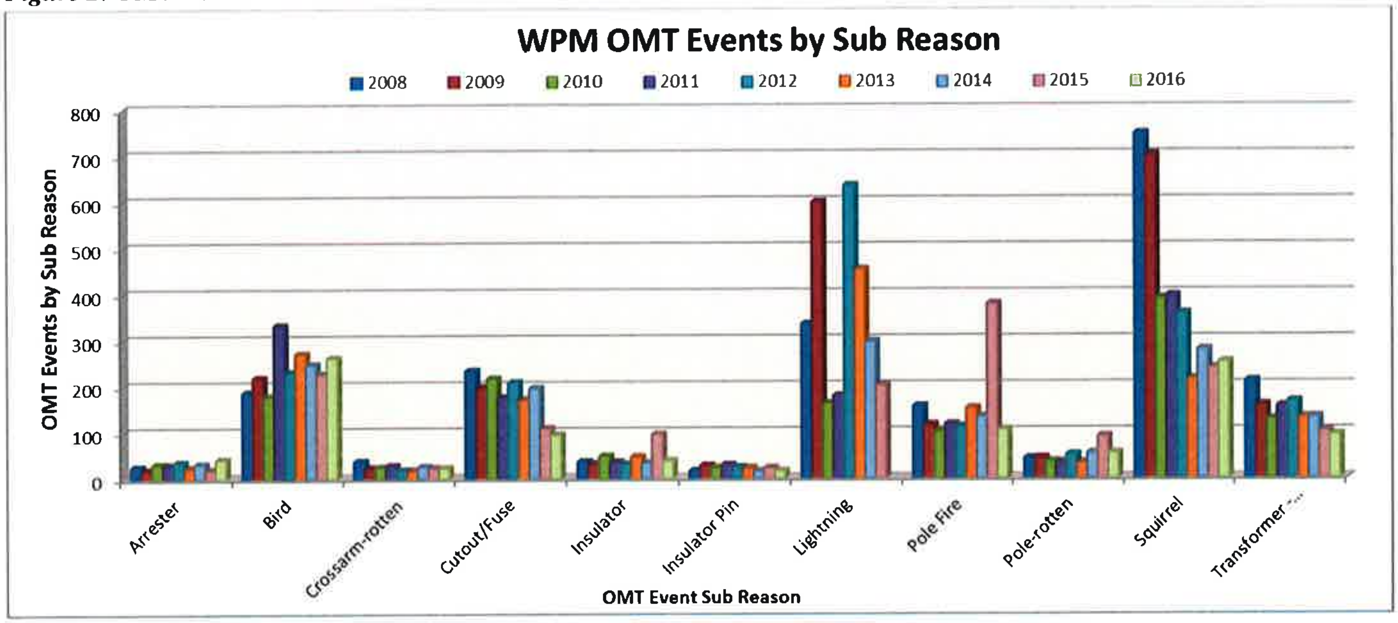
The Outage Management Tool (OMT) is used by Asset Management to track asset conditions and show trends of failures of specific equipment that should be targeted for replacement. This information is also used to track key Program performance as shown in Table 1 below. The number of outage type events has been reduced by over 40% from 2009 through 2015. 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 in the future.

Table 1: Event Reduction Results

KPI Description	WPM Goal Related number of OMT Events	Actual WPM Related number of OMT Events	Projected Miles Follow-up Work**	Actual Miles Follow-up Work Completed
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

The type of OMT events are broken down into more detail in Table 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 transformers 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. Table 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, per Asset Management. 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



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. 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 .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 and 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

3 PROPOSAL AND RECOMMENDED SOLUTION

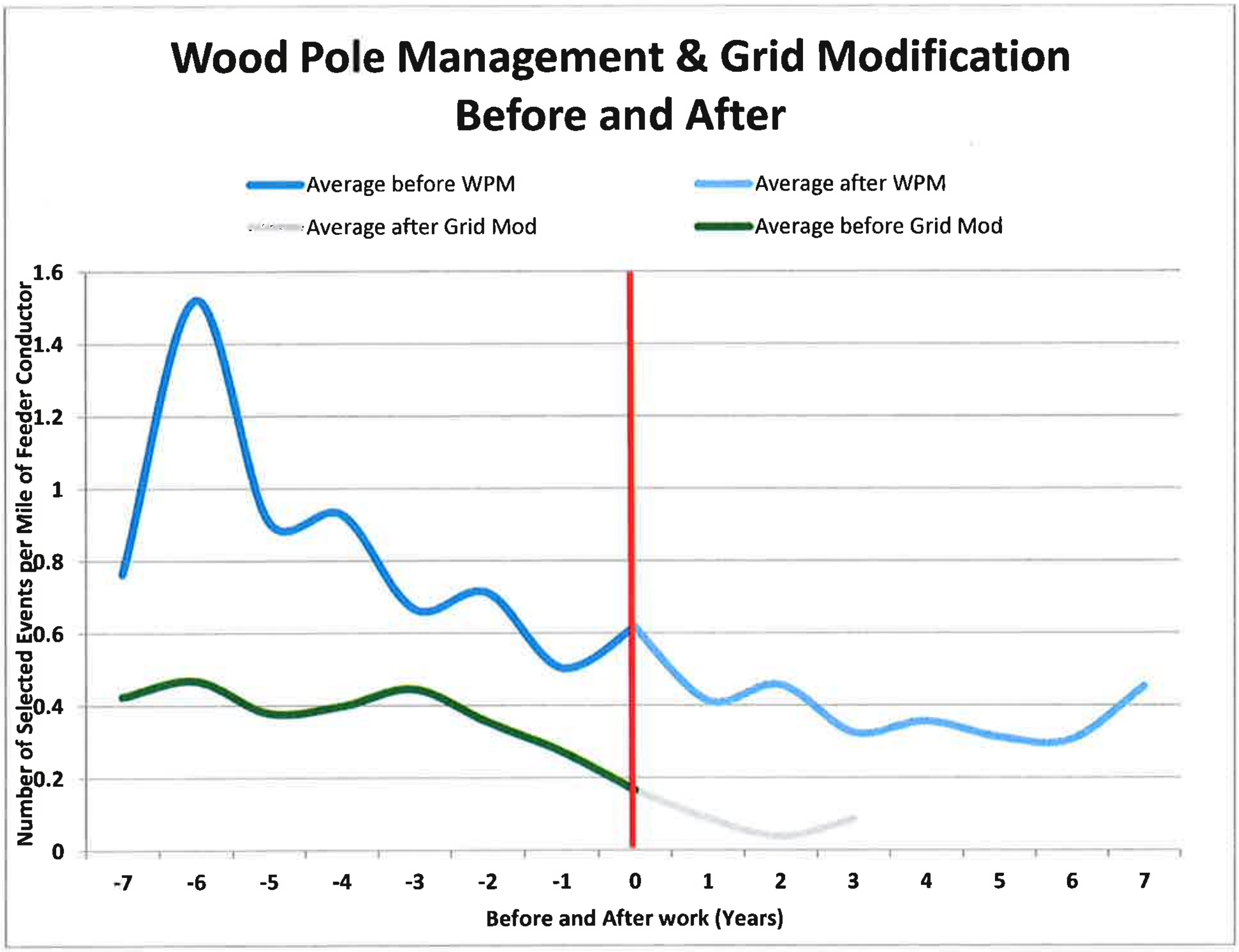
Option	Capital Cost	Start	Complete	Risk Mitigation
Do nothing	$0	Increases OMT events by 1700 events		
Distribution Wood Pole Management Program inspects all feeders on a 20 year cycle and repairs and replaces wood poles, crossarms, missing lightning arresters, missing/stolen grounds, bad cutouts, bad insulators, leaking transformers, replace guy wires not meeting current code requirements when the pole is replaced.	*$9,000,000M*	*012017*	*122017*	*Annually/indefinite*
*Alternative 1: Distribution Wood Pole Management Program inspects all feeders on a 20 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 **and replaces pre-1981 transformers***	*$10,712,022*	*012021*	*122021*	*Annually/indefinite*
Alternative 2: Everything in Alternative 1 except completed on a 10 year cycle.	*$17,296,437*	*012021*	*012021*	*Annually/Indefinite*

Based on analysis the current twenty year Wood Pole Management cycle delivers the best life cycle value for the funding level. Alternative 2 would decrease the inspection cycle down to ten years but at nearly double the capital cost. There is also additional O&M cost to support alternative 2. Asset Management and Distribution Engineering will continue to monitor system reliability to determine if adjustments are required in the future.

Distribution Wood Pole Management 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, safely, reliably, and is cost effective through the use of unit based pricing. Figure 2 below shows the significant improvement in “events per mile of feeder” resulting from this Program. The peak of events per mile was approximately 6 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.

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.

Figure 3: Reduction of Events per mile before and after feeders are completed.



The primary stakeholders are Asset Management, Distribution Engineering, Environmental, Real Estate, Asset Maintenance, Electric Operations, and our electric customers.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Distribution Wood Pole Management 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: 4/6/2017

Print Name: Mark Gabert

Title: WPM Program Manager

Role: Business Case Owner

Signature: Date: 4/17/17

Print Name: Bryan Cox

Title: Sr Dir of HR Operations

Role: Business Case Sponsor

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Mark Gabert	04/13/17	Bryan Cox	04/14/17	Initial version

Template Version: 02/24/2017

Primary URD Cable Replacement 2017

1 GENERAL INFORMATION

Requested Spend Amount	$1,000,000
Requesting Organization/Department	Asset Maintenance
Business Case Owner	Cody Krogh
Business Case Sponsor	Bryan Cox
Sponsor Organization/Department	Asset Maintenance
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

Cable condition and outage information is collected and analyzed by Asset Management. This information is reviewed with Asset Maintenance to establish an effective construction plan that prioritizes work based on faults and number of customer impacted. Asset Maintenance then collaborates with Electric Operations to coordinate the work. Asset Maintenance tracks the work budget, scope, and schedule.

2 BUSINESS PROBLEM

The primary driver for the Underground Residential Development (URD) Cable Replacement Program is to improve system reliability by removing URD cable with a high failure rate. The other driver is to reduce O&M costs related to responding to customer outages caused by the failed cable.

This work is needed to complete the replacement of the un-jacketed first generation underground primary distribution cable referred to as URD cable. This first generation URD cable was installed from 1971 to 1982. There was over 6,000,000 feet of URD cable installed during this time period. Subsequent to installation the URD cable began to experience an increasing failure rate. From 1992 to 2005 the cable failure rates quadrupled from 2 faults to 8 faults per 10 miles of cable. The faults reached a peak of 238 annual failures in 2007. Increased capital funding to replace this URD cable from 2005 through 2009 helped stabilize the failure rates. Continued funding and replacement of the cable has enabled a downward trend in failures as shown below in table 1. Cable installed after 1982 has not shown the high failure rate.

This work is required to continue to reduce primary URD cable failures and increase reliability. Historically there have been over 200 cable faults per year. The average cost to respond to a fault in 2015 was about $3000 per event due to the challenging nature of the work to locate and repair the cable underground. The estimated remaining pre-1982 cable is around 1,000,000 circuit feet.

Primary URD Cable Replacement 2017

The tables below demonstrate the effectiveness of this program to reduce faults and outage expenses through the replacement of the defective cable. The trend of cable faults and expenses decrease over time as the older cable is removed from the system.

Table1: URD Cable Replacement Results

KPI Description	Projected URD Cable - Primary OMT Events	Actual URD Cable - Primary OMT Events	Projected Number of Feet Replaced	Actual Number of Feet Replaced
2009	143	136	178,000	213,000
2010	119	93	178,000	217,883
2011	94	95	178,000	225,823
2012	70	72	178,000	117,247
2013	45	93	0	35,874
2014	45	88	0	35,515
2015	45	64	0	24,155

Table 2: URD Cable Replacement Cost Impact

Metric Description	Projected Avoided Outage Benefit due to URD Cable - Pri Caused Outages	Actual Avoided Outage Benefit due to URD Cable - Pri Outages
2009	$1,038,613	$1,056,113
2010	$1,228,275	$1,295,225
2011	$1,368,561	$1,352,648
2012	$1,516,159	$1,481,504
2013	$1,744,539	$1,494,738
2014	$1,898,311	$1,580,378
2015	$1,997,052	$1,720,020

Reference:

Electric Distribution System, 2016 Asset Management Plan

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
[Recommended Solution] Continue to Replace	$1M	04 2017	12 2037

The Primary URD Cable Replacement Program requires design resources and construction labor to complete the field work. There is also some analytics/engineering to identify remaining cable segment locations. Given the projected low capital spend level, the majority of the construction labor will be performed by Avista Crews. Contract crews are typically used to plow in the cable, bore conduit or trench and install conduit in the trench. Avista crews then pull the cable into the conduit and complete the installation.

The Do Nothing approach presents significant reliability risk and added O&M cost. The historic positive results from the URD cable replacement program shown above in section two provide strong justification for continuing the current funding plan.

Over 6,000,000 feet of URD was installed before 1982. Programmed replacement of the problem cable has been on-going at varying funding levels. The estimated remaining pre-1982 cable is around 1,000,000 circuit feet. At the current proposed funding rate of $1M per year this program is planned for the next 20 years. Reduced funding would extend this time and result in additional outages and O&M expenses.

The URD Cable Replacement Program aligns with Avista's strategic vision by increasing reliability to the electric distribution system. Safe and Reliable infrastructure is the focus area for this program.

The projected annual capital spend of $1M per year is reasonable based on the realized reduction in faults from previous work and this spend level enables continued replacement of the high failure rate cable. Repair of the cable has not shown to be cost effective because the cable typically faults in another location.

Avista customers will be positively impacted by this program by realizing fewer outages from the URD cable failure. This results in improved system reliability. Avista electric operations is positively impacted through converting this work to planned work that enables more efficient use of labor. It also reduces O&M expenses. Asset Management is responsible for tracking URD cable outages from Outage Management Tool (OMT) and tracking replacement locations and cost. The Asset Maintenance group is responsible for identifying cable segments and managing the coordination of work.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Primary URD Cable Replacement 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: 4-14-2017

Print Name: Cody Krogh

Title: Mgr Asset Maintenance

Role: Business Case Owner

Signature: Date: 4-17-17

Print Name: Bryan Cox

Title: Sr Dir of HR Operations

Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Cody Krogh	4/14/2017	Bryan Cox	4/14/2017	Initial version

Template Version: 03/07/2017

New Revenue - Growth

1 GENERAL INFORMATION

Requested Spend Amount	$47,443,826
Requesting Organization/Department	Energy Delivery
Business Case Owner	David Howell
Business Case Sponsor	Heather Rosentrater
Sponsor Organization/Department	Energy Delivery
Category	Program
Driver	Customer Requested

1.1 Steering Committee or Advisory Group Information

The Energy Delivery Director Team assumes the role of advisory group for the New Revenue – Growth Business Case, with quarterly reporting to the Board of Directors through the Financial Planning & Analysis department. The appropriate extension and service tariffs are designed and updated by the Avista Rates Department, in cooperation with Construction Services, and the Financial Planning & Analysis department. All Customer Project Coordinators are trained regularly, by Rates and Finance, on tariff application.

2 BUSINESS PROBLEM

- The New Revenue – Growth Business Case is driven by tariff requirements that mandate obligation to serve new customer load when requested within our franchised area. Growth is also seen as a method to spread costs over a wider customer base, keeping rate pressure lower than would otherwise be experienced.
- Avista is required to serve appropriate new load, complying with our Certificate of Convenience and Necessity, and as part of our Obligation to Serve.
- Avista uses a rolling 12-month Cost Per New Service spreadsheet to measure ER1000, Electric New Revenue, and ER1001, Gas New Revenue spending. Device blankets are subject to demand for both new revenue and non-revenue installation and replacement.
- Enclosed are Internal Rate of Return runs from the Revenue Requirements Model for each state and service, showing the breakeven spending to achieve our current 7.29% authorized Rate of Return. These allow us to periodically validate the Line Extension tariffs, to ensure that we are not creating excessive rate pressure in connecting new customers.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Serve new customer load, and purchase appropriate devices	*$47,443,826*	*01 2017*	*12 2099*
No other alternatives allowed under current tariff.	*$M*	*MM YYYY*	*MM YYYY*

- The New Revenue – Growth Business Case will provide funds for connecting new Electric and Gas customers in accordance with our filed tariffs in each state
- Our obligation to serve, mandates that we must extend service to new customers in our franchised service areas. We do not currently have an alternative to serving new customers. All projects are subject to our Line Extension Tariffs, filed with each State Utility Commission.
- Enclosed is a spreadsheet showing projected spend through 2021 with a breakout by Expenditure Request for the New Revenue – Growth Business Case. Electric and Gas devices are also included, such as Meters, Transformers, Gas Regulators, and ERTs (Encoder Receiver Transmitter). Many of the Meters, Transformers, and ERTs are used as replacements for Transformer Change Out Program, Wood Pole Management, and Periodic Meter Changes. The costs are allocated based on an estimate of how many devices of each type will be used for replacement, rather than new connects. Those splits are shown on the spending summary.
- The New Revenue – Growth Business Case serves as support of several focus areas in Avista. We seek to serve the interests of our customers, in a safe and responsible manner, while strengthening the financial performance of the utility. Our growth contributes to strong communities, ongoing value to our customers, and the device portion of the business case keeps our system safe and reliable.
- The requested funds are broken down in the enclosed spreadsheet, and value assigned to each component.
- All new customers on Avista's system are benefitted by this business case. In addition, all customers who have their metering or regulation changed, or who have transformers replaced, benefit from this business case.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the New Revenue – Growth 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: David Howell Date: 4/14/17

Print Name: David Howell

Title: Director, Operations

Role: Business Case Owner

Signature: Date: 4/23/17

Print Name: Heather Rosentrater

Title: Vice President, Operations

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	*Neil Thorson*	*03/17/17*	*Heather Rosentrater*	*03/17/17*	*Initial version*

Template Version: 03/07/2017

ER		2016	2017	2018	2019	2020	2021
1000	**Electric New Revenue**						
	Residential Connects	5,030	5,060	4,886	5,067	5,177	5,177
	Residential Cost/Svc	2,300	2,500	2,500	2,500	2,500	2,500
	Residential Dollars	11,569,000	12,650,000	12,215,000	12,667,500	12,942,500	12,942,500
	Commercial Connects	1,000	850	821	851	870	870
	Commercial Cost/Svc	2,219	2,500	2,500	2,500	2,500	2,500
	Commercial Dollars	2,218,900	2,125,000	2,051,927	2,127,940	2,174,135	2,174,135
	ER1000 Total	**13,787,901**	**14,775,000**	**14,266,927**	**14,795,440**	**15,116,635**	**15,116,635**
1001	**Gas New Revenue**						
	Residential Connects	5,295	5,685	5,479	5,656	5,774	5,744
	Residential Cost/Svc	2,384	3,095	3,095	3,095	3,095	3,095
	Residential Dollars	12,624,683	17,592,801	16,955,313	17,503,058	17,868,220	17,775,382
	Commercial Connects	500	560	540	557	569	566
	Commercial Cost/Svc	2,384	3,000	3,000	3,000	3,000	3,000
	Commercial Dollars	1,192,133	1,680,000	1,619,124	1,671,430	1,706,301	1,697,435
	ER1001 Total	**13,816,818**	**19,272,801**	**18,574,437**	**19,174,488**	**19,574,521**	**19,472,818**
1002	**Electric Meters**						
		550,000	550,000	550,000	500,000	500,000	500,000
	ER1002 Total	**550,000**	**550,000**	**550,000**	**500,000**	**500,000**	**500,000**
1003	**Transformers**						
	Growth and Other	3,134,000	3,196,680	3,260,614	3,325,826	3,392,342	3,460,189
	WPM	100,000	300,000	350,000	1,200,000	1,200,000	1,200,000
	TCOP	3,000,000	2,000,000	2,000,000	-	-	-
	Fdr Rebuild	266,400	266,400	266,400	266,400	266,400	266,400
	ER1003 Total	**6,500,400**	**5,763,080**	**5,877,014**	**4,792,226**	**4,858,742**	**4,926,589**
1004	**Street Lights**						
		700,000	900,000	900,000	900,000	900,000	900,000
	ER1004 Total	**700,000**	**900,000**	**900,000**	**900,000**	**900,000**	**900,000**
1005	**Area Lights**						
		625,000	650,000	675,000	700,000	700,000	700,000
	ER1005 Total	**625,000**	**650,000**	**675,000**	**700,000**	**700,000**	**700,000**
1009	**Network Protectors**						
		950,000	960,000	980,000	980,000	980,000	980,000
	ER1009 Total	**950,000**	**960,000**	**980,000**	**980,000**	**980,000**	**980,000**
1050	**Gas Meters**						
	Growth	516,751	556,867	536,688	554,026	565,585	562,646
	PMC	1,427,681	1,470,512	1,514,627	1,560,066	1,606,868	1,655,074
	ER1050 Total	**1,944,432**	**2,027,379**	**2,051,316**	**2,114,092**	**2,172,453**	**2,217,720**

1051	Gas Regulators						
	Growth	103,350	237,997	229,373	236,783	241,723	240,467
	PMC	237,668	244,798	252,142	259,706	267,497	275,522
	ER1051 Total	**341,018**	**482,795**	**481,515**	**496,489**	**509,220**	**515,989**
1053	Gas ERTs						
	Growth	222,203	218,575	210,655	217,460	221,997	220,843
	PMC	479,803	494,196	509,022	524,293	540,021	556,222
	ERT Replacement	1,517,291	400,000	412,000	424,360	437,091	450,204
	ER1053 Total	**2,219,297**	**1,112,771**	**1,131,677**	**1,166,113**	**1,199,109**	**1,227,269**
1108	Hallett & White Subst						
		1,900,000	950,000	950,000	-	-	-
	ER1009 Total	**1,900,000**	**950,000**	**950,000**	**-**	**-**	**-**
Growth Business Case Summary							
ER1000	Electric New Revenue	13,787,901	14,775,000	14,266,927	14,795,440	15,116,635	15,116,635
ER1001	Gas New Revenue	13,816,818	19,272,801	18,574,437	19,174,488	19,574,521	19,472,818
ER1002	Electric Meters	550,000	550,000	550,000	500,000	500,000	500,000
ER1003	Transformers	6,500,400	5,763,080	5,877,014	4,792,226	4,858,742	4,926,589
ER1004	Street Lights	700,000	900,000	900,000	900,000	900,000	900,000
ER1005	Area Lights	625,000	650,000	675,000	700,000	700,000	700,000
ER1009	Network Protectors	950,000	960,000	980,000	980,000	980,000	980,000
ER1050	Gas Meters	1,944,432	2,027,379	2,051,316	2,114,092	2,172,453	2,217,720
ER1051	Gas Regulators	341,018	482,795	481,515	496,489	509,220	515,989
ER1053	Gas ERTs	2,219,297	1,112,771	1,131,677	1,166,113	1,199,109	1,227,269
ER1108	Hallet & White Subst	1,900,000	950,000	950,000	-	-	-
	Total Growth	**43,334,866**	**47,443,826**	**46,437,885**	**45,618,847**	**46,510,681**	**46,557,021**

State Income Tax Rate 0.47%
Federal Income Tax Rate 35.00%
Discount Factor 6.35%
Capital Class .... 2 (1) General Structures.
(2) Generation, Transmission, and Distribution.
(3) Other Equipment.
(4) Transportation Equipment.

Book Life (Years) .... Update 55
Property Tax Rate 1.50%
O&M Escalation Factor 3.00%

Debt .... [illegible]
Preferred Stock .... [illegible]
Common Equity .... [illegible]

Principal 11,000
Interest 6.35%
Term 55
Levelized Gr. Mar. Requirement 723

Lev ROE 219
NPV equity 3,329

IRR CALC
11,000 pv princ
840 pv lvlized margin
7.29% IRR

Gross Revenue	100.0000%
Uncollectables	[illegible]
Commission Fees	[illegible]
Washington Excise Tax	[illegible]
Franchise Fees	0.0000%
Misc. Revenue Items	4.3287%
Before State Income Tax	95.6713%
State Income Tax	0.0000%
Before Federal Income Tax	95.6713%
Federal Income Tax	33.4850%
Conversion Factor	62.1863%

nominal sum 34,438 (v)
PV GM 12,776
TERM 55
LEVELIZED 840

ID Electric - Residential

(a)	Capital Additions Tax Basis (b)	Book Basis (c)	Rate Base BOP (d)	Accum. Book Deprec. (e)	Tax Deprec. (f)	Book Dep. on Tax Basis (g)	Deferred Taxes (h)	Rate Base EOP (i)	Book Deprec. (j)	Average Rate Base (k)	Interest Expense (l)	Equity Return (m)	O&M & A&G Expense (n)	Property Taxes (o)	Misc. Revenue Items (p)	State Income Tax (q)	Federal Income Taxes (r)	Total Gross Marg Reqmnt (s)	Present Val Gross Marg Reqmnt (t)	ACTUAL ROR BY YEAR (u)	840
Total =>	7,850	7,850			7,850	7,850	(0)		7,850		4,437	7,631	0	3,356	1,236	55	4,064	28,629	11,000		Savings or margin by year
Period																					
1	7,850	7,850	7,850	71	294	71	78	7,701	71	7,775	104	179	0	118	26	1	96	595	560	6.79%	840
2	0	0	7,701	214	567	143	148	7,409	143	7,555	202	348	0	117	45	3	186	1,044	923	4.59%	840
3	0	0	7,409	357	524	143	134	7,133	143	7,271	195	335	0	115	44	2	179	1,012	842	4.92%	840
4	0	0	7,133	500	485	143	120	6,871	143	7,002	188	323	0	112	42	2	172	983	768	5.25%	840
5	0	0	6,871	642	449	143	107	6,621	143	6,746	181	311	0	110	41	2	166	954	701	5.60%	840
6			6,621	785	415	143	95	6,383	143	6,502	174	300	0	108	40	2	160	927	641	5.95%	840
7			6,383	928	384	143	84	6,156	143	6,269	168	289	0	106	39	2	154	901	585	6.32%	840
8			6,156	1,070	355	143	74	5,939	143	6,047	162	279	0	104	38	2	149	876	535	6.69%	840
9			5,939	1,213	350	143	73	5,723	143	5,831	156	269	0	102	37	2	143	852	489	7.09%	840
10			5,723	1,356	350	143	73	5,508	143	5,616	151	259	0	100	36	2	138	827	447	7.51%	840
11			5,508	1,499	350	143	73	5,293	143	5,400	145	249	0	97	35	2	133	803	408	7.97%	840
12			5,293	1,641	350	143	73	5,077	143	5,185	139	239	0	95	34	2	127	779	372	8.47%	840
13			5,077	1,784	350	143	73	4,862	143	4,970	133	229	0	93	33	2	122	755	339	9.01%	840
14			4,862	1,927	350	143	73	4,647	143	4,754	127	219	0	91	32	2	117	730	308	9.60%	840
15			4,647	2,070	350	143	73	4,431	143	4,539	122	209	0	89	30	2	112	706	280	10.24%	840
16			4,431	2,212	350	143	73	4,216	143	4,324	116	199	0	87	29	1	106	682	255	10.95%	840
17			4,216	2,355	350	143	73	4,001	143	4,108	110	189	0	85	28	1	101	657	231	11.73%	840
18			4,001	2,498	350	143	73	3,785	143	3,893	104	179	0	82	27	1	96	633	209	12.60%	840
19			3,785	2,640	350	143	73	3,570	143	3,678	99	170	0	80	26	1	90	609	189	13.57%	840
20			3,570	2,783	350	143	73	3,355	143	3,462	93	160	0	78	25	1	85	585	171	14.66%	840
21			3,355	2,926	175	143	11	3,201	143	3,278	88	151	0	76	24	1	80	564	155	15.72%	840
22			3,201	3,069	0	143	(50)	3,108	143	3,154	85	145	0	74	24	1	77	549	142	16.52%	840
23			3,108	3,211	0	143	(50)	3,015	143	3,062	82	141	0	72	23	1	75	537	130	17.19%	840
24			3,015	3,354	0	143	(50)	2,922	143	2,969	80	137	0	70	23	1	73	525	120	17.89%	840
25			2,922	3,497	0	143	(50)	2,830	143	2,876	77	133	0	67	22	1	71	514	110	18.64%	840
26			2,830	3,640	0	143	(50)	2,737	143	2,783	75	128	0	65	22	1	68	502	101	19.44%	840
27			2,737	3,782	0	143	(50)	2,644	143	2,690	72	124	0	63	21	1	66	490	93	20.29%	840
28			2,644	3,925	0	143	(50)	2,551	143	2,598	70	120	0	61	21	1	64	478	85	21.21%	840
29			2,551	4,068	0	143	(50)	2,458	143	2,505	67	115	0	59	20	1	61	467	78	22.19%	840
30			2,458	4,210	0	143	(50)	2,366	143	2,412	65	111	0	57	20	1	59	455	72	23.25%	840
31			2,366	4,353	0	143	(50)	2,273	143	2,319	62	107	0	55	19	1	57	443	66	24.40%	840
32			2,273	4,496	0	143	(50)	2,180	143	2,227	60	103	0	52	19	1	55	431	60	25.64%	840
33			2,180	4,639	0	143	(50)	2,087	143	2,134	57	98	0	50	18	1	52	420	55	26.98%	840
34			2,087	4,781	0	143	(50)	1,995	143	2,041	55	94	0	48	18	1	50	408	50	28.45%	840
35			1,995	4,924	0	143	(50)	1,902	143	1,948	52	90	0	46	17	1	48	396	46	30.06%	840
36			1,902	5,067	0	143	(50)	1,809	143	1,855	50	86	0	44	17	1	45	385	42	31.83%	840
37			1,809	5,210	0	143	(50)	1,716	143	1,763	47	81	0	42	16	1	43	373	38	33.79%	840
38			1,716	5,352	0	143	(50)	1,624	143	1,670	45	77	0	40	16	1	41	361	35	35.97%	840
39			1,624	5,495	0	143	(50)	1,531	143	1,577	42	73	0	37	15	1	39	349	32	38.40%	840
40			1,531	5,638	0	143	(50)	1,438	143	1,484	40	68	0	35	15	0	36	338	29	41.13%	840
41			1,438	5,780	0	143	(50)	1,345	143	1,392	37	64	0	33	14	0	34	326	26	44.23%	840
42			1,345	5,923	0	143	(50)	1,252	143	1,299	35	60	0	31	14	0	32	314	24	47.77%	840
43			1,252	6,066		143	(50)	1,160	143	1,206	32	56	0	29	13	0	29	302	21	51.86%	840
44			1,160	6,209		143	(50)	1,067	143	1,113	30	51	0	27	13	0	27	291	19	56.62%	840
45			1,067	6,351		143	(50)	974	143	1,021	27	47	0	25	12	0	25	279	17	62.26%	840
46			974	6,494		143	(50)	881	143	928	25	43	0	22	12	0	23	267	16	69.02%	840
47			881	6,637		143	(50)	789	143	835	22	38	0	20	11	0	20	256	14	77.28%	840
48			789	6,780		143	(50)	696	143	742	20	34	0	18	11	0	18	244	13	87.61%	840
49			696	6,922		143	(50)	603	143	649	17	30	0	16	10	0	16	232	11	100.89%	840
50			603	7,065		143	(50)	510	143	557	15	26	0	14	10	0	13	220	10	118.59%	840
51			510	7,208		143	(50)	417	143	464	12	21	0	12	9	0	11	209	9	143.38%	840

State Income Tax Rate	0.47%	
Federal Income Tax Rate	35.00%	
Discount Factor	6.35%	
Capital Class	2	(1) General Structures. (2) Generation, Transmission, and Distribution. (3) Other Equipment. (4) Transportation Equipment.
Book Life (Years)	Update 55	
Property Tax Rate	1.50%	
O&M Escalation Factor	3.00%	

Debt	[redacted]			
Preferred Stock				
Common Equity				

Principal	11,000
Interest	6.35%
Term	55
Levelized Gr. Mar. Requirement	723

IRR CALC

11,000	pv princ
840	pv Mized margin
7.29%	IRR

Lev ROE	219
NPV equity	3,329

Gross Revenue	100.0000%
Uncollectables	[redacted]
Commission Fees	
Washington Excise Tax	
Franchise Fees	0.0000%
Misc. Revenue Items	4.3287%
Before State Income Tax	95.6713%
State Income Tax	0.0000%
Before Federal Income Tax	95.6713%
Federal Income Tax	33.4850%
Conversion Factor	62.1863%

nominal sum	34,438
(v)	
PV GM	12,776
TERM	55
LEVELIZED	840

WA Electric - Residential

	Capital Additions																				
	Tax Basis	Book Basis	Rate Base BOP	Accum. Book Deprec.	Tax Deprec.	Book Dep. on Tax Basis	Deferred Taxes	Rate Base EOP	Book Deprec.	Average Rate Base	Interest Expense	Equity Return	O&M & A&G Expense	Property Taxes	Misc. Revenue Items	State Income Tax	Federal Income Taxes	Total Gross Marg Reqmnt	Present Val Gross Marg Reqmnt	ACTUAL ROR BY YEAR	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	
Total => Period	7,850	7,850			7,850	7,850	(0)		7,850		4,437	7,631	0	3,356	1,236	55	4,064	28,629	11,000		Savings or margin by year
1	7,850	7,850	7,850	71	294	71	78	7,701	71	7,775	104	179	0	118	26	1	96	595	560	6.79%	840
2	0	0	7,701	214	567	143	148	7,409	143	7,555	202	348	0	117	45	3	186	1,044	923	4.59%	840
3	0	0	7,409	357	524	143	134	7,133	143	7,271	195	335	0	115	44	2	179	1,012	842	4.92%	840
4	0	0	7,133	500	485	143	120	6,871	143	7,002	188	323	0	112	42	2	172	983	768	5.25%	840
5	0	0	6,871	642	449	143	107	6,621	143	6,746	181	311	0	110	41	2	166	954	701	5.60%	840
6			6,621	785	415	143	95	6,383	143	6,502	174	300	0	108	40	2	160	927	641	5.95%	840
7			6,383	928	384	143	84	6,156	143	6,269	168	289	0	106	39	2	154	901	585	6.32%	840
8			6,156	1,070	355	143	74	5,939	143	6,047	162	279	0	104	38	2	149	876	535	6.69%	840
9			5,939	1,213	350	143	73	5,723	143	5,831	156	269	0	102	37	2	143	852	489	7.09%	840
10			5,723	1,356	350	143	73	5,508	143	5,616	151	259	0	100	36	2	138	827	447	7.51%	840
11			5,508	1,499	350	143	73	5,293	143	5,400	145	249	0	97	35	2	133	803	408	7.97%	840
12			5,293	1,641	350	143	73	5,077	143	5,185	139	239	0	95	34	2	127	779	372	8.47%	840
13			5,077	1,784	350	143	73	4,862	143	4,970	133	229	0	93	33	2	122	755	339	9.01%	840
14			4,862	1,927	350	143	73	4,647	143	4,754	127	219	0	91	32	2	117	730	308	9.60%	840
15			4,647	2,070	350	143	73	4,431	143	4,539	122	209	0	89	30	2	112	706	280	10.24%	840
16			4,431	2,212	350	143	73	4,216	143	4,324	116	199	0	87	29	1	106	682	255	10.95%	840
17			4,216	2,355	350	143	73	4,001	143	4,108	110	189	0	85	28	1	101	657	231	11.73%	840
18			4,001	2,498	350	143	73	3,785	143	3,893	104	179	0	82	27	1	96	633	209	12.60%	840
19			3,785	2,640	350	143	73	3,570	143	3,678	99	170	0	80	26	1	90	609	189	13.57%	840
20			3,570	2,783	350	143	73	3,355	143	3,462	93	160	0	78	25	1	85	585	171	14.66%	840
21			3,355	2,926	175	143	11	3,201	143	3,278	88	151	0	76	24	1	80	564	155	15.72%	840
22			3,201	3,069	0	143	(50)	3,108	143	3,154	85	145	0	74	24	1	77	549	142	16.52%	840
23			3,108	3,211	0	143	(50)	3,015	143	3,062	82	141	0	72	23	1	75	537	130	17.19%	840
24			3,015	3,354	0	143	(50)	2,922	143	2,969	80	137	0	70	23	1	73	525	120	17.89%	840
25			2,922	3,497	0	143	(50)	2,830	143	2,876	77	133	0	67	22	1	71	514	110	18.64%	840
26			2,830	3,640	0	143	(50)	2,737	143	2,783	75	128	0	65	22	1	68	502	101	19.44%	840
27			2,737	3,782	0	143	(50)	2,644	143	2,690	72	124	0	63	21	1	66	490	93	20.29%	840
28			2,644	3,925	0	143	(50)	2,551	143	2,598	70	120	0	61	21	1	64	478	85	21.21%	840
29			2,551	4,068	0	143	(50)	2,458	143	2,505	67	115	0	59	20	1	61	467	78	22.19%	840
30			2,458	4,210	0	143	(50)	2,366	143	2,412	65	111	0	57	20	1	59	455	72	23.25%	840
31			2,366	4,353	0	143	(50)	2,273	143	2,319	62	107	0	55	19	1	57	443	66	24.40%	840
32			2,273	4,496	0	143	(50)	2,180	143	2,227	60	103	0	52	19	1	55	431	60	25.64%	840
33			2,180	4,639	0	143	(50)	2,087	143	2,134	57	98	0	50	18	1	52	420	55	26.98%	840
34			2,087	4,781	0	143	(50)	1,995	143	2,041	55	94	0	48	18	1	50	408	50	28.45%	840
35			1,995	4,924	0	143	(50)	1,902	143	1,948	52	90	0	46	17	1	48	396	46	30.06%	840
36			1,902	5,067	0	143	(50)	1,809	143	1,855	50	86	0	44	17	1	45	385	42	31.83%	840
37			1,809	5,210	0	143	(50)	1,716	143	1,763	47	81	0	42	16	1	43	373	38	33.79%	840
38			1,716	5,352	0	143	(50)	1,624	143	1,670	45	77	0	40	16	1	41	361	35	35.97%	840
39			1,624	5,495	0	143	(50)	1,531	143	1,577	42	73	0	37	15	1	39	349	32	38.40%	840
40			1,531	5,638	0	143	(50)	1,438	143	1,484	40	68	0	35	15	0	36	338	29	41.13%	840
41			1,438	5,780	0	143	(50)	1,345	143	1,392	37	64	0	33	14	0	34	326	26	44.23%	840
42			1,345	5,923	0	143	(50)	1,252	143	1,299	35	60	0	31	14	0	32	314	24	47.77%	840
43			1,252	6,066		143	(50)	1,160	143	1,206	32	56	0	29	13	0	29	302	21	51.86%	840
44			1,160	6,209		143	(50)	1,067	143	1,113	30	51	0	27	13	0	27	291	19	56.62%	840
45			1,067	6,351		143	(50)	974	143	1,021	27	47	0	25	12	0	25	279	17	62.26%	840
46			974	6,494		143	(50)	881	143	928	25	43	0	22	12	0	23	267	16	69.02%	840
47			881	6,637		143	(50)	789	143	835	22	38	0	20	11	0	20	256	14	77.28%	840
48			789	6,780		143	(50)	696	143	742	20	34	0	18	11	0	18	244	13	87.61%	840
49			696	6,922		143	(50)	603	143	649	17	30	0	16	10	0	16	232	11	100.89%	840
50			603	7,065		143	(50)	510	143	557	15	26	0	14	10	0	13	220	10	118.59%	840
51			510	7,208		143	(50)	417	143	464	12	21	0	12	9	0	11	209	9	143.38%	840

State Income Tax Rate 0.47%
Federal Income Tax Rate 35.00%
Discount Factor 6.35%
Capital Class .... 2 (1) General Structures.
(2) Generation, Transmission, and Distribution.
(3) Other Equipment.
(4) Transportation Equipment.

Book Life (Years) .... Update 45
Property Tax Rate 1.50%
O&M Escalation Factor 3.00%

Debt	[redacted]			
Preferred Stock				
Common Equity				

Principal 5,424
Interest 6.35%
Term 45
Levelized Gr. Mar. Requirement 368

Lev ROE 106
NPV equity 1,563

IRR CALC
5,424 pv princ
416 pv lvlized margin
7.29% IRR

Gross Revenue	100.0000%
Uncollectables	[redacted]
Commission Fees	
Washington Excise Tax	
Franchise Fees	0.0000%
Misc. Revenue Items	4.3287%
Before State Income Tax	95.6713%
State Income Tax	0.0000%
Before Federal Income Tax	95.6713%
Federal Income Tax	33.4850%
Conversion Factor	62.1863%

nominal sum
16,989
(v)
PV GM
6,140
TERM
45

ID Gas - Residential

(a)	Capital Additions Tax Basis (b)	Book Basis (c)	Rate Base BOP (d)	Accum. Book Deprec. (e)	Tax Deprec. (f)	Book Dep. on Tax Basis (g)	Deferred Taxes (h)	Rate Base EOP (i)	Book Deprec. (j)	Average Rate Base (k)	Interest Expense (l)	Equity Return (m)	O&M & A&G Expense (n)	Property Taxes (o)	Misc. Revenue Items (p)	State Income Tax (q)	Federal Income Taxes (r)	Total Gross Marg Reqmnt (s)	Present Val Gross Marg Reqmnt (t)	ACTUAL ROR BY YEAR (u)	LEVELIZED 416
Total => Period	3,910	3,910			3,910	3,910	0		3,910		1,869	3,215	0	1,378	546	23	1,711	12,654	5,424		Savings or margin by year
1	3,910	3,910	3,910	43	147	43	36	3,830	43	3,870	52	89	0	59	13	1	48	305	286	6.48%	414
2	0	0	3,830	130	282	87	68	3,675	87	3,753	101	173	0	58	23	1	92	535	473	4.07%	414
3	0	0	3,675	217	261	87	61	3,527	87	3,601	97	166	0	57	22	1	89	518	431	4.41%	414
4	0	0	3,527	304	242	87	54	3,386	87	3,457	93	159	0	55	22	1	85	502	392	4.75%	414
5	0	0	3,386	391	223	87	48	3,252	87	3,319	89	153	0	54	21	1	82	487	358	5.11%	414
6			3,252	478	207	87	42	3,123	87	3,187	85	147	0	53	20	1	78	472	326	5.49%	414
7			3,123	565	191	87	37	2,999	87	3,061	82	141	0	51	20	1	75	458	297	5.88%	414
8			2,999	652	177	87	31	2,881	87	2,940	79	136	0	50	19	1	72	444	271	6.29%	414
9			2,881	739	174	87	31	2,763	87	2,822	76	130	0	49	19	1	69	430	247	6.72%	414
10			2,763	825	174	87	31	2,646	87	2,705	72	125	0	48	18	1	66	417	225	7.19%	414
11			2,646	912	174	87	31	2,528	87	2,587	69	119	0	46	17	1	64	404	205	7.71%	414
12			2,528	999	174	87	31	2,411	87	2,470	66	114	0	45	17	1	61	390	186	8.27%	414
13			2,411	1,086	174	87	31	2,293	87	2,352	63	108	0	44	16	1	58	377	169	8.88%	414
14			2,293	1,173	174	87	31	2,176	87	2,235	60	103	0	42	16	1	55	363	153	9.57%	414
15			2,176	1,260	174	87	31	2,058	87	2,117	57	98	0	41	15	1	52	350	139	10.33%	414
16			2,058	1,347	174	87	31	1,941	87	2,000	54	92	0	40	15	1	49	337	126	11.17%	414
17			1,941	1,434	174	87	31	1,823	87	1,882	50	87	0	38	14	1	46	323	113	12.13%	414
18			1,823	1,521	174	87	31	1,706	87	1,765	47	81	0	37	13	1	43	310	102	13.21%	414
19			1,706	1,607	174	87	31	1,588	87	1,647	44	76	0	36	13	1	40	297	92	14.44%	414
20			1,588	1,694	174	87	31	1,471	87	1,529	41	71	0	35	12	1	38	283	83	15.87%	414
21			1,471	1,781	87	87	0	1,384	87	1,427	38	66	0	33	12	0	35	271	74	17.31%	414
22			1,384	1,868	0	87	(30)	1,327	87	1,355	36	62	0	32	11	0	33	263	68	18.48%	414
23			1,327	1,955	0	87	(30)	1,271	87	1,299	35	60	0	31	11	0	32	256	62	19.52%	414
24			1,271	2,042	0	87	(30)	1,214	87	1,243	33	57	0	29	11	0	30	248	57	20.65%	414
25			1,214	2,129	0	87	(30)	1,158	87	1,186	32	55	0	28	10	0	29	241	52	21.89%	414
26			1,158	2,216	0	87	(30)	1,101	87	1,130	30	52	0	27	10	0	28	234	47	23.25%	414
27			1,101	2,303	0	87	(30)	1,045	87	1,073	29	49	0	25	10	0	26	227	43	24.75%	414
28			1,045	2,389	0	87	(30)	988	87	1,017	27	47	0	24	9	0	25	220	39	26.43%	414
29			988	2,476	0	87	(30)	932	87	960	26	44	0	23	9	0	23	213	36	28.30%	414
30			932	2,563	0	87	(30)	875	87	904	24	42	0	22	9	0	22	206	32	30.40%	414
31			875	2,650	0	87	(30)	819	87	847	23	39	0	20	9	0	21	198	29	32.78%	414
32			819	2,737	0	87	(30)	762	87	791	21	36	0	19	8	0	19	191	27	35.51%	414
33			762	2,824	0	87	(30)	706	87	734	20	34	0	18	8	0	18	184	24	38.65%	414
34			706	2,911	0	87	(30)	649	87	678	18	31	0	16	8	0	17	177	22	42.31%	414
35			649	2,998	0	87	(30)	593	87	621	17	29	0	15	7	0	15	170	20	46.65%	414
36			593	3,085	0	87	(30)	537	87	565	15	26	0	14	7	0	14	163	18	51.85%	414
37			537	3,171	0	87	(30)	480	87	508	14	23	0	12	7	0	12	156	16	58.20%	414
38			480	3,258	0	87	(30)	424	87	452	12	21	0	11	6	0	11	148	14	66.15%	414
39			424	3,345	0	87	(30)	367	87	395	11	18	0	10	6	0	10	141	13	76.36%	414
40			367	3,432	0	87	(30)	311	87	339	9	16	0	8	6	0	8	134	11	89.98%	414
41			311	3,519	0	87	(30)	254	87	282	8	13	0	7	5	0	7	127	10	109.04%	414
42			254	3,606	0	87	(30)	198	87	226	6	10	0	6	5	0	5	120	9	137.64%	414
43			198	3,693		87	(30)	141	87	169	5	8	0	5	5	0	4	113	8	185.31%	414
44			141	3,780		87	(30)	85	87	113	3	5	0	3	5	0	3	106	7	280.63%	414
45			85	3,867		87	(30)	28	87	56	2	3	0	2	4	0	1	98	6	566.62%	414
46			28	3,910		43	(15)	0	43	14	0	1	0	1	2	0	0	47	3	2605.95%	414
47			0	3,910		0	0	0	0	0	0	0	0	0	0	0	0	0	0	##############	414
48			0	3,910		0	0	0	0	0	0	0	0	0	0	0	0	0	0	##############	414
49			0	3,910		0	0	0	0	0	0	0	0	0	0	0	0	0	0	##############	414
50			0	3,910		0	0	0	0	0	0	0	0	0	0	0	0	0	0	##############	414
51			0	3,910		0	0	0	0	0	0	0	0	0	0	0	0	0	0	##############	414

State Income Tax Rate	0.47%
Federal Income Tax Rate	35.00%
Discount Factor	6.35%
Capital Class	2

(1) General Structures
(2) Generation, Transmission, and Distribution
(3) Other Equipment
(4) Transportation Equipment

Book Life (Years)	Update	45
Property Tax Rate		1.50%
O&M Escalation Factor		3.00%

Debt	[redacted]
Preferred Stock	
Common Equity	
Principal	4,186
Interest	6.35%
Term	45
Levelized Gr. Mar. Requirement	284
Lev ROE	82
NPV equity	1,207

IRR CALC

4,186	pv princ
321	pv lvlized margin
7.29%	IRR

Gross Revenue	100.0000%
Uncollectables	[redacted]
Commission Fees	
Washington Excise Tax	
Franchise Fees	0.0000%
Misc. Revenue Items	4.3287%
Before State Income Tax	95.6713%
State Income Tax	0.0000%
Before Federal Income Tax	95.6713%
Federal Income Tax	33.4850%
Conversion Factor	62.1863%

nominal sum	13,102
	(v)
PV GM	4,735
TERM	45
LEVELIZED	321

OR Gas - Residential

(a)	Capital Additions Tax Basis (b)	Book Basis (c)	Rate Base BOP (d)	Accum. Book Deprec. (e)	Tax Deprec. (f)	Book Dep. on Tax Basis (g)	Deferred Taxes (h)	Rate Base EOP (i)	Book Deprec. (j)	Average Rate Base (k)	Interest Expense (l)	Equity Return (m)	O&M & A&G Expense (n)	Property Taxes (o)	Misc. Revenue Items (p)	State Income Tax (q)	Federal Income Taxes (r)	Total Gross Marg Reqmnt (s)	Present Val Gross Marg Reqmnt (t)	ACTUAL ROR BY YEAR (u)	Savings or margin by year
Total => Period	3,018	3,018			3,018	3,018	(0)		3,018		1,443	2,482	0	1,064	422	18	1,321	9,767	4,186		
1	3,018	3,018	3,018	34	113	34	28	2,957	34	2,987	40	69	0	45	10	0	37	235	221	6.47%	320
2	0	0	2,957	101	218	67	53	2,837	67	2,897	78	134	0	45	18	1	71	413	365	4.06%	320
3	0	0	2,837	168	202	67	47	2,723	67	2,780	74	128	0	44	17	1	68	400	333	4.39%	320
4	0	0	2,723	235	186	67	42	2,614	67	2,668	72	123	0	43	17	1	66	388	303	4.74%	320
5	0	0	2,614	302	172	67	37	2,510	67	2,562	69	118	0	42	16	1	63	376	276	5.10%	320
6			2,510	369	160	67	32	2,410	67	2,460	66	113	0	41	16	1	60	364	252	5.48%	320
7			2,410	436	148	67	28	2,315	67	2,363	63	109	0	40	15	1	58	353	229	5.87%	320
8			2,315	503	137	67	24	2,224	67	2,269	61	105	0	39	15	1	56	343	209	6.28%	320
9			2,224	570	135	67	24	2,133	67	2,178	58	100	0	38	14	1	54	332	191	6.71%	320
10			2,133	637	135	67	24	2,042	67	2,088	56	96	0	37	14	1	51	322	174	7.18%	320
11			2,042	704	135	67	24	1,952	67	1,997	54	92	0	36	13	1	49	312	158	7.69%	320
12			1,952	771	135	67	24	1,861	67	1,906	51	88	0	35	13	1	47	301	144	8.25%	320
13			1,861	838	135	67	24	1,770	67	1,816	49	84	0	34	13	1	45	291	131	8.87%	320
14			1,770	905	135	67	24	1,679	67	1,725	46	80	0	33	12	1	42	281	118	9.55%	320
15			1,679	972	135	67	24	1,589	67	1,634	44	75	0	32	12	1	40	270	107	10.31%	320
16			1,589	1,040	135	67	24	1,498	67	1,543	41	71	0	31	11	1	38	260	97	11.16%	320
17			1,498	1,107	135	67	24	1,407	67	1,453	39	67	0	30	11	0	36	250	88	12.11%	320
18			1,407	1,174	135	67	24	1,317	67	1,362	37	63	0	29	10	0	33	239	79	13.19%	320
19			1,317	1,241	135	67	24	1,226	67	1,271	34	59	0	28	10	0	31	229	71	14.42%	320
20			1,226	1,308	135	67	24	1,135	67	1,181	32	54	0	27	9	0	29	219	64	15.84%	320
21			1,135	1,375	67	67	0	1,068	67	1,102	30	51	0	26	9	0	27	209	57	17.28%	320
22			1,068	1,442	0	67	(23)	1,024	67	1,046	28	48	0	25	9	0	26	203	52	18.46%	320
23			1,024	1,509	0	67	(23)	981	67	1,003	27	46	0	24	9	0	25	197	48	19.49%	320
24			981	1,576	0	67	(23)	937	67	959	26	44	0	23	8	0	24	192	44	20.62%	320
25			937	1,643	0	67	(23)	894	67	915	25	42	0	22	8	0	22	186	40	21.86%	320
26			894	1,710	0	67	(23)	850	67	872	23	40	0	21	8	0	21	181	36	23.22%	320
27			850	1,777	0	67	(23)	806	67	828	22	38	0	20	8	0	20	175	33	24.72%	320
28			806	1,844	0	67	(23)	763	67	785	21	36	0	19	7	0	19	170	30	26.39%	320
29			763	1,911	0	67	(23)	719	67	741	20	34	0	18	7	0	18	164	28	28.26%	320
30			719	1,978	0	67	(23)	676	67	697	19	32	0	17	7	0	17	159	25	30.36%	320
31			676	2,046	0	67	(23)	632	67	654	18	30	0	16	7	0	16	153	23	32.74%	320
32			632	2,113	0	67	(23)	589	67	610	16	28	0	15	6	0	15	148	21	35.46%	320
33			589	2,180	0	67	(23)	545	67	567	15	26	0	14	6	0	14	142	19	38.60%	320
34			545	2,247	0	67	(23)	501	67	523	14	24	0	13	6	0	13	137	17	42.26%	320
35			501	2,314	0	67	(23)	458	67	480	13	22	0	12	6	0	12	131	15	46.59%	320
36			458	2,381	0	67	(23)	414	67	436	12	20	0	11	5	0	11	126	14	51.78%	320
37			414	2,448	0	67	(23)	371	67	392	11	18	0	10	5	0	10	120	12	58.13%	320
38			371	2,515	0	67	(23)	327	67	349	9	16	0	9	5	0	8	115	11	66.06%	320
39			327	2,582	0	67	(23)	283	67	305	8	14	0	8	5	0	7	109	10	76.27%	320
40			283	2,649	0	67	(23)	240	67	262	7	12	0	7	4	0	6	104	9	89.87%	320
41			240	2,716	0	67	(23)	196	67	218	6	10	0	6	4	0	5	98	8	108.91%	320
42			196	2,783	0	67	(23)	153	67	174	5	8	0	5	4	0	4	93	7	137.48%	320
43			153	2,850		67	(23)	109	67	131	4	6	0	4	4	0	3	87	6	185.09%	320
44			109	2,917		67	(23)	65	67	87	2	4	0	3	4	0	2	82	5	280.30%	320
45			65	2,984		67	(23)	22	67	44	1	2	0	2	3	0	1	76	5	565.95%	320
46			22	3,018		34	(12)	0	34	11	0	1	0	1	2	0	0	37	2	2603.31%	320
47			0	3,018		0	0	0	0	0	0	0	0	0	0	0	0	0	0	##############	320
48			0	3,018		0	0	0	0	0	0	0	0	0	0	0	0	0	0	##############	320
49			0	3,018		0	0	0	0	0	0	0	0	0	0	0	0	0	0	##############	320
50			0	3,018		0	0	0	0	0	0	0	0	0	0	0	0	0	0	##############	320
51			0	3,018		0	0	0	0	0	0	0	0	0	0	0	0	0	0	##############	320

GAS REV REQ OR calibrated IRR 2-11-14.xlsm

State Income Tax Rate	0.47%		
Federal Income Tax Rate	35.00%		
Discount Factor	6.35%		
Capital Class	2	(1) General Structures.	
		(2) Generation, Transmission, and Distribution.	
		(3) Other Equipment.	
		(4) Transportation Equipment.	
Book Life (Years)	Update	45	
Property Tax Rate	1.50%		
O&M Escalation Factor	3.00%		

Debt	[illegible]	[illegible]	[illegible]	[illegible]
Preferred Stock	[illegible]	[illegible]	[illegible]	[illegible]
Common Equity	[illegible]	[illegible]	[illegible]	[illegible]
			[illegible]	[illegible]
Principal	6,013			
Interest	6.35%			
Term	45			
Levelized Gr. Mar. Requirement	407			
Lev ROE	117			
NPV equity	1,733			

IRR CALC

6,013	pv princ
461	pv lvlized margin
7.29%	IRR

Gross Revenue	100.0000%
Uncollectables	[illegible]
Commission Fees	[illegible]
Washington Excise Tax	[illegible]
Franchise Fees	0.0000%
Misc. Revenue Items	4.3287%
Before State Income Tax	95.6713%
State Income Tax	0.0000%
Before Federal Income Tax	95.6713%
Federal Income Tax	33.4850%
Conversion Factor	62.1863%

nominal sum	18,817
	(v)
PV GM	6,800
TERM	45
LEVELIZED	461

WA Gas - Residential

(a)	Capital Additions Tax Basis (b)	Book Basis (c)	Rate Base BOP (d)	Accum. Book Deprec. (e)	Tax Deprec. (f)	Book Dep. on Tax Basis (g)	Deferred Taxes (h)	Rate Base EOP (i)	Book Deprec. (j)	Average Rate Base (k)	Interest Expense (l)	Equity Return (m)	O&M & A&G Expense (n)	Property Taxes (o)	Misc. Revenue Items (p)	State Income Tax (q)	Federal Income Taxes (r)	Total Gross Marg Reqmnt (s)	Present Val Gross Marg Reqmnt (t)	ACTUAL ROR BY YEAR (u)	Savings or margin by year
Total => Period	4,335	4,335			4,335	4,335	(0)		4,335		2,072	3,565	0	1,528	606	26	1,897	14,029	6,013		
1	4,335	4,335	4,335	48	163	48	40	4,247	48	4,291	57	99	0	65	15	1	53	338	317	6.47%	459
2	0	0	4,247	145	313	96	76	4,075	96	4,161	112	192	0	64	26	1	102	593	525	4.06%	459
3	0	0	4,075	241	289	96	68	3,911	96	3,993	107	184	0	63	25	1	98	575	478	4.39%	459
4	0	0	3,911	337	268	96	60	3,754	96	3,833	103	177	0	61	24	1	94	557	435	4.74%	459
5	0	0	3,754	434	248	96	53	3,605	96	3,680	99	170	0	60	23	1	90	540	397	5.10%	459
6			3,605	530	229	96	46	3,462	96	3,534	95	163	0	59	23	1	87	523	362	5.47%	459
7			3,462	626	212	96	40	3,325	96	3,394	91	156	0	57	22	1	83	507	330	5.87%	459
8			3,325	723	196	96	35	3,194	96	3,260	87	150	0	56	21	1	80	492	301	6.27%	459
9			3,194	819	193	96	34	3,064	96	3,129	84	144	0	54	21	1	77	477	274	6.71%	459
10			3,064	915	193	96	34	2,934	96	2,999	80	138	0	53	20	1	74	462	250	7.18%	459
11			2,934	1,012	193	96	34	2,803	96	2,868	77	132	0	51	19	1	70	448	227	7.69%	459
12			2,803	1,108	193	96	34	2,673	96	2,738	73	126	0	50	19	1	67	433	207	8.25%	459
13			2,673	1,204	193	96	34	2,543	96	2,608	70	120	0	48	18	1	64	418	188	8.87%	459
14			2,543	1,301	193	96	34	2,412	96	2,478	66	114	0	47	17	1	61	403	170	9.55%	459
15			2,412	1,397	193	96	34	2,282	96	2,347	63	108	0	46	17	1	58	388	154	10.31%	459
16			2,282	1,493	193	96	34	2,152	96	2,217	59	102	0	44	16	1	54	373	139	11.15%	459
17			2,152	1,590	193	96	34	2,021	96	2,087	56	96	0	43	15	1	51	358	126	12.11%	459
18			2,021	1,686	193	96	34	1,891	96	1,956	52	90	0	41	15	1	48	344	113	13.19%	459
19			1,891	1,782	193	96	34	1,761	96	1,826	49	84	0	40	14	1	45	329	102	14.42%	459
20			1,761	1,879	193	96	34	1,631	96	1,696	45	78	0	38	14	1	42	314	92	15.84%	459
21			1,631	1,975	97	96	0	1,534	96	1,582	42	73	0	37	13	1	39	301	83	17.28%	459
22			1,534	2,071	0	96	(34)	1,471	96	1,503	40	69	0	35	13	0	37	291	75	18.45%	459
23			1,471	2,168	0	96	(34)	1,409	96	1,440	39	66	0	34	12	0	35	283	69	19.49%	459
24			1,409	2,264	0	96	(34)	1,346	96	1,378	37	64	0	33	12	0	34	275	63	20.62%	459
25			1,346	2,360	0	96	(34)	1,284	96	1,315	35	61	0	31	12	0	32	267	57	21.85%	459
26			1,284	2,457	0	96	(34)	1,221	96	1,252	34	58	0	30	11	0	31	260	52	23.21%	459
27			1,221	2,553	0	96	(34)	1,158	96	1,190	32	55	0	28	11	0	29	252	48	24.72%	459
28			1,158	2,649	0	96	(34)	1,096	96	1,127	30	52	0	27	11	0	28	244	43	26.39%	459
29			1,096	2,746	0	96	(34)	1,033	96	1,064	29	49	0	25	10	0	26	236	40	28.25%	459
30			1,033	2,842	0	96	(34)	971	96	1,002	27	46	0	24	10	0	25	228	36	30.35%	459
31			971	2,938	0	96	(34)	908	96	939	25	43	0	22	9	0	23	220	33	32.73%	459
32			908	3,035	0	96	(34)	845	96	877	23	40	0	21	9	0	21	212	30	35.45%	459
33			845	3,131	0	96	(34)	783	96	814	22	38	0	20	9	0	20	204	27	38.59%	459
34			783	3,227	0	96	(34)	720	96	751	20	35	0	18	8	0	18	196	24	42.25%	459
35			720	3,324	0	96	(34)	657	96	689	18	32	0	17	8	0	17	188	22	46.58%	459
36			657	3,420	0	96	(34)	595	96	626	17	29	0	15	8	0	15	180	20	51.78%	459
37			595	3,516	0	96	(34)	532	96	564	15	26	0	14	7	0	14	172	18	58.12%	459
38			532	3,613	0	96	(34)	470	96	501	13	23	0	12	7	0	12	165	16	66.06%	459
39			470	3,709	0	96	(34)	407	96	438	12	20	0	11	7	0	11	157	14	76.26%	459
40			407	3,805	0	96	(34)	344	96	376	10	17	0	9	6	0	9	149	13	89.86%	459
41			344	3,902	0	96	(34)	282	96	313	8	14	0	8	6	0	8	141	11	108.90%	459
42			282	3,998	0	96	(34)	219	96	250	7	12	0	7	6	0	6	133	10	137.46%	459
43			219	4,094		96	(34)	157	96	188	5	9	0	5	5	0	4	125	9	185.07%	459
44			157	4,191		96	(34)	94	96	125	3	6	0	4	5	0	3	117	8	280.27%	459
45			94	4,287		96	(34)	31	96	63	2	3	0	2	5	0	1	109	7	565.90%	459
46			31	4,335		48	(17)	(0)	48	16	0	1	0	1	2	0	0	53	3	2603.08%	459
47			(0)	4,335		0	0	(0)	0	(0)	(0)	(0)	0	(0)	(0)	(0)	(0)	(0)	(0)	##############	459
48			(0)	4,335		0	0	(0)	0	(0)	(0)	(0)	0	(0)	(0)	(0)	(0)	(0)	(0)	##############	459
49			(0)	4,335		0	0	(0)	0	(0)	(0)	(0)	0	(0)	(0)	(0)	(0)	(0)	(0)	##############	459
50			(0)	4,335		0	0	(0)	0	(0)	(0)	(0)	0	(0)	(0)	(0)	(0)	(0)	(0)	##############	459
51			(0)	4,335		0	0	(0)	0	(0)	(0)	(0)	0	(0)	(0)	(0)	(0)	(0)	(0)	##############	459

Distribution Minor Rebuild

1 GENERAL INFORMATION

Requested Spend Amount	$12,300,000
Requesting Organization/Department	Electric Operations
Business Case Owner	Cody Krogh
Business Case Sponsor	Bryan Cox
Sponsor Organization/Department	Operations
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The Distribution Minor Rebuild work is overseen by the local area operations engineers, general foremen, and area construction managers. Often, the work addresses failed asset replacements or customer requests that are unplanned. Occasionally, larger projects with an identified need and short timeframe for implementation are constructed under the Distribution Minor Rebuild business. Minor Rebuild work occurs regularly and historical averages are used to estimate the appropriate funding allocations.

The local area operation engineers, general foremen, and area construction managers manage the work as it is identified throughout the given construction season. A more formal governance is currently being developed for this business case, which will provide a check or gate on which projects in the business become approved for scheduling.

2 BUSINESS PROBLEM

The work done under the distribution minor rebuild is driven by keeping the distribution system in reliable condition for customers and safe condition for the workers, responsiveness to unplanned damaged to distribution assets not related to weather events, as well as small customer driven rebuilds. Throughout the entire distribution system, minor rebuilds or replacements of asset units need to be completed to maintain system reliability and safety.

Below is a categorical breakdown which fall within the Distribution Minor Rebuild business.

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.

Trouble Related Work – Work required to repair damaged facilities related to non-storm related outages. A common example of trouble related work is a car hit pole.

Joint Use Requested Rebuilds – “Make-ready” work required to existing facilities in order to accommodate joint use installations. The costs associated with the joint use work are typically reimbursed by the requesting joint use party(s).

Distribution Minor Rebuild

Deteriorated Pole Replacements – Changing out isolated wood poles that fail Avista's inspection standards that are not on schedule for a planned replacement under Avista's Asset Maintenance programs.

General Rebuilds – Work can be initiated through a variation of sources. General rebuild work is typically small in scope (i.e. one or two poles) and typically addresses unplanned work that is identified as priority because of:

- NESC code violations (e.g., inadequate clearance)
- Failed or failing equipment (e.g., rotten cross-arms)
- Inadequately sized or classed equipment for serving an existing customer or group of customers (such as an undersized transformer or fuses)
- Other minor projects include minor loop feeds, installing air switches, line regulators, line reclosers, and short reconductoring projects for reliability improvements.

Figure 1 shows a pie chart of the mentioned categorical breakdown to demonstrate the magnitude of each category. The figure gives a three year average, which has remained historically constant.

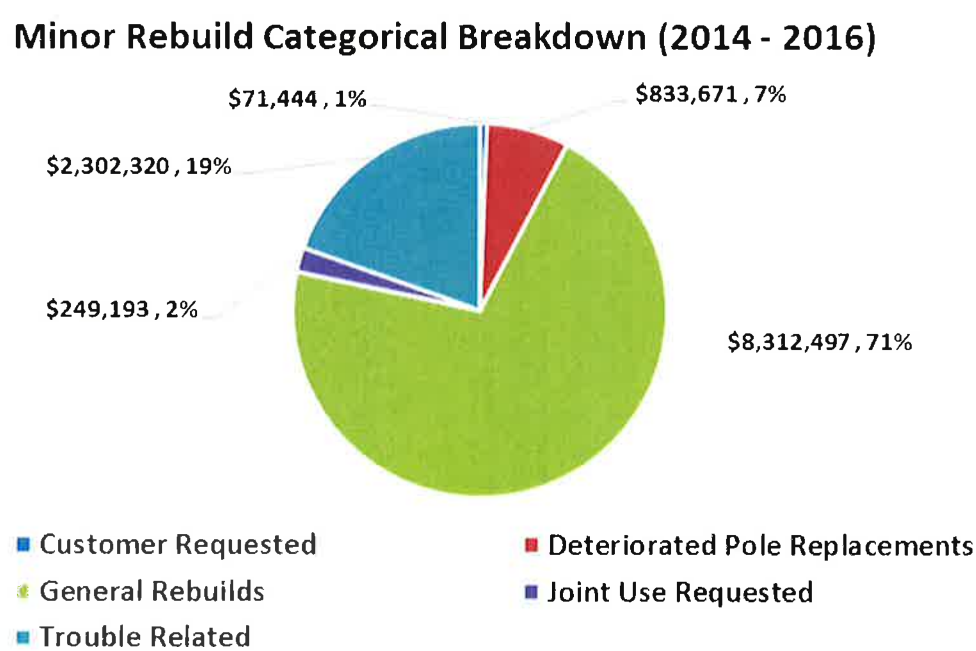


Figure 1: Distribution Minor Rebuild Categorical Breakdown

Distribution Minor Rebuild

In 2016, 1,115 work orders were created with the average cost equaling only $4,400, which demonstrates the business is made of thousands of small dollar amount jobs. Occasionally larger rebuild projects, such as small reconductor project, are undertaken as Distribution Minor Blanket projects. A common reason is the work is considered critical and non-discretionary. Only 28 work orders were created over $25,000, averaging $54,000 per work order in 2016.

Figure 2 displays a breakdown of the different types of charges that occur in the Minor Rebuild. 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.

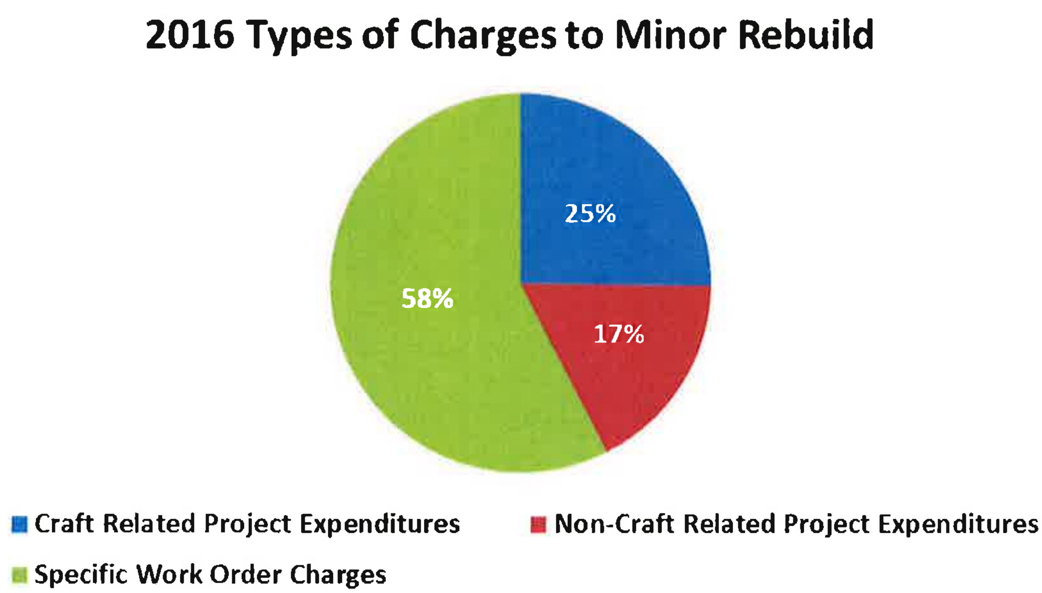


Figure 2: Types of Charges to Minor Rebuild (2016)

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

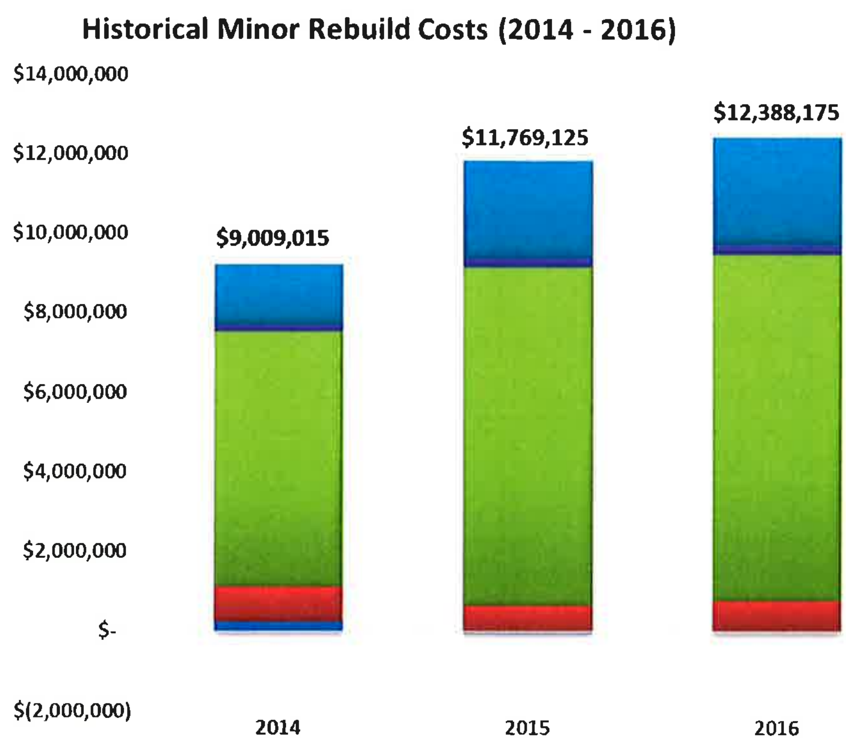
- **Craft Related Project Expenditures**: Craft labor (servicemen, general foremen, local rep), associated vehicle usage, trouble related work charges
- **Non-Craft Related Project Expenditures**: Non-craft labor, associated vehicle usage, contribution reimbursables (credits), and material issues/returns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

Distribution Minor Rebuild work is one of the many components that contribute to 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 funds the replacement of a car-hit pole in the alley, a broken cross-arm, a burned up transformer, or fixes a joint use code violation, and a myriad of other safety related projects. By not funding the business will also affect the ability to respond to customers' needs for modifications to their electrical service. Lastly, it is acknowledged some minor rebuilds left unrepaired will not result in immediate catastrophic failures to the distribution system (i.e. a broken pole pin insulator), 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 pockets of the distribution system.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Unfunded	$0	N/A	
Fund Unplanned Work (based on historical quantities)	$12,300,000	Continuous Program	

Figure 3 is the historical spend required to fully fund the Minor Rebuild business.



	2014	2015	2016
Trouble Related Rebuilds	$1,478,356	$2,400,179	$2,665,215
Joint Use	$190,489	$261,069	$254,814
General Minor Rebuilds	$6,389,964	$8,474,276	$8,703,540
Deteriorated Pole Replacement	$892,854	$678,196	$782,397
Customer Requested	$251,550	$(39,795)	$(17,792)

Figure 3: Minor Rebuild Historical Spend

Figure 3 shows a steady increase in costs for unplanned minor rebuild work from 2014 to 2016. The categories of Joint Use, General Minor Rebuilds, and Trouble

Related Rebuilds increased annually over the three years, while Deteriorated Pole Replacements remained steady in costs. Customer Requested Rebuilds are typically a credit to the business because most are reimbursed in part or in full by the customer. As shown in 2014, Customer Requested Rebuilds are not always reimbursed back to the business.

The Distribution Minor Rebuild business 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.

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. While the work is unplanned, minor rebuilds to the distribution system occur on a regular basis every year and make up a significant portion of the business within Engineering and Operations. While unplanned and isolated minor rebuilds will always exists in the distribution system, unplanned work is minimized to the greatest extent through other systematic infrastructure programs.

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The Distribution Minor Rebuild business aligns with the company's focus of **Safe & Reliable Infrastructure**, to invest in our infrastructure to achieve optimum life-cycle performance – safely, reliably and at a fair price.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Distribution Minor Rebuild 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:	4-14-2017
Print Name:	Cody Krogh		
Title:	Mgr Asset Maintenance		
Role:	Business Case Owner		

Signature:		Date:	4-17-17
Print Name:	Bryan Cox		
Title:	Sr Dir of HR Operations		
Role:	Business Case Sponsor		

5 VERSION HISTORY

Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Landen Grant	4/13/2017	Cody Krogh	4/14/2017	Initial version

Template Version: 02/24/2017

Meter Minor Blanket

1 GENERAL INFORMATION

Requested Spend Amount	$505,000*
Requesting Organization/Department	Z08/Electric Meter Shop
Business Case Owner	Dan Austin
Business Case Sponsor	Bryan Cox
Sponsor Organization/Department	Operations
Category	
Driver	

**Note: 2017 Request includes additional one time request of $205,000 for the A-base meter replacement project. This work is in support of the AMI project.*

1.1 Steering Committee or Advisory Group Information

The determination for how the funds in this business case will be spent is a joint decision made by the Manager and General Foreman. A meter usage forecast will be used to guide the decision making process. The forecast will be based on the past five years of meter installs, current install rates, and manufacturer lead times.

2 BUSINESS PROBLEM

The primary driver for this business case is failed plant and operations. We regularly experience failed plant when meters and/or metering equipment fails. Meters are a critical component to supplying our customers with electricity and to accurately measure their energy consumption. Please refer to Attachment 1 for the most recent meter failure analysis completed by Asset Management in early 2017. This analysis shows the failure curves for both digital and mechanical meters. The analysis suggests that the more digital meters that are installed the higher the meter failure rate becomes. However, mechanical meters are no longer manufactured by our meter vendors because they have moved to the digital market.

When meters fail at existing customer service point's immediate action must be taken to repair or replace the meter. This is because a failed meter will not provide accurate consumption data. Funding is necessary to replace or make needed repairs otherwise the customer billing data will have to be estimated. Billing estimation lowers the quality of service we provide our customers because estimated data can be viewed by the customer as inaccurate. Additionally, estimated billing data can put rate pressure on our customer base if usage is under estimated. If usage is over estimated it unfairly penalizes the customer whose bill is being estimated.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	*Capital Cost*	*O&M Cost*	*Start*	*Complete*
Fully fund new electric meter purchases	*$505,000*	*$0*	*01 2017*	*12 2017*
RMA meters	*313,994*	*$278,448.72*	*01 2017*	*12 2017*
Repair or Refurbish meters	*313,994*	*$281,013.48*	*01 2017*	*12 2017*

This business case will reduce the O&M required to replace failed meters. As you can see tabulated in the above table the lowest cost option is to fully fund this business case. The reduction in O&M is associated with the meter replacement portion of this business case.

Historically there has been three solutions to replace failed meters:

1.) Refurbish and repair in house
2.) Return Merchandise Authorization (RMA)
3.) Replace failed meter with new meters

3.1 REFURBISH AND REPAIR IN HOUSE

As Avista's population of digital meters grows and the mechanical meter population shrinks the less viable this option becomes. This is because digital meters require special equipment and training to repair, which is not available to our technicians. Also of note is that mechanical meters are no longer manufactured by our meter vendors because they have moved to the digital market. It is very rare for our technicians to remove a mechanical meter from the field as a result of failure. The majority, if not all, of the meter failures we experience in a given year are from the digital meter families. Table 1 shows how many digital and mechanical meters we have installed in WA and ID. This table also shows the average failure rate we experience annually. This option was not chosen due to the equipment and technical training required as well as the higher cost associated with the labor to refurbish meters.

Meter Type	*Qty.*
Single-Phase Mechanical	172,215
Single-Phase Digital	187,100
Poly-Phase Mechanical	5,781
Poly-Phase Digital	17,346
Total	***382,442***
Average failures per year	3882

Table 1: Meter Quantities by Type

Charge Type	Cost
Refurbish Labor	$37.26
Install Labor	$35.76
Total	$73.02

Table 2: Tabulated Cost to Refurbish Meters

3.2 RETURN MERCHANDISE AUTHORIZATION (RMA)

Option 2 is more costly than purchasing new meters due to the manufacturer's costs, shipping costs, and labor associated with the RMA process. Recent repair costs were quoted from our meter vendor to be between $20 and $40 dollars per meter. Table 3 shows the total cost to RMA a single meter. This cost was developed using very conservative values for each charge type and may be higher if more expensive (Poly-phase) meter types were included. This option was not chosen due to the high cost.

Charge Type	Cost
RMA Labor	$9.31
Shipping	$7.17
Repair Charges	$20.00
Install Labor	$35.76
Total	$72.74

Table 3: Tabulated Cost to Install RMA Meters

3.3 REPLACE FAILED METERS WITH NEW METERS

The final option is to purchase meters new for meter failure replacements. This is the lowest cost solution as shown in Table 4. There is a cost savings with new meters because there is no labor associated with refurbishing and testing and there is no RMA charges as compared to Options 1 and 2. This business case supports Options 3 to purchase new meters to replace failed meters.

Charge Type	Cost
Purchase Cost	$20.43
Labor	$35.76
Total	$56.19

Table 4: Tabulated Cost to Install New Meters

Meter Minor Blanket

Do nothing is not an option because at minimum we need functioning meters to replace failed meters. Doing nothing would keep Avista from accurately billing our existing customer base.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Meter Minor Blanket 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: Daniel J Austin Date: 4-14-2017
Print Name: Dan Austin
Title: Electric Meter Shop Manager
Role: Business Case Owner

Signature: Date: 4-17-17
Print Name: Bryan Cox
Title: Sr Dir of HR Operations
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	Dan Austin	4/13/2017	Bryan Cox	4/14/2017	Initial version

Template Version: 03/07/2017

Attachment 1: Electric Meter Model Review

Electric Meter
Model Review.pptx

Downtown Network

1 GENERAL INFORMATION

Requested Spend Amount	$2,300,000
Requesting Organization/Department	Electric Operations
Business Case Owner	Ryan Bradeen
Business Case Sponsor	Bryan Cox
Sponsor Organization/Department	Electric Operations
Category	Program
Driver	Customer Service Quality & Reliability

1.1 Steering Committee or Advisory Group Information

The Downtown Network work is overseen by the local area manager and engineers. The majority of the work is planned, but when construction season starts there can be unplanned work. Local area operation engineers and the construction manager manage the work as it is identified throughout the given construction season. Many projects are planned by the operation engineers or the construction manager for situations that do not allow for the 3 to 5 year capital planning process. Any City of Spokane driven work takes priority.

2 BUSINESS PROBLEM

Avista owns and maintains an underground electric network that serves the core business, financial, and city government district of downtown Spokane from Division Street to Cedar and from Interstate 90 to the south bank of the Spokane River. It is operated as a networked secondary system. Most mid to large cities in the United States operate similar electric grids. The system is configured to allow a single element forced outage (transformer, cable segment) without impact to customers. Outages can and do occur, but those generally involve substation equipment failures or failures associated with work in progress. Like most utilities that operate networked secondary systems, Avista uses three dedicated cable crews specifically trained to operate, construct, inspect, and maintain these systems. Topology in the Network is unique to Avista electric distribution and requires specialized material, equipment, tooling, and training to perform planned replacement, road moves, and capacity growth projects.

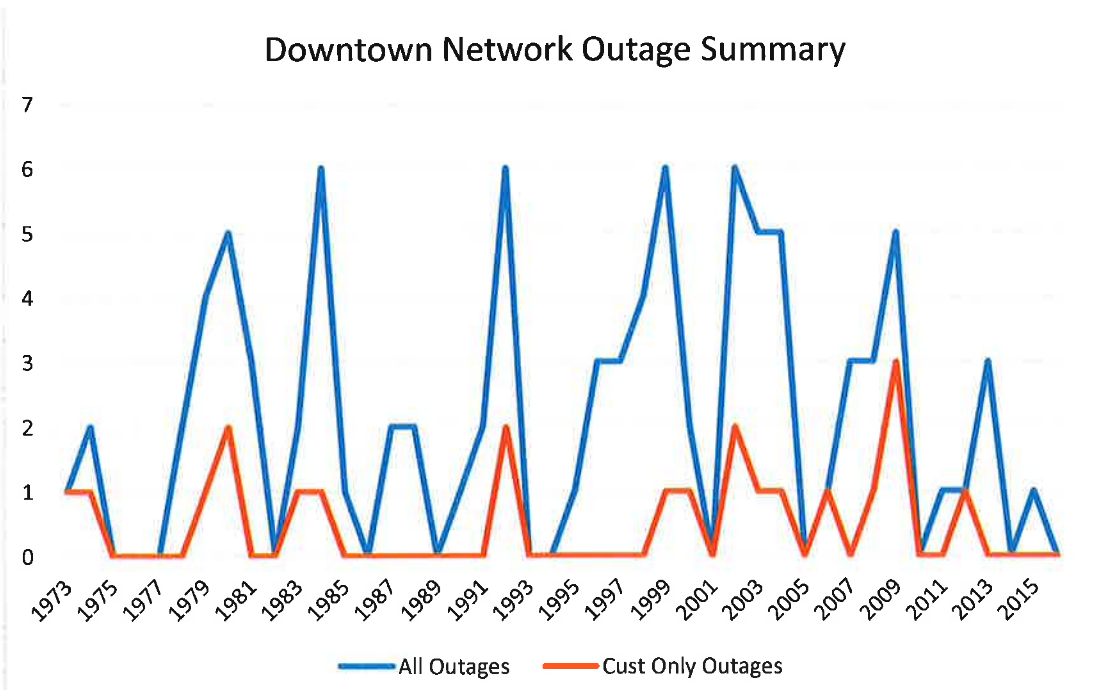
The Spokane Electric Network encompasses over a thousand underground manholes, hand-holes, and vaults. Within the Network's boundaries there are 176 3-phase subway style transformers, 176 network protectors, 176 relays (solid state/2 electromechanical), and multiple pad-mounted and submersible transformers. They are all maintained by Network cable crews. Approximately half of the transformers and protectors have been updated and are Polychlorinated Biphenyls free. Over half of the primary cabling in the Downtown Network is Paper

Downtown Network

Insulated Lead Cable (PILC) installed in the 1930s. Many of the Network's 741 electric services were installed as early as 1907.

The work that is done for the Downtown Network is focused on keeping the Network system in a safe and reliable condition, as well as maintaining customer driven rebuilds, and being proactive in capital replacements of deteriorated infrastructure. Throughout the entire Network distribution system rebuilds or replacements of assets need to be completed to maintain system reliability. Most facilities are in the right of way and public safety is a priority. Also, unplanned damages occur to the system randomly and if left unattended would result in an unsafe and unreliable network distribution system (e.g. a manhole lid collapse). Lastly, customers sometimes have unplanned power service requirements that change or are modified, which result in the utility having to either modify the Network distribution system near the customer or upstream of the customer to meet the customer's request.

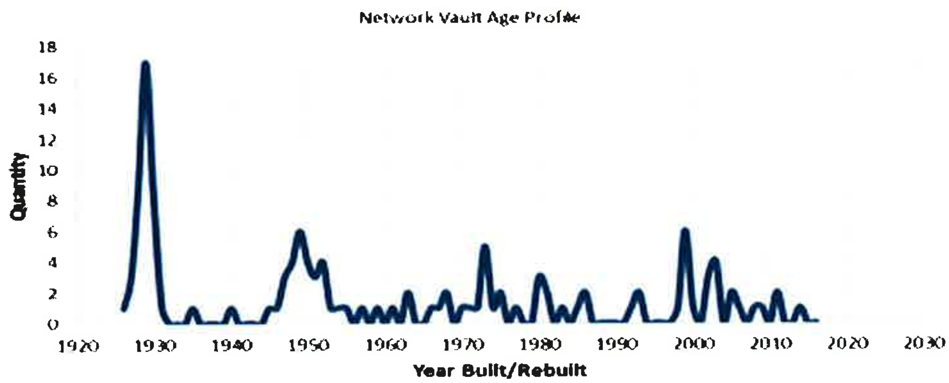
As the age of the infrastructure approaches the end of its life, the Network is in constant need for improved structural facilities both for the safety of our power infrastructure and for the safety of the public. The majority of the Network's structures have exceeded their expected life resulting in outages, as shown in the diagram below, affecting customer's electric service. The Network is replacing a significant amount of the structural system. As the Network updates facilities, they create major construction jobs for the infrastructure and the electric grid, and this will continue for the next several decades.



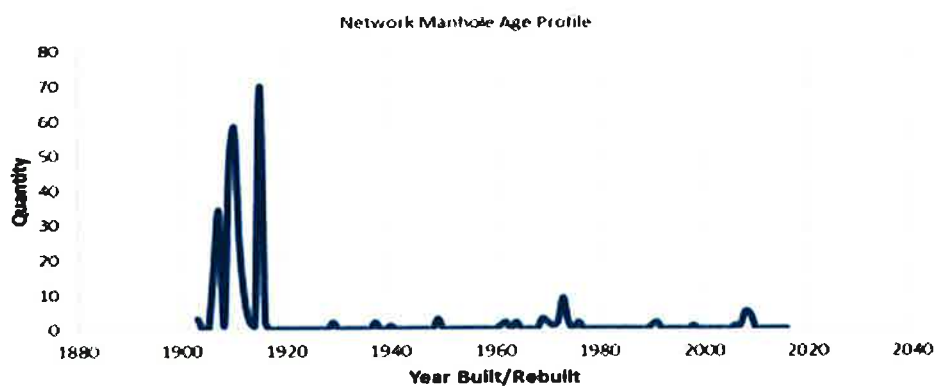
Downtown Network

The downtown network outages summary graph shows an increase in total outages during the 1980s and a decline in total outages during the last 10 years. One probable reason for this is the proactive replacement of old cable. Many failures in the 1980s were from failing splices, more common with the old standard PILC cable. Feeder outages rarely cause customer outages.

Network Vault Age Profile



Manhole Age Profile



The Downtown Network work is one of the many components that contribute to the overall reliability of the Network distribution system as well as responsiveness to customer requested service demands.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Recommended Solution	$2,300,000	01 2017	12 2017

Avista is obligated to meet customer demands. The risk of doing nothing will result in customers going without power, broken franchise agreements with the city, and the system deteriorating beyond repair.

The recommended solution maintains a safe and reliable infrastructure as part of our responsibility to provide service. The business case provides a solution for the utility to address infrastructure failures and customer driven modifications to the distribution system.

While the work is planned (e.g. city projects, transformer and cable replacements) there is unplanned customer driven work that surfaces annually and can result in a significant portion of the projects.

The Downtown Network business aligns with the company's focus of **Safe & Reliable Infrastructure** to invest in our infrastructure to achieve optimum life-cycle performance – safely, reliably and at a fair price.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Downtown Network 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: Ryan Bradeen Date: 4-26-17

Print Name: Ryan Bradeen

Title: Mgr Ops – Downtown Network

Role: Business Case Owner

Signature: Date: 4/24/17

Print Name: Bryan Cox

Title: Sr Dir of HR Operations

Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Ryan Bradeen	4/5/2017	Bryan Cox	4/18/2017	Initial version

Template Version: 03/07/2017

Electric Relocation and Replacement Program

1 GENERAL INFORMATION

Requested Spend Amount	$2,750,000
Requesting Organization/Department	Operations
Business Case Owner	Cody Krogh
Business Case Sponsor	Bryan Cox
Sponsor Organization/Department	Operations
Category	Program
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

The Electric Distribution and Transmission Relocation and Replacement Program work is overseen by the local area operations engineers and area construction managers. The work is mostly unplanned and non-specific in nature, but occurs regularly and historical averages are used to estimate a quantity. The local area operation engineers and area construction managers manage the work as it is identified throughout the given construction season.

2 BUSINESS PROBLEM

The Electric Distribution and Transmission Road Moves/Relocation program is driven by compliance mandated by "Franchise Agreement" contracts with local city and state entities and "permits" issued by Railroad owners. In general, 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 for 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 request 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 Electric Relocations are agreed to and executed per the jurisdictional Franchise Agreement or Permit.

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.

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.

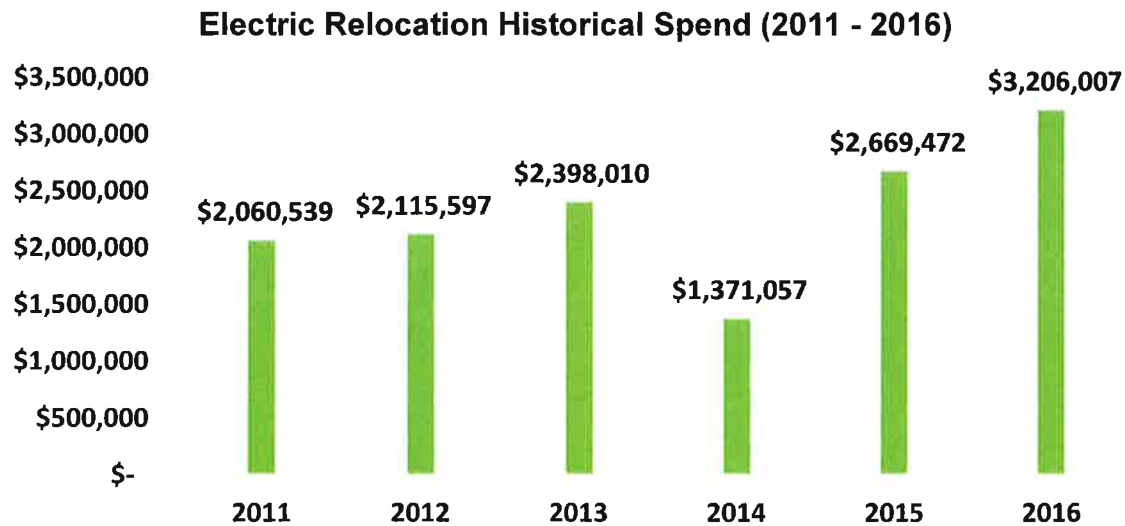
Under a Franchise Agreement or Permit, Avista is allowed to occupy space within a ROW owned by the respective jurisdiction in order to serve its customers. Electric relocations occur every year during the construction season, but are unplanned, so historical trends are used to estimate the annual cost to fully fund all the relocation projects. The annual costs of electric relocations has 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.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Unfunded	$0		
Fully Funded	**$2,750,000**	**Ongoing Program**	

Electric Relocation projects are managed, coordinated, and executed within the Operations department. When a transportation agency has a road project requiring Avista to relocate its facility, a Customer Project Coordinator (CPC) is designated full time to coordinate the project with the agency as the direct contact from Avista. The CPC manages, coordinates, and designs the relocation of Avista's distribution or transmission facility. He or she will meet with line foreman in the field to scope out the project and identify any construction obstructions (i.e. equipment access). The Real Estate group, under Environmental Affairs, often is involved in Electric Relocation projects to obtain further easements or get permits approved.

Because the Electric Relocations 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 Electric Relocation (2011 – 2016). The average spend over the six years is $2.3 million. However, if 2014 spend is thrown out as an outlier, it is clear the trend in electric relocations is trending upward. 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.



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.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Electric Relocation and Replacement Program 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:	4-14-2017
Print Name:	Cody Krogh		
Title:	Mgr Asset Maintenance		
Role:	Business Case Owner		

Signature:		Date:	4-17-17
Print Name:	Bryan Cox		
Title:	Sr Dir of HR Operations		
Role:	Business Case Sponsor		

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Cody Krogh	4/14/2017	Bryan Cox	4/14/2017	Initial version

Template Version: 03/07/2017

Primary URD Cable Replacement 2017

1 GENERAL INFORMATION

Requested Spend Amount	$1,000,000
Requesting Organization/Department	Asset Maintenance
Business Case Owner	Cody Krogh
Business Case Sponsor	Bryan Cox
Sponsor Organization/Department	Asset Maintenance
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

Cable condition and outage information is collected and analyzed by Asset Management. This information is reviewed with Asset Maintenance to establish an effective construction plan that prioritizes work based on faults and number of customer impacted. Asset Maintenance then collaborates with Electric Operations to coordinate the work. Asset Maintenance tracks the work budget, scope, and schedule.

2 BUSINESS PROBLEM

The primary driver for the Underground Residential Development (URD) Cable Replacement Program is to improve system reliability by removing URD cable with a high failure rate. The other driver is to reduce O&M costs related to responding to customer outages caused by the failed cable.

This work is needed to complete the replacement of the un-jacketed first generation underground primary distribution cable referred to as URD cable. This first generation URD cable was installed from 1971 to 1982. There was over 6,000,000 feet of URD cable installed during this time period. Subsequent to installation the URD cable began to experience an increasing failure rate. From 1992 to 2005 the cable failure rates quadrupled from 2 faults to 8 faults per 10 miles of cable. The faults reached a peak of 238 annual failures in 2007. Increased capital funding to replace this URD cable from 2005 through 2009 helped stabilize the failure rates. Continued funding and replacement of the cable has enabled a downward trend in failures as shown below in table 1. Cable installed after 1982 has not shown the high failure rate.

This work is required to continue to reduce primary URD cable failures and increase reliability. Historically there have been over 200 cable faults per year. The average cost to respond to a fault in 2015 was about $3000 per event due to the challenging nature of the work to locate and repair the cable underground. The estimated remaining pre-1982 cable is around 1,000,000 circuit feet.

Primary URD Cable Replacement 2017

The tables below demonstrate the effectiveness of this program to reduce faults and outage expenses through the replacement of the defective cable. The trend of cable faults and expenses decrease over time as the older cable is removed from the system.

Table1: URD Cable Replacement Results

KPI Description	Projected URD Cable - Primary OMT Events	Actual URD Cable - Primary OMT Events	Projected Number of Feet Replaced	Actual Number of Feet Replaced
2009	143	136	178,000	213,000
2010	119	93	178,000	217,883
2011	94	95	178,000	225,823
2012	70	72	178,000	117,247
2013	45	93	0	35,874
2014	45	88	0	35,515
2015	45	64	0	24,155

Table 2: URD Cable Replacement Cost Impact

Metric Description	Projected Avoided Outage Benefit due to URD Cable - Pri Caused Outages	Actual Avoided Outage Benefit due to URD Cable - Pri Outages
2009	$1,038,613	$1,056,113
2010	$1,228,275	$1,295,225
2011	$1,368,561	$1,352,648
2012	$1,516,159	$1,481,504
2013	$1,744,539	$1,494,738
2014	$1,898,311	$1,580,378
2015	$1,997,052	$1,720,020

Reference:

Electric Distribution System, 2016 Asset Management Plan

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
[Recommended Solution] Continue to Replace	$1M	04 2017	12 2037

The Primary URD Cable Replacement Program requires design resources and construction labor to complete the field work. There is also some analytics/engineering to identify remaining cable segment locations. Given the projected low capital spend level, the majority of the construction labor will be performed by Avista Crews. Contract crews are typically used to plow in the cable, bore conduit or trench and install conduit in the trench. Avista crews then pull the cable into the conduit and complete the installation.

The Do Nothing approach presents significant reliability risk and added O&M cost. The historic positive results from the URD cable replacement program shown above in section two provide strong justification for continuing the current funding plan.

Over 6,000,000 feet of URD was installed before 1982. Programmed replacement of the problem cable has been on-going at varying funding levels. The estimated remaining pre-1982 cable is around 1,000,000 circuit feet. At the current proposed funding rate of $1M per year this program is planned for the next 20 years. Reduced funding would extend this time and result in additional outages and O&M expenses.

The URD Cable Replacement Program aligns with Avista's strategic vision by increasing reliability to the electric distribution system. Safe and Reliable infrastructure is the focus area for this program.

The projected annual capital spend of $1M per year is reasonable based on the realized reduction in faults from previous work and this spend level enables continued replacement of the high failure rate cable. Repair of the cable has not shown to be cost effective because the cable typically faults in another location.

Avista customers will be positively impacted by this program by realizing fewer outages from the URD cable failure. This results in improved system reliability. Avista electric operations is positively impacted through converting this work to planned work that enables more efficient use of labor. It also reduces O&M expenses. Asset Management is responsible for tracking URD cable outages from Outage Management Tool (OMT) and tracking replacement locations and cost. The Asset Maintenance group is responsible for identifying cable segments and managing the coordination of work.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Primary URD Cable Replacement 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: 4-14-2017

Print Name: Cody Krogh

Title: Mgr Asset Maintenance

Role: Business Case Owner

Signature: _______________ Date: 4-17-17

Print Name: Bryan Cox

Title: Sr Dir of HR Operations

Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Cody Krogh	4/14/2017	Bryan Cox	4/14/2017	Initial version

Template Version: 03/07/2017

Environmental Compliance

1 GENERAL INFORMATION

Requested Spend Amount	$400,000
Requesting Organization/Department	Environmental Compliance
Business Case Owner	Darrell Soyars
Business Case Sponsor	Bruce Howard
Sponsor Organization/Department	Legal
Category	Mandatory
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

Avista is subject to multiple Federal, State and Local environmental regulatory requirements. Environmental Compliance is tasked with managing and maintaining compliance with the applicable requirements from these programs, some of which require capital projects from time to time.

The Environmental Compliance group maintains a risk-based ranking of potential compliance issues that includes our current approach, accompanied documentation and a target date for resolution. This ranking is typically dynamic as smaller issues rise and fall or as larger issues are addressed through various process changes, audits or projects.

2 BUSINESS PROBLEM

Regulatory programs and standards have been established to control the handling, emission, discharge, and disposal of harmful substances. These programs are implemented directly by Federal agencies or delegated to the State or local authority. In many cases, they are applied to sources through permit programs which control the release of pollutants into the environment.

Two efforts currently require capital funding under this business case:

1. The proper handling and disposal of hazardous waste, specifically oil-filled electrical equipment governed by Resource Conservation and Recovery Act (RCRA), Toxic Substances Control Act (TSCA) and related State regulations. This funding covers all activities associated with the proper handling and disposal of hazardous waste, specifically oil-filled electrical equipment as part of the asset decommissioning process. This includes labor and equipment from when the equipment is removed from service, transported back to the Spokane Waste and Asset Recovery Facility where they are identified, investigated, inventoried, sampled, sorted, stored and/or shipped to the proper waste vendor for proper disposal. These activities are accomplished by numerous field personnel including two hazardous waste technicians. The handling of these materials is mandated by state and federal rules

2. Specific site mitigation required by our U.S. Forest Service Special Use Permit (SUP) which allows right-of-way and access to our transmission and distribution assets on public land.

The SUP outlined specific mitigation projects when it was renewed in 2009 for a period of 30 years'. Approximately 60% of these have been completed to date. The specific mitigation or restoration projects were an agreed upon remedy from past impacts from our activities related to our transmission and distribution assets. New mitigation requests do result from on-going activities to maintain our assets. Some of these arise from security issues related to managing public access while others are weather related or considered acts of god.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0	N/A	
Fund the Hazardous Waste Disposal	$250,000	01 2017	12 2017
Fund the USFS SUP mitigation activities	$150,000	01 2017	12 2017

Hazardous Waste Disposal

Funding allows Avista to maintain compliance with Federal, State requirements. Our compliance approach is the most cost effective method to support how construction and operational work is currently being accomplished at Avista Corp. We have explored other methods such as utilizing alternative support or contractors but these result in higher cost and increased liability.

Non-Funding would create significant environmental risk and potential liability which may prove detrimental to our customers, the company, and the communities we serve. There are no practicable alternatives to environmental compliance as stated in our Environmental Policy which describes our commitment to protect human health and the environment: We comply with all applicable environmental laws, regulations, and company procedures.

US Forest Service Special Use Permit (SUP)

Funding the SUP mitigation is essential to remaining in compliance with the conditions of the SUP. This allows for continued permission to occupy and operate our facilities on US Forest Service Land. Alternatives to crossing US Forest Service land were likely considered prior to the construction of these Transmission and Distribution lines; we are not aware of a cost effective alternative that could be employed allowing the removal of our assets and the surrender of our SUP.

Non-Funding of mitigation efforts would pose potential risk of cancellation of our SUP, which would undermine the ability to keep and maintain these facilities on Forest Service lands. We would also be subject to direct enforcement by the Forest Service via penalties or orders. This could cause interruption in service and increase in rates to our customers.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Environmental Compliance 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: 4/14/17
Print Name: DARRELL SOYARS
Title: ENVIRONMENTAL MGR.
Role: Business Case Owner

Signature: Date: 4/17/17
Print Name: BRUCE F HOWARD
Title: DIRECTOR, ENV. AFFAIRS
Role: Business Case Sponsor

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Heide Evans	03/29/17	Darrell Soyars	04/10/17	Initial version

Template Version: 02/24/2017

WSDOT Franchises

1 GENERAL INFORMATION

Requested Spend Amount	$ 200,000
Requesting Organization/Department	Real Estate
Business Case Owner	Rod Price
Business Case Sponsor	Bruce Howard
Sponsor Organization/Department	Legal
Category	Program
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

The spending decisions in this program are governed by the Director of Environmental Affairs and Real Estate, the Manager of Real Estate, and the Real Estate Permit Coordinator. This committee meets as needed to review project progress, timelines, needs, and other considerations.

2 BUSINESS PROBLEM

This is a program designed to renew expired franchises for Avista facilities located within Washington State highway right of way. Our plan will be to complete this program no later than the end of 2020. Annualized costs are listed in the table in section 3.

In accordance with WAC 468-34 and RCW 47.44, Avista enters into 25-year agreements with the Washington State Department of Transportation (WSDOT) to permit Avista to construct, operate and maintain electric and gas facilities within Washington highway rights of way. These agreements are referred to as franchises. WSDOT manages franchises by reaches of a state highway from county line to county line. Avista has 35 such franchises, 33 of which have expired. We cannot renew these franchises until we conduct a "Control Zone" analysis and mitigation plan for every single above ground object within the highway right of way. WSDOT rules require compliance with control zones prior to franchise renewal. By not having these franchises completed, Avista is at risk of not being allowed to conduct utility work within the WSDOT right of way.

To reduce fatalities associated with roadside accidents, the Revised Code of Washington (RCW) 47.32.130, gives jurisdiction to the Washington State Department of Transportation (WSDOT) to enforce control zone guidelines. The WSDOT Utilities Manual M 22-87.07 defines the objectives, general practices, policies and procedures in the design, administration, and coordination of utility franchises within state right of way and properties impacted by above ground objects.

- Under the WSDOT Control Zone (CZ) Mitigation Plan, Avista is required to:
    - Geo-locate all above ground utility objects within WSDOT right of way.
    - Determine CZ risk levels referred to as "Location" levels I, II, or III.
    - Address objects with a risk level of I and II through a combination of mitigation, redesign, relocating, etc.
    - Submit franchise applications with analysis, mitigation plans, and designs for each of the 33 expired franchises.
- Through recent analysis, Avista has determined approximately 1,320 poles, and other above ground objects are located within WSDOT right of way and control zone, and are either location I or II.

- We now must use the data collected to determine mitigation plans, designs and timelines for each of the 1,320 objects.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing and move all facilities into private right of way	$375,000	06/2017	12/2025
Fund a franchise renewal at a lower level	$150,000	1/2017	12/2030
Carry out a franchise renewal program as proposed	$200,000	012017	12/2020
Increase funding to speed information gathering	$1,500,000	1/2017	12/2017

Not funding the WSDOT Franchise renewal program would cause Avista's construction projects to be delayed, due to mitigating facilities inside the control zone, and place Avista at risk of being forced out of highway rights-of-way. This would expose Avista to potential third-party claims. It would take several years and a considerably higher amount of funding to purchase hundreds of miles of easements from private landowners.

Funding the data collection, analysis and presentation needed to support our franchise renewal applications, as well as the reimbursement of costs to WSDOT for its time to review and process our applications, Avista can reduce the permitting process with WSDOT by weeks, if not months. The proposed program annual funding is based on Avista's resources and DOT's ability to review and respond.

We evaluated funding this effort at both lower and higher amounts. Reducing the funding would mean delaying the franchise renewal process, and risking concerns by WSDOT that we are not responsive to control zone issues. Alternatively, budgeting more in order to submit renewal application packages in bulk, would create a more aggressive, and expensive schedule. This approach would almost certainly put a heavy workload on limited DOT staff, where the work product would wait, and possibly create re-work due to changes prior to DOT review. Therefore, we believe the measured time-phased approach is much more workable. This schedule is also the result of discussions with WSDOT on timelines that they can support.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the WSDOT Franchises 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: [signature] Date: 4/14/17
Print Name: Rod Price
Title: Real Estate Manager
Role: Business Case Owner

Signature: [signature] Date: 4/17/17
Print Name: BRUCE F. HOWARD
Title: DIRECTOR, ENV. AFFAIRS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Heide Evans	3/27/17	Bruce Howard	4/12/17	Initial version

Template Version: 03/07/2017

LED Change-Out Program

1 GENERAL INFORMATION

Requested Spend Amount	$2,900,000
Requesting Organization/Department	Operations
Business Case Owner	Landen Grant
Business Case Sponsor	Bryan Cox
Sponsor Organization/Department	Operations
Category	Project
Driver	Customer Service Quality & Reliability

1.1 Steering Committee or Advisory Group Information

Internal stakeholders meet together every six months to discuss program progress and how their respective departments are impacted by the work. They guide the program on any processes requiring modification or developing new processes to help improve the program. Internal stakeholders include Construction Services, Distribution Engineering, Warehouse and Investment Recovery, Supply Chain, External Communications, Mobile Dispatch, Enterprise Asset Management, Customer Enterprise Technology, and Regional Business Managers. External stakeholders are state and local governments who have jurisdiction over roads and streets where Avista provides illumination. Neighborhood councils are a particular external stakeholder which is often involved before their neighborhood is converted to LED because the residential areas are sensitive to street lighting.

2 BUSINESS PROBLEM

Any local or state government which has jurisdiction over streets and highways has an obligation to the general public they serve to provide acceptable illumination levels on their streets, sidewalks, and/or highways intended for vehicle driver and pedestrian safety. Avista manages streetlights for many local and state government entities to provide such street, sidewalk, and/or highway illumination for their streets by installing overhead streetlights.

The primary driver for converting overhead streetlights from High-Pressure Sodium (HPS) lights to LED lights is the significant improvement in energy savings, lighting quality to customers, and resource cost savings.

Secondly, converting streetlights to LED technology helps bring Avista in compliance with the Washington State Initiative 937 (or the Clean Energy Initiative), which ensured that at least fifteen percent of the electricity Washington state gets from major utilities comes from clean, renewable sources, and that Washington utilities undertake all cost-effective energy conservation measures. LED streetlight technology is part of the mentioned energy conservation measure.

The desire to begin the LED Change-Out Program in 2015 stems from an immediate savings in energy, positive financial impacts, benefits associated with personal injury and property theft, and resource cost savings.

LED Change-Out Program

- Each 100 watt and 200 watt HPS light replaced will save approximately 65 watts and 128 watts, respectively, per fixture. Once all of the 100 watt and 200 watt HPS street lights are replaced, the annual energy savings will be 9,903 MWH each year.
- With respect to the financial impacts of converting to LED streetlight technology, the customer internal rate of return is 8.46%, assuming the current cost of materials and life expectancy of the photocells and LED streetlight fixtures.
- From a public safety perspective, the consequence of converting to LED streetlights in lieu of replacing burned-out HPS bulbs shows a risk reduction for customers of nearly eight times less for potential injury, a serious fatal accident, and property theft.
- Lastly, company resource demands are reduced after the initial conversion to LED technology. The Average Annual Labor Man-Hours for current practices of changing burned-out HPS bulbs is estimated at 5,200 man-hours and 2,600 equipment hours, while the average man-hours required during the fifteen year life of the LED fixtures are 3,200 man-hours and 1,800 equipment hours.

In 2011, the average cost to maintain a HPS streetlight was nearly $92 per fixture with only about $10 of the cost being the actual material. The remaining costs were the main constituents of the overall cost as seen in **Figure 1**.

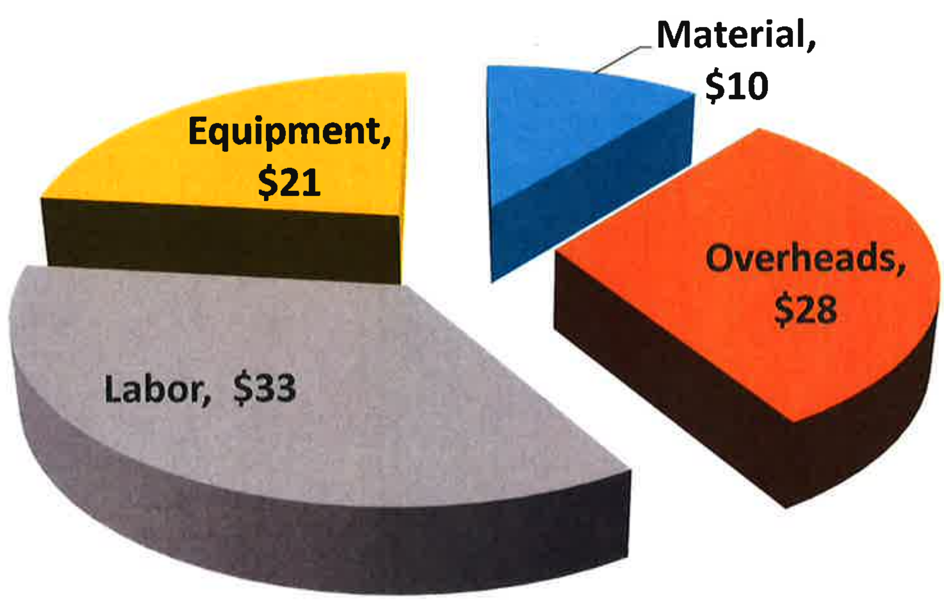


Figure 1: 2011 Cost Breakdown of a HPS Light Fixture

Also, a lifetime material usage analysis on the HPS light fixtures estimated a Mean Time to Failure (MTTF) for the various light fixture components. **Table 1** shows the results for each streetlight component.

Component Groups	Material Usage Quantities	Replacement Ratio	MTTF (Years)
fuse	641	1%	84
lamp	7,930	15%	7
photocell	5,151	10%	10
starter board	1,126	2%	48
street light fixture	683	2%	55

Table 1: 2011 Mean Time To Failure (MTTF) for HPS Streetlights

Upon completion of all streetlights changed-out to LED fixtures, a guarantee of real energy savings can be measured on an individual light fixture basis and then extrapolated to the entire system. Most LED fixtures have the capability to have real-time energy consumption measurements taken and reported back to Avista. Also, once all the streetlights are converted to LED, the number of service requests for streetlight burn-out should drop significantly from the number of service requests prior to 2015.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0	N/A	
Base Case (current practice of replacing burned-out HPS bulbs or replacing a fixture if broken)	$1.70M	Ongoing	
Optimized HPS Case (planned replacement of HPS bulbs and photocells)	$1.67M	10/2015	12/2019
LED Case (change-out all fixtures to LED)	$2.32M	10/2015	12/2019

Three alternative cases were considered in an analysis performed by the Asset Management Department of converting streetlights to LED technology. The current case or **Base Case** replaces failed HPS streetlight components only when they fail. The second case, called the **LED Case**, replaces the current HPS streetlights with new LED fixtures and implements a planned replacement at fifteen years for the light fixture and photocell. The analysis noted that inside the new LED Case model, a fifteen year replacement strategy proved more cost effective over the lifecycle than running LED lights to failure. Thirdly, the **Optimized HPS Case** represents keeping the current HPS light fixtures and performing planned replacements of the HPS bulbs and photocells at five year cycles for the bulbs and ten year cycle for the photocells.

Key assumptions made in the alternatives analysis are outlined below.

The **Base Case** and the **Optimized HPS Case**, because they propose using HPS fixtures, have the same failure characteristics shown in **Table 2**.

Table 1, HPS Light Component Failure Characteristics

Component	Population Failure Rate (10%) by Year___	Population Failure Rate (20%) by Year___	Mean Time to Failure (50% of the initial population will have failed by ____ Years)
HPS 100 W Bulb	3.4	4.4	6.7
Photocells	5.7	7.3	10.6
Starter Board	7.4	10.5	16.3

Table 3 shows the failure characteristics assumed for LED fixtures and components based on manufacturer's information and an assumed failure shape characteristic.

Table 2, Assumed LED Light Component Failure Curves

Component	Population Failure Rate (10%) by Year___	Population Failure Rate (20%) by Year___	Mean Time to Failure (50% of the initial population will have failed by Year ____
New Style Photocell	7.9	10.2	14.9
LED Light Fixture	12.1	15.5	22.6

For all three cases, a model was created to help compare the risks including, resource needs, potential energy savings, and financial impacts of each case. In the end, the **LED Case** will save customers money over the **Base Case**. While the **Optimized HPS Case** provides a better financial return to our customers compared to both the Base Case and LED Case when considering strictly labor and material costs, the energy savings associated with the LED Case becomes an overcoming driver. The customers will still see savings over the life of the LED fixtures compared to today's practices in the Base Case and eliminate the need for 2.3 Megawatts of generation at night. In addition, customers will realize an annual system energy savings of 9,903 Megawatt hours.

Table 4 is a Projected Planned Capital and O&M budget for next twenty-four years, showing the initial change-out and a subsequent planned LED change-out fifteen years later.

LED Change-Out Program

Table 4, Projected Planned 24 Year Capital and O&M Budgets for Street Lights (100W streetlights only)

Year	Capital Budget with LED Conversion	O&M Budget with LED Conversion	O&M Budget without LED Conversion	O&M Offset with LED Conversion
2015	$2,319,248	$193,824	$732,012	$538,188
2016	$2,323,370	$198,241	$746,652	$548,411
2017	$2,335,605	$203,970	$761,585	$557,615
2018	$2,354,418	$210,732	$776,817	$566,085
2019	$2,393,676	$220,542	$792,353	$571,811
2020	$97,159	$228,035	$808,200	$580,165
2021	$140,218	$238,563	$824,364	$585,801
2022	$225,059	$255,240	$840,852	$585,612
2023	$291,367	$269,314	$857,669	$588,354
2024	$330,003	$279,462	$874,822	$595,360
2025	$411,862	$295,973	$892,318	$596,346
2026	$496,398	$312,965	$910,165	$597,200
2027	$544,068	$324,702	$928,368	$603,666
2028	$646,035	$344,414	$946,935	$602,521
2029	$704,571	$357,923	$965,874	$607,952
2030	$2,059,519	$264,983	$985,192	$720,209
2031	$2,118,200	$274,195	$1,004,895	$730,700
2032	$2,144,239	$282,089	$1,024,993	$742,905
2033	$2,178,558	$291,200	$1,045,493	$754,293
2034	$2,263,814	$304,680	$1,066,403	$761,724
2035	$277,074	$318,617	$1,087,731	$769,114
2036	$334,083	$330,312	$1,109,486	$779,174
2037	$444,031	$345,078	$1,131,676	$786,598
2038	$522,725	$355,799	$1,154,309	$798,510
2039	$603,525	$371,337	$1,177,395	$806,058

LED Change-Out Program

Table 4 shows the resource savings with the **LED Case**. The last column to the right gives the estimated O&M savings, which is the result of installing new LED streetlight fixtures verses installing a new HPS bulb or photocell, which is the scenario in the **Base Case** and **Optimized HPS Case**. The column labeled *O&M Budget without LED Conversion* shows the annual O&M costs in the **Base Case**. The O&M cost in the **Optimized HPS Case** would be higher than the **Base Case** since it includes a programmatic change-out of all HPS bulbs.

The LED Change-Out Program achieves the objective of saving energy, reducing resource costs, and improving nighttime light quality, which are all objectives customers will immediately benefit from.

The LED Change-Out Program has a five year timetable, beginning in 2015, to change-out all existing Avista owned non decorative streetlights to LED (Light Emitting Diode), which equates to over 35,000 change-outs. The program schedule is orientated by circuit feeder, similar to other programs. The priorities of what circuit feeders or cities in the service territory are to be completed first is based on efficiencies. At times, coordination with cities may impact the schedule of when an area is changed out.

As shown in Table 4, the requested annual amount of nearly $2.32 million for five years (2015 – 2019) is the minimum funding amount to complete the LED Change-Out Program in the five years. If funded below the $2.32 million for five years, the realized O&M savings to customers would be delayed to subsequent years, and to a lesser amount. However, if the Program is funded above the requested annual amount of $2.32 million for five years, customers will realize the O&M savings sooner and to a greater degree.

The impacts of the LED Change-Out Program span across multiple departments at Avista. Operations is responsible for managing the work and executing the light change-outs in the field, primarily by Avista's servicemen and local reps. Avista's Operations Support Group (Mobile Dispatch) and Enterprise Asset Management (EAM) Technology are responsible for creating work orders for all 28,000 change-outs and dispatching them to the field. The Customer and Shared Services department, particularity Enterprise Systems – Customer Care & Billing (CC&B), is impacted by the project because the customer billing changes upon converting to LED light fixtures. For the **LED Case**, the implementation of converting to LED streetlights will require only one additional Full Time Employee (FTE) over a five year period. To remain with HPS streetlights, as in the **Base Case** and **Optimized HPS Case**, will require no additional or new staffing.

The entire alternative analysis report is attached for further detail.

To summarize the overarching benefits of the LED Change-Out Program and the justification to begin the five year program sooner than later are the immediate energy savings and resource savings. Customers will benefit with every light changed out in the form of better lighting quality, reduced energy consumption and reduced labor cost. To delay the program is to delay the immediate savings to customers. The LED Change-Out Program is in alignment with the company's strategic vision of delivering reliable energy service and the choices that matter most to our customers. As part of the program, infrastructure is replaced with longer lasting equipment. By providing more efficient equipment and quality lighting, this results in an energy savings and safety increases for our customers.

The LED Change-Out Program extends across multiple departments at Avista impacting them directly or indirectly. Each department identified as a stakeholder will nominate an engaged representative to act as the liaison between the program and their department. The department stakeholder representative will also take part to promote their department's interests in the business.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the LED Change-Out Program 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: 4/13/2017

Print Name: Landen Grant

Title: Project Manager

Role: Business Case Owner

Signature: Date: 5/18/17

Print Name: Bryan Cox

Title: Sr Dir of HR Operations

Role: Business Case Sponsor

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Landen Grant	4/13/2017	Bryan Cox	4/14/2017	Initial version

Template Version: 02/24/2017

Segment Reconductor and FDR Tie

GENERAL INFORMATION

Requested Spend Amount	$5,000,000 / year (on-going)
Requesting Organization/Department	Distribution Engineering – C51
Business Case Owner	David James
Business Case Sponsors	David Howell, Josh DiLuciano, Heather Rosentrater
Sponsor Organization/Department	Energy Delivery / Distribution Engineering
Category	Program
Driver	Performance & Capacity

STEERING COMMITTEE OR ADVISORY GROUP INFORMATION

Distribution Area Engineers and Distribution System Planning.

Tim Figart – Spokane

Scott Weber & Marshall Law – East Region

Dan Knutson – Othello, Davenport

Marc Lippincott – Colville

Elizabeth Frederiksen – South Region

Will Stone – Distribution System Planning

David James – Distribution Eng. Mng.

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 **Synergee** load flow program.

Segment Reconductor and FDR Tie

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 (W. Stone).
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 Mngt).
6. Feeder Automation Strategy – a design guide to assist the CPC/Engineer when making decisions involving automated devices (Distribution Engineering).
7. Synergee Computer Program – the load flow program derives topology information from Avista's GIS system. Updates to the Synergee 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.

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).

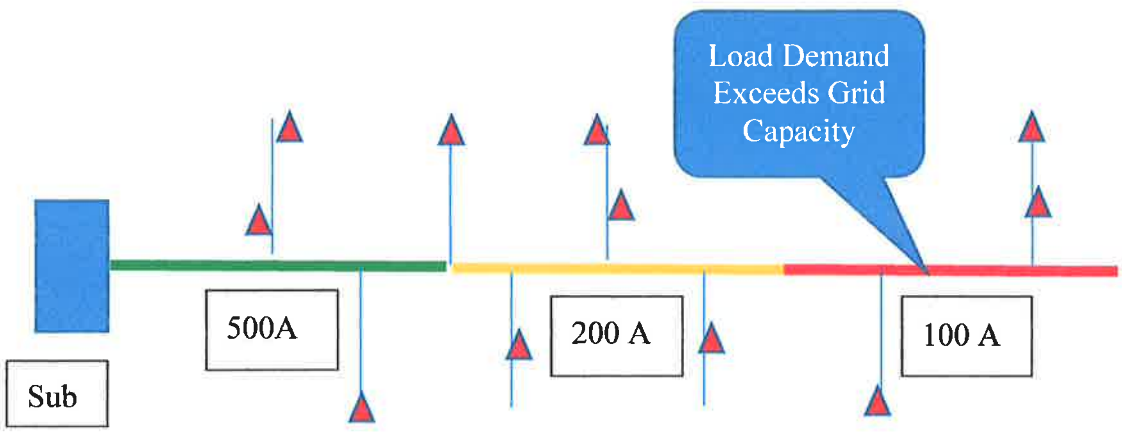


Illustration of Distribution Grid Capacity Constraint
Avista's Distribution System contains over 75 different wires and cables

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)

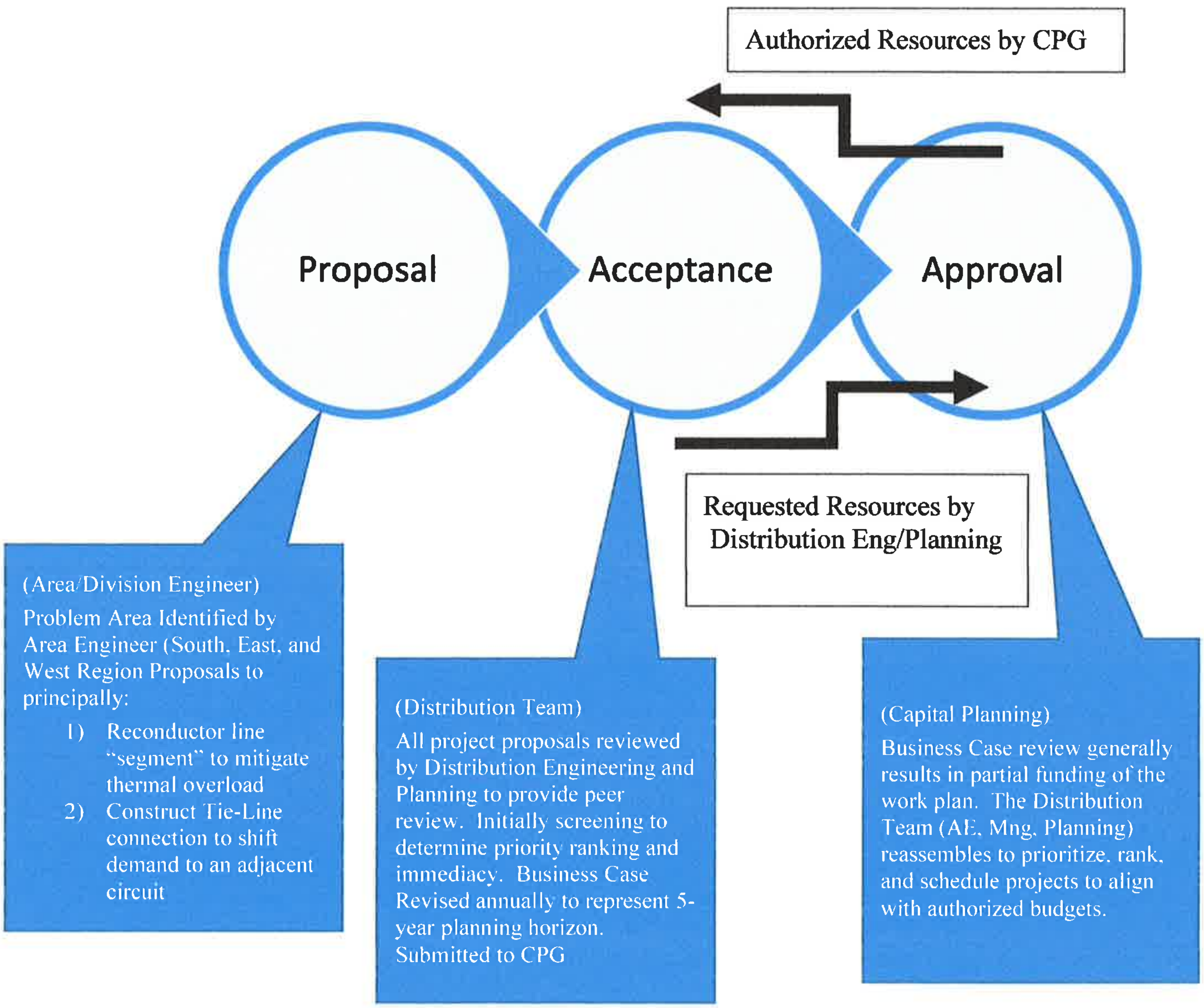
Avista's distribution grid contain over 1,000 miles of conductor equivalent or smaller than #6 Copper.

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.



Segment Reconductor and FDR Tie

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	All electric components all thermally limited. Reconductoring is the most direct approach to mitigating overloaded circuits.

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 Friday April 7, 2017.

http://sharepoint/departments/enso/dist/default.aspx

Region	2017	2018	2019	2020	2021
West	2,485,000 13 projects	2,500,000	2,500,000	2,500,000	2,500,000
East	1,315,000 9 projects	1,250,000	1,250,000	1,250,000	1,250,000
South	1,375,000 8 projects	1,150,000	1,250,000	1,250,000	1,250,000
Total	**5,175,000** **30 projects**	**4,900,000**	**5,000,000**	**5,000,000**	**5,000,000**

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.

Segment Reconductor and FDR Tie

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: [signature] Date: 4/19/17
Print Name: DAVID JAMES
Title: Dist. Eng. Mngr
Role: Business Case Owner

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

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

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.1	David James		Above signatures	04/07/17	Initial version

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%	753.83	-9	4	-9	2	-9	4
Fall	395	347	377	215.6	9.1%	351.60	-10	3	-10	2	-9	3

Year	Historical Demand (A) 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 - 149) S Scott
82239	600	ON	2907F	(1 - 99) E Main

Year	Reliability 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	389-443931-0
Location:	Pacific-2nd and Scott		
Min. Volts (V)	123.08	1O#15	394-2660217-0
Location :	Under the WSU Riverpoint Campus		

2015 5 Worst Outages

Incident ID	Date	Cust. Hrs.	# Eff Cus.	Dur.	Cause	Location
866363	7-Dec	1014:46:08	131	6:40	Pole Fire	1036 E DESMET AVE UNIT 8
867075	8-Dec	593:30:08	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
786436	19-Mar	24:11:30	5	4:53	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

Top 10 (% Of Rated) Transmission Breakers

				Reading At Last Run	Rated Limit	% Of Rated
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

				Reading At Last Run	Rated Limit	% Of Rated
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

				Reading At Last Run	Rated Limit	% Of Rated
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	423.8	537.6	78.7
7	9TH_CENT	CB	12F4	340.0	435.0	78.2
8	SANDPNT	CB	4523	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 Lippincott	Dan Kostson	
3	Spokane	Spokane	Deer Park	Mar/Pull	L/C	Grangevill	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		LKY341	WAL545		VAL12F2		
27	BKR12F2	NW12F4		PAL312	TEN1293		LKY342			VAL12F3		
28	BKR12F3	NW13T23		POT321	TEN1294		LKY343					
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										

*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

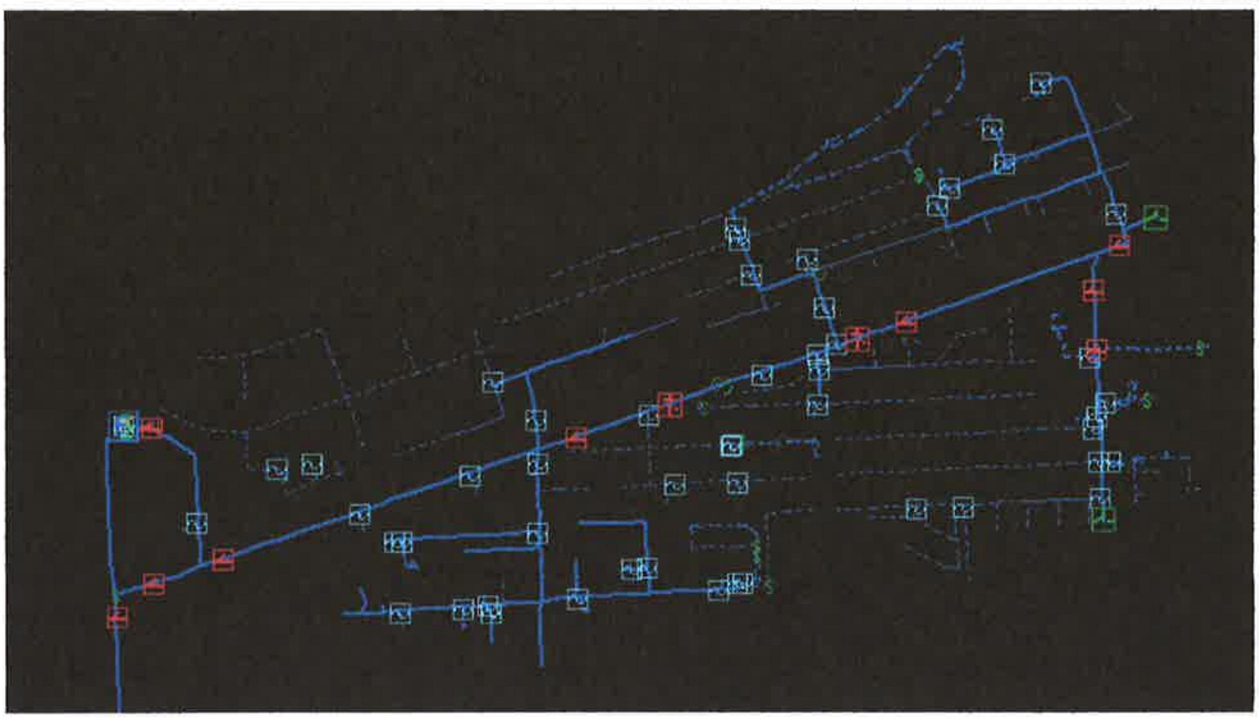
12/10/2013	LMR	LEWISTON MILL ROAD ENERGIZATION FALL 2014
12/10/2013	NLW	N LEW 13 KV SUB MOVED TO N LEWISTON 230 KV 2014
9/23/2014	GRA	NEW GREENACRES SUB 2015
9/24/2014	GIF	ADD 13 KV AT GIFFORD IN 2015
7/20/2016	RAT	231 and 233 DMS
8/26/2016	HAR	4KV CONVERSION, ASSIGN DAY TO BB

Segment Reconductor and FDR Tie

Synergee 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.

Synergee Computer System: Millwood 12F4 Circuit



SCADA - SOO and BuCC

1 GENERAL INFORMATION

Requested Spend Amount	$1,054,000
Requesting Organization/Department	T&D - SCADA/EMS/DMS - System Operations
Business Case Owner	Brad Calbick
Business Case Sponsor	Mike Magruder/Heather Rosentrater
Sponsor Organization/Department	Energy Delivery
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The program's yearly Requested Spend Amount are reviewed and authorized by the Capital Budget Group. 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. The business case owner re-prioritizes items throughout the year as necessary to address evolving business and compliance requirements. Any mid-year increases in the program's requested spend amount require authorization by the Capital Budget Group.

2 BUSINESS PROBLEM

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.

The primary driver for this business case is to maintain and improve our real-time T&D System Operations, upgrading and replacing systems as they become outdated and obsolete. Many projects within this business case replace or upgrade equipment to meet mandatory obligations required by the Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC), and the US Pipeline and Hazardous Materials Safety Administration (PHMSA). Other projects replace existing failed or failing equipment to maintain operability. See below for information on operational needs supported by this business case.

- Transmission Operations – Certified System Operators monitor electrical system conditions around-the-clock. They perform switching operations, maintain system voltage, and respond to abnormal conditions. Constant communication occurs with neighboring systems and regional authorities to assure system reliability. Operators respond to emergency situations such as black start restoration, load shedding, disturbance response, and activation of the Backup Control Center.

- Balancing Authority – To maintain the balance between load, interchange, and generation, automated calculations occur every four seconds which determine Avista's electrical power obligation based on customer load, contracted power purchases & sales, and the system frequency at that instant. Controls are automatically issued to generating stations to adjust generation to meet our obligations. Control algorithms are optimized to minimize unnecessary mechanical stress while maximizing compliance with control requirements.
- Gas Operations – Gas Controllers monitor gas system conditions around-the-clock. They direct field crews, maintain system integrity, and respond to abnormal conditions. Controllers respond to emergency situations.
- Critical Infrastructure Protection – Numerous protection measures are deployed to protect critical systems from unauthorized physical and electronic access. NERC standards have dozens of requirements regarding protection of critical infrastructure. In-depth and lengthy audits are performed every 3 years by the regional reliability organization, the Western Electricity Coordinating Council. Potentially significant financial penalties result from any instances of non-compliance.
- NERC reliability standards are being continually changed. New and changed standards are adopted which will address emergency operations, transmission operations, critical infrastructure protection, communications, and balancing authority operations.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Fully funded "SCADA - SOO and BuCC" business case	$1,054,000	01/2017	12/2017

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.

Included are hardware, software, and operating system replacement and upgrades, as well as deployment of additional capabilities to satisfy new operational standards and requirements.

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).

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.

The "Do Nothing" option was considered. This business case addresses the need to provide the technical capabilities and tools to remotely monitor and control our electric and gas infrastructure. The systems which accomplish this are integral to meeting our responsibilities to ensure public and personnel safety, monitor and respond to system conditions, protect equipment, and protect from cyber threats. These systems need to be periodically upgraded and expanded to continue to meet existing and new requirements. There is really no responsible "alternative" to this business case.

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.)

Further justification of the need of this business case is listed below.

- There are numerous mandates in effect which compel these expenditures, numerous NERC Standards, and PHMSA's Control Room Management rule, in particular (49 CFR Parts 192 and 195).
- There is no practical risk mitigation should we fail to meet these requirements.
- This is a continuous program. Work is started and completed throughout each year, and in some cases, such as major upgrades, spans multiple years.
- 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."
- The amount requested is based partially upon historical spending needs, and partially on known upcoming major projects.
- Our Customers include:
  - Retail and wholesale electric customers

        - Wholesale electric transmission customers
        - Retail gas customers
- 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

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the "SCADA - SOO and BuCC" business case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Bradley T. Calbick Date: 4/20/2017
Print Name: Bradley T. Calbick, P.E.
Title: Manager of SCADA/EMS/DMS
Role: Business Case Owner

Signature: Michael A. Magruder Date: 4/20/2017
Print Name: Michael A. Magruder, P.E.
Title: Energy Delivery Director, Transmission & Distribution System Operations
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	Calbick	2017-04-10	Magruder	2017-04-14	Initial version

Template Version: 03/07/2017

Substation – Station Rebuilds Program

1 GENERAL INFORMATION

Requested Spend Amount	$12,850,000 per year on-going
Requesting Organization/Department	T&D – Substation Engineering
Business Case Owner	Ken Sweigart
Business Case Sponsors	Josh DiLuciano and Scott Waples
Sponsor Organization/Department	T&D
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. The Engineering Roundtable 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

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). Future complete station rebuilds and/or replacements will be outside the scope of this business case and will be addressed individually.

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.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Requested Start	Requested Complete	Risk Mitigation
Alternate 1: Do nothing	$0	N/A		
Alternate 2: *Maintain present level of Station Rebuilds*	$12.85M	2017	N/A (Program)	• Lower Operating Risk
Alternate 3: *Maintain minimum level of Station Rebuilds*	0-$12M	-	N/A (Program)	• Higher Operating Risk

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.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Substation – Station Rebuilds Program 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:	5/19/2017
Print Name:	Kenneth Sweigart		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:		Date:	5/19/17
Print Name:	Josh DiLuciano		
Title:	Director, Electrical Engineering		
Role:	Business Case Sponsor		

Signature:		Date:	5/19/2017
Print Name:	Scott Waples		
Title:	Director, Planning and Asset Mgmt		
Role:	Business Case Sponsor		

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	*Ken Sweigart*		*Above signatures*	*4/14/17*	*Initial version*
2.0	*Jeff Schlect*	*5/17/17*	*Above signatures*	5/19/17	*Consolidation of capital maintenance and major rebuild cases*

Template Version: 03/07/2017

Transmission – Minor Rebuild

1 GENERAL INFORMATION

Requested Spend Amount	$1,555,249
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 Transmission Design Engineering Manager manages the prioritization of projects within this business case based on inputs from the Asset Maintenance group and the maintenance engineer in the Transmission Design group.

2 BUSINESS PROBLEM

The Transmission Minor Rebuild Business Case covers the follow-up work to Wood Pole Inspections and Aerial Patrol inspections in ER 2057, and Air Switch Replacements in ER 2254.

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.

A relevant metric to this business case is the System Operator's Log, with a focus on tracking the number of outages related to asset failures. This number would be expected to increase over time if this program is not funded. 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.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Requested Start	Requested Complete	Risk Mitigation
Do nothing	$0	N/A		
Continue Transmission Minor Rebuild Program	*$1.55M*	*2017*	*N/A (Program)*	• *Transmission Outages caused by Asset Failures, and associated risk of fires*

Transmission – Minor Rebuild

The recommended solution is to replace poles, cross-arms, and other assets identified by inspection, and replace Transmission Air Switches located outside of the substations that have reached their end of life.

This program has been in place for many years and there are no expected business impacts (such as staffing, etc.) to continue the program in place.

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 Minor Rebuild program.

Transfers to plant will typically occur over a July-December monthly spread, as the work is typically completed in summer and 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.

The amount requested aligns with the amount of work typically identified on an annual basis from pole inspections and aerial inspections. The goal of this funding level is to ensure that the Transmission Design Engineering department doesn't fall behind on addressing the issues as they are identified. This amount will need to increase annually to adjust for increased material and labor costs.

Internal stakeholders in this business case include Asset Maintenance and System Operations.

4 APPROVAL AND AUTHORIZATION

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

Signature: David R. 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*	*4/14/17*	*Initial version*

Template Version: 02/24/2017

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

Hallett and White Station Rebuild – Capacity Increase

1 GENERAL INFORMATION

Requested Spend Amount	$3,250,000
Requesting Organization/Department	Distribution Planning
Business Case Owner	Ken Sweigart
Business Case Sponsor	Josh DiLuciano and Scott Waples
Sponsor Organization/Department	T&D
Category	Project
Driver	Customer Requested

1.1 Steering Committee or Advisory Group Information

- Ken Sweigart – Manager, Substation Engineering
- Project Engineer/Project Manager – Justin Dick

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

Hallett and White is currently a 20MVA single transformer station. UTC Aerospace (formerly Goodrich) has increased load beyond the capacity of a single dedicated feeder that currently feeds the facility. They are projecting an addition of 10MVA by 2024 in phases starting in 2018. Additionally, Avista was contacted by Inland Power and Light as they were looking for additional load serving capability in the West Plains as well. Through a collaborative process it was determined that a feeder out of H&W would serve their needs for the immediate future. A contract was signed in February 2017 with the intent to energize a dedicated 10MVA feeder to IP&L by December 2018. These two primary drivers necessitate an increased capacity at H&W.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Alt 1: Status Quo			
Alt 2: Construct Flint Station and serve remotely			
Alt 3: Rebuild H&W to 2x30MVA station	*$3.25M*	*2017*	*2019*

Alternative 1 – Status Quo/Do Nothing:

This alternative is not recommended because it does not mitigate the expected capacity constraints.

Alternative 2 – Construct Flint Station and Extend Distribution:

This alternative is not recommended as it is inefficient and costly to string the required distribution from the Flint site to the load centers. It also would not be in compliance with the contract signed with IP&L.

Alternative 3 – Rebuild Hallett and White and Increase Station Capacity:

This alternative is the most cost effective and operable, and also the only alternative in compliance with the contract as signed with IP&L. It also most immediately and effectively meets the needs of UTC. It is the best next step in improving and expanding load service in the western Spokane County area.

Solution:

Alternative 3: The scope recommended consists of two phases:

PHASE 1:

System Impact & Facilities Study for IP&L Feeder	Feb 1, 2017
Interconnection Agreement for IP&L Feeder	Feb 1, 2017
Execute Interconnection Agreement with IP&L	Apr 1, 2017
Substation Engineering & Design Physical Transmittal	Jun 15, 2017
Substation Engineering & Design Electrical Transmittal	Dec 7, 2017
Procurement & Receipt of Major Equipment	Jul 31, 2017
Site Preparation Complete	Dec 31, 2017
Foundations and Structures Complete	Mar 31, 2018
Electrical Construction 30 MVA Transformer 2 Complete	Nov 30, 2018
Substation Check-Out 30 MVA Transformer 2	Dec 14, 2018
Feeder Energization 30 MVA Transformer 2	Dec 17, 2018

COST: $2.25M

IN SERVICE: 12/17/2018

PHASE 2:

Substation Removal & Salvage Transmittal	Jan 12, 2018
Substation Engineering & Design Physical Transmittal	Apr 1, 2018
Substation Engineering & Design Electrical Transmittal	Aug 1, 2018
Removal of Existing Equipment	Jan 31, 2019
Site Preparation Complete	Feb 17, 2019
Foundations and Structures Complete	Mar 31, 2019
Electrical Construction 30 MVA Transformer 1 Complete	Aug 30, 2019
Substation Check-Out 30 MVA Transformer 1	Sep 13, 2019
Feeder Energization 30 MVA Transformer 1	Sep 16, 2019

COST: $1M

IN SERVICE: 9/16/2019

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Hallett and White Station Rebuild – Capacity Increase 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:	5/22/2017
Print Name:	Kenneth Sweigart		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		
Signature:		Date:	5/22/17
Print Name:	Josh DiLuciano		
Title:	Director, Electrical Engineering		
Role:	Business Case Sponsor		
Signature:		Date:	4/19/2017
Print Name:	Scott Waples		
Title:	Director, Planning and Asset Mgmt		
Role:	Business Case Sponsor		

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	*Stone/Schlect*	*5/19/17*	*Above signatures*	*5/22/17*	*Initial version*

Template Version: 03/07/2017

Electric Storm

1 GENERAL INFORMATION

Requested Spend Amount	$3,090,000
Requesting Organization/Department	Operations
Business Case Owner	Cody Krogh
Business Case Sponsor	Bryan Cox
Sponsor Organization/Department	Operations
Category	Program
Driver	Failed Plant & Operations

1.1 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 and historical averages are used to estimate an annual quantity. In the event of larger scale storms, like the historical storm event in November 2015, a formal Incident Command System (ICS) is created to manage the resources needed to respond.

2 BUSINESS PROBLEM

The electric storm business case is driven by restoring Avista's transmission, substation, and distribution systems (damaged plant) into serviceable condition during a weather storm event where assets are damaged. Storm events are random and often with short notice. The business case of Storms is funding a rapid response to unplanned damages and outages so customer outages are minimized. The business provides funds for replacing poles, cross arms, conductor, transformers, and all 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 facility is vital to providing reliable service to our customers.

The annual budget amount is determined based on historical average experience rate of Capital restoration work.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Unfunded	$0		
Fully Funded	$3,090,000M	*Continuous* Program	

Figure 1 shows the historical costs (2005 – 2016) for the distribution storm business. From 2005 to 2013, the average annual cost for distribution storms was $2.1 million dollars, with a range of $893k (2005) to $2.7M (2013). The years of 2014 and 2015 experienced an anomaly with 2014 having two uncharacteristic

Electric Storm

major wind events during the summer and November 2015 was a historic 100-year wind storm 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.

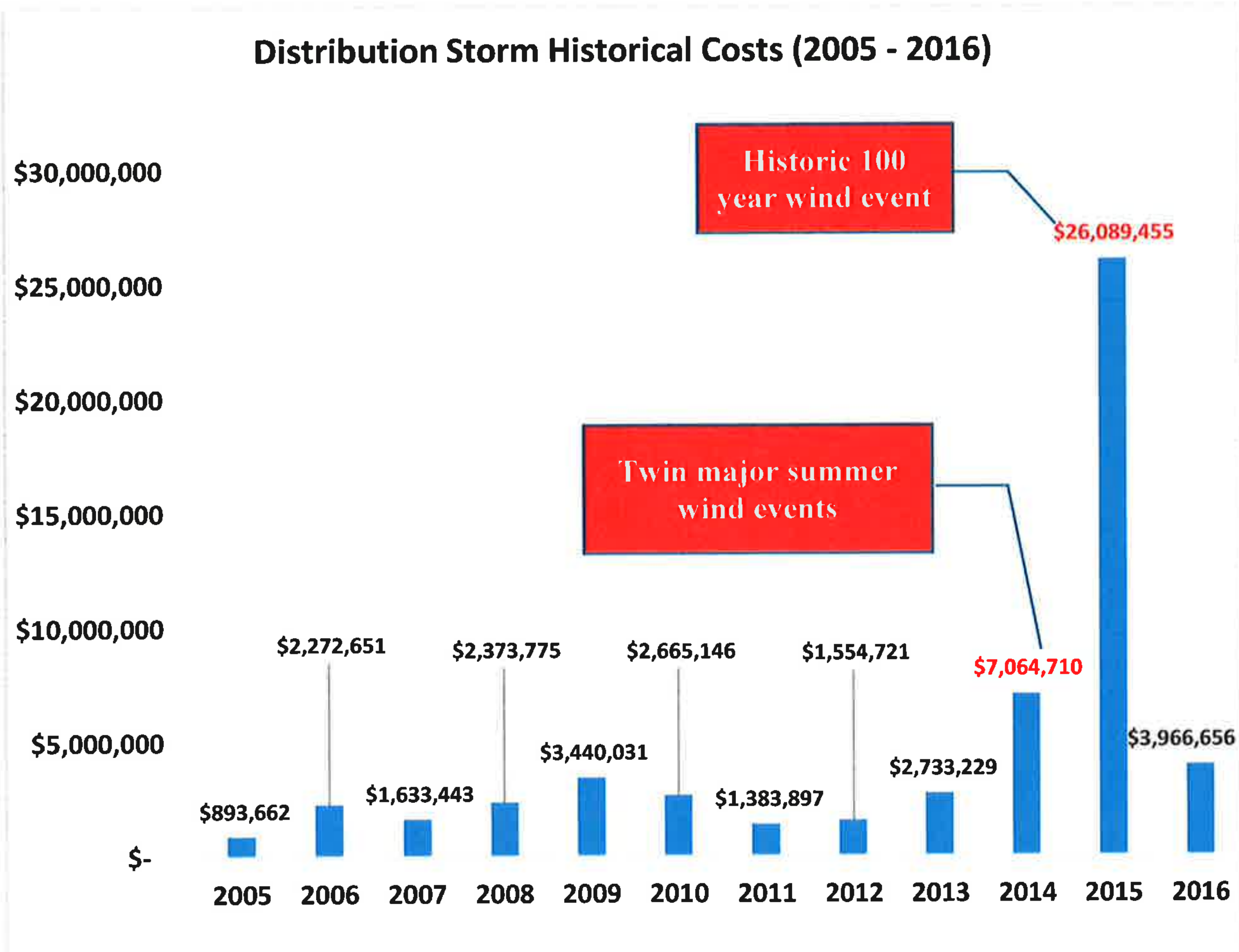


Figure 1: Dx Storm Historical Costs

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.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Electric Storm 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:	4-14-2017
Print Name:	Cody Krogh		
Title:	Mgr Asset Maintenance		
Role:	Business Case Owner		

Signature:		Date:	4-17-17
Print Name:	Bryan Cox		
Title:	Sr Dir of HR Operations		
Role:	Business Case Sponsor		

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Cody Krogh	4/14/2017	Bryan Cox	4/14/2017	Initial version

Template Version: 03/07/2017

Colstrip Transmission

1 GENERAL INFORMATION

Requested Spend Amount	$560,000 (Ongoing Annual Program)
Requesting Organization/Department	Transmission Services
Business Case Owner	Jeff Schlect
Business Case Sponsor	Heather Rosentrater
Sponsor Organization/Department	Energy Delivery / Transmission Services
Category	Mandatory
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

The Colstrip Transmission Committee, consisting of representatives of each of the parties to the Colstrip Project Transmission Agreement ("Agreement"), reviews and approves, on an annual basis, the capital and O&M expense program proposed by NorthWestern Energy (the designated Transmission Operator under the Agreement). Pursuant to Section 22 of the Agreement, Avista provides annual input to, and approval for, the Colstrip Transmission System capital and O&M expense program commensurate with its ownership shares in the Colstrip Transmission System.[1]

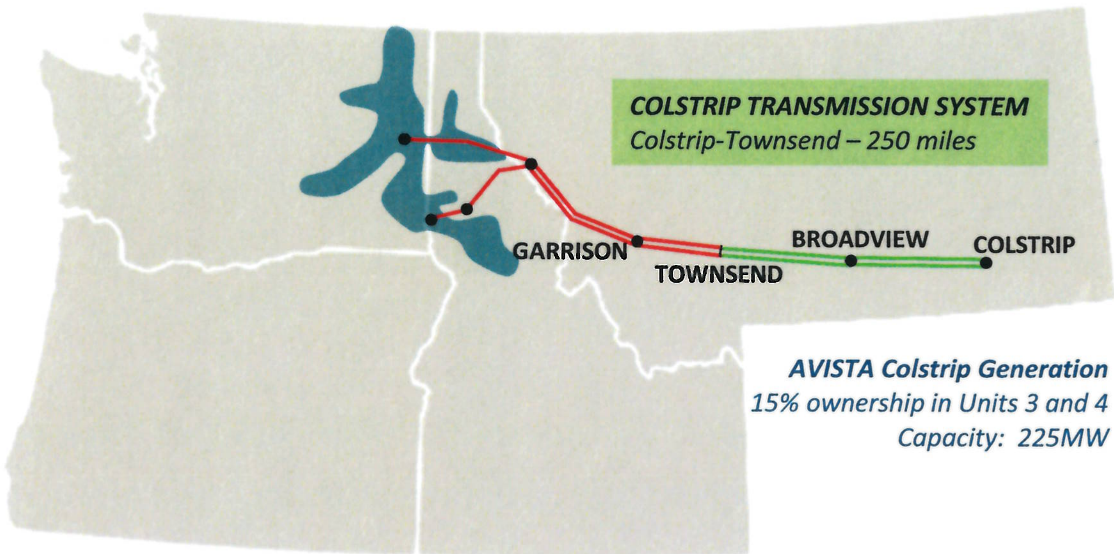
2 BUSINESS PROBLEM

As part of the construction and integration of Colstrip Units 3 and 4 in the early 1980s for the benefit of the Company's native load retail customers, the Colstrip project participants constructed the Colstrip Transmission System, approximately 250 miles of double circuit 500kV transmission facilities extending from the Colstrip Project westward to the Broadview 500kV Substation and the Townsend point of interconnection between the Colstrip Transmission System and the Bonneville Power Administration's Eastern Intertie 500kV facilities.

Avista owns a 15% share of Colstrip Units 3 and 4 (approximately 225MW). Reliable operation of the Colstrip Transmission System is necessary to transfer Colstrip output to the respective systems of each joint project owner, including Avista (other project owners are: NorthWestern Energy, PacifiCorp, Portland General Electric and Puget Sound Energy). Avista and the other joint project owners are party to the Colstrip Project Transmission Agreement which, among other things, obligates Avista to fund its commensurate share of all construction and maintenance expenses for the ongoing operation, maintenance, renewal and replacement of the jointly owned Colstrip Transmission System facilities.

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

Colstrip Transmission



Examples of recent expenditures in the Colstrip Transmission System include:

- End-of-life replacement of 500kV power circuit breakers at the Colstrip 500/230kV Substation
- Erosion mitigation caused by record high runoff in the Big Horn River, threatening the stability of two 500kV structures
- Construction of optical ground wire (OPGW) communication facilities between Broadview and Colstrip to meet dual communication path requirements under North American Electric Reliability Corporation (NERC) standards
- 500kV relay replacements
- Hardware, software and operating system upgrades to maintain compliance with applicable operating standards

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

[2] Among its other provisions, the U.S. Energy Policy Act of 2005 provided for the establishment of mandatory reliability standards and authorized the Federal Energy Regulatory Commission (FERC) to assess penalties of up to $1 million per day per violation for non-compliance with these standards and other FERC regulations. FERC has certified the North American Electric Reliability Organization (NERC) to establish and enforce these reliability standards. The Company has a statutory obligation to plan, improve, upgrade, and operate its transmission system, including the Colstrip Transmission System, to maintain compliance with these standards and is required to self-certify its compliance with these standards on an annual basis.

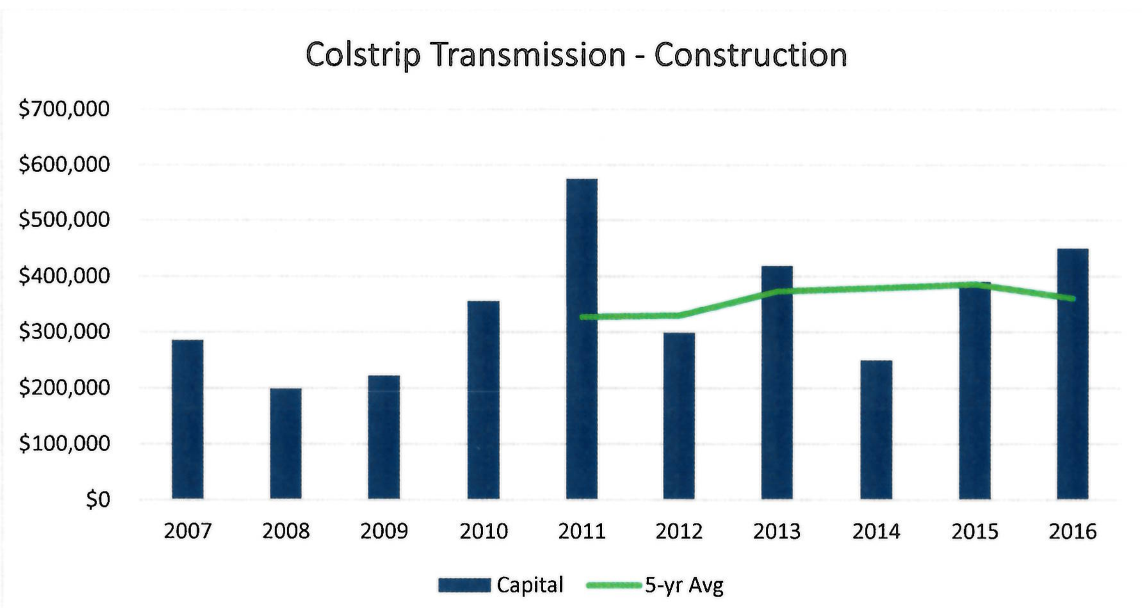
3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing – Contract default	Undetermined		
Capital Funding under the Agreement	$560,000	1981	Ongoing

Consistent with Avista's rights and obligations under the Agreement, Avista must continue to fund the Colstrip Transmission System construction and maintenance budgets, as approved by the Colstrip Transmission Committee under Section 22 of the Agreement. NorthWestern Energy, as the Transmission Operator under the Agreement, manages all design and construction activities for the Colstrip Transmission System. Accordingly, ongoing capital funding under this item has no incremental construction labor or other staffing impacts to Avista. Funding under the Colstrip Transmission Agreement is supported by existing resources in the Transmission Services, Legal and Financial Planning and Analysis groups.

Any failure by Avista to make payment or withhold capital funding for the Colstrip Transmission System will be an act of default pursuant to Section 25 of the Agreement. In any such case, a Colstrip project participant loses its right to use the Colstrip Transmission System, which would eliminate its ability to transfer its output from the Colstrip Project to its native load retail customers.

For purposes of assessing future capital funding under this Business Case, the Company's average capital funding obligations under the Agreement over the past five years is $361,000.



4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Colstrip Transmission 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:	4-14-2017
Print Name:	Jeff Schlect		
Title:	Senior Manager, FERC Policy and Transmission Services		
Role:	Business Case Owner		

Signature:		Date:	4/23/17
Print Name:	Heather Rosentrater		
Title:	Vice-President, Energy Delivery		
Role:	Business Case Sponsor		

Signature:		Date:	4/14/17
Print Name:	Randy Gnaedinger		
Title:	Colstrip Transmission Committee Member - Avista		
Role:	Steering/Advisory Committee Review		

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeff Schlect	4/10/2017	Jeff Schlect	4/14/2017	Initial version

Template Version: 03/07/2017

Environmental Compliance

1 GENERAL INFORMATION

Requested Spend Amount	$400,000
Requesting Organization/Department	Environmental Compliance
Business Case Owner	Darrell Soyars
Business Case Sponsor	Bruce Howard
Sponsor Organization/Department	Legal
Category	Mandatory
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

Avista is subject to multiple Federal, State and Local environmental regulatory requirements. Environmental Compliance is tasked with managing and maintaining compliance with the applicable requirements from these programs, some of which require capital projects from time to time.

The Environmental Compliance group maintains a risk-based ranking of potential compliance issues that includes our current approach, accompanied documentation and a target date for resolution. This ranking is typically dynamic as smaller issues rise and fall or as larger issues are addressed through various process changes, audits or projects.

2 BUSINESS PROBLEM

Regulatory programs and standards have been established to control the handling, emission, discharge, and disposal of harmful substances. These programs are implemented directly by Federal agencies or delegated to the State or local authority. In many cases, they are applied to sources through permit programs which control the release of pollutants into the environment.

Two efforts currently require capital funding under this business case:

1. The proper handling and disposal of hazardous waste, specifically oil-filled electrical equipment governed by Resource Conservation and Recovery Act (RCRA), Toxic Substances Control Act (TSCA) and related State regulations. This funding covers all activities associated with the proper handling and disposal of hazardous waste, specifically oil-filled electrical equipment as part of the asset decommissioning process. This includes labor and equipment from when the equipment is removed from service, transported back to the Spokane Waste and Asset Recovery Facility where they are identified, investigated, inventoried, sampled, sorted, stored and/or shipped to the proper waste vendor for proper disposal. These activities are accomplished by numerous field personnel including two hazardous waste technicians. The handling of these materials is mandated by state and federal rules

2. Specific site mitigation required by our U.S. Forest Service Special Use Permit (SUP) which allows right-of-way and access to our transmission and distribution assets on public land.

The SUP outlined specific mitigation projects when it was renewed in 2009 for a period of 30 years'. Approximately 60% of these have been completed to date. The specific mitigation or restoration projects were an agreed upon remedy from past impacts from our activities related to our transmission and distribution assets. New mitigation requests do result from on-going activities to maintain our assets. Some of these arise from security issues related to managing public access while others are weather related or considered acts of god.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0	N/A	
Fund the Hazardous Waste Disposal	$250,000	01 2017	12 2017
Fund the USFS SUP mitigation activities	$150,000	01 2017	12 2017

Hazardous Waste Disposal

Funding allows Avista to maintain compliance with Federal, State requirements. Our compliance approach is the most cost effective method to support how construction and operational work is currently being accomplished at Avista Corp. We have explored other methods such as utilizing alternative support or contractors but these result in higher cost and increased liability.

Non-Funding would create significant environmental risk and potential liability which may prove detrimental to our customers, the company, and the communities we serve. There are no practicable alternatives to environmental compliance as stated in our Environmental Policy which describes our commitment to protect human health and the environment: We comply with all applicable environmental laws, regulations, and company procedures.

US Forest Service Special Use Permit (SUP)

Funding the SUP mitigation is essential to remaining in compliance with the conditions of the SUP. This allows for continued permission to occupy and operate our facilities on US Forest Service Land. Alternatives to crossing US Forest Service land were likely considered prior to the construction of these Transmission and Distribution lines; we are not aware of a cost effective alternative that could be employed allowing the removal of our assets and the surrender of our SUP.

Non-Funding of mitigation efforts would pose potential risk of cancellation of our SUP, which would undermine the ability to keep and maintain these facilities on Forest Service lands. We would also be subject to direct enforcement by the Forest Service via penalties or orders. This could cause interruption in service and increase in rates to our customers.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Environmental Compliance 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: 4/14/17

Print Name: DARRELL SOYARS

Title: ENVIRONMENTAL MGR.

Role: Business Case Owner

Signature: Date: 4/17/17

Print Name: BRUCE F HOWARD

Title: DIRECTOR, ENV. AFFAIRS

Role: Business Case Sponsor

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Heide Evans	03/29/17	Darrell Soyars	04/10/17	Initial version

Template Version: 02/24/2017

Garden Springs 230/115kV Station Integration

1 GENERAL INFORMATION

Requested Spend Amount	$33,000,000
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

Construct a new 230/115 kV substation at the existing Garden Springs property. The new station will terminate the existing Airway Heights - Sunset, Sunset - Westside and South Fairchild Tap 115 kV Transmission Lines. The 230 kV bus will be energized by a new 230 kV line from Westside Substation which will require the completion of the Westside Rebuild Project and a new interconnection at Westside with the BPA Bell - Coulee #5 230 kV Transmission Line. Both of the newly designated Garden Springs - Sunset 115 kV Transmission Lines will be required to be reconductored with 150 MVA capacity conductor.

The Substation will be constructed in two phases. Phase 1 consists of building a 115/13kV yard with 115kV integration, while Phase 2 includes the 230kV yard, transformation, and 230kV integration.

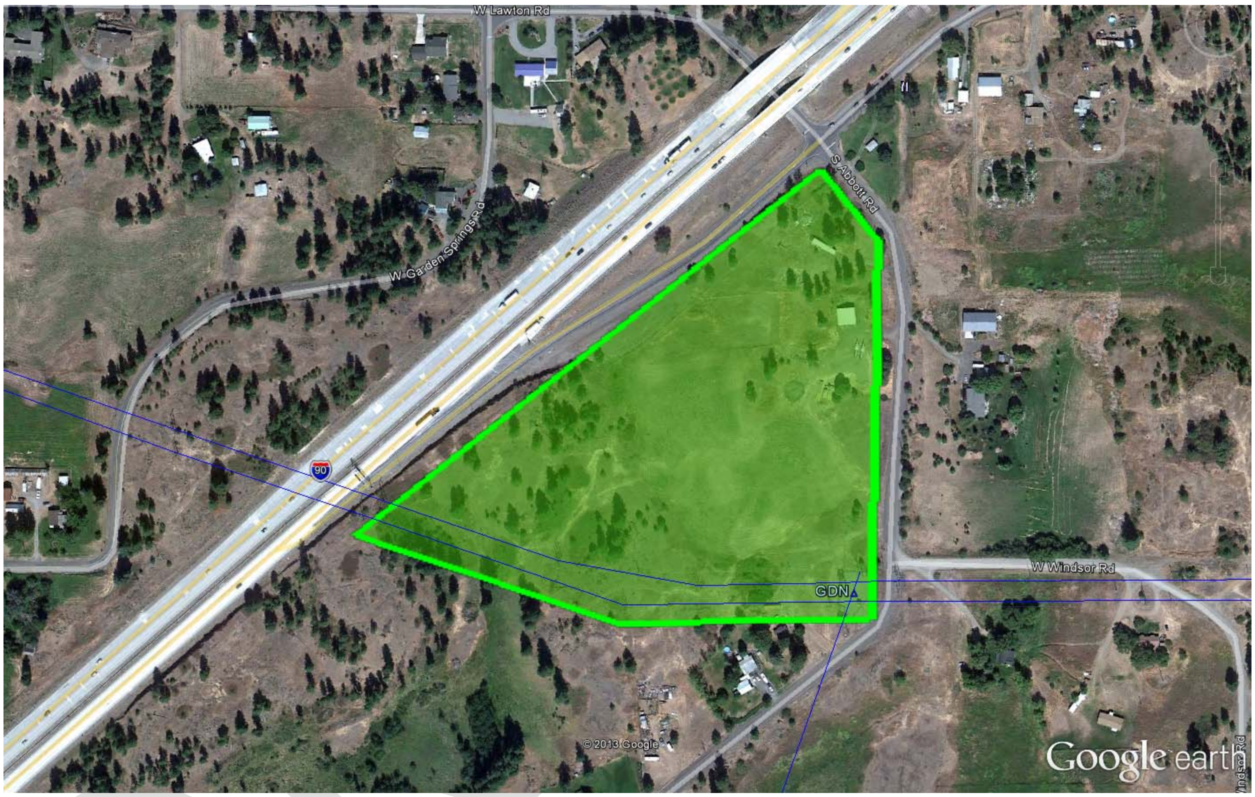
2 BUSINESS PROBLEM

The 2010 Spokane Area Regional Assessment identified specific transmission system performance issues in the five and the ten-year planning horizons. Many of the issues are caused by inadequate 230/115 kV transformation in the area. Presently there are four substations in the Spokane Area providing 230/115 kV transformation: Beacon (500 MVA), Bell (250 MVA), Boulder (500 MVA), and Westside (250 MVA). The concept of constructing Garden Springs Substation is to add 500 MVA of transformation capacity. This project is required to mitigate NERC TPL-001-4 standard violations for P2 and P6 events.

Additionally, the distribution stations in this area are connected to radial transmission lines. Manual operator action is necessary to restore service to customers following automatic circuit breaker operation to isolate a fault. Currently the Sunset-Westside 115kV Transmission Line includes the South Fairchild 115 kV Tap, to which the Four Lakes 115 kV Tap is connected, leaving a total exposure of 31 miles for all customers served by the Cheney, Fairchild South, Four Lakes, Hayford and Hallett & White substations.

Avista has identified a preferred location for the new Garden Springs 230/115/13kV Station. Selection of this property is primarily due to the convergence of 115 kV transmission lines. The Airway Heights-Sunset and Sunset-Westside 115 kV Transmission Lines pass through the property allowing for ease of integrating the new substation with the existing 115 kV transmission system, eliminating the need to construct additional new 115 kV transmission lines. Figure 1 provides an overhead view of the preferred property.

There are a minimum of seven (7) thermal or voltage limit violations identified to take place within the 10-year planning horizon if this project is not constructed. Additional supporting documentation may be found in the *Garden Springs Integration Project Feasibility Study* report authored by John Gross.



- ***Figure 1: Garden Springs Substation Property.***

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Alt 1: Do nothing	$0		
Alt 2: Option 1B - Garden Springs Integration Project Feasibility Study (Draft Version B 2013) **Phase 1**	$9M	01 2018	12 2020
Alt 2: Option 1B - Garden Springs Integration Project Feasibility Study (Draft Version B 2013) **Phase 2**	$24M	01 2022	12 2025
Alt 3: Airway Heights-Westside 115kV Line			
Alt 4: Garden Springs 230/115kV Station with Garden Springs-Westside 230kV Line			
Alt 5: No 230kV Infrastructure – 115kV Rebuilds			

Alternative 1 – Do Nothing / Status Quo:

This alternative is not recommended because it does not mitigate the expected capacity constraints, and does not comply with applicable NERC transmission planning standards. Operating Procedures may be used to defer some system deficiencies.

Alternative 2 – Garden Springs 230/115kV Station:

This alternative constructs a new 230 kV station at the existing Garden Springs property to connect the existing 115 kV transmission lines passing through the property into the station. The 230 kV station (Phase 2) would be sourced through a new 230 kV transmission line interconnection with the Bonneville Power Administration (BPA). The 115 kV portion of the new station (Phase 1) is a part of the West Plains Transmission Reinforcement Plan which addresses reliability issues and provides operational flexibility. All system deficiencies identified will be mitigated.

Alternative 3 – Airway Heights-Westside 115 kV Transmission Line:

Constructing a new 9.5-mile 115 kV transmission line from Airway Heights to Westside was considered as an alternative. Outages at the Westside station, including the P6 outage of both 230/115 kV transformers and P7 outage of the 230 kV double circuit into Westside, continue to cause performance issues. A new 230 kV source to the Spokane area provides a more robust long term solution.

Alternative 4 – Garden Springs 230 kV Station with 230 kV Transmission Line to Westside:

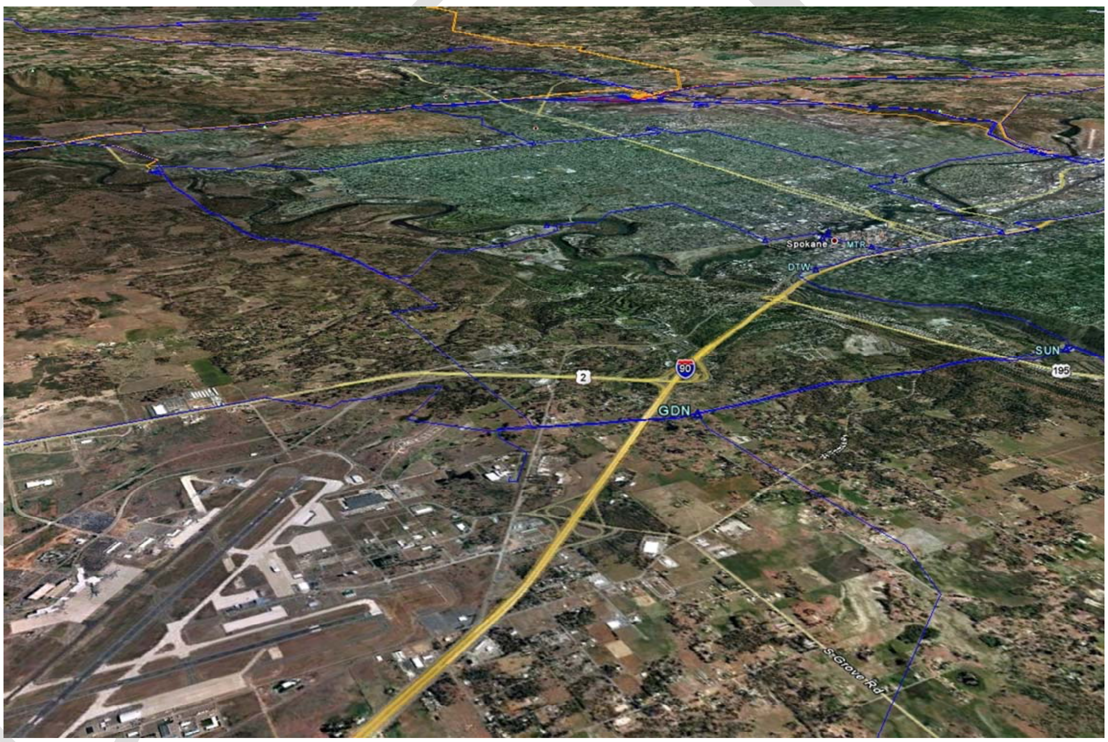
Constructing a 7.9-mile 230 kV transmission line from Westside to the new Garden Springs station was considered instead of the proposed Bluebird-Garden Springs 230 kV Transmission Line interconnection with BPA. Performance issues are not fully mitigated with this alternative. Specifically, the P7 outage of the 230 kV double circuit into Westside continues to be an issue and right-of-way events between Westside and Garden Springs stations do not meet performance criteria.

Alternative 5 – No New 230 kV Infrastructure – 115 kV Transmission Line Rebuilds:

Rebuilding several 115 kV transmission lines in the Spokane area instead of constructing any new 230 kV infrastructure was considered. The alternative does not provide the necessary redundancy but instead creates a higher dependence upon existing facilities.

Garden Springs Integration Project Feasibility Study

SPOKANE AREA



TRANSMISSION PLANNING

Prepared by John Gross

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Garden Springs 230/115kV Station 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: __________

Print Name: Kenneth Sweigart

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: Scott Waples

Title: Director, Planning and Asset Mgmt

Role: Business Case Sponsor

5 VERSION HISTORY

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

Template Version: 03/07/2017

Noxon 230kV Switchyard HV Breaker Replacement

1 GENERAL INFORMATION

Requested Spend Amount	$4,000,000
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) – 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.

This project has also been reviewed by the Engineering Roundtable.

2 BUSINESS PROBLEM

Transmission Planning identified a need of 6 breakers to be replaced per Short Circuit Analysis studies performed in the 2016 assessment. The 230 kV breakers are the Westinghouse oil circuit breakers with a name plate interrupting duty of 12.5 kA. The maximum 3-phase short circuit calculated at Noxon Rapids is 14.31 kA.

Since the limiting ratings are both an urgent safety and reliability issue new breakers were ordered in early 2016. Avista has taken delivery of the new Mitsubishi 230 kV type "F" SF6 breakers. The new breakers are capable of interrupting fault currents of 40 kA and operating at steady state voltages of 253 kV. The Mitsubishi type "F" circuit breaker represents the new standard 230 kV design breaker for Avista. Completion of this project is required to mitigate a deficiency identified by TPL-001-4 and to ensure compliance with the NERC standard.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Alt 1: Status Quo	$0		
Alt 2: Fault Reduction Scheme			
Alt 3: Tie Breaker to be operated normally open			
Alt 4: Reduce generation at Noxon Rapids HED			
Alt 5: Construct DBDB Station at Noxon Rapids			
Alt 6: Replace (6) limiting breakers (plus OCB Tie Breaker) within existing switchyard	*$4M*	*2017*	*2018*

Noxon 230kV Switchyard HV Breaker Replacement

Alternative 1 – Status Quo/Do Nothing:

This alternative is not recommended because it does not mitigate the safety and operational issues associated with over-dutied equipment within a station.

Alternative 2 – Fault Reduction Scheme:

This alternative is not recommended because the fault current at the Noxon 230kV Station, after opening a remote breaker, remains greater than the nameplate interrupting duty of the Noxon 230kV circuit breakers. This alternative also does not follow standard industry practices for distance relaying settings.

Alternative 3 – Tie Breaker Operated Normally Open:

This alternative is not recommended because this operating condition will affect neighboring parties. This will isolate Avista's generating units on the bus tied to BPA's transmission system with no normally closed transmission path to integrate Avista's generation onto the Avista transmission system. It will also isolate Avista's new 230kV reactors on the BPA system, thereby leaving no reactive control tied to Avista's 230kV transmission system. Extensive studies for the Montana-to-Northwest transmission path will need to be addressed with affected transmission entities through a WECC process.

Alternative 4 – Reduce Generation at Noxon Rapids HED:

This alternative is not recommended because the ground fault current at the Noxon 230kV Station would remain too high. The only way to get the fault current low enough is to disconnect the Noxon generator step-up transformers at the station which would leave the entire station out of service. Also, Noxon Unit No. 5 is typically used for operating reserves and reserve sharing, which would be eliminated with the station out of service. Eliminating this generation capability would be costly and infeasible.

Alternative 5 – Construct DBDB Station:

This alternative mitigates all issues but is presently not recommended due to its longer lead time to construct. The over-dutied circuit breakers are a current safety issue and need to be addressed immediately. The Noxon Switchyard Rebuild project alternative remains necessary due to asset condition and poor operational flexibility with the current station configuration, impacting both the Avista and BPA transmission systems.

Alternative 6 – Replace Over-Dutied Breakers in Existing Switchyard:

This alternative is the least-cost effective option to immediately address the safety and operational issues by providing sufficient fault-interrupting capability at Noxon 230kV Station. This alternative also mitigates identified NERC TPL-001-4 R 2.3 deficiencies in the 2016 Planning Annual Assessment.

Solution:

Alternative 6: Transmission Planning recommends replacing the six limiting breakers within the existing switchyard. In addition, the oil filled HV Bus Tie Breaker will also be replaced, bringing the total number to seven (7):

Replace 3 breakers, R334, R332, and R336 at Noxon Rapids Station in Fall of 2017

Replace remaining 4 breakers at Noxon Rapids Station in 2018

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Noxon 230kV Switchyard HV Breaker Replacement 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: 4/18/2017
Print Name: Kenneth Sweigart
Title: Manager, Substation Engineering
Role: Business Case Owner

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

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

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	*Ken Sweigart Jeff Schlect*	4/14/17	*Above signatures*	*4/19/17*	*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

Saddle Mountain 230/115kV Station (New) Integration Project

1 GENERAL INFORMATION

Requested Spend Amount	$40,000,000
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) – 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 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. Completion of this project is required to maintain compliance with NERC TPL-001-4.

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	*$75M*		
Alt 4: Install Generation	-		
Alt 5: Build Saddle Mountain 230/115kV Substation Project with associated support projects	*$40M*	*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.

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 need to be included 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: $35M

IN SERVICE: 12/31/2020

PHASE 2:

1) Rebuild Othello City to 115 kV Ring Bus with 5 positions
2) Build new line from Saddle Mountain 115 kV to Othello City Station 115kV

COST: $5M

IN SERVICE: 12/31/2021

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 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: 4/18/2017
Print Name: KENNETH SWEIGART
Title: MANAGER, SUBSTATION ENGINEERING
Role: Business Case Owner

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

Signature: 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	*Ken Sweigart*		*Above signatures*	*4/14/17*	*Initial version*

Template Version: 03/07/2017

Spokane Valley Transmission Reinforcement Project

1 GENERAL INFORMATION

Requested Spend Amount	$6,500,000
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) – 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.

2 BUSINESS PROBLEM

Completion is this project is required to mitigate a NERC TPL-001-4 system deficiency. The transmission system in the Spokane Valley currently fails TPL-001-4(P2.4), which is an internal Breaker Fault (Bus-tie Breaker) on A717 at the Boulder Station. In addition the system fails the NERC TPL-001-4 P2 Contingency for the 2017 Heavy Summer Scenario. Completion of this project is required to ensure Avista maintains compliance with NERC regulations and Avista's planning documents.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Alt 1: Status Quo	$0		
Alt 2: Complete the already started Spokane Valley Transmission Reinforcement Project	*$6.5M*	*01 2012*	*12 2019*
Alt 3: Reconfigure the CDA Reconfiguration Project			

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:

The remaining portions of the Spokane Valley Transmission Reinforcement project are constructing the Irvin Station and rebuilding a portion of the Beacon – Boulder #2 115 kV Transmission Line. All system deficiencies are mitigated and the desired operational flexibility to serve large industrial customers is realized.

Alternative 3:

Revert the system to the condition prior to the Coeur d'Alene Reconfiguration Project creating the Boulder – Rathdrum and Post Falls – Ramsey 115 kV transmission lines. Operational concerns will present themselves specifically with a P2.1 planned outage followed by a forced P1 event in the Coeur d'Alene area. (The P2.1 and P1 event combination is not a TPL-001-4 event.) Operational flexibility constrained by large industrial customers will continue to persist.

Solution:

Alternative 2, complete the Spokane Valley Transmission Reinforcement project. Remaining project scope includes the following:

Construct the Irvin Station terminating the Beacon – Boulder #1 and #2, Irvin – IEP, and Irvin – Opportunity 115 kV transmission lines as a breaker and a half configuration: $4 million, energize 2019

Rebuild the existing Beacon – Boulder #2 115 kV Transmission Line from Beacon to Millwood to 795 ACSS conductor: $2.5 million, energize 2019

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Spokane Valley Transmission Reinforcement Project 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: David Howell Date: 4/17/17.
Print Name: David Howell
Title: Dir Electrical Engrs
Role: Business Case Sponsor

Signature: [signature] Date: 4/18/2017
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	*Ken Sweigart*		*Above signatures*	*4/14/17*	*Initial version*

Template Version: 03/07/2017

Transmission NERC Low-Risk Priority Lines Mitigation

1 GENERAL INFORMATION

Requested Spend Amount	$2,000,000
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	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

The Transmission Design Engineering Manager manages the prioritization of projects within this business case based on inputs from the LiDAR studies that have been performed.

2 BUSINESS PROBLEM

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). This program is expected to be completed in 2020.

The lines that were found to have clearance discrepancies were categorized High, Medium, and Low Priority based on the following criteria:

- High: Bulk Grid 230 kV linking Avista generation to primary load
- Medium: Remaining 230 kV lines, and 115kV lines linking Avista generation to primary load
- Low: Remaining 115 kV lines

A relevant metric to this business case can be found in the NERC Alert Mitigation spreadsheet maintained by Avista's Reliability & Compliance Manager, which shows the status of mitigation work completed and work outstanding.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Requested Start	Requested Complete	Risk Mitigation
Do nothing	$0	N/A		
Continue NERC Low Priority Lines Mitigation program	*$2M*	*2017*	*2020*	• *Public safety concern; and Avista could be found at fault if an electrical contact incident occurs, because of these lines being out of compliance with the NESC code and WAC.*

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.

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 commitment to stay in compliance with all applicable regulations.

The amount requested is a good faith estimate of the work left to be completed on the Low Priority transmission lines.

The internal stakeholders in this business case include System Operations and Reliability/Compliance.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Transmission NERC Low-Risk Priority Lines Mitigation Program* 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: 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*	*4/14/17*	*Initial version*

Template Version: 02/24/2017

Transmission NERC Medium-Risk Priority Lines Mitigation

1 GENERAL INFORMATION

Requested Spend Amount	$2,000,000
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	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

The Transmission Design Engineering Manager manages the prioritization of projects within this business case based on the number and location of line clearance discrepancies found that do not meet NESC code.

2 BUSINESS PROBLEM

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 "Medium Priority" 230kV and 115kV transmission lines, including Noxon-Hot Springs #2 230kV and Devils Gap-Stratford 115kV. 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 2017.

The lines that were found to have clearance discrepancies were categorized High, Medium, and Low Priority based on the following criteria:

- High: Bulk Grid 230 kV linking Avista generation to primary load
- Medium: Remaining 230 kV lines, and 115kV lines linking Avista generation to primary load
- Low: Remaining 115 kV lines

A relevant metric to this business case can be found in the NERC Alert Mitigation spreadsheet maintained by Avista's Reliability & Compliance Manager, which shows the status of mitigation work completed and work outstanding.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Requested Start	Requested Complete	Risk Mitigation
Do nothing	$0	N/A		
Continue NERC Medium Priority Lines Mitigation program	*$2M*	*2014*	*2017*	• *Public safety concern; and Avista could be found at fault if an electrical contact incident occurs, because of these lines being out of compliance with the NESC code and WAC.*

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.

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 commitment to stay in compliance with all applicable regulations.

The amount requested is a good faith estimate of the work left to be completed on the Medium Priority transmission lines.

The internal stakeholders in this business case include System Operations and Reliability/Compliance.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Transmission NERC Medium-Risk Priority Lines Mitigation Program* 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: 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: [signature] 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*	*4/14/17*	*Initial version*

Template Version: 02/24/2017

Transmission Construction – Compliance

1 GENERAL INFORMATION

Requested Spend Amount	$11,850,000
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	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

The Engineering Roundtable manages the prioritization of projects within this business case based on the annual Corrective Action Plans developed by the System Planning group. The Engineering Roundtable 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 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 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).

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Requested Start	Requested Complete	Risk Mitigation
Do nothing	$0	N/A		
Implement Transmission Construction – Compliance program	*$11.85M*	*2017*	*N/A (Program)*	*Potential fines (up to $1M/day) for possible noncompliance with NERC Reliability Standards*

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.

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. Relevant sections of the NERC Sanction Guidelines are cited below.

NERC Sanction Guideline Summary[1]

2.9 Concealment or Intentional Violation

NERC or the Regional Entity shall always consider as an aggravating factor any attempt by a violator to conceal the violation from NERC or the Regional Entity, or any intentional violation incurred for purposes other than a demonstrably good faith effort to avoid a significant and greater threat to the immediate reliability of the Bulk Power System.

2.10 Economic Choice to Violate

Penalties shall be sufficient to assure that entities responsible for complying with Reliability Standards do not have incentives to make economic choices that cause or unduly risk violations of Reliability Standards, or incidents resulting from violations of the Reliability Standards. Economic choice includes economic gain for, or the avoidance of costs to, the violator. NERC or the Regional Entity shall

[1] NERC Rules of Procedure, Appendix 4B, *Sanction Guidelines of the North American Electric Reliability Corporation,* July 1, 2014, pp 4-5.

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.

This business case aligns with the organization's commitment to comply with all applicable laws and regulations. The amount requested represents the portion of the Transmission Reconductors & Rebuilds business case that is being spent on compliance-related projects in 2017. Annual funding will fluctuate based on the scope identified in the Corrective Action Plans.

Internal stakeholders in this business case include System Planning, System Operations, and Compliance.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Transmission Construction* 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: Lamont A. Miles Date: 4/18/17
Print Name: Lamont A. Miles
Title: Transmission Design Manager
Role: Business Case Owner

Signature: David Howell Date: 4/18/17.
Print Name: David Howell
Title: Dir Electrical Engineering
Role: Business Case Sponsor

Signature: [signature] 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*	*4/14/17*	*Initial version*

Template Version: 02/24/2017

Tribal Permits & Settlements

1 GENERAL INFORMATION

Requested Spend Amount	$ 300,000
Requesting Organization/Department	A01 – Native American Relations
Business Case Owner	Toni Pessemier
Business Case Sponsor	Jason Thackston
Sponsor Organization/Department	Energy Resources
Category	Program
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

There is no specific Steering Committee for this Business Case. The Advisory Group is our Native American Relations department, who negotiates easements and settlements with the individual Native American Tribes. Projects are driven by any installation or rebuild of facility on Tribal lands. The Native American Relations department meets with Tribal representatives to negotiate easements, or modification of easements in conjunction with construction projects.

2 BUSINESS PROBLEM

- This business case is driven by compliance, the legal requirement to obtain and maintain easements for our transmission and distribution lines. This is required under Part 25 of the Code of Federal Regulations, Section 169. Several of these cross Native American Tribal land, requiring us to maintain easements or fees to occupy those areas. The Native American Relations department of Avista is the interface with the Tribes, and conducts negotiations on behalf of Avista.
- Failure to maintain easements would put us in immediate violation of Federal Law. We would be required, lacking an easement, to remove our facility from Tribal land. Many of our easements are for transmission lines, therefore this is not a viable option.
- The primary measure would be to have active easements on all Tribal encroachments. Currently, Avista maintains 81.7 miles of transmission lines on Tribal land.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Continue to negotiate easements as required	$300,000	01 2017	12 2099

Tribal Permits & Settlements

Relocate all Transmission lines off of Tribal land	$61,190,000	01 2018	12 2023

- The only alternative to settling easements, would be to vacate those easements and reroute all of our facility off of Tribal land. This would be an extremely expensive alternative, as indicated above. In fact, for Tribal distribution assets, there is no viable option, due to obligation to serve.
- The primary risk of relocation would be the longer distances involved, and the risk of obtaining satisfactory easements on non-Tribal land.
- This is ongoing work, as these easements are not long-lived, and are subject to change as we change the nature of the facility covered by them.
- Through spending the approximately $300,000 annually, Avista maintains all easements through Tribal land, and maintains good working relationships with the Tribes.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Tribal Permits & Settlements 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: Toni Pessemier Date: 4/17/17

Print Name: Toni Pessemier

Title: Indian Relations Advisor

Role: Business Case Owner

Signature: Date: 4/18/17

Print Name: Jason Thackston

Title: Sr. V.P. Energy Resources

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	Toni Pessemier	04/12/17	Jason Thackston	04/12/17	Initial version

Template Version: 03/07/2017

Westside 230/115kV Station Rebuild

1 GENERAL INFORMATION

Requested Spend Amount	$32,000,000
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) – Sara Koeff

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.

2 BUSINESS PROBLEM

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).

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Alt 1: Status Quo			
Alt 2: Westside Transformer Replacement	*$32M*	*2015*	*2022*
Alt 3: Garden Springs 230kV Station Integration			
Alt 4: Replace Westside Transformers without Station Rebuild			

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.

Westside 230/115kV Station Rebuild

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 off load 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.

Solution:

Alternative 2: Westside Transformer Replacement is the recommended solution. 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

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Westside 230/115kV Station Rebuild 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:	4/18/2017
Print Name:	Kenneth Sweigart		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:		Date:	4/18/2017
Print Name:	Lamont Miles		
Title:	Manager, Transmission Design		
Role:	Business Case Owner		

Signature:		Date:	4/14/17.
Print Name:	David Howell		
Title:	Director, Electrical Engineering		
Role:	Business Case Sponsor		

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

5 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

SCADA Build-Out Program

1 GENERAL INFORMATION

Requested Spend Amount	$7,7M per year, $115M total over 15 years
Requesting Organization/Department	T&D – Substation Engineering
Business Case Owner	Ken Sweigart
Business Case Sponsor	David Howell
Sponsor Organization/Department	T&D
Category	Program
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

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

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

Avista is committed to the Grid Modernization Initiative. This initiative, among other things, allows for the automation of feeder devices. This enhancement reduces and/or mitigates outages. For Grid Modernization to fully realize its potential, feeder information must be brought into the Substation and back-hauled through SCADA & Communications, eventually allowing for Conservation Voltage Reduction (CVR).

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing			
Recommended Solution	*$115M*	*01 2017*	*12 2032*

This project will complete the installations of SCADA and EMS/DMS capability to all Avista substations. This will provide System Operations with clear visibility, indication, and control at every sub. In addition, Grid Modernization will have the necessary communications infrastructure for complete installation and operation on all feeders. System Planning, Asset Management, Operations, and Engineering will have real time and historical data to support efficient, flexible, and safe operation and design of the system for the future.

Alternatives considered include:

- Do Nothing: Presently only have full SCADA with EMS/DMS capability at 35 substations. Another 35 do not have any SCADA and 90 have limited SCADA with obsolete equipment, minimal room for expansion, etc. Present priorities will never allow us to get to all subs.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *SCADA Build-Out Program 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: David Howell Date: 4/17/17
Print Name: David Howell
Title: Dir. Electrical Engineering.
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	*Ken Sweigart*		*Above signatures*	*04/14/17*	*Initial version*

Template Version: 03/07/2017

Substation – Capital Spares Program

1 GENERAL INFORMATION

Requested Spend Amount	$4,750,000 per year on-going
Requesting Organization/Department	T&D – Substation Engineering
Business Case Owner	Ken Sweigart
Business Case Sponsor	David Howell/Scott Waples
Sponsor Organization/Department	T&D
Category	Program
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

- Manager, Substation Engineering - Ken Sweigart
- Project Engineer/Project Manager (PE/PM) – Scott Wilson

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 Substation - Capital Spares program maintains Avista's inventory of Power Transformers and High Voltage Circuit Breakers. This inventory of critical apparatus is capitalized upon receipt and placed in service for both planned and emergency installations as required.

Transformers and High Voltage Circuit Breakers (capital spares) are placed into service based on requirements and need. An available stock of transformers and breakers are needed to support Avista's obligation to serve under emergency conditions and for planned replacements. This inventory is managed by Substation Engineering.

The annual program expenditures may vary significantly in years when an Autotransformer (230/115 kV) is purchased. In years without an Autotransformer purchase, minor variations will occur based on planned projects as well as replenishing apparatus inventory levels required for adequate capital spares. Items within this business case are long lead time items and adequate apparatus levels must be maintained to ensure reliable operations and the ability to respond to planned worked.

Funding for this business case will change year to year based on required inventory to support reliable operations, replacement of obsolete equipment, and to support future substation construction needs.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Alternative 1: Eliminate Spares Program			
Alternative 2: Retain present level of Spares Program	$4.75M		

Alternatives considered include:

- Alternative 1: We will not have vital system capital spares required to maintain our electric system in the event of failures (emergency), planned system improvements (reliability), or obligation to serve (growth). In addition, some of this apparatus may be required for compliance upgrades in reliability and capacity. Lack of an adequate Capital Spares level extends outages, and increases the premium paid to expedite and install replacement equipment.
- Alternative 2: Maintaining the present level of Capital Spares funding, as evaluated by Substation Engineering. This level of funding provides the best alternative to minimize the consequences presented by outage risks associated with major equipment failures, and best positions Avista to efficiently perform construction. Annual funding requirements will be established consistent with historical failures, need for future spares to support reliable operations, and provide support for required capital improvements to support capacity.

Solution:

Recommendation - Alternative 2.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Substation – Capital Spares Program 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: 4/18/2017
Print Name: KENNETH SWEIGART
Title: MANAGER, SUBSTATION ENGINEERING
Role: Business Case Owner

Signature: David Howell Date: 4/18/17
Print Name: David Howell
Title: Dir. Electrical Engineering
Role: Business Case Sponsor

Signature: Date: 4/19/2017
Print Name: Scot 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	*Ken Sweigart*		*Above signatures*	*4/14/17*	*Initial version*

Template Version: 03/07/2017

Substation – New Distribution Station Capacity Program

1 GENERAL INFORMATION

Requested Spend Amount	$6,000,000 per year on-going
Requesting Organization/Department	T&D – Substation Engineering
Business Case Owner	Ken Sweigart
Business Case Sponsor	David Howell
Sponsor Organization/Department	T&D
Category	Program
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

- Ken Sweigart – 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.

2 BUSINESS PROBLEM

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.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Recommended Solution	*$6M*		

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.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Substation – New Distribution Station Capacity Program 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: 4/18/2017
Print Name: KENNETH SWEIGART
Title: MANAGER, SUBSTATION ENGINEERING
Role: Business Case Owner

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

5 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

Gas Deteriorated Steel Pipe Replacement Program, ER 3001

1 GENERAL INFORMATION

Requested Spend Amount	$1,000,000 – Annual Program Request
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner	Jeff Webb, Seth Samsell
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	Gas Operations & Engineering
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

All known deteriorated pipe segments are compiled by each of our local Gas Operations District offices. These segments are analyzed for risk and ranked using Avista's Distribution Integrity Management Plan (DIMP). Gas Engineering and each Gas Operations District take this risk ranking into account when prioritizing projects. Each Gas Operations district is allotted a portion of the overall budget and the project for each District will typically be designed and managed locally. There are circumstances where lower priority projects may be accelerated if it makes sense to coordinate the timing of pipe replacement projects with other utility or road projects. The overall program budget is managed by Gas Engineering.

2 BUSINESS PROBLEM

As a Natural Gas Operator, Avista is mandated by Federal Code to maintain and operate an active Integrity Management Program which analyzes risk associated with the threats of gas facilities. Multiple factors impact risk and the replacement of facilities including, but not limited to, material failures, environmental impacts, increased leak frequency, buried threaded connections, unconventional/obsolete pipe sizes, no protective coating (bare steel) and/or problems with protective coating on pipe. This program is intended to address these risks.

In regards to unconventional or obsolete pipe sizes, public risk is compounded by operational risk and the associated challenges of having to work on pipe sizes that are not supported by today's manufacturers. Standard fittings do not fit some of this pipe, which limits the flexibility Operation Districts have to manage emergencies if shut down of the facilities is required and a valve is not located in a convenient location.

Sections of existing steel piping within Avista's gas distribution system are aging and showing signs of deterioration or are operating with an increased risk of failure primarily due to, but not limited to, corrosion of steel material. Sections of gas main with known corrosion related issues no longer operate reliably and/or safely. Higher frequency of leaks on these existing facilities result in higher risk of operation and higher risk to the customers served in the areas with these aging facilities. This risk only increases the longer these facilities continue to operate.

This program is primarily focused on addressing deteriorated pipe in Avista's Oregon territories as this is where some of the highest known risk exists, however there will be an occasional need to utilize this program in Avista's other service territories as well. See Image 1 below for a list of known projects within this program.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
*Option 1 – Do nothing/*defer project	$0	N/A	
Option 2 – Preferred Solution, Strategically replace sections of high risk steel piping	$1,000,000	January	December
Option 3 – Alternative Solution, Reduced funding option: Strategically replace sections of high risk steel piping	$500,000	January	December

Option 1 – Do nothing/defer project

If no money is spent proactively replacing at risk pipe, then greater efforts would be required to reactively address each specific leak or corrosion issue as it occurs. This presents increased risk and safety concerns for the public located in the vicinity of high risk facilities with known leaks or leak potential as well as corrosion issues. Operational risks and challenges will continue that are related to unconventional/obsolete pipe sizes. Not addressing known risks within our distribution facilities would have a negative impact on overall Operations & Maintenance Costs and would potentially be in violation of Federal Code requirements for maintaining an active Integrity Management Program resulting in State or Federal fines. It is very difficult to anticipate what the financial impact of this would be. These risks cannot be mitigated without the replacement of these facilities and risk increases the longer these facilities continue to operate. This option is not recommended.

Option 2 – Preferred Solution, Strategically replace sections of high risk steel piping

It is recommended as part of a programmatic approach to identify and replace sections of existing steel piping that are showing signs of aging and deterioration or that are operating with an increased risk of failure within the natural gas distribution system. Completing this type of work as part of a continuing annual program is more proactive and is anticipated to have less overall cost impact than by addressing each specific leak or corrosion issue as it is encountered. A programmatic approach will also allow time for better analysis and planning to help determine if larger diameter pipes are needed for additional capacity in these service areas to help improve system operation for all downstream customers.

Gas Deteriorated Steel Pipe Replacement Program, ER 3001

This program aligns with Avista's organizational focus on our responsibility to maintain a safe and reliable infrastructure for all of our customers and in each of our services territories. The intent of this program includes, but is not limited to, the following:

- An opportunity to target areas that will improve risk, public safety and system reliability for all of our customers as part of our Distribution Integrity Management Plan (DIMP)
- An opportunity to systematically prioritize and replace facilities on an annual basis reducing a portion of the risk annually and spreading the cost of replacement out over multiple years

Option 3 – Alternative Solution, Reduced funding option: Strategically replace sections of high risk steel piping

Another option is to approach the risk associated with deteriorated pipe with a reduced funding approach. Reduced funding will result in replacement of fewer pipe segments that are showing signs of aging and deterioration or that are operating with an increased risk of failure within the natural gas distribution system. The reduced funding alternative would still allow us to benefit by addressing facilities with known risk of failure, but at a pace slower than we feel is appropriate at this time to address these known risks. The outcome, should this option be selected, would result in the continued operation of known high risk facilities which leads to increased public and operational risk as previously described in Option 1. Annual levels of spending may need to be adjusted in this program. However, as best as Avista is able to tell at this time, what is proposed is the correct amount to address the known risks resulting from the Distribution Integrity Management Plan analysis.

District	Site	Estimated Cost	2017	2018	2019	2020	2021	2016 DIMP Score/ft	Footage
Medford	DPR - B Street & Pioneer 6" Replacement, Ashland OR	$ 300,000		X				3140	4464
Medford	DPR - Bare Steel, Medford, OR	?						?	
Medford	DPR - McLaughlin 8" Replacement, Ph 3, Medford OR	$ 50,000	X					4199	418
Medford	DPR - McLaughlin 8" Replacement, Ph 4, Medford OR	$ 50,000	X					4735	586
Medford	DPR - McLaughlin 8" Replacement, Ph 5, Medford OR	$ 50,000	X					1815	577
Medford	DPR - McLaughlin 8" Replacement, Ph 6, Medford OR	$ 50,000	X					4448	537

Gas Deteriorated Steel Pipe Replacement Program, ER 3001

Medford	DPR - McLaughlin 8" Replacement, Ph 7, Medford OR	$ 50,000	X					2307	608
Medford	DPR - McLaughlin 8" Replacement, Ph 8, Medford OR	$ 50,000		X				4165	536
Medford	DPR - OR Shakespearean 6", Medford OR	$ 70,000		X				?	
Medford	DPR - S Oakdale Ave Undersized, Medford OR	$ 20,000		X				1914	1432
Medford	DPR - 16 Western Ave Pipe Replacement, Medford OR	$ 70,000		X				?	
Medford	DPR - W 8th St Replacement				X			2933	2006
Medford	DPR - Kenwood Ave. (incl Bare Steel)				X			3787	809
Medford	4" line between Peach and Quince	$ 70,000			X			?	
Roseburg	Channon & Madison, Roseburg	$ 100,000	X						
Roseburg	NE Emerald, Roseburg	$ 100,000		X					
La Grande	DPR - Cathodic Area #8 Replace, Ph 9, La Grande OR	$ 225,000	X						
La Grande	DPR - Cathodic Area #8 Replace, Ph 10, La Grande OR	$ 225,000		X					
La Grande	DPR - Cathodic Area #8 Replace, Ph 11, La Grande OR	$ 225,000			X				
La Grande	DPR - Cathodic Area #8 Replace, Ph 12, La Grande OR	$ 350,000				X			
Klamath Falls	DPR - Mills Addition, Ph5, K Falls OR	$ 250,000						2998	20109
Klamath Falls	DPR - Mills Addition, Ph6, K Falls OR	$ 250,000	X					2922	24088
Klamath Falls	DPR - Mills Addition, Ph7, K Falls OR	$ 300,000		X				3040	23908
Klamath Falls	DPR - Mills Addition, Ph8, K Falls OR	$ 300,000			X			3107	11246
Klamath Falls	DPR - Mills Addition, Ph9, K Falls OR	$ 300,000				X		3325	14832
Klamath Falls	DPR - Presidents Streets, Ph 3, K Falls OR						X	?	

Image 1 – List of known projects

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Deteriorated Pipe Steel Replacement 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 Natural Gas

Role: Business Case Sponsor

5 VERSION HISTORY

Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Seth Samsell	04/17/17			Initial version

Template Version: 02/24/2017

Gas ERT Replacement Program, ER 3054

1 GENERAL INFORMATION

Requested Spend Amount	$200,000
Requesting Organization/Department	Gas Engineering
Business Case Owner	Jeff Webb, David Smith
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 - Gas Engineering
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

Gas Engineering recognized that a significant negative impact to both Avista Gas Operations and to Avista's gas customers is being caused when an Encoder Receiver Transmitter (ERT) module experiences a battery failure while in service on a gas meter. The Asset Management department was consulted by Gas Engineering for assistance developing a strategic program to replace ERT modules before their battery expires. The result of the study suggested the most efficient method for replacing these assets that resulted in the highest customer satisfaction and lowest cost. The asset management study is attached to this document for reference. Gas Engineering is responsible for managing this program.

2 BUSINESS PROBLEM

ERTs are electro-mechanical devices that allow gas meters to be read remotely. These ERTs are powered by lithium batteries, which discharge over time and must eventually be replaced.

There are approximately 106,000 ERTs in Oregon. Figure 1 below shows the approximate quantity of ERTs installed each year in Oregon. The large quantity of ERT installations will result in an unmanageable quantity of battery failures in the future if not replaced at an optimized frequency. When batteries fail, customer's estimated usage is entered into the billing system manually. This manual process causes a high chance of customer dissatisfaction because of potential billing errors associated with bill estimation. Customers often express their dissatisfaction through commission complaints.

Since the batteries are gel sealed inside the ERT to protect against weather and the environment, it is more cost effective to replace the whole ERT, not just the battery. Avista used to replace batteries and reseal them, but determined it was not cost effective to do so. The average battery life for ERT modules is 15 years.

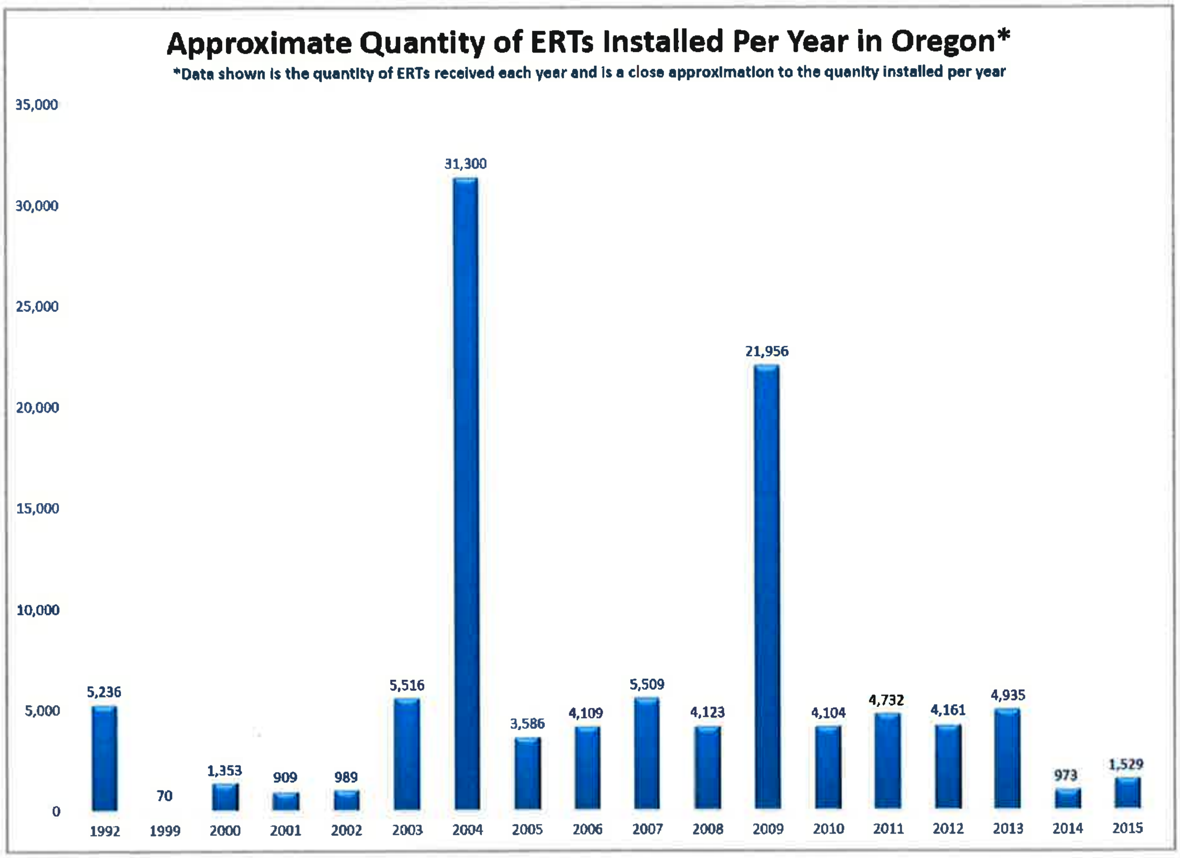


Figure 1 – Approximate Quantity of ERTs Installed per year in Oregon

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete	Risk Mitigation
Option 1 – Do nothing, Operate the ERT modules until their battery fails.	$405,200	N/A		
Option 2 – Preferred Solution, Replace the oldest 7,000 ERTs each year on a 15 year cycle	$180,000	01/2016	04/2031	
Option 3 – Alternative Solution, Replace 7,000 ERTs based on geographic location each year on a 15 year cycle	$126,040	01/2016	04/2031	

Option 1 – Do nothing, Operate the ERT modules until their battery fails.

If the ERT is operated until the battery fails, the number of battery failures will increase to an unsustainable level. Figure 2 below shows the number of expected ERT battery failures in this "Run-to-Failure" model. At its peak, more than 20,000 ERTs are predicted to fail annually, each requiring a maintenance call to replace, causing an undue burden on Operations personnel and equipment. This large number of failed ERTs will also cause an unreasonable number of meters that would need to be read manually and their usage estimated. A cost analysis was performed and is discussed below under Option 3.

Figure 2 – Quantity of ERT Battery Failures per Year in Run-to Failure Model

Option 2 – Preferred Solution, Replace the oldest 7,000 ERTs each year on a 15 year cycle.

This option involves replacing the oldest ERTs each year, regardless of their geographic location. The benefit to this approach is that the oldest ERTs are targeted, resulting in less battery failures and, as a result, fewer estimated customer bills. The disadvantage to this approach is that the oldest ERTs may not be geographically close to one another, increasing travel time in-between ERT locations. A cost analysis was performed and is discussed below.

Option 3 – Alternative Solution, Replace 7,000 ERTs based on geographic location each year on a 15 year cycle.

This option involves replacing a geographic cluster of ERTs. The benefit to this approach is that the ERTs are located close to one another, which equates to less travel time in-between ERT locations. The disadvantage to this approach is that the oldest ERTs may not be replaced if they are outside of the geographic zone, so there would be a higher quantity of ERT failures. A cost analysis was performed and is discussed below.

Cost Analysis Comments:

A third party contractor provided a cost estimate for both replacement Options 2 and 3, and the cost to replace the oldest ERTs was not significantly more than replacing the geographically located ERT clusters, therefore it costs less over the life of the program (15 years) to replace the oldest ERTs (Option 2). Figure 3 shows the cost comparison between Options 1, 2 and 3. Option 2 results in a $12,500,000 savings compared to Option 1 and a $5,000,000 savings compared to Option 3. Option 2 provides a levelized replacement strategy and will minimize the financial impact of ERT failures as well as introduce new, levelized populations of ERTs into the system for future preventive maintenance. Customers will also be the least impacted by choosing option 2 because the oldest ERTs are replaced first, reducing the amount of battery failures and the resultant number of customer bill estimations.

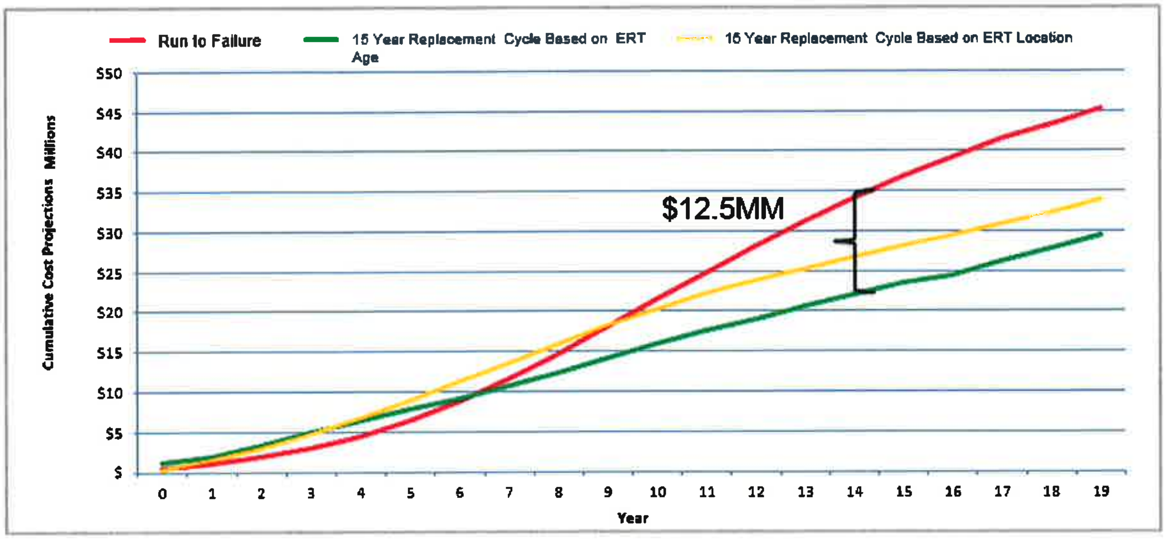


Figure 3 – Cost Comparison for Options: 1 (red), 2 (green), and 3 (yellow).

Due to the "pre-capitalization process", the cost of the ERT will go against ER1053 (Gas ERT Minor Blanket), not this business case.

The Advanced Metering Infrastructure (AMI) project will replace ERT modules in Washington and Idaho, therefore the ERT Replacement Program will be focused on Oregon only at this time. This program will continue in Oregon until either the technology or the lifecycle of the ERT changes.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas ERT Replacement 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:	Mike Faulkenberry	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	4/17/17	Mike Faulkenberry	04/17/2017	Initial version

Template Version: 02/24/2017

Gas Regulator Station Replacement Program, ER 3002

1 GENERAL INFORMATION

Requested Spend Amount	$800,000
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	Asset Condition

1.1 Steering Committee or Advisory Group Information

Gas Engineering, Gas Operations, and the Gas Meter Shop work together to administer the Regulator Station Replacement Program. Gas Engineering is ultimately responsible for prioritizing the projects and reporting out financial updates to the Capital Budget Group.

A master list of Regulator Stations (pressure reduction 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 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.

2 BUSINESS PROBLEM

This annual program will replace or upgrade existing at risk Regulator Stations and industrial meter sets that are at the end of their service life 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.

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.

These regulator stations require annual maintenance per 49 CFR 192.739, if the equipment at the stations 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.

Our customers 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 stations can be remedied under just one project.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 - Do nothing	$0		
Option 2 – Preferred Solution, Replace at risk regulator stations at current funding level	$800,000	January	December
Option 3 – Alternative Solution, Replace regulator stations at a reduced funding level option	$400,000	January	December

Option 1 - Do nothing

The do nothing option will force Avista to operate at risk regulator stations and industrial meter sets in an unsafe, unreliable, and sometimes non-code compliant manner.

Option 2 – Preferred Solution, Replace at risk regulator stations at current funding level

The current level of spending 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.

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.

Option 3 – Alternative Solution, Reduced funding level option

If this program is funded at a reduced rate, there are two possible ways to accomplish this. One is to replace fewer regulator stations and industrial meter sets. As explained above, there is already a backlog of high risk stations to be replaced, so this option 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.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Regulator Station Replacement 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 of Gas Engineering
Role: Business Case Owner

Signature: M. Faulkenberry   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

New Revenue - Growth

1 GENERAL INFORMATION

Requested Spend Amount	$47,443,826
Requesting Organization/Department	Energy Delivery
Business Case Owner	David Howell
Business Case Sponsor	Heather Rosentrater
Sponsor Organization/Department	Energy Delivery
Category	Program
Driver	Customer Requested

1.1 Steering Committee or Advisory Group Information

The Energy Delivery Director Team assumes the role of advisory group for the New Revenue – Growth Business Case, with quarterly reporting to the Board of Directors through the Financial Planning & Analysis department. The appropriate extension and service tariffs are designed and updated by the Avista Rates Department, in cooperation with Construction Services, and the Financial Planning & Analysis department. All Customer Project Coordinators are trained regularly, by Rates and Finance, on tariff application.

2 BUSINESS PROBLEM

- The New Revenue – Growth Business Case is driven by tariff requirements that mandate obligation to serve new customer load when requested within our franchised area. Growth is also seen as a method to spread costs over a wider customer base, keeping rate pressure lower than would otherwise be experienced.
- Avista is required to serve appropriate new load, complying with our Certificate of Convenience and Necessity, and as part of our Obligation to Serve.
- Avista uses a rolling 12-month Cost Per New Service spreadsheet to measure ER1000, Electric New Revenue, and ER1001, Gas New Revenue spending. Device blankets are subject to demand for both new revenue and non-revenue installation and replacement.
- Enclosed are Internal Rate of Return runs from the Revenue Requirements Model for each state and service, showing the breakeven spending to achieve our current 7.29% authorized Rate of Return. These allow us to periodically validate the Line Extension tariffs, to ensure that we are not creating excessive rate pressure in connecting new customers.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Serve new customer load, and purchase appropriate devices	*$47,443,826*	*01 2017*	*12 2099*
No other alternatives allowed under current tariff.	*$M*	*MM YYYY*	*MM YYYY*

- The New Revenue – Growth Business Case will provide funds for connecting new Electric and Gas customers in accordance with our filed tariffs in each state
- Our obligation to serve, mandates that we must extend service to new customers in our franchised service areas. We do not currently have an alternative to serving new customers. All projects are subject to our Line Extension Tariffs, filed with each State Utility Commission.
- Enclosed is a spreadsheet showing projected spend through 2021 with a breakout by Expenditure Request for the New Revenue – Growth Business Case. Electric and Gas devices are also included, such as Meters, Transformers, Gas Regulators, and ERTs (Encoder Receiver Transmitter). Many of the Meters, Transformers, and ERTs are used as replacements for Transformer Change Out Program, Wood Pole Management, and Periodic Meter Changes. The costs are allocated based on an estimate of how many devices of each type will be used for replacement, rather than new connects. Those splits are shown on the spending summary.
- The New Revenue – Growth Business Case serves as support of several focus areas in Avista. We seek to serve the interests of our customers, in a safe and responsible manner, while strengthening the financial performance of the utility. Our growth contributes to strong communities, ongoing value to our customers, and the device portion of the business case keeps our system safe and reliable.
- The requested funds are broken down in the enclosed spreadsheet, and value assigned to each component.
- All new customers on Avista's system are benefitted by this business case. In addition, all customers who have their metering or regulation changed, or who have transformers replaced, benefit from this business case.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the New Revenue – Growth 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: David Howell Date: 4/14/17.

Print Name: David Howell

Title: Director, Operations

Role: Business Case Owner

Signature: Date: 4/23/17

Print Name: Heather Rosentrater

Title: Vice President, Operations

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	*Neil Thorson*	*03/17/17*	*Heather Rosentrater*	*03/17/17*	*Initial version*

Template Version: 03/07/2017

ER		2016	2017	2018	2019	2020	2021
1000	**Electric New Revenue**						
	Residential Connects	5,030	5,060	4,886	5,067	5,177	5,177
	Residential Cost/Svc	2,300	2,500	2,500	2,500	2,500	2,500
	Residential Dollars	11,569,000	12,650,000	12,215,000	12,667,500	12,942,500	12,942,500
	Commercial Connects	1,000	850	821	851	870	870
	Commercial Cost/Svc	2,219	2,500	2,500	2,500	2,500	2,500
	Commercial Dollars	2,218,900	2,125,000	2,051,927	2,127,940	2,174,135	2,174,135
	ER1000 Total	**13,787,901**	**14,775,000**	**14,266,927**	**14,795,440**	**15,116,635**	**15,116,635**
1001	**Gas New Revenue**						
	Residential Connects	5,295	5,685	5,479	5,656	5,774	5,744
	Residential Cost/Svc	2,384	3,095	3,095	3,095	3,095	3,095
	Residential Dollars	12,624,683	17,592,801	16,955,313	17,503,058	17,868,220	17,775,382
	Commercial Connects	500	560	540	557	569	566
	Commercial Cost/Svc	2,384	3,000	3,000	3,000	3,000	3,000
	Commercial Dollars	1,192,133	1,680,000	1,619,124	1,671,430	1,706,301	1,697,435
	ER1001 Total	**13,816,818**	**19,272,801**	**18,574,437**	**19,174,488**	**19,574,521**	**19,472,818**
1002	**Electric Meters**						
		550,000	550,000	550,000	500,000	500,000	500,000
	ER1002 Total	**550,000**	**550,000**	**550,000**	**500,000**	**500,000**	**500,000**
1003	**Transformers**						
	Growth and Other	3,134,000	3,196,680	3,260,614	3,325,826	3,392,342	3,460,189
	WPM	100,000	300,000	350,000	1,200,000	1,200,000	1,200,000
	TCOP	3,000,000	2,000,000	2,000,000	-	-	-
	Fdr Rebuild	266,400	266,400	266,400	266,400	266,400	266,400
	ER1003 Total	**6,500,400**	**5,763,080**	**5,877,014**	**4,792,226**	**4,858,742**	**4,926,589**
1004	**Street Lights**						
		700,000	900,000	900,000	900,000	900,000	900,000
	ER1004 Total	**700,000**	**900,000**	**900,000**	**900,000**	**900,000**	**900,000**
1005	**Area Lights**						
		625,000	650,000	675,000	700,000	700,000	700,000
	ER1005 Total	**625,000**	**650,000**	**675,000**	**700,000**	**700,000**	**700,000**
1009	**Network Protectors**						
		950,000	960,000	980,000	980,000	980,000	980,000
	ER1009 Total	**950,000**	**960,000**	**980,000**	**980,000**	**980,000**	**980,000**
1050	**Gas Meters**						
	Growth	516,751	556,867	536,688	554,026	565,585	562,646
	PMC	1,427,681	1,470,512	1,514,627	1,560,066	1,606,868	1,655,074
	ER1050 Total	**1,944,432**	**2,027,379**	**2,051,316**	**2,114,092**	**2,172,453**	**2,217,720**

1051	**Gas Regulators**						
	Growth	103,350	237,997	229,373	236,783	241,723	240,467
	PMC	237,668	244,798	252,142	259,706	267,497	275,522
	ER1051 Total	**341,018**	**482,795**	**481,515**	**496,489**	**509,220**	**515,989**
1053	**Gas ERTs**						
	Growth	222,203	218,575	210,655	217,460	221,997	220,843
	PMC	479,803	494,196	509,022	524,293	540,021	556,222
	ERT Replacement	1,517,291	400,000	412,000	424,360	437,091	450,204
	ER1053 Total	**2,219,297**	**1,112,771**	**1,131,677**	**1,166,113**	**1,199,109**	**1,227,269**
1108	**Hallett & White Subst**						
		1,900,000	950,000	950,000	-	-	-
	ER1009 Total	**1,900,000**	**950,000**	**950,000**	**-**	**-**	**-**

Growth Business Case Summary							
ER1000	Electric New Revenue	13,787,901	14,775,000	14,266,927	14,795,440	15,116,635	15,116,635
ER1001	Gas New Revenue	13,816,818	19,272,801	18,574,437	19,174,488	19,574,521	19,472,818
ER1002	Electric Meters	550,000	550,000	550,000	500,000	500,000	500,000
ER1003	Transformers	6,500,400	5,763,080	5,877,014	4,792,226	4,858,742	4,926,589
ER1004	Street Lights	700,000	900,000	900,000	900,000	900,000	900,000
ER1005	Area Lights	625,000	650,000	675,000	700,000	700,000	700,000
ER1009	Network Protectors	950,000	960,000	980,000	980,000	980,000	980,000
ER1050	Gas Meters	1,944,432	2,027,379	2,051,316	2,114,092	2,172,453	2,217,720
ER1051	Gas Regulators	341,018	482,795	481,515	496,489	509,220	515,989
ER1053	Gas ERTs	2,219,297	1,112,771	1,131,677	1,166,113	1,199,109	1,227,269
ER1108	Hallet & White Subst	1,900,000	950,000	950,000	-	-	-
	Total Growth	**43,334,866**	**47,443,826**	**46,437,885**	**45,618,847**	**46,510,681**	**46,557,021**

State Income Tax Rate 0.47%
Federal Income Tax Rate 35.00%
Discount Factor 6.35%
Capital Class .... 2 (1) General Structures.
(2) Generation, Transmission, and Distribution.
(3) Other Equipment.
(4) Transportation Equipment.

Book Life (Years) .... Update 55
Property Tax Rate 1.50%
O&M Escalation Factor 3.00%

Debt .... [redacted]
Preferred Stock ....
Common Equity ....

Principal 11,000
Interest 6.35%
Term 55
Levelized Gr. Mar. Requirement 723

Lev ROE 219
NPV equity 3,329

IRR CALC
11,000 pv princ
840 pv lvlized margin
7.29% IRR

Gross Revenue	100.0000%
Uncollectables	[redacted]
Commission Fees	
Washington Excise Tax	
Franchise Fees	0.0000%
Misc. Revenue Items	4.3287%
Before State Income Tax	95.6713%
State Income Tax	0.0000%
Before Federal Income Tax	95.6713%
Federal Income Tax	33.4850%
Conversion Factor	62.1863%

nominal sum 34,438 (v)
PV GM 12,776
TERM 55
LEVELIZED 840

ID Electric - Residential

(a)	Capital Additions Tax Basis (b)	Book Basis (c)	Rate Base BOP (d)	Accum. Book Deprec. (e)	Tax Deprec. (f)	Book Dep. on Tax Basis (g)	Deferred Taxes (h)	Rate Base EOP (i)	Book Deprec. (j)	Average Rate Base (k)	Interest Expense (l)	Equity Return (m)	O&M & A&G Expense (n)	Property Taxes (o)	Misc. Revenue Items (p)	State Income Tax (q)	Federal Income Taxes (r)	Total Gross Marg Reqmnt (s)	Present Val Gross Marg Reqmnt (t)	ACTUAL ROR BY YEAR (u)	840
Total => Period	7,850	7,850			7,850	7,850	(0)		7,850		4,437	7,631	0	3,356	1,236	55	4,064	28,629	11,000		Savings or margin by year
1	7,850	7,850	7,850	71	294	71	78	7,701	71	7,775	104	179	0	118	26	1	96	595	560	6.79%	840
2	0	0	7,701	214	567	143	148	7,409	143	7,555	202	348	0	117	45	3	186	1,044	923	4.59%	840
3	0	0	7,409	357	524	143	134	7,133	143	7,271	195	335	0	115	44	2	179	1,012	842	4.92%	840
4	0	0	7,133	500	485	143	120	6,871	143	7,002	188	323	0	112	42	2	172	983	768	5.25%	840
5	0	0	6,871	642	449	143	107	6,621	143	6,746	181	311	0	110	41	2	166	954	701	5.60%	840
6			6,621	785	415	143	95	6,383	143	6,502	174	300	0	108	40	2	160	927	641	5.95%	840
7			6,383	928	384	143	84	6,156	143	6,269	168	289	0	106	39	2	154	901	585	6.32%	840
8			6,156	1,070	355	143	74	5,939	143	6,047	162	279	0	104	38	2	149	876	535	6.69%	840
9			5,939	1,213	350	143	73	5,723	143	5,831	156	269	0	102	37	2	143	852	489	7.09%	840
10			5,723	1,356	350	143	73	5,508	143	5,616	151	259	0	100	36	2	138	827	447	7.51%	840
11			5,508	1,499	350	143	73	5,293	143	5,400	145	249	0	97	35	2	133	803	408	7.97%	840
12			5,293	1,641	350	143	73	5,077	143	5,185	139	239	0	95	34	2	127	779	372	8.47%	840
13			5,077	1,784	350	143	73	4,862	143	4,970	133	229	0	93	33	2	122	755	339	9.01%	840
14			4,862	1,927	350	143	73	4,647	143	4,754	127	219	0	91	32	2	117	730	308	9.60%	840
15			4,647	2,070	350	143	73	4,431	143	4,539	122	209	0	89	30	2	112	706	280	10.24%	840
16			4,431	2,212	350	143	73	4,216	143	4,324	116	199	0	87	29	1	106	682	255	10.95%	840
17			4,216	2,355	350	143	73	4,001	143	4,108	110	189	0	85	28	1	101	657	231	11.73%	840
18			4,001	2,498	350	143	73	3,785	143	3,893	104	179	0	82	27	1	96	633	209	12.60%	840
19			3,785	2,640	350	143	73	3,570	143	3,678	99	170	0	80	26	1	90	609	189	13.57%	840
20			3,570	2,783	350	143	73	3,355	143	3,462	93	160	0	78	25	1	85	585	171	14.66%	840
21			3,355	2,926	175	143	11	3,201	143	3,278	88	151	0	76	24	1	80	564	155	15.72%	840
22			3,201	3,069	0	143	(50)	3,108	143	3,154	85	145	0	74	24	1	77	549	142	16.52%	840
23			3,108	3,211	0	143	(50)	3,015	143	3,062	82	141	0	72	23	1	75	537	130	17.19%	840
24			3,015	3,354	0	143	(50)	2,922	143	2,969	80	137	0	70	23	1	73	525	120	17.89%	840
25			2,922	3,497	0	143	(50)	2,830	143	2,876	77	133	0	67	22	1	71	514	110	18.64%	840
26			2,830	3,640	0	143	(50)	2,737	143	2,783	75	128	0	65	22	1	68	502	101	19.44%	840
27			2,737	3,782	0	143	(50)	2,644	143	2,690	72	124	0	63	21	1	66	490	93	20.29%	840
28			2,644	3,925	0	143	(50)	2,551	143	2,598	70	120	0	61	21	1	64	478	85	21.21%	840
29			2,551	4,068	0	143	(50)	2,458	143	2,505	67	115	0	59	20	1	61	467	78	22.19%	840
30			2,458	4,210	0	143	(50)	2,366	143	2,412	65	111	0	57	20	1	59	455	72	23.25%	840
31			2,366	4,353	0	143	(50)	2,273	143	2,319	62	107	0	55	19	1	57	443	66	24.40%	840
32			2,273	4,496	0	143	(50)	2,180	143	2,227	60	103	0	52	19	1	55	431	60	25.64%	840
33			2,180	4,639	0	143	(50)	2,087	143	2,134	57	98	0	50	18	1	52	420	55	26.98%	840
34			2,087	4,781	0	143	(50)	1,995	143	2,041	55	94	0	48	18	1	50	408	50	28.45%	840
35			1,995	4,924	0	143	(50)	1,902	143	1,948	52	90	0	46	17	1	48	396	46	30.06%	840
36			1,902	5,067	0	143	(50)	1,809	143	1,855	50	86	0	44	17	1	45	385	42	31.83%	840
37			1,809	5,210	0	143	(50)	1,716	143	1,763	47	81	0	42	16	1	43	373	38	33.79%	840
38			1,716	5,352	0	143	(50)	1,624	143	1,670	45	77	0	40	16	1	41	361	35	35.97%	840
39			1,624	5,495	0	143	(50)	1,531	143	1,577	42	73	0	37	15	1	39	349	32	38.40%	840
40			1,531	5,638	0	143	(50)	1,438	143	1,484	40	68	0	35	15	0	36	338	29	41.13%	840
41			1,438	5,780	0	143	(50)	1,345	143	1,392	37	64	0	33	14	0	34	326	26	44.23%	840
42			1,345	5,923	0	143	(50)	1,252	143	1,299	35	60	0	31	14	0	32	314	24	47.77%	840
43			1,252	6,066		143	(50)	1,160	143	1,206	32	56	0	29	13	0	29	302	21	51.86%	840
44			1,160	6,209		143	(50)	1,067	143	1,113	30	51	0	27	13	0	27	291	19	56.62%	840
45			1,067	6,351		143	(50)	974	143	1,021	27	47	0	25	12	0	25	279	17	62.26%	840
46			974	6,494		143	(50)	881	143	928	25	43	0	22	12	0	23	267	16	69.02%	840
47			881	6,637		143	(50)	789	143	835	22	38	0	20	11	0	20	256	14	77.28%	840
48			789	6,780		143	(50)	696	143	742	20	34	0	18	11	0	18	244	13	87.61%	840
49			696	6,922		143	(50)	603	143	649	17	30	0	16	10	0	16	232	11	100.89%	840
50			603	7,065		143	(50)	510	143	557	15	26	0	14	10	0	13	220	10	118.59%	840
51			510	7,208		143	(50)	417	143	464	12	21	0	12	9	0	11	209	9	143.38%	840

State Income Tax Rate	0.47%	
Federal Income Tax Rate	35.00%	
Discount Factor	6.35%	
Capital Class	2	(1) General Structures. (2) Generation, Transmission, and Distribution. (3) Other Equipment. (4) Transportation Equipment.
Book Life (Years)	Update	55
Property Tax Rate	1.50%	
O&M Escalation Factor	3.00%	

Debt	[illegible]	[illegible]	[illegible]	[illegible]
Preferred Stock	[illegible]	[illegible]	[illegible]	[illegible]
Common Equity	[illegible]	[illegible]	[illegible]	[illegible]
			[illegible]	[illegible]

Principal	11,000
Interest	6.35%
Term	55
Levelized Gr. Mar. Requirement	723
Lev ROE	219
NPV equity	3,329

IRR CALC

11,000	pv princ
840	pv lvlized margin
7.29%	IRR

Gross Revenue	100.0000%
Uncollectables	[illegible]
Commission Fees	[illegible]
Washington Excise Tax	[illegible]
Franchise Fees	0.0000%
Misc. Revenue Items	4.3287%
Before State Income Tax	95.6713%
State Income Tax	0.0000%
Before Federal Income Tax	95.6713%
Federal Income Tax	33.4850%
Conversion Factor	62.1863%

nominal sum	34,438
(v)	
PV GM	12,776
TERM	55
LEVELIZED	840

WA Electric - Residential

(a)	Capital Additions Tax Basis (b)	Book Basis (c)	Rate Base BOP (d)	Accum. Book Deprec. (e)	Tax Deprec. (f)	Book Dep. on Tax Basis (g)	Deferred Taxes (h)	Rate Base EOP (i)	Book Deprec. (j)	Average Rate Base (k)	Interest Expense (l)	Equity Return (m)	O&M & A&G Expense (n)	Property Taxes (o)	Misc. Revenue Items (p)	State Income Tax (q)	Federal Income Taxes (r)	Total Gross Marg Reqmnt (s)	Present Val Gross Marg Reqmnt (t)	ACTUAL ROR BY YEAR (u)	
Total => Period	7,850	7,850			7,850	7,850	(0)		7,850		4,437	7,631	0	3,356	1,236	55	4,064	28,629	11,000		Savings or margin by year
1	7,850	7,850	7,850	71	294	71	78	7,701	71	7,775	104	179	0	118	26	1	96	595	560	6.79%	840
2	0	0	7,701	214	567	143	148	7,409	143	7,555	202	348	0	117	45	3	186	1,044	923	4.59%	840
3	0	0	7,409	357	524	143	134	7,133	143	7,271	195	335	0	115	44	2	179	1,012	842	4.92%	840
4	0	0	7,133	500	485	143	120	6,871	143	7,002	188	323	0	112	42	2	172	983	768	5.25%	840
5	0	0	6,871	642	449	143	107	6,621	143	6,746	181	311	0	110	41	2	166	954	701	5.60%	840
6			6,621	785	415	143	95	6,383	143	6,502	174	300	0	108	40	2	160	927	641	5.95%	840
7			6,383	928	384	143	84	6,156	143	6,269	168	289	0	106	39	2	154	901	585	6.32%	840
8			6,156	1,070	355	143	74	5,939	143	6,047	162	279	0	104	38	2	149	876	535	6.69%	840
9			5,939	1,213	350	143	73	5,723	143	5,831	156	269	0	102	37	2	143	852	489	7.09%	840
10			5,723	1,356	350	143	73	5,508	143	5,616	151	259	0	100	36	2	138	827	447	7.51%	840
11			5,508	1,499	350	143	73	5,293	143	5,400	145	249	0	97	35	2	133	803	408	7.97%	840
12			5,293	1,641	350	143	73	5,077	143	5,185	139	239	0	95	34	2	127	779	372	8.47%	840
13			5,077	1,784	350	143	73	4,862	143	4,970	133	229	0	93	33	2	122	755	339	9.01%	840
14			4,862	1,927	350	143	73	4,647	143	4,754	127	219	0	91	32	2	117	730	308	9.60%	840
15			4,647	2,070	350	143	73	4,431	143	4,539	122	209	0	89	30	2	112	706	280	10.24%	840
16			4,431	2,212	350	143	73	4,216	143	4,324	116	199	0	87	29	1	106	682	255	10.95%	840
17			4,216	2,355	350	143	73	4,001	143	4,108	110	189	0	85	28	1	101	657	231	11.73%	840
18			4,001	2,498	350	143	73	3,785	143	3,893	104	179	0	82	27	1	96	633	209	12.60%	840
19			3,785	2,640	350	143	73	3,570	143	3,678	99	170	0	80	26	1	90	609	189	13.57%	840
20			3,570	2,783	350	143	73	3,355	143	3,462	93	160	0	78	25	1	85	585	171	14.66%	840
21			3,355	2,926	175	143	11	3,201	143	3,278	88	151	0	76	24	1	80	564	155	15.72%	840
22			3,201	3,069	0	143	(50)	3,108	143	3,154	85	145	0	74	24	1	77	549	142	16.52%	840
23			3,108	3,211	0	143	(50)	3,015	143	3,062	82	141	0	72	23	1	75	537	130	17.19%	840
24			3,015	3,354	0	143	(50)	2,922	143	2,969	80	137	0	70	23	1	73	525	120	17.89%	840
25			2,922	3,497	0	143	(50)	2,830	143	2,876	77	133	0	67	22	1	71	514	110	18.64%	840
26			2,830	3,640	0	143	(50)	2,737	143	2,783	75	128	0	65	22	1	68	502	101	19.44%	840
27			2,737	3,782	0	143	(50)	2,644	143	2,690	72	124	0	63	21	1	66	490	93	20.29%	840
28			2,644	3,925	0	143	(50)	2,551	143	2,598	70	120	0	61	21	1	64	478	85	21.21%	840
29			2,551	4,068	0	143	(50)	2,458	143	2,505	67	115	0	59	20	1	61	467	78	22.19%	840
30			2,458	4,210	0	143	(50)	2,366	143	2,412	65	111	0	57	20	1	59	455	72	23.25%	840
31			2,366	4,353	0	143	(50)	2,273	143	2,319	62	107	0	55	19	1	57	443	66	24.40%	840
32			2,273	4,496	0	143	(50)	2,180	143	2,227	60	103	0	52	19	1	55	431	60	25.64%	840
33			2,180	4,639	0	143	(50)	2,087	143	2,134	57	98	0	50	18	1	52	420	55	26.98%	840
34			2,087	4,781	0	143	(50)	1,995	143	2,041	55	94	0	48	18	1	50	408	50	28.45%	840
35			1,995	4,924	0	143	(50)	1,902	143	1,948	52	90	0	46	17	1	48	396	46	30.06%	840
36			1,902	5,067	0	143	(50)	1,809	143	1,855	50	86	0	44	17	1	45	385	42	31.83%	840
37			1,809	5,210	0	143	(50)	1,716	143	1,763	47	81	0	42	16	1	43	373	38	33.79%	840
38			1,716	5,352	0	143	(50)	1,624	143	1,670	45	77	0	40	16	1	41	361	35	35.97%	840
39			1,624	5,495	0	143	(50)	1,531	143	1,577	42	73	0	37	15	1	39	349	32	38.40%	840
40			1,531	5,638	0	143	(50)	1,438	143	1,484	40	68	0	35	15	0	36	338	29	41.13%	840
41			1,438	5,780	0	143	(50)	1,345	143	1,392	37	64	0	33	14	0	34	326	26	44.23%	840
42			1,345	5,923	0	143	(50)	1,252	143	1,299	35	60	0	31	14	0	32	314	24	47.77%	840
43			1,252	6,066		143	(50)	1,160	143	1,206	32	56	0	29	13	0	29	302	21	51.86%	840
44			1,160	6,209		143	(50)	1,067	143	1,113	30	51	0	27	13	0	27	291	19	56.62%	840
45			1,067	6,351		143	(50)	974	143	1,021	27	47	0	25	12	0	25	279	17	62.26%	840
46			974	6,494		143	(50)	881	143	928	25	43	0	22	12	0	23	267	16	69.02%	840
47			881	6,637		143	(50)	789	143	835	22	38	0	20	11	0	20	256	14	77.28%	840
48			789	6,780		143	(50)	696	143	742	20	34	0	18	11	0	18	244	13	87.61%	840
49			696	6,922		143	(50)	603	143	649	17	30	0	16	10	0	16	232	11	100.89%	840
50			603	7,065		143	(50)	510	143	557	15	26	0	14	10	0	13	220	10	118.59%	840
51			510	7,208		143	(50)	417	143	464	12	21	0	12	9	0	11	209	9	143.38%	840

State Income Tax Rate	0.47%
Federal Income Tax Rate	35.00%
Discount Factor	6.35%
Capital Class	2 (1) General Structures. (2) Generation, Transmission, and Distribution. (3) Other Equipment. (4) Transportation Equipment.
Book Life (Years)	Update 45
Property Tax Rate	1.50%
O&M Escalation Factor	3.00%

Debt	[redacted]			
Preferred Stock				
Common Equity				

Principal	5,424
Interest	6.35%
Term	45
Levelized Gr. Mar. Requirement	368
Lev ROE	106
NPV equity	1,563

IRR CALC

5,424	pv princ
416	pv lvlized margin
7.29%	IRR

Gross Revenue	100.0000%
Uncollectables	[redacted]
Commission Fees	
Washington Excise Tax	
Franchise Fees	0.0000%
Misc. Revenue Items	4.3287%
Before State Income Tax	95.6713%
State Income Tax	0.0000%
Before Federal Income Tax	95.6713%
Federal Income Tax	33.4850%
Conversion Factor	62.1863%

nominal sum	16,989
(v)	
PV GM	6,140
TERM	45
LEVELIZED	416

ID Gas - Residential

(a)	Capital Additions Tax Basis (b)	Book Basis (c)	Rate Base BOP (d)	Accum. Book Deprec. (e)	Tax Deprec. (f)	Book Dep. on Tax Basis (g)	Deferred Taxes (h)	Rate Base EOP (i)	Book Deprec. (j)	Average Rate Base (k)	Interest Expense (l)	Equity Return (m)	O&M & A&G Expense (n)	Property Taxes (o)	Misc. Revenue Items (p)	State Income Tax (q)	Federal Income Taxes (r)	Total Gross Marg Reqmnt (s)	Present Val Gross Marg Reqmnt (t)	ACTUAL ROR BY YEAR (u)	Savings or margin by year
Total => Period	3,910	3,910			3,910	3,910	0		3,910		1,869	3,215	0	1,378	546	23	1,711	12,654	5,424		
1	3,910	3,910	3,910	43	147	43	36	3,830	43	3,870	52	89	0	59	13	1	48	305	286	6.48%	414
2	0	0	3,830	130	282	87	68	3,675	87	3,753	101	173	0	58	23	1	92	535	473	4.07%	414
3	0	0	3,675	217	261	87	61	3,527	87	3,601	97	166	0	57	22	1	89	518	431	4.41%	414
4	0	0	3,527	304	242	87	54	3,386	87	3,457	93	159	0	55	22	1	85	502	392	4.75%	414
5	0	0	3,386	391	223	87	48	3,252	87	3,319	89	153	0	54	21	1	82	487	358	5.11%	414
6			3,252	478	207	87	42	3,123	87	3,187	85	147	0	53	20	1	78	472	326	5.49%	414
7			3,123	565	191	87	37	2,999	87	3,061	82	141	0	51	20	1	75	458	297	5.88%	414
8			2,999	652	177	87	31	2,881	87	2,940	79	136	0	50	19	1	72	444	271	6.29%	414
9			2,881	739	174	87	31	2,763	87	2,822	76	130	0	49	19	1	69	430	247	6.72%	414
10			2,763	825	174	87	31	2,646	87	2,705	72	125	0	48	18	1	66	417	225	7.19%	414
11			2,646	912	174	87	31	2,528	87	2,587	69	119	0	46	17	1	64	404	205	7.71%	414
12			2,528	999	174	87	31	2,411	87	2,470	66	114	0	45	17	1	61	390	186	8.27%	414
13			2,411	1,086	174	87	31	2,293	87	2,352	63	108	0	44	16	1	58	377	169	8.88%	414
14			2,293	1,173	174	87	31	2,176	87	2,235	60	103	0	42	16	1	55	363	153	9.57%	414
15			2,176	1,260	174	87	31	2,058	87	2,117	57	98	0	41	15	1	52	350	139	10.33%	414
16			2,058	1,347	174	87	31	1,941	87	2,000	54	92	0	40	15	1	49	337	126	11.17%	414
17			1,941	1,434	174	87	31	1,823	87	1,882	50	87	0	38	14	1	46	323	113	12.13%	414
18			1,823	1,521	174	87	31	1,706	87	1,765	47	81	0	37	13	1	43	310	102	13.21%	414
19			1,706	1,607	174	87	31	1,588	87	1,647	44	76	0	36	13	1	40	297	92	14.44%	414
20			1,588	1,694	174	87	31	1,471	87	1,529	41	71	0	35	12	1	38	283	83	15.87%	414
21			1,471	1,781	87	87	0	1,384	87	1,427	38	66	0	33	12	0	35	271	74	17.31%	414
22			1,384	1,868	0	87	(30)	1,327	87	1,355	36	62	0	32	11	0	33	263	68	18.48%	414
23			1,327	1,955	0	87	(30)	1,271	87	1,299	35	60	0	31	11	0	32	256	62	19.52%	414
24			1,271	2,042	0	87	(30)	1,214	87	1,243	33	57	0	29	11	0	30	248	57	20.65%	414
25			1,214	2,129	0	87	(30)	1,158	87	1,186	32	55	0	28	10	0	29	241	52	21.89%	414
26			1,158	2,216	0	87	(30)	1,101	87	1,130	30	52	0	27	10	0	28	234	47	23.25%	414
27			1,101	2,303	0	87	(30)	1,045	87	1,073	29	49	0	25	10	0	26	227	43	24.75%	414
28			1,045	2,389	0	87	(30)	988	87	1,017	27	47	0	24	9	0	25	220	39	26.43%	414
29			988	2,476	0	87	(30)	932	87	960	26	44	0	23	9	0	23	213	36	28.30%	414
30			932	2,563	0	87	(30)	875	87	904	24	42	0	22	9	0	22	206	32	30.40%	414
31			875	2,650	0	87	(30)	819	87	847	23	39	0	20	9	0	21	198	29	32.78%	414
32			819	2,737	0	87	(30)	762	87	791	21	36	0	19	8	0	19	191	27	35.51%	414
33			762	2,824	0	87	(30)	706	87	734	20	34	0	18	8	0	18	184	24	38.65%	414
34			706	2,911	0	87	(30)	649	87	678	18	31	0	16	8	0	17	177	22	42.31%	414
35			649	2,998	0	87	(30)	593	87	621	17	29	0	15	7	0	15	170	20	46.65%	414
36			593	3,085	0	87	(30)	537	87	565	15	26	0	14	7	0	14	163	18	51.85%	414
37			537	3,171	0	87	(30)	480	87	508	14	23	0	12	7	0	12	156	16	58.20%	414
38			480	3,258	0	87	(30)	424	87	452	12	21	0	11	6	0	11	148	14	66.15%	414
39			424	3,345	0	87	(30)	367	87	395	11	18	0	10	6	0	10	141	13	76.36%	414
40			367	3,432	0	87	(30)	311	87	339	9	16	0	8	6	0	8	134	11	89.98%	414
41			311	3,519	0	87	(30)	254	87	282	8	13	0	7	5	0	7	127	10	109.04%	414
42			254	3,606	0	87	(30)	198	87	226	6	10	0	6	5	0	5	120	9	137.64%	414
43			198	3,693		87	(30)	141	87	169	5	8	0	5	5	0	4	113	8	185.31%	414
44			141	3,780		87	(30)	85	87	113	3	5	0	3	5	0	3	106	7	280.63%	414
45			85	3,867		87	(30)	28	87	56	2	3	0	2	4	0	1	98	6	566.62%	414
46			28	3,910		43	(15)	0	43	14	0	1	0	1	2	0	0	47	3	2605.95%	414
47			0	3,910		0	0	0	0	0	0	0	0	0	0	0	0	0	0	##############	414
48			0	3,910		0	0	0	0	0	0	0	0	0	0	0	0	0	0	##############	414
49			0	3,910		0	0	0	0	0	0	0	0	0	0	0	0	0	0	##############	414
50			0	3,910		0	0	0	0	0	0	0	0	0	0	0	0	0	0	##############	414
51			0	3,910		0	0	0	0	0	0	0	0	0	0	0	0	0	0	##############	414

State Income Tax Rate	0.47%
Federal Income Tax Rate	35.00%
Discount Factor	6.35%
Capital Class	2
Book Life (Years)	Update 45
Property Tax Rate	1.50%
O&M Escalation Factor	3.00%

(1) General Structures.
(2) Generation, Transmission, and Distribution.
(3) Other Equipment.
(4) Transportation Equipment.

Debt	[illegible]	[illegible]	[illegible]	[illegible]
Preferred Stock	[illegible]	[illegible]	[illegible]	[illegible]
Common Equity	[illegible]	[illegible]	[illegible]	[illegible]
			[illegible]	[illegible]

Principal	4,186
Interest	6.35%
Term	45
Levelized Gr. Mar. Requirement	284
Lev ROE	82
NPV equity	1,207

IRR CALC

4,186	pv princ
321	pv lvlized margin
7.29%	IRR

Gross Revenue	100.0000%
Uncollectables	[illegible]
Commission Fees	[illegible]
Washington Excise Tax	[illegible]
Franchise Fees	0.0000%
Misc. Revenue Items	4.3287%
Before State Income Tax	95.6713%
State Income Tax	0.0000%
Before Federal Income Tax	95.6713%
Federal Income Tax	33.4850%
Conversion Factor	62.1863%

nominal sum	13,102 (v)
PV GM	4,735
TERM	45
LEVELIZED	321

OR Gas - Residential

(a)	Capital Additions Tax Basis (b)	Book Basis (c)	Rate Base BOP (d)	Accum. Book Deprec. (e)	Tax Deprec. (f)	Book Dep. on Tax Basis (g)	Deferred Taxes (h)	Rate Base EOP (i)	Book Deprec. (j)	Average Rate Base (k)	Interest Expense (l)	Equity Return (m)	O&M & A&G Expense (n)	Property Taxes (o)	Misc. Revenue Items (p)	State Income Tax (q)	Federal Income Taxes (r)	Total Gross Marg Reqmnt (s)	Present Val Gross Marg Reqmnt (t)	ACTUAL ROR BY YEAR (u)	Savings or margin by year
Total => Period	3,018	3,018			3,018	3,018	(0)		3,018		1,443	2,482	0	1,064	422	18	1,321	9,767	4,186		
1	3,018	3,018	3,018	34	113	34	28	2,957	34	2,987	40	69	0	45	10	0	37	235	221	6.47%	320
2	0	0	2,957	101	218	67	53	2,837	67	2,897	78	134	0	45	18	1	71	413	365	4.06%	320
3	0	0	2,837	168	202	67	47	2,723	67	2,780	74	128	0	44	17	1	68	400	333	4.39%	320
4	0	0	2,723	235	186	67	42	2,614	67	2,668	72	123	0	43	17	1	66	388	303	4.74%	320
5	0	0	2,614	302	172	67	37	2,510	67	2,562	69	118	0	42	16	1	63	376	276	5.10%	320
6			2,510	369	160	67	32	2,410	67	2,460	66	113	0	41	16	1	60	364	252	5.48%	320
7			2,410	436	148	67	28	2,315	67	2,363	63	109	0	40	15	1	58	353	229	5.87%	320
8			2,315	503	137	67	24	2,224	67	2,269	61	105	0	39	15	1	56	343	209	6.28%	320
9			2,224	570	135	67	24	2,133	67	2,178	58	100	0	38	14	1	54	332	191	6.71%	320
10			2,133	637	135	67	24	2,042	67	2,088	56	96	0	37	14	1	51	322	174	7.18%	320
11			2,042	704	135	67	24	1,952	67	1,997	54	92	0	36	13	1	49	312	158	7.69%	320
12			1,952	771	135	67	24	1,861	67	1,906	51	88	0	35	13	1	47	301	144	8.25%	320
13			1,861	838	135	67	24	1,770	67	1,816	49	84	0	34	13	1	45	291	131	8.87%	320
14			1,770	905	135	67	24	1,679	67	1,725	46	80	0	33	12	1	42	281	118	9.55%	320
15			1,679	972	135	67	24	1,589	67	1,634	44	75	0	32	12	1	40	270	107	10.31%	320
16			1,589	1,040	135	67	24	1,498	67	1,543	41	71	0	31	11	1	38	260	97	11.16%	320
17			1,498	1,107	135	67	24	1,407	67	1,453	39	67	0	30	11	0	36	250	88	12.11%	320
18			1,407	1,174	135	67	24	1,317	67	1,362	37	63	0	29	10	0	33	239	79	13.19%	320
19			1,317	1,241	135	67	24	1,226	67	1,271	34	59	0	28	10	0	31	229	71	14.42%	320
20			1,226	1,308	135	67	24	1,135	67	1,181	32	54	0	27	9	0	29	219	64	15.84%	320
21			1,135	1,375	67	67	0	1,068	67	1,102	30	51	0	26	9	0	27	209	57	17.28%	320
22			1,068	1,442	0	67	(23)	1,024	67	1,046	28	48	0	25	9	0	26	203	52	18.46%	320
23			1,024	1,509	0	67	(23)	981	67	1,003	27	46	0	24	9	0	25	197	48	19.49%	320
24			981	1,576	0	67	(23)	937	67	959	26	44	0	23	8	0	24	192	44	20.62%	320
25			937	1,643	0	67	(23)	894	67	915	25	42	0	22	8	0	22	186	40	21.86%	320
26			894	1,710	0	67	(23)	850	67	872	23	40	0	21	8	0	21	181	36	23.22%	320
27			850	1,777	0	67	(23)	806	67	828	22	38	0	20	8	0	20	175	33	24.72%	320
28			806	1,844	0	67	(23)	763	67	785	21	36	0	19	7	0	19	170	30	26.39%	320
29			763	1,911	0	67	(23)	719	67	741	20	34	0	18	7	0	18	164	28	28.26%	320
30			719	1,978	0	67	(23)	676	67	697	19	32	0	17	7	0	17	159	25	30.36%	320
31			676	2,046	0	67	(23)	632	67	654	18	30	0	16	7	0	16	153	23	32.74%	320
32			632	2,113	0	67	(23)	589	67	610	16	28	0	15	6	0	15	148	21	35.46%	320
33			589	2,180	0	67	(23)	545	67	567	15	26	0	14	6	0	14	142	19	38.60%	320
34			545	2,247	0	67	(23)	501	67	523	14	24	0	13	6	0	13	137	17	42.26%	320
35			501	2,314	0	67	(23)	458	67	480	13	22	0	12	6	0	12	131	15	46.59%	320
36			458	2,381	0	67	(23)	414	67	436	12	20	0	11	5	0	11	126	14	51.78%	320
37			414	2,448	0	67	(23)	371	67	392	11	18	0	10	5	0	10	120	12	58.13%	320
38			371	2,515	0	67	(23)	327	67	349	9	16	0	9	5	0	8	115	11	66.06%	320
39			327	2,582	0	67	(23)	283	67	305	8	14	0	8	5	0	7	109	10	76.27%	320
40			283	2,649	0	67	(23)	240	67	262	7	12	0	7	4	0	6	104	9	89.87%	320
41			240	2,716	0	67	(23)	196	67	218	6	10	0	6	4	0	5	98	8	108.91%	320
42			196	2,783	0	67	(23)	153	67	174	5	8	0	5	4	0	4	93	7	137.48%	320
43			153	2,850		67	(23)	109	67	131	4	6	0	4	4	0	3	87	6	185.09%	320
44			109	2,917		67	(23)	65	67	87	2	4	0	3	4	0	2	82	5	280.30%	320
45			65	2,984		67	(23)	22	67	44	1	2	0	2	3	0	1	76	5	565.95%	320
46			22	3,018		34	(12)	0	34	11	0	1	0	1	2	0	0	37	2	2603.31%	320
47			0	3,018		0	0	0	0	0	0	0	0	0	0	0	0	0	0	##############	320
48			0	3,018		0	0	0	0	0	0	0	0	0	0	0	0	0	0	##############	320
49			0	3,018		0	0	0	0	0	0	0	0	0	0	0	0	0	0	##############	320
50			0	3,018		0	0	0	0	0	0	0	0	0	0	0	0	0	0	##############	320
51			0	3,018		0	0	0	0	0	0	0	0	0	0	0	0	0	0	##############	320

State Income Tax Rate	0.47%	Debt	[redacted]
Federal Income Tax Rate	35.00%	Preferred Stock	[redacted]
Discount Factor	6.35%	Common Equity	[redacted]
Capital Class	2 (1) General Structures, (2) Generation, Transmission, and Distribution, (3) Other Equipment, (4) Transportation Equipment		
Book Life (Years)	Update 45	Principal	6,013
Property Tax Rate	1.50%	Interest	6.35%
O&M Escalation Factor	3.00%	Term	45
		Levelized Gr. Mar. Requirement	407
		Lev ROE	117
		NPV equity	1,733

IRR CALC	
6,013	pv princ
461	pv lvlized margin
7.29%	IRR

Gross Revenue	100.0000%
Uncollectables	[redacted]
Commission Fees	[redacted]
Washington Excise Tax	[redacted]
Franchise Fees	0.0000%
Misc. Revenue Items	4.3287%
Before State Income Tax	95.6713%
State Income Tax	0.0000%
Before Federal Income Tax	95.6713%
Federal Income Tax	33.4850%
Conversion Factor	62.1863%

nominal sum	18,817 (v)
PV GM	6,800
TERM	45
LEVELIZED	461

WA Gas - Residential

(a)	Capital Additions: Tax Basis (b)	Book Basis (c)	Rate Base BOP (d)	Accum. Book Deprec. (e)	Tax Deprec. (f)	Book Dep. on Tax Basis (g)	Deferred Taxes (h)	Rate Base EOP (i)	Book Deprec. (j)	Average Rate Base (k)	Interest Expense (l)	Equity Return (m)	O&M & A&G Expense (n)	Property Taxes (o)	Misc. Revenue Items (p)	State Income Tax (q)	Federal Income Taxes (r)	Total Gross Marg Reqmnt (s)	Present Val Gross Marg Reqmnt (t)	ACTUAL ROR BY YEAR (u)	
Total => Period	4,335	4,335			4,335	4,335	(0)		4,335		2,072	3,565	0	1,528	606	26	1,897	14,029	6,013		Savings or margin by year
1	4,335	4,335	4,335	48	163	48	40	4,247	48	4,291	57	99	0	65	15	1	53	338	317	6.47%	459
2	0	0	4,247	145	313	96	76	4,075	96	4,161	112	192	0	64	26	1	102	593	525	4.06%	459
3	0	0	4,075	241	289	96	68	3,911	96	3,993	107	184	0	63	25	1	98	575	478	4.39%	459
4	0	0	3,911	337	268	96	60	3,754	96	3,833	103	177	0	61	24	1	94	557	435	4.74%	459
5	0	0	3,754	434	248	96	53	3,605	96	3,680	99	170	0	60	23	1	90	540	397	5.10%	459
6			3,605	530	229	96	46	3,462	96	3,534	95	163	0	59	23	1	87	523	362	5.47%	459
7			3,462	626	212	96	40	3,325	96	3,394	91	156	0	57	22	1	83	507	330	5.87%	459
8			3,325	723	196	96	35	3,194	96	3,260	87	150	0	56	21	1	80	492	301	6.27%	459
9			3,194	819	193	96	34	3,064	96	3,129	84	144	0	54	21	1	77	477	274	6.71%	459
10			3,064	915	193	96	34	2,934	96	2,999	80	138	0	53	20	1	74	462	250	7.18%	459
11			2,934	1,012	193	96	34	2,803	96	2,868	77	132	0	51	19	1	70	448	227	7.69%	459
12			2,803	1,108	193	96	34	2,673	96	2,738	73	126	0	50	19	1	67	433	207	8.25%	459
13			2,673	1,204	193	96	34	2,543	96	2,608	70	120	0	48	18	1	64	418	188	8.87%	459
14			2,543	1,301	193	96	34	2,412	96	2,478	66	114	0	47	17	1	61	403	170	9.55%	459
15			2,412	1,397	193	96	34	2,282	96	2,347	63	108	0	46	17	1	58	388	154	10.31%	459
16			2,282	1,493	193	96	34	2,152	96	2,217	59	102	0	44	16	1	54	373	139	11.15%	459
17			2,152	1,590	193	96	34	2,021	96	2,087	56	96	0	43	15	1	51	358	126	12.11%	459
18			2,021	1,686	193	96	34	1,891	96	1,956	52	90	0	41	15	1	48	344	113	13.19%	459
19			1,891	1,782	193	96	34	1,761	96	1,826	49	84	0	40	14	1	45	329	102	14.42%	459
20			1,761	1,879	193	96	34	1,631	96	1,696	45	78	0	38	14	1	42	314	92	15.84%	459
21			1,631	1,975	97	96	0	1,534	96	1,582	42	73	0	37	13	1	39	301	83	17.28%	459
22			1,534	2,071	0	96	(34)	1,471	96	1,503	40	69	0	35	13	0	37	291	75	18.45%	459
23			1,471	2,168	0	96	(34)	1,409	96	1,440	39	66	0	34	12	0	35	283	69	19.49%	459
24			1,409	2,264	0	96	(34)	1,346	96	1,378	37	64	0	33	12	0	34	275	63	20.62%	459
25			1,346	2,360	0	96	(34)	1,284	96	1,315	35	61	0	31	12	0	32	267	57	21.85%	459
26			1,284	2,457	0	96	(34)	1,221	96	1,252	34	58	0	30	11	0	31	260	52	23.21%	459
27			1,221	2,553	0	96	(34)	1,158	96	1,190	32	55	0	28	11	0	29	252	48	24.72%	459
28			1,158	2,649	0	96	(34)	1,096	96	1,127	30	52	0	27	11	0	28	244	43	26.39%	459
29			1,096	2,746	0	96	(34)	1,033	96	1,064	29	49	0	25	10	0	26	236	40	28.25%	459
30			1,033	2,842	0	96	(34)	971	96	1,002	27	46	0	24	10	0	25	228	36	30.35%	459
31			971	2,938	0	96	(34)	908	96	939	25	43	0	22	9	0	23	220	33	32.73%	459
32			908	3,035	0	96	(34)	845	96	877	23	40	0	21	9	0	21	212	30	35.45%	459
33			845	3,131	0	96	(34)	783	96	814	22	38	0	20	9	0	20	204	27	38.59%	459
34			783	3,227	0	96	(34)	720	96	751	20	35	0	18	8	0	18	196	24	42.25%	459
35			720	3,324	0	96	(34)	657	96	689	18	32	0	17	8	0	17	188	22	46.58%	459
36			657	3,420	0	96	(34)	595	96	626	17	29	0	15	8	0	15	180	20	51.78%	459
37			595	3,516	0	96	(34)	532	96	564	15	26	0	14	7	0	14	172	18	58.12%	459
38			532	3,613	0	96	(34)	470	96	501	13	23	0	12	7	0	12	165	16	66.06%	459
39			470	3,709	0	96	(34)	407	96	438	12	20	0	11	7	0	11	157	14	76.26%	459
40			407	3,805	0	96	(34)	344	96	376	10	17	0	9	6	0	9	149	13	89.86%	459
41			344	3,902	0	96	(34)	282	96	313	8	14	0	8	6	0	8	141	11	108.90%	459
42			282	3,998	0	96	(34)	219	96	250	7	12	0	7	6	0	6	133	10	137.46%	459
43			219	4,094		96	(34)	157	96	188	5	9	0	5	5	0	4	125	9	185.07%	459
44			157	4,191		96	(34)	94	96	125	3	6	0	4	5	0	3	117	8	280.27%	459
45			94	4,287		96	(34)	31	96	63	2	3	0	2	5	0	1	109	7	565.90%	459
46			31	4,335		48	(17)	(0)	48	16	0	1	0	1	2	0	0	53	3	2603.08%	459
47			(0)	4,335		0	0	(0)	0	(0)	(0)	(0)	0	(0)	(0)	(0)	(0)	(0)	(0)	##############	459
48			(0)	4,335		0	0	(0)	0	(0)	(0)	(0)	0	(0)	(0)	(0)	(0)	(0)	(0)	##############	459
49			(0)	4,335		0	0	(0)	0	(0)	(0)	(0)	0	(0)	(0)	(0)	(0)	(0)	(0)	##############	459
50			(0)	4,335		0	0	(0)	0	(0)	(0)	(0)	0	(0)	(0)	(0)	(0)	(0)	(0)	##############	459
51			(0)	4,335		0	0	(0)	0	(0)	(0)	(0)	0	(0)	(0)	(0)	(0)	(0)	(0)	##############	459

GAS REV REQ WA calibrated IRR 2-11-14.xlsm

Gas Non-Revenue Program, ER 3005

1 GENERAL INFORMATION

Requested Spend Amount	$6,000,000 – Annual Request
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 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 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.

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, 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 but considers what is the right thing to do in these situations. This type of betterment falls under this program.

The need for a meter barricade 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 on existing meters sets is capital only in Washington State and only until 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

Gas Non-Revenue Program, ER 3005

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 barricades – Not installing meter protection is against Federal Rules 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 barricades – 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 may be installed in front of structures without gas service, making it easier to serve them with gas in the future should choose to change their energy source.

Option 3 – Alternative Solution, Reduced funding

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

Requested by others & leak repair – *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.

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

Farm tap elimination - *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 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 of Gas Engineering		
Role:	Business Case Owner		

Signature:	Mike Faulkenberry	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: 02/24/2017

Gas Cathodic Protection Program, ER 3004

1 GENERAL INFORMATION

Requested Spend Amount	$800,000
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. 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.

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	01-2017	12-2017

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 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: MF 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	04/13/2017	Mike Faulkenberry	04/17/2017	Initial version

Template Version: 03/07/2017

GAS FACILITY REPLACEMENT PROGRAM (GFRP)
ALDYL A PIPE REPLACEMENT

1 GENERAL INFORMATION

Requested Spend Amount	$20,000,000 - $22,000,000 Annually
Requesting Organization/Department	Natural Gas / Gas Facility Replacement Program
Business Case Owner	Michael B. Whitby
Business Case Sponsor	Heather Rosentrater / Mike Faulkenberry
Sponsor Organization/Department	Energy Delivery / Gas Delivery
Category	Program
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

ADVISORY GROUP:

The Gas Facility Replacement Program (GFRP) Advisory Group consists of the GFRP's Program/Project Manager, Gas Operations Contract Construction Manager, Director of Natural Gas, and the Manager of Gas Design & Measurement. This group meets each month to review program wide Earned Value results, the status of the delivery of all individual projects, budget allocations and variances, internal resource demands, customer care results and issues, contractor performance, and to communicate potential program risks and shortfalls when necessary.

In addition, Avista's Asset Management Group provides periodic input, and or validation of the replacement plan and schedule.

The GFRP's annual work load is captured in an annual "Operating Plan & Projects" document.

2 BUSINESS PROBLEM

MAJOR DRIVERS OF THE GAS FACILITY REPLACEMENT PROGRAM:

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 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.

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.

GAS FACILITY REPLACEMENT PROGRAM (GFRP)
ALDYL A PIPE REPLACEMENT

AVISTA HAS A REGULATORY MANDATE TO COMPLETE THIS PROGRAM.

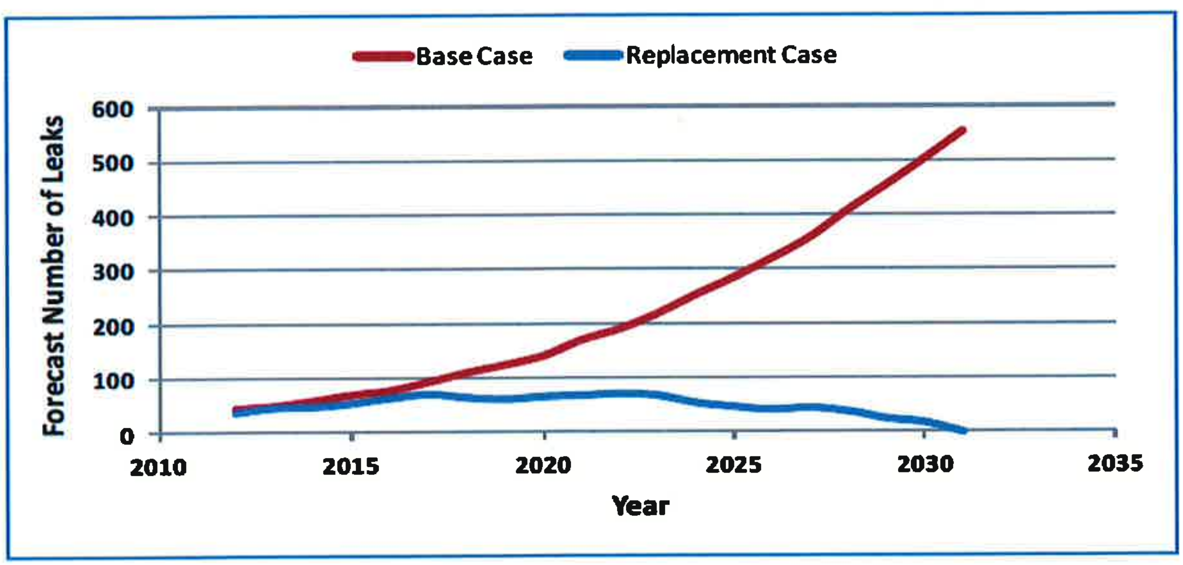
On December 31, 2012 the Washington Utilities and Transportation Commission (WUTC) issued its' policy statement on Accelerated Replacement of Pipeline Facilities with Elevated Risks which requires gas utility companies to file a plan every two year for replacing pipe that represents an elevated risk of failure. The requirement to file a Pipe Replacement Plan (PRP) commenced on June 1, 2013. In response to this order, Avista's first two-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. 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.

While the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utilities Commission (OPUC) have not required gas utility companies to file pipe replacement plans, 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.

ALDYL A RISK MANAGEMENT: BASE CASE VS. REPLACEMENT CASE:

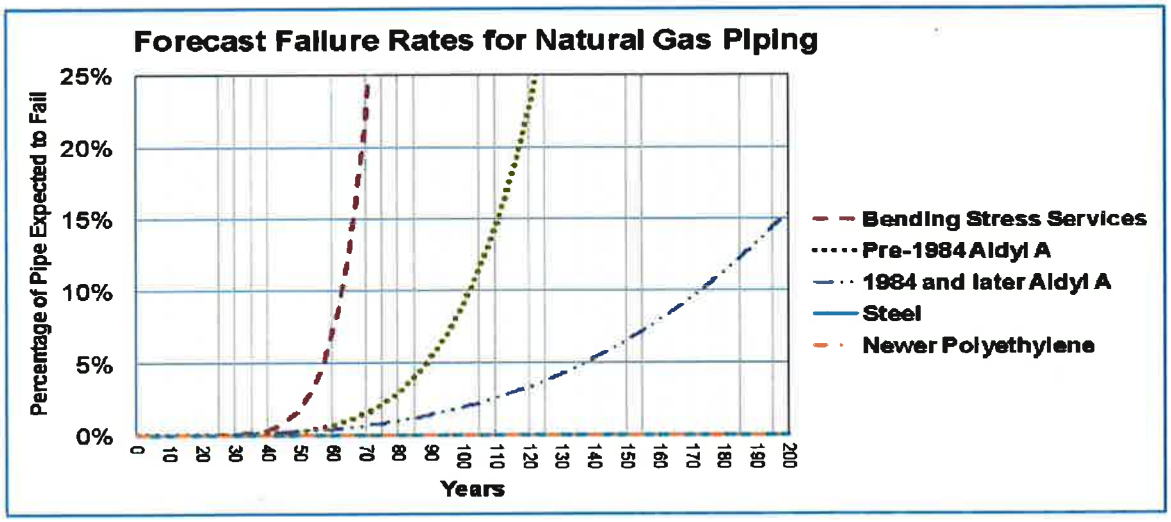
The need to conduct this program has been identified in "Avista's Proposed Protocol for Managing Select Aldyl A Pipe in Avista Utility's Natural Gas System" report. Further, and more specifically, due to the tendency for this material to suffer brittle-like cracking leak failures, Aldyl A will eventually 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.

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 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. Figure 5 of the report is shown below:



The GFRP's Service Tee Transition Rebuild Program is structured to mitigate the risks associated with the "Bending Stress Services" category within a five-year time frame. The Aldyl A Main Pipe Replacement Program has been structured to mitigate the "Pre-1984 Aldyl A" over a twenty year time frame.

OBJECTIVES & MEASURES OF SUCCESS:

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 all 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.

REFERENCE STUDIES:

"Avista's Proposed Protocol for Managing Select Aldyl A Pipe in Avista Utility's Natural Gas System" report has been attached.

GAS FACILITY REPLACEMENT PROGRAM (GFRP)
ALDYL A PIPE REPLACEMENT

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Replace all Priority Aldyl A Pipe in Avista's System in a Timeframe of 20 Years	*≈ $355M*	*01 2012*	*12 2031*

GAS FACILITY REPLACEMENT PROGRAM IMPACTS TO BUSINESS FUNCTIONS & PROCESSES:

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 resource are to plan, design, oversee, manage, and administer the significant body of projectized work as assigned to "external" contract construction resources.

Periodically, on an as-needed basis, the GFRP will call on other business units for support.

Since pipe replacement work is a capital expenditure, the impact to O&M cost has been minimal. Occasionally GFRP projects will encounter circumstances that necessitate O&M expenditures. When known, these O&M costs are estimated prior to construction. The GFRP tracks & monitors O&M costs each month.

ALTERNATIVES CONSIDERED:

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..

GAS FACILITY REPLACEMENT PROGRAM (GFRP)
ALDYL A PIPE REPLACEMENT

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.

TIMELINE:

Start: 2012

End: 2031

The annual list of projects are established as unique "blanket projects" that transfer to plant each month as they are "used & useful".

STRATEGIC ALIGNMENT & VISION:

The GFRP's Aldyl A Pipe Replacement efforts aligns with Avista's commitment to invest in our infrastructure to achieve optimum lifecycle performance – safely, reliably and at a fair price. The Program eliminates risk by replacing at risk pipe, which in turn increases system reliability. In effort to ensure a fair price for the work, the GFRP has established "Unit Price" type contract with a multi-year duration of 5 years. On five year intervals, the GFRP plans to test the market for "fair pricing" by issuing a Request for Proposal (RFP) and by receiving competitive proposals for the work. The first ever GFRP RFP yielded (7) interested contractors, (6) qualified proposals, and a two contracts; 1. Main Pipe Replacement. 2. Service Tee Transition Rebuild (STTR).

GAS FACILITY REPLACEMENT PROGRAM (GFRP)
ALDYL A PIPE REPLACEMENT

BUDGET JUSTIFICATION:

As a mandated Pipe Replacement Program, the recommended 20 year replacement approach does not include a specific cost/benefit analysis document, however based on recent pipe replacement cost experience, the program currently estimates the budget to be $20,000,000 - $22, 000,000 annually.

CUSTOMERS & STAKEHOLDERS:

Avista's customers and the general public expect our natural gas system to operate safely, and reliably without inconvenience or incidents. Avista is dedicated to, and focused on maintaining a safe and reliable system that shields the public from inconvenience and imprudent risks. The proposed pipe replacement program has been initiated with the purpose of mitigating the known risks within our natural gas distribution system. Given this context, the Gas Facility Replacement Program's portfolio of projects could therefore be considered as customer-related benefit.

The GFRP's Aldyl A Pipe Replacement projects touch many internal & external stakeholders. A comprehensive list of stakeholders can be located in the annual "GFRP Operating Plan & Projects" booklet.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the ***Gas Facility Replacement Program (Aldyl A Pipe Replacement)*** 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. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: [signature] Date: 4/07/17

Print Name: Michael B. Whitby

Title: Program/Project Manager

Role: Business Case Owner

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

Print Name: Mike Faulkenberry

Title: Director Natural Gas

Role: Business Case Sponsor

4 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	*Michael Whitby*	*04/07/2017*	*Mike Faulkenberry*	*04//17/2017*	*Initial version*

Template Version: 03/07/2017

GAS FACILITY REPLACEMENT PROGRAM (GFRP)
ALDYL A PIPE REPLACEMENT

supplant

Gas HP Pipeline Remediation Program, ER 3057

1 GENERAL INFORMATION

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

1.1 Steering Committee or Advisory Group Information

The Gas Compliance department is responsible for ensuring Avista is compliant with Federal and State Regulations governing the distribution of natural gas. When a new regulation is brought into effect, the Gas Compliance department will determine if Avista is meeting the requirement or not. If the new requirement is not being met, the Gas Compliance department will notify the appropriate work group and work with them to determine the appropriate path forward to ensure compliance. Gas Engineering is responsible for managing this program.

2 BUSINESS PROBLEM

Current industry Pipeline Safety code requires pipeline operators to have pressure test documentation and material specifications for pipelines distributing natural gas. Avista has some deficiencies in these types of records, but industry regulators (state inspectors) historically have not placed much emphasis on this, specifically for facilities that operate at lower stress levels and therefore at a lesser risk to the public. Avista's history, very similar to that of other utilities, involves pipeline construction during times when the pipeline safety code was not in effect or taken to be that important. Also, Avista has acquired properties from other companies and therefore had no control over their testing practices and record keeping prior to the acquisition. The regulatory climate is now changing and more scrutiny is being placed on having these records.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is actively working on a new rule that is expected to be published in December of 2017 called "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines". When implemented, it will require pipeline operators to have "traceable, verifiable, and complete" Maximum Allowable Operating Pressure (MAOP) records for its transmission facilities. Our understanding of the Rule is that Avista will now need to begin aggressively addressing portions of our system in order to be in compliance. Until the Rule is published, it is not clear yet what the timeframe will be to create a plan and mitigate all deficiencies.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 - Do nothing / Defer project	$0		
Option 2 – Preferred Solution, Continue to remediate segments of high pressure pipeline.	$3,000,000	2016	2022
Option 3 – Alternative Solution, Reduced funding option: Replace segments of high pressure pipeline.	$1,500,000	2016	2022

Option 1 – Do nothing / Defer project.

If segments of transmission pipeline without traceable, verifiable, and complete MAOP records are not mitigated, Avista will be non-compliant with Federal Pipeline Safety Codes, especially when the Rule mentioned above becomes final. If the work in this program is not completed, Avista will be going against industry guidance and trends. Once the Federal Rules become final, penalties and fines may be imposed for not completing this work.

Option 2 – Preferred Solution, Continue to remediate segments of high pressure pipeline.

As stated above, the proposed Federal Rule will force action to address lack of sufficient MAOP records. Transmission pipelines without traceable, verifiable, and complete MAOP records will be replaced or mitigated within this program. Reasons for this work will include, but are not limited to; incomplete construction and pressure test documents, pipe quality deficiencies from the manufacturing process, and risk reduction in densely populated areas. As a result of completing this option, public and employee safety will be improved by replacing at risk pipe.

Officials and spokesmen from both PHMSA and the American Gas Association (AGA) have stated it is not prudent for operators to wait for the Federal Rule to become finalized before bettering their systems in this category of work. Avista has been in the process of remediating pipelines under this program since 2015. Incidentally, many of these facilities have been in service for over 30 years.

Depending on the final language of the Rule, the annual levels of spending may need to be adjusted in this program. However, as best as Avista is able to tell at this time, what is proposed is the correct pace to complete this Program. The current rate of work is reasonable with Avista's Engineering and construction workforces.

Avista will address replacement or mitigation of its pipelines in the order of highest operating stress and highest levels of record deficiencies. This program will be prioritized in all three of its natural gas operating states and will analyze risks and priorities regardless of jurisdiction. The projects in 2017 will likely all be in Oregon. Replacement projects in 2018 and beyond have not yet been determined.

Option 3 – Alternative Solution, Reduced funding option: Replace segments of high pressure pipeline.

Reduced funding will result in replacing fewer pipeline segments with insufficient MAOP records. This will be at a pace slower than has been accomplished historically and slower than what we feel is the ideal rate as described above. The outcome, should this option be selected, may be pipeline segments being out of compliance with Federal Regulations and a greater amount of backlog to work through once the Rule is published.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas HP Pipeline Remediation 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: [signature] Date: 4-17-17
Print Name: Jeff Webb
Title: Manager Gas Engineering
Role: Business Case Owner

Signature: [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	Dave Smith	03/09/2017	Mike Faulkenberry	04/17/2017	Initial version

Template Version: 02/24/2017

Gas Isolated Steel Replacement Program, ER 3007

1 GENERAL INFORMATION

Requested Spend Amount	$2,050,000 – Annual Request
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner	Jeff Webb, Jodie Lamb
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 Construction Management is responsible for identifying the work. The work is then dispatched to Gas Operations to complete. The overall program budget is managed by Gas Engineering.

2 BUSINESS PROBLEM

The program objective is to identify and document isolated steel pipe sections, including isolated risers, and to replace each riser or pipeline section within a specified timeframe after its identification. The program started in November 2011 and is planned to be complete by November 2021. 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.

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. 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 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 completed under this program results in a safer gas distribution system.

Gas Isolated Steel Replacement Program, ER 3007

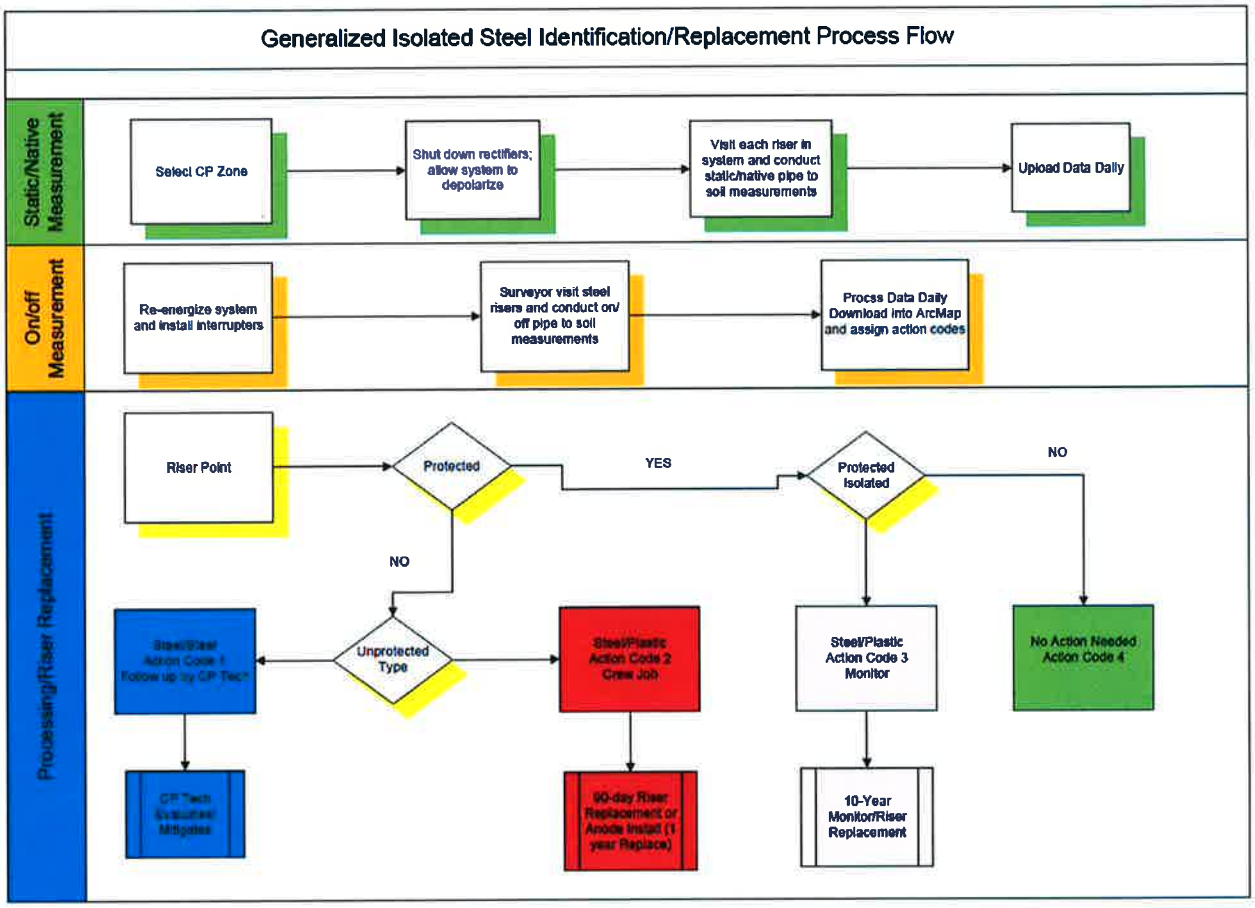


Image 1 – Generalized Work Flow

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

Option 1 – Do nothing

The alternative to completing this program would be to not finish the work within the timeframe dictated 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 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: [signature] Date: 4-17-17

Print Name: Jeff Webb

Title: Manager Gas Engineering

Role: Business Case Owner

Signature: [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: 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: M Faulkenberry 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 Overbuilt Pipe Replacement Program, ER 3006

1 GENERAL INFORMATION

Requested Spend Amount	$900,000 – Annual Program Request
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner	Jeff Webb, Seth Samsell
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	Gas Operations & Engineering
Category	Program
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

All the known mobile home parks with overbuilt pipe are analyzed and risk ranked as part of Avista's Distribution Integrity Management Plan (DIMP). This analysis allows Gas Engineering and each of the Gas Operations Districts to prioritize risk associated with overbuilt pipe projects in each respective service area and complete projects with the highest risk first. Each Operations District is allotted a portion of the overall budget and the project priorities for each District are typically managed locally. The overall program budget is managed by Gas Engineering.

2 BUSINESS PROBLEM

As a Natural Gas Operator we are required to operate within the minimum safety standards described in Part 192 of the Federal Code of Regulations governing the transportation of natural gas by pipeline. Sections of existing gas piping within Avista's gas distribution system have experienced encroachment or have been overbuilt by customer constructed improvements (i.e. living structures, sheds, decks, etc…) and can no longer be operated or maintained safely.

Overbuilds restrict company access to the pipe resulting in accessibility issues as well as the inability to perform particular maintenance required by Federal Code such as leakage survey. Leakage surveys are typically performed by walking directly above the gas facilities while operating leak detection equipment. This maintenance becomes impossible if access to the ground above the facility becomes hindered. Overbuilds not originally designed to be in an overbuilt condition are also a violation of the Federal Code for an overbuilt facility as they do not meet code requirements for installation within a sealed conduit that can be vented outside of the overlying structure.

Overbuilds present an increased risk to customers as well as operational risk due to the ability of potential leaks to migrate into or become entrapped within structures built over the gas facility resulting in hazard to life and property. Multiple factors impact risk and the replacement of these facilities, but of primary concern is the increased risk hazard due to leak. Overbuilds also increase Operations and Maintenance costs as Avista is often required to return to overbuild locations multiple times to attempt and complete leak survey and other maintenance tasks that cannot be completed at the normal scheduled time due to the overbuild.

This program is primarily focused on addressing overbuilt pipe in mobile home parks as this is where the highest risk and greatest quantity exist due to the dynamic nature of these facilities. However overbuilds are not isolated to mobile home parks and the need exists for this program to be utilized in all of Avista's service territories. Image 1 below is a list of know projects within this program.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing/defer project	$0	N/A	
Option 2 – Preferred Solution, Complete programmatic replacement of overbuilt sections of pipe.	$900,000	01 2017	12 2017
Option 3 – Alternate Solution #1, Reduced Funding Option: Complete programmatic replacement of overbuilt sections of pipe.	$450,000	01 2017	12 2017
Option 4 – Alternate Solution #2, Attempt to enforce Avista's easement rights	Unknown	Unknown	Unknown

Option 1 – Do nothing/defer project

The do nothing option will continue to operate these facilities without replacement. There is significant risk associated with not remediating these facilities and this would be a violation of the Code of Federal Regulations subjecting Avista to potential State and Federal fines associated with operating facilities that are out of compliance. The financial impact of this alternative is very difficult to estimate as penalties for non-compliance are on a case by case basis. Known risks cannot be mitigated without replacement of these facilities or remediation of the overbuild condition. This option is not recommended.

Option 2 – Preferred Solution, Complete programmatic replacement of overbuilt sections of pipe

It is recommended as part of a programmatic approach to identify and replace sections of existing pipes that can no longer be operated safely as they have experienced encroachment or have been overbuilt by customer constructed improvements. Completing this type of work as part of a program will allow for the prioritization of overbuilt facilities based upon those instances with the highest risk to customers as well as operationally. Our Distribution Integrity Management Program (DIMP) help prioritize the projects within each district. This methodology is also more proactive and is anticipated to have less overall cost impact than by addressing each specific issue as it is encountered. This program helps address Avista's responsibility as a Natural Gas Operator in working to maintain compliance with the Code of Federal Regulations that governs the operation of natural gas distribution systems. It also aligns with Avista's organizational focus to operate safe and reliable infrastructure for all of our customers in each of our service territories.

The current funding level balances available manpower with other programs administered at the District Offices and allows crews to also work on other compliance and risk reduction type activities. Annual levels of spending may need to be adjusted in this program as the risks in DIMP are reassessed annually.

Option 3 – Alternative Solution #1, Reduced funding option: Complete programmatic replacement of overbuilt sections of pipe

Another option is to approach the risk associated with overbuilds with reduced funding. Reduced funding will result in replacement of fewer sections of overbuilt piping. The reduced funding alternative would still allow us a benefit by addressing some of the overbuilt facilities with known risk, but at a pace slower than we feel appropriate to address these safety concerns and maintain compliance. The outcome, should this option be selected, would result in the continued operation of facilities known to be out of compliance and which are currently operating with higher risk to customers and operations personnel. Additionally, Operations & Maintenance funds would not decrease since Avista is often required to return to an overbuild locations multiple times to attempt and complete a leak survey or other maintenance tasks that cannot be completed due to the overbuild. This option would be a partial employment of both Options 1 and 2 and is not recommended.

Option 4 – Alternative Solution #2, Enforce Avista's easement rights.

A final option to this program is to attempt to enforce Avista's "rights" and try to force the owners, renters, or mobile home parks owners to be liable for these fixes, however the original piping in these locations typically has weak or no easement protection. Proving the existing customer was responsible for the cause of the overbuild can be difficult and sometimes impossible. Avista has experienced in the past that attempts to force customer to pay for these modifications are difficult and often legal fees approach the cost of the work. Legal actions often take an extensive time and resource commitment. Additionally the negative public relations associated with such a philosophy would be very difficult to overcome. This option is not recommended.

Gas Overbuilt Pipe Replacement Program, ER 3006

District	Site	Estimated Co	2017	2018	2019	2020	2021	2016 DIMP Score/ft
Total			$ 504,000	$462,500				
CDA	900 Idaho St, space 304	$ 5,000	$ 5,000					2445
Kellogg	8 Various Services	$ 20,000	$ 20,000					?
Medford	555 Freeman Rd, Central Point OR	$ 450,000					$450,000	1930
Medford	301 Freeman Rd, Central Point OR	$ 285,000			$285,000			4145
Medford	1055 N 5th St, Jacksonville OR	$ 380,000	$ 200,000	$280,000				3042
Medford	2252 Table Rock, Medford OR	$ 325,000				$325,000		3485
Medford	2335 Table Rock, Medford OR	$ 135,000					$135,000	2894
Medford	3555 S Pacific, Medford OR	$ 480,000					2021+	1400
Medford	4425 W Main St, Medford OR	$ 15,000			$ 15,000			717
Roseburg	Drifter's Loop	$ 67,000		$ 67,000				2958
Roseburg	Main St ------------MHP Winston	$ 75,500		$ 75,500				2853
Roseburg	2721 NE Stephens MHP, Roseburg OR	$ 45,000	$ 45,000					1616
LaGrande	Stonewood Ph. 3, La Grande OR	$ 100,000	$150,000					1936
Klamath Falls	Bartlett Mobile Park, K Falls OR	$ 14,000	$ 14,000					4768
Klamath Falls	Villa West MHP 2241 Greensprings	$ 10,000		$ 10,000				1988
Klamath Falls	6800 S. 6th Street. – Wisemans Mobile Home Park	$ 25,000	$ 25,000					3845
Klamath Falls	5602 Denver Ave. – Woodland Mobile Home Park	$ 30,000		$ 30,000				2827

Image 1 – List of known projects within this program.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Overbuilt Pipe Replacement 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: Mike Faulkenberry 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	Seth Samsell	04/17/2017	Jeff Webb	04/17/2017	Initial version

Template Version: 02/24/2017

Gas PMC Program, ER 3055

1 GENERAL INFORMATION

Requested Spend Amount	$1,200,000
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 Engineering, Gas Operations, Gas Meter Shop, and Technical Services work together to administer the Gas Planned Meter Change-out (PMC) program and ensure compliance with the various state rules and tariffs related to gas meter testing. Gas Engineering is ultimately responsible for the PMC plan and annual reports that are submitted to each of the state commissions. Gas Operations and the Gas Meter Shop remove the meters from the customer's premise and install new ones. 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.

2 BUSINESS PROBLEM

Avista is required by 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.

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

Avista's statistical sampling methodology is 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.

Annually the 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 lower costs and also 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.

This program assures that our customers' natural gas use is measured accurately.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$0		
Option 2 – Preferred Solution, Complete programmatic work as described	$1,200,000	January	December

Option 1 – Do nothing/defer project

If this program were not completed fully and accurately, Avista would be out of compliance with state 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.

Option 2 – Preferred Solution, Complete the programmatic work at the current funding level

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.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas PMC 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	04/16/2017	Mike Faulkenberry	04/17/2017	Initial Version

Template Version: 02/24/2017

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.

3 PROPOSAL AND RECOMMENDED SOLUTION

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

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 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: Mike Faulkenberry 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 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 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.

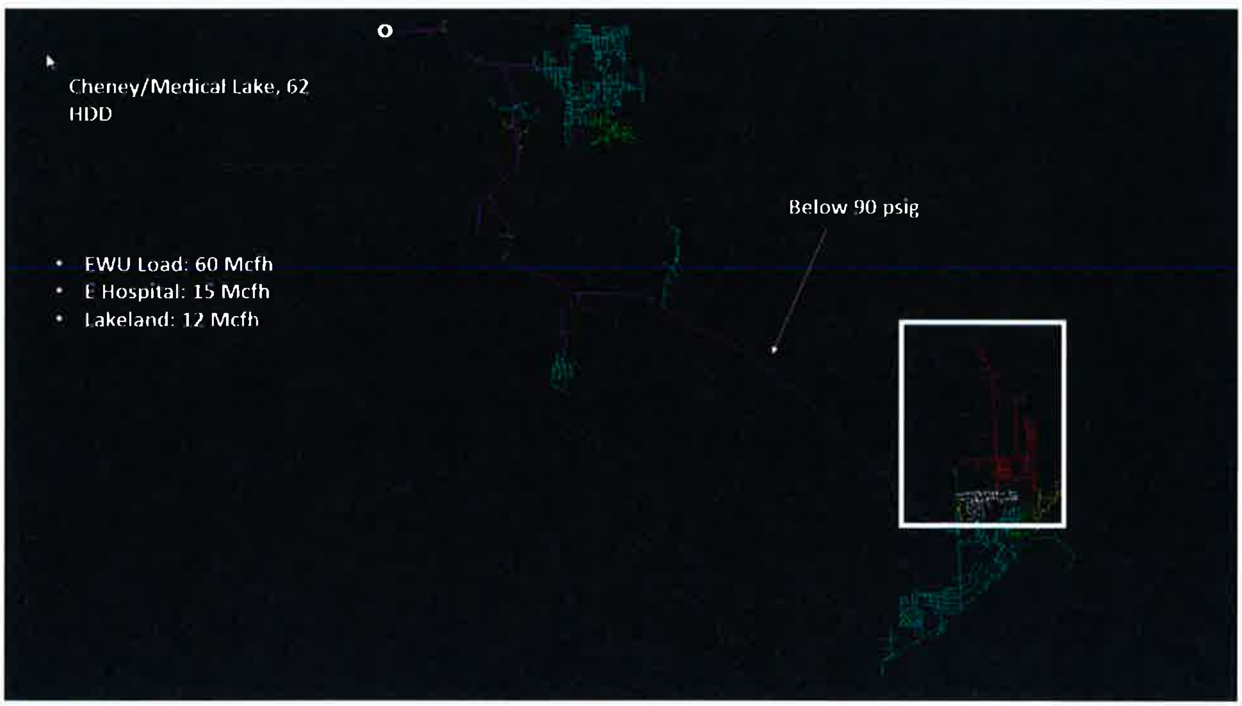


Image 1 – Distribution system pressures before proposed reinforcement (62 HDD is shown, design is 82 HDD)

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		

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 N Spokane Hwy 2 HP Main Reinforcement, ER 3237

1 GENERAL INFORMATION

Requested Spend Amount	$2,000,000
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	Project
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

The Gas Planning department routinely runs an analysis on Avista's gas distribution system to identify areas of the system with insufficient capacity to serve firm customer's 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 options are then reviewed with the Gas Engineering Manager and a preferred alternative selected to proceed with a funding request.

2 BUSINESS PROBLEM

Based on load studies performed by the Gas Planning department, the distribution system in North Spokane has insufficient capacity to serve over 4,000 firm customers on a design day. Sufficient capacity is defined as pressures at or above 15 pounds per square inch (psig) in the distribution system on a design day analysis. Additionally, Avista serves the Inland Asphalt plant located north of this location and it is not able to be reliably served in spring and fall due to capacity limitations on the distribution system.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$0	N/A	
Option 2 – Install 12,000' of high pressure pipe to reinforce the North Spokane area.	$2M	*12 2016*	*12 2017*
Option 3 – Install 12,000' of intermediate pressure pipe to reinforce the North Spokane area.	$500K	12 2016	12 2017

Gas N Spokane Hwy 2 HP Main Reinforcement, ER 3237

Option 1 – Do nothing.

Without a reinforcement project, Avista is at risk of not having sufficient capacity to serve firm customer load in North Spokane on a design day scenario. See Image 1 on page 3 for a load study analysis showing the distribution system that is at risk.

Option 2 – Install 12,000' of high pressure pipe to reinforce the North Spokane Area.

This option includes the installation of 8" high pressure main, as well as a regulator station that will supply additional capacity to the North Spokane area. These new facilities will be installed on private easements – Ensuring long-term reliability and low operating costs. This new main will substantially increase capacity in the North Spokane area and load study model estimates that the increased capacity would result in no customers loosing gas service on a design day. See Image 2 on page 4 for a load study analysis showing how the proposed reinforcement provides sufficient capacity to the North Spokane area distribution system.

Option 3 - Install 12,000' of intermediate pressure pipe to reinforce the North Spokane Area.

This option includes the installation of 6" intermediate pressure main that will supply additional capacity to the North Spokane area. This new main will increase capacity in the North Spokane area. There are two major disadvantages of this option. First, the system will not meet Avista's minimum pressure requirement of 15 psig on a design day. Second, this option does not allow for growth that is, and will continue to happen in this region of North Spokane. See image 3 on page 5 for the load study analysis of this option.

Gas N Spokane Hwy 2 HP Main Reinforcement, ER 3237

Image 1 – Distribution System Pressures before Proposed Reinforcement

Gas N Spokane Hwy 2 HP Main Reinforcement, ER 3237

Image 2 – Distribution System Pressures after Proposed High Pressure Reinforcement (Option 2)

Gas N Spokane Hwy 2 HP Main Reinforcement, ER 3237

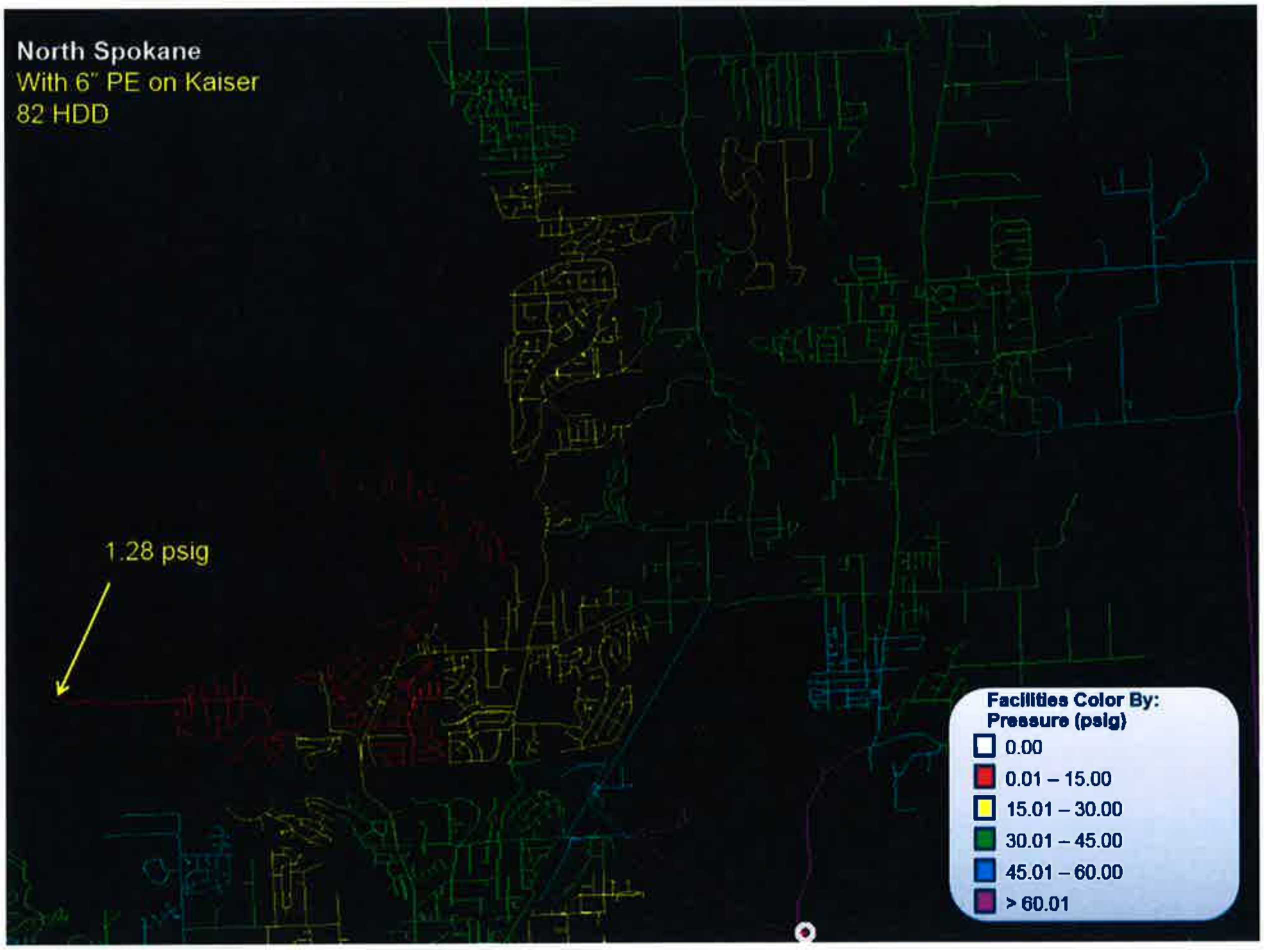


Image 3 – Distribution System Pressures after Proposed Intermediate Pressure Reinforcement (Option 3)

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas N Spokane Hwy 2 HP Main 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:	Jeff Webb	Date:	4-17-17
Print Name:	Jeff Webb		
Title:	Manger of Gas Engineering		
Role:	Business Case Owner		

Gas N Spokane Hwy 2 HP Main Reinforcement, ER 3237

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	Tim Harding	03/13/17	Mike Faulkenberry	04/17/2017	Initial version

Template Version: 03/07/2017

Gas Pullman HP Reinforcement Project, ER 3309

1 GENERAL INFORMATION

Requested Spend Amount	$2,500,000 (2020)
Requesting Organization/Department	B51 – 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

Based on load studies performed by the Gas Planning department, the load growth in the Pullman, WA area has exceeded the capacity of the existing Pullman Gate Station (supply point into Avista's system). This impacts Avista's obligation to serve Firm customers on a design day. The contracted capacity at the Pullman Gate Station is 786 thousand cubic feet per hour (Mcfh) and the projected Firm load on a design day is 916 Mcfh. This difference puts approximately 1,300 customers at risk of losing gas service.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$0		
Option 2 – Preferred Solution, Install of 3 miles of High Pressure pipe from Moscow Gate Station	$2,500,000	06 2019	12 2020
Option 3 – Alternative Solution, Rebuild the Pullman Gate Station	$ TBD	06 2019	12 2020

Option 1 – Do nothing

Without a reinforcement project Avista does not have sufficient capacity to meet its obligation to serve existing Firm customer load in the Pullman, WA on a design day scenario, and is not able to support future customer growth. See Image 1 below for a graph showing the Expected Load vs Contracted Capacity. Approximately 1,300 customers are at risk of losing their gas service during a cold weather event.

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 3 miles of High Pressure pipe from the Moscow Gate Station

The high pressure (HP) main from the Moscow Gate Station is approximately three miles from the HP main that is fed from the Pullman Gate Station. By installing main between the two systems the loads would be balanced and station capacities better utilized. This option will add reliability by creating a looped system (bringing a second source to an area) and will provide additional growth opportunities along the way for individuals currently without gas service.

Option 3 – Alternative Solution, Rebuild the Pullman Gate Station

A rebuild of the Pullman gate station would address the capacity constraints but would not add any reliability to the system nor any new growth opportunities. The cost of this project, based off of similar recent work, would be comparable in cost to Option 2.

Additional efforts will be spent in 2019 to develop the alternate solutions and confirm that Option 2 is still the preferred solution.

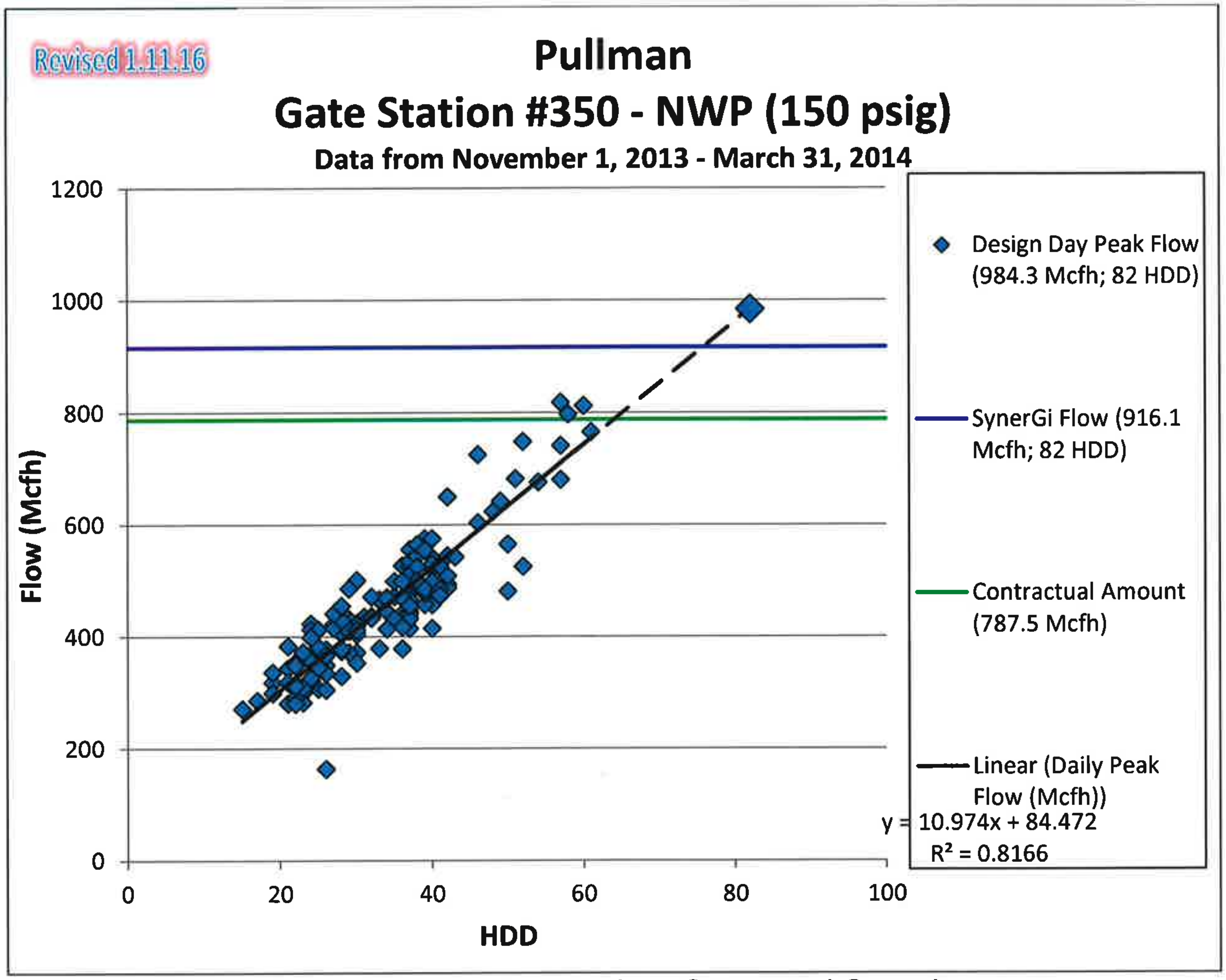


Image 1 – Expected Load vs. Contracted Capacity

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Pullman 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:	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 Reinforcement Program, ER 3000

1 GENERAL INFORMATION

Requested Spend Amount	$1,000,000
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	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

This annual program will identify and provide for necessary capacity reinforcements to the existing natural gas distribution system in WA, ID, and OR. Avista has an obligation to serve existing Firm gas customers by providing adequate capacity on design day 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 projects may be completed under the blanket project numbers set up for each district.

Projects that are identified in this program are prioritized by a Gas Planning model, see Image 1 below for a list of high and medium priority projects. The prioritization is based on the computer model that analyzes actual meter usage data from each customer, extrapolates that data to predict a demand load at design temperature conditions, and then analyzes each gas distribution system to determine if reinforcements are necessary. If system capacities are not sufficient the model can also be used to determine the benefits of different types of reinforcement projects by running "what if?" scenarios. Once the projects are identified, they are risk ranked based on the number of customers affected and the temperature levels at which the risks begin.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$0		
Option 2 – Preferred Solution, Complete with full funding	$1,000,000	January	December
Option 3 – Alternative Solution, Complete with reduced funding level	$500,000	January	December

Option 1 – Do nothing

Without a Reinforcement Program, Avista does not have sufficient capacity to meet our obligation to serve existing Firm customer load on a design day scenario, and is not able to support future customer growth.

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, Complete with full funding

If funding continues as requested, the high priority by projects are scheduled to be completed in 2018 and the medium priority projects by 2021. The low priority projects will take approximately three more years to complete after that. At that point, the backlog of projects will be completed and funding can be reduced substantially, but not completely as reinforcements will always be needed as new customers are added.

Option 3 – Alternative Solution, Complete with reduced funding level

If funding is reduced, then the timeline to complete the projects and the risks of outages extends proportionally. The more winters we keep our system below capacity, the higher likelihood of have a cold weather event that could cause outages.

Gas Reinforcement Program, ER 3000

	last updated		Rank	Feet		Description	
OBJECTID	SIZENUMBER	MATEI	NOTES	SHAPE.	STATUS	LOCATION	CITY
704	6"	Plastic	High	207	Proposed	Riverside Connection to 12"	Spokane
705	6"	Plastic	High	813	Proposed	Front St. and Spokane Falls Blv. Main Upgrade	Spokane
5186	6"	Steel HP	High	16874	Proposed	***HP Connection Between La Grande and Union (21 Customers)***	La Grande
6457	6"	Steel HP	High	10316	Proposed	***HP Kaiser Extension (1260 Customers)***	Spokane
6777	2"	Plastic	High	408	Proposed	Loomis and Railroad (1 Customer)	St John
11257	4"	Plastic	High	2000	Replacement	ADL Replacement for Genesee (323 Customers)	Genesee
11258	4"	Plastic	High	3402	Replacement	ADL Replacement for Genesee (323 Customers)	Genesee
11259	4"	Plastic	High	2306	Replacement	ADL Replacement for Genesee (323 Customers)	Genesee
11260	4"	Plastic	High	2190	Replacement	ADL Replacement for Genesee (323 Customers)	Genesee
11261	4"	Plastic	High	3688	Replacement	ADL Replacement for Genesee (323 Customers)	Genesee
11914	6"	Plastic	High	10893	Proposed	Myrtle Creek 4" Replacement (938 Customers)	Myrtle Creek
13498	4"	Plastic	High	2557	Replacement	ADL Replacement for Genesee (323 Customers)	Genesee
15098	2"	Plastic	High	202	New	<Null>	Medford
15099	2"	Plastic	High	294	New	Medford East 6 psig System	Medford
15100	2"	Plastic	High	240	New	Medford East 6 psig System	Medford
15103	6"	Plastic	High	14224	Replacement	Jacksonville Main Replacement	Jacksonville
15105	4"	Plastic	High	3853	Replacement	Winston Main Replacement	Winston
15106	6"	Steel	High	20412	Replacement	Klamath Main Replacement	Klamath Falls
15737	2"	Plastic	High	610	Proposed	Intersection of Lenter and Lathen	Moscow
15738	6"	Steel	High	4152	Replacement	6" Main Replacement	Moscow
16057	6"	Steel	High	9418	Replacement	South Hill	Spokane
16058	2"	Steel	High	143	Proposed	Near 33rd and Lincoln	Spokane
16060	2"	Steel	High	224	Proposed	Near 34th and Perry	Spokane
16063	2"	Steel	High	363	Proposed	9th and Eastern	Spokane
16064	2"	Plastic	High	80	Proposed	Kahuna and Carnahan	Spokane
16065	2"	Plastic	High	144	Proposed	14th and Eastern	Spokane
16066	2"	Steel	High	236	Proposed	6th and Havana	Spokane
16067	Unknown	Unknowr	High	85	New	REGULATOR STATION. West Medford 6 psig system	Medford
16068	4"	Plastic	High	3073	Replacement	Palouse 2" Main Replacement	Palouse
393	2"	<Null>	Medium	564	Proposed	23rd St. Loop Connection	Lewiston
394	6"	Plastic	Medium	1582	Proposed	Empire Center Rd. Main Connection	Post Falls
408	6"	Steel HP	Medium	6687	Proposed	***HP Schweitzer Mountain Rd. to Boyer HP Extention (179 customers)***	Sandpoint
414	6"	Plastic	Medium	889	Replacement	Front St. and Spokane Falls Blv. Main Upgrade	Spokane
416	2"	Plastic	Medium	578	Proposed	Port and North St. Connection (139 customers)	Clarkston
700	4"	Plastic	Medium	5080	Proposed	Lakeshore and Sagle Rd. Development Main Extention	Sagle
706	6"	Plastic	Medium	7072	Proposed	Lakeshore and Sagle Rd. Development Main Extention	Sagle
1396	12"	Steel HP	Medium	2067	Replacemant	***HP N River Rd. Upgrade (77 customers)***	Rouge River
1397	12"	Steel HP	Medium	2032	Replacement	***HP 4th St. Upgrade 2***	Gold Hill
1402	4"	Plastic	Medium	11	Proposed	Douglas and Main St. Connection	Roseburg
1659	2"	Plastic	Medium	127	Proposed	State Rd. Main Extension (188 customers)	Sutherlin
1660	2"	Plastic	Medium	301	Proposed	State Rd. Main Extension (188 customers)	Sutherlin
1661	2"	Plastic	medium	409	Proposed	State Rd. Main Extension (188 customers)	Sutherlin
1662	2"	Plastic	Medium	152	Proposed	Umpque Main Connection (188 customers)	Sutherlin
1664	2"	Plastic	Medium	155	Proposed	Central Rd. Crossing (188 customers)	Sutherlin
1665	2"	Plastic	Medium	213	Proposed	Mardonna and Second st. (188 customers)	Sutherlin
1666	2"	Plastic	Medium	161	Proposed	Third St. Main Connection (188 customers)	Sutherlin
1667	2"	Plastic	medium	341	Proposed	Grove Rd. Main Extension (188 customers)	Sutherlin
1668	2"	Plastic	Medium	349	Replacement	6th St. Main Connection (188 customers)	Sutherlin
1670	6"	Plastic	Medium	4948	Proposed	Hawthorne to Central St. Main Connection (188 customers)	Sutherlin
2299	12"	Steel HP	Medium	590	Replacement	***HP 4th St. Upgrade 1***	Gold Hill
3257	6"	Steel HP	Medium	1272	Replacement	***HP Lewiston West Gate Downstream Upgrade***	Lewiston
3258	6"	Steel HP	Medium	428	Replacement	***HP 5th st. HP Upgrade***	Lewiston
3899	6"	Plastic	Medium	21632	Replacement	ADL Replacement for Endicott Rd. (384 Customers)	Colfax
7098	8"	Steel HP	Medium	5255	Proposed	***HP Phase II Idaho and Brookie***	Rathdrum
10937	6"	Plastic	Medium	1731	Replacement	Chilco Rd and Old HWY 95 (1 Customer)	Chilco, ID
11577	6"	Steel HP	Medium	19573	Proposed	***HP Warden***	Warden
11578	6"	Plastic	Medium	16004	Proposed	Austin Rd and Monroe (56 Customers)	Spokane
12217	6"	Steel HP	Medium	8113	Proposed	***HP Phase III***	Rathdrum

Image 1 – Prioritized list of reinforcements

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas 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 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 Telemetry Program, ER 3117

1 GENERAL INFORMATION

Requested Spend Amount	$200,000
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner	Jeff Webb
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	Gas Operations & Engineering
Category	Program
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

The Gas Measurement Engineer works with the Gas Telemetry Technicians, Gas Planning, Gas Engineering, Metering Automation, Gas Operations, Gas Control Room, Supervisory Control and Data Acquisition (SCADA), and Gas Supply groups to determine possible projects or locations for new telemetry sites or upgrades of existing equipment. The Gas Engineering Manager reviews the recommendations from the Gas Measurement Engineer and approves the specific projects within this program. A five year plan is also created by the Gas Measurement Engineer and approved by the Gas Engineering Manager.

2 BUSINESS PROBLEM

This program will continue the installations of gas telemetry throughout Avista's gas service territory. Gas telemetry is used to remotely monitor system pressures, volumes, and flows from areas of special interest such as Gate Stations (supply point into Avista's system), gas transportation customers, Regulator Stations (pressure reductions stations), selected large industrial customers, and distribution systems with more than one source of gas.

Further enhancing the telemetry sites will increase the visibility the Gas Control Room and Gas Operations has of the gas system to help analyze operational concerns and monitor cold weather performance. Alarm points can be set in the telemetry devices to alert the Gas Control Room of any abnormal operating condition.

Additionally, data from these telemetry sites is used to validate the system modeling tool (load study) that Gas Planning creates every year. Since the data collected is electronic, it can be represented graphically to quickly analyze any anomalies.

The Gas Supply department benefits from these projects by having metering data at Gate Stations that is independent of the interstate pipeline's metering (suppliers of gas to Avista). This makes it easy to find calculation or metering errors at the Gate Stations. Billing errors left unfound can create problems that lead to extra work and manual corrections between Avista and the interstate pipelines.

The customers and general public benefit from Avista having good "visibility" to the gas transmission and distribution system. This allows for a quicker response and better decision making from the Gas Control Room and Gas Operations when an abnormal or emergency situation occurs. For example, we are quickly notified electronically of low pressure situations that if not addressed in a timely manner could result in significant loss of gas service to our customers. If there were no telemetry, Avista would have to wait for customers to call in after they've lost gas service which at that point would have a significant impact to our customers and require substantial time and manpower to restore service.

Avista strives to replace equipment that has reached the end of its service life with new equipment that makes use of current technology. We also review existing installations for opportunities to improve reliability, acquire more data, or more efficient ways of collecting the data.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$0	N/A	
Option 2 – Preferred Solution, Replace/install telemetry at the current funding level	$200,000	January	December

Option 1 – Do nothing

To make no further additions to Avista's telemetry system would result in less capability to see "real time" performance of the gas system, inability to see operational abnormalities in a timely fashion, subject our customer to increased chances of low or high pressure situations and their related safety risks, and the reliability of the existing system would decline due to equipment failures.

Option 2 – Preferred Solution, Replace/install telemetry at the current funding level

At the current funding level, Avista adds approximately 5 new sites and upgrades approximately 15 sites per year. This allows the high priority sites to be addressed as the need arises or equipment fails.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Telemetry 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: M Faulkenberry 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: 02/24/2017

Gas Warden HP Reinforcement, ER 3308

1 GENERAL INFORMATION

Requested Spend Amount	$6,000,000 (2019)
Requesting Organization/Department	B51 – 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

Warden, WA currently has two concerns associated with capacity. 1) the town is supplied gas from the fully-subscribed and capacity-constrained Moses Lake lateral (owned by Williams NWP). Warden has a design-day need projected to be 1,472 dekatherm per day (Dth/day). Avista has Firm transportation capacity for 1,180 Dth/day. The capacity gap of 292 Dth/day can be served on a non-Firm basis, but there is a risk of not being able to serve Firm customers in Warden during severe cold weather events. In order to meet our obligation to serve current Firm loads in Warden on a peak day, AVA requires incremental capacity from Williams NWP. The Gas Supply Department will be coordinating the capacity increase from Williams NWP. 2) The high pressure (HP) supply line into town has reached its capacity. Sufficient capacity is defined as pressures at or above 90 pounds per square inch (psig) in a HP distribution system on a design day analysis. Gas Engineering will be responsible for distribution system changes. This ER is specific to the work and costs associated with the distribution system updates.

As a result of current capacity/supply constraints, industrial gas growth opportunities are hampered within the Port of Warden Industrial Park as well as other sites in the area. Grant County Economic Development Council and the Port of Warden have contacted Avista several times related to different commercial ventures interested in the Port site.

Schedule and timing are critical aspects of this project. Expansion on the Williams NWP Moses Lake Lateral is a four year project from authorization to expansion.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 - Do nothing, Cold Wx Action Plan	$0		
Option 2 – Preferred Solution, Install a new Gate Station and 3.2 miles of HP pipeline	$6,000,000	06 2018	12 2019
Options 3 – Alternative Solution, Upsize the existing HP main	$ TBD	06 2018	12 2019

Option 1 - Do Nothing

Without a reinforcement project, Avista does not have sufficient capacity to meet its obligation to serve Firm customer loads in the Warden, WA area on a design day scenario. See Image 1 for a load study analysis showing the Warden HP system with insufficient capacity to serve existing customers. Doing nothing would put the company at a high risk of outages. Additionally there is no available capacity for future customers interested in commercial ventures in the area.

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 6" HP supply line

This option would provide the greatest flexibility by adding a new Gate Station (supply point into Avista's system) and HP supply line. 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 gas source to the area and will provide additional growth opportunities along the way for individuals without gas service.

Gas Engineering has developed a cost estimate for constructing a new gate station and installing approximately 3.2 miles of 6" HP distribution pipeline to serve the Firm customers in the Warden area (shown as the red line in Image 3 below) and will support future growth opportunities. The final capacity requirements are still being finalized, so the costs may change depending on the size of the Gate Station and the HP main.

Option 3 – Alternative Solution, Upsize the existing Gate Station and HP supply line

This option would replace the existing 4" diameter supply line from the existing 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. However, replacing the existing 4" HP will likely cost more than the proposed new route due to the expenses associated with construction along the state highway. This option will not have the benefits of increasing reliability to the distribution system by adding a second source to the area, nor will it provide additional growth opportunities along the way for individuals without gas service along the new route.

Image 1 – Gas System Pressures before Proposed Reinforcement

Gas Warden HP Reinforcement, ER 3308

Image 2 – Distribution System Pressures after Proposed Reinforcement

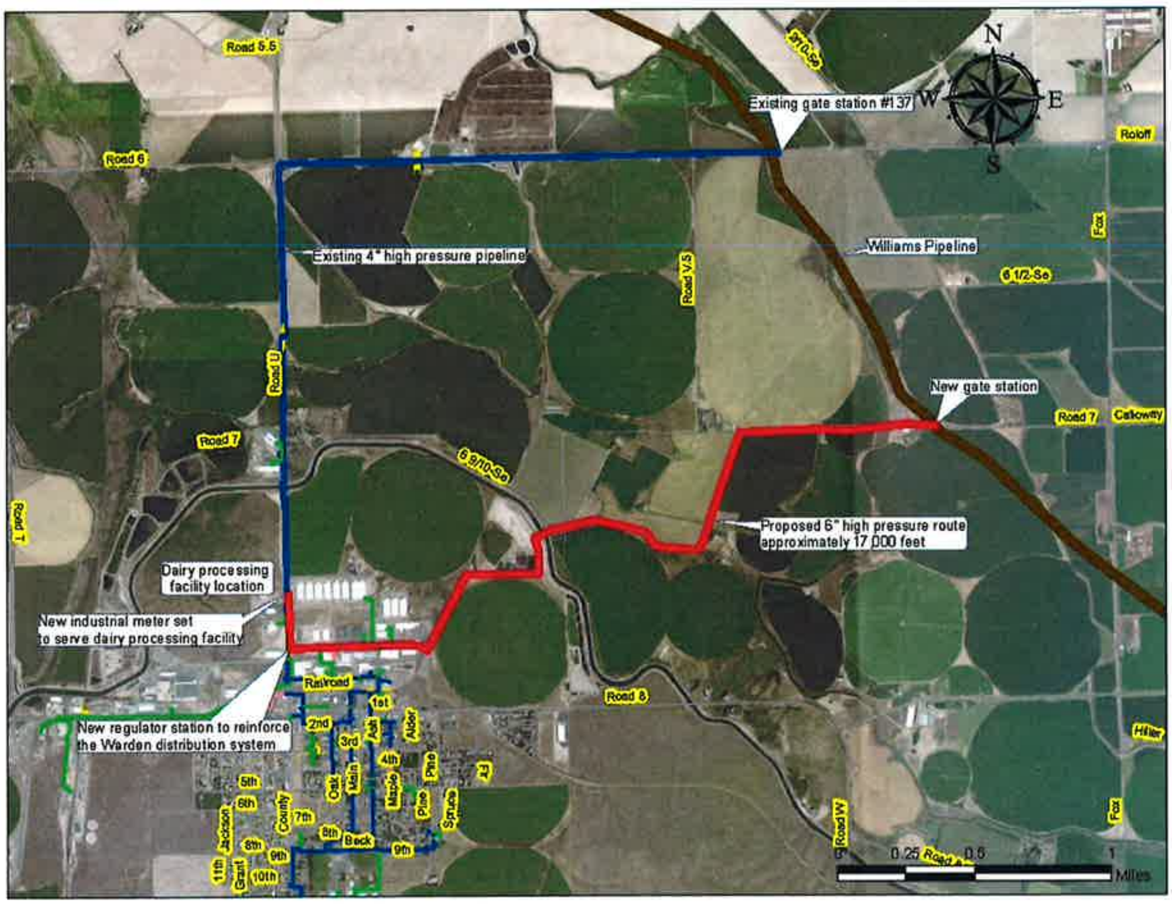


Image 3 – Proposed HP route and Gate Station location

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Warden 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 Natural Gas

Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeff Webb	03/17/2017	Mike Faulkenberry	04/17/2017	Initial version

Template Version: 03/07/2017

Campus Repurposing Phase 1

1 GENERAL INFORMATION

Requested Spend Amount	$24,400,000
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 and Asset Condition

1.1 Steering Committee or Advisory Group Information

The Campus Repurposing Phase 1 Steering Committee is made up of a cross section of directors that represent groups impacted by the projects, as well as 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, Phase 1 is a multiyear plan that address the following issues:

- Employee space needs
- Improving safety and efficiency of campus traffic flow
- Outdated warehouse / stores space and processes
- Outdated Hazardous waste & materials space and processes
- Outdated transformer oil recovery space and processes
- Outdated investment recovery space and processes
- Lack of materials storage yards, no short-term flexibility
- Alignment of campus parking and number of employees based at main campus

Campus Repurposing Phase 1

The Avista corporate campus comprises 28 acres located next to the Spokane River in heart of the Logan Neighborhood. The campus is just north of the downtown Spokane corridor.

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 initiated 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.

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

Option	Capital Cost	Start	Complete
Option 1 (Recommended) – Perform 9 strategically designed projects to optimize corporate campus workflows.	$24,400,000	Jan 2011	April 2017
Option 2 – Purchase alternate sites elsewhere for various needs.	up to ~400,000,000	n/a	n/a
Option 3 – Do nothing.	$1M - $3M yearly (Capital and O&M misc. costs – approx.)	n/a	n/a

OPTION 1 – PERFORM THE FOLLOWING NINE MAJOR PROJECTS:

1. Construct new Warehouse Building & new 120 stall parking lot
2. Remodel old Warehouse space in Service Building to office
3. Construct new Waste & Asset Recovery Building
4. Build new Generation, Production, and Substation Support (GPSS) Storage Building at Beacon Storage Yard
5. Expand outdoor Warehouse storage yard, Phase 1
6. Remodel existing canopy for new Investment Recovery
7. Remodel Spokane Construction office area in Service Building
8. Remodel GPSS office area in Service Building
9. Expand outdoor Warehouse storage yard, Phase 2

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

- Modernize the aged warehouse space within the service building.
- 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.
- Provide office space options for future Avista employee growth.

Descriptions of each project are discussed on the pages to follow.

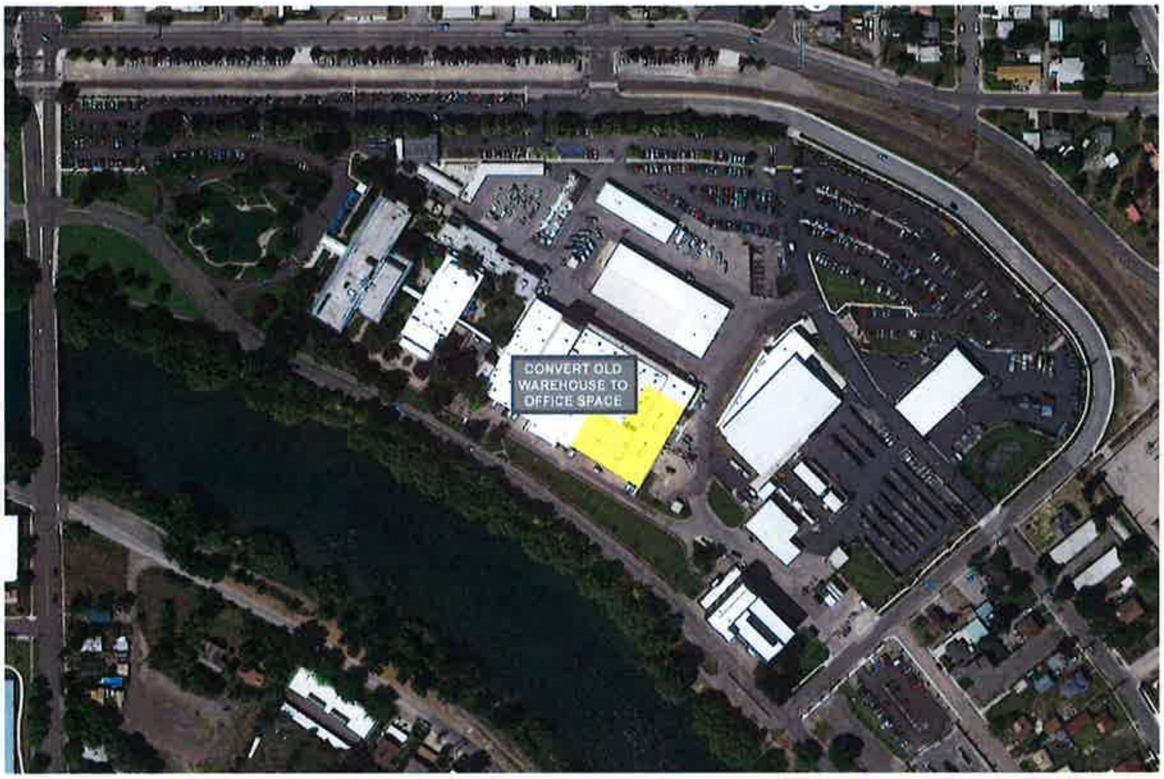
Campus Repurposing Phase 1

Project 1: New Warehouse Building & Parking Lot

The new warehouse building and parking lot expansion was completed in 2013. Its location was determined due to its need to be adjacent to our line truck crews for easy staging. The new building created vertical shelving efficiencies with a 30-foot height, whereas in its previous space in the service building, it was only 14 feet high. The customer benefits for this facility include better response time and reliability due to enhanced and efficient storage and material handling of all products currently within the Avista electric and gas field infrastructure. Upon completion, this project has provided both quantifiable and non-quantifiable benefits in employee and delivery efficiency, storage needs and energy use.

Campus Repurposing Phase 1

Project 2: Service Building Renovation into Office Space



The Service Building Renovation was completed in 2014. It remodeled what was formerly the Warehouse space into administrative office space, with the ability to seat approximately 100 employees. It also created new restrooms, a new mailroom/graphics space, several conference rooms, and a break area. The customer benefits for this remodel includes lower cost and increased efficiency due to allowing Avista administrative functions to remain consolidated on one campus, rather than being scattered amongst multiple buildings around the region.

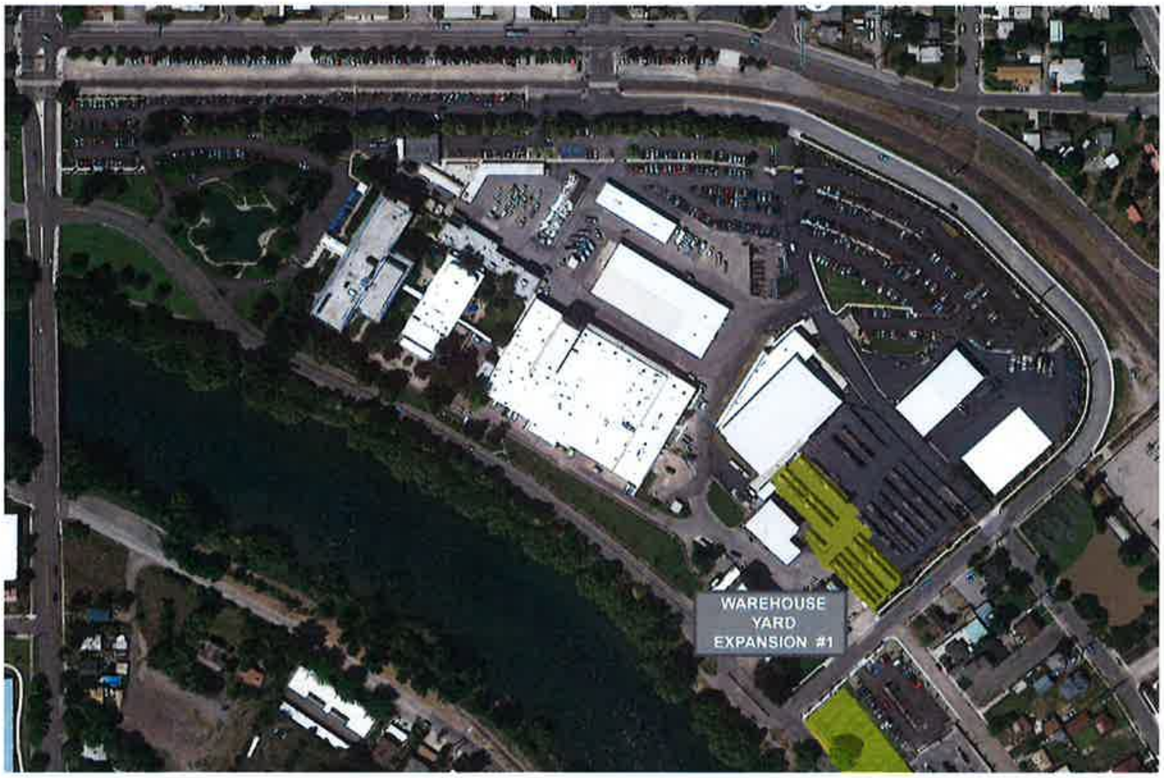
Campus Repurposing Phase 1

Project 3: Waste & Asset Recovery Building

The Waste & Asset Recovery Building was completed in 2015. It consolidated Avista's hazardous waste / materials collection and the transformer oil recovery / collection functions into one building. Both processes were previously performed in buildings approx. 25 years old. These older buildings followed all state and federally mandated environmental regulations, but the new facility will allow for a much more efficient and streamlined process to continue meet these standards. All waste and transformers collected by our Avista field crews are processed in the new building. This includes Avista crews not only local to Spokane, but also all other satellite service centers, who ship their waste and transformers back to this new building. The customer benefits for this building includes enhanced safety for our customers by eliminating PCB oil containing transformers, and overall reduction of hazardous products and contaminants throughout the customer service territory. Upon completion, this project has provided further quantifiable and non-quantifiable benefits in employee and delivery efficiencies and building energy usage reductions.

Campus Repurposing Phase 1

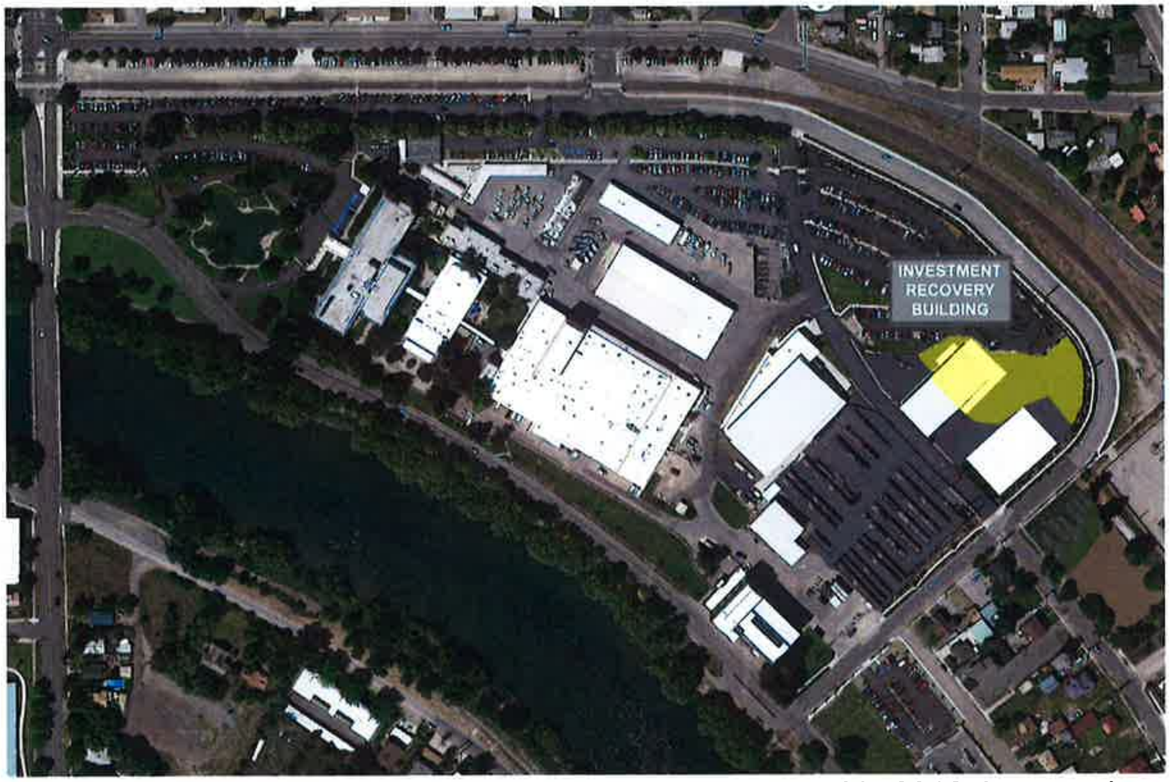
Projects 4 and 5: GPSS Storage Building and Warehouse Storage Yard Expansion #1



The Avista Generation, Production and Substation Support (GPSS) storage building was completed in 2015. It relocated an existing storage building at the corporate campus to make way for the Warehouse Yard Expansion #1. It was built at our Beacon storage yard, approximately two miles east of the corporate campus.

The Warehouse Yard Expansion #1 project was completed in 2015. It increased the size of our current warehouse exterior storage yard and consolidated many materials and equipment that were previously stored in inconvenient, inefficient "pockets" on the corporate campus. As part of the project, a new storm water treatment swale was also installed to divert all rainwater that could be contaminated by oils and mastics inherent in asphalt paving. The swale was appropriately sized for additional asphalt paving for future projects. The customer benefits for this facility include better response time and reliability due to enhanced and efficient storage and material handling of products currently within the Avista electric and gas field infrastructure. Further benefits include public safety with the storm water swale preventing possible contaminants from leeching into the Spokane River. Upon completion, this project has provided annual estimated cost savings of approximately $19,000 in employee efficiency.

Project 6: New Investment Recovery Building



The new Investment Recovery (IR) building was completed in 2016. It created a new home for our recycling crews that deconstruct, sort, and catalog all applicable Avista components that field crews bring back from their daily work orders. This includes Avista crews not only local to Spokane, but also all other satellite service centers, who ship their recyclable materials back to this new building. Previously, IR was housed in a building approximately 25 years old. The customer benefits for this facility include better reliability and lower cost of service due to enhanced and efficient material handling of recyclable products currently within the Avista electric and gas field infrastructure. In fact, if some products pass inspection, they are re-stocked in the warehouse for future re-use, rather than being diverted to a landfill. Upon completion, this project has provided annual cost savings in employee and operational efficiencies, as well as non-quantifiable safety benefits, below:

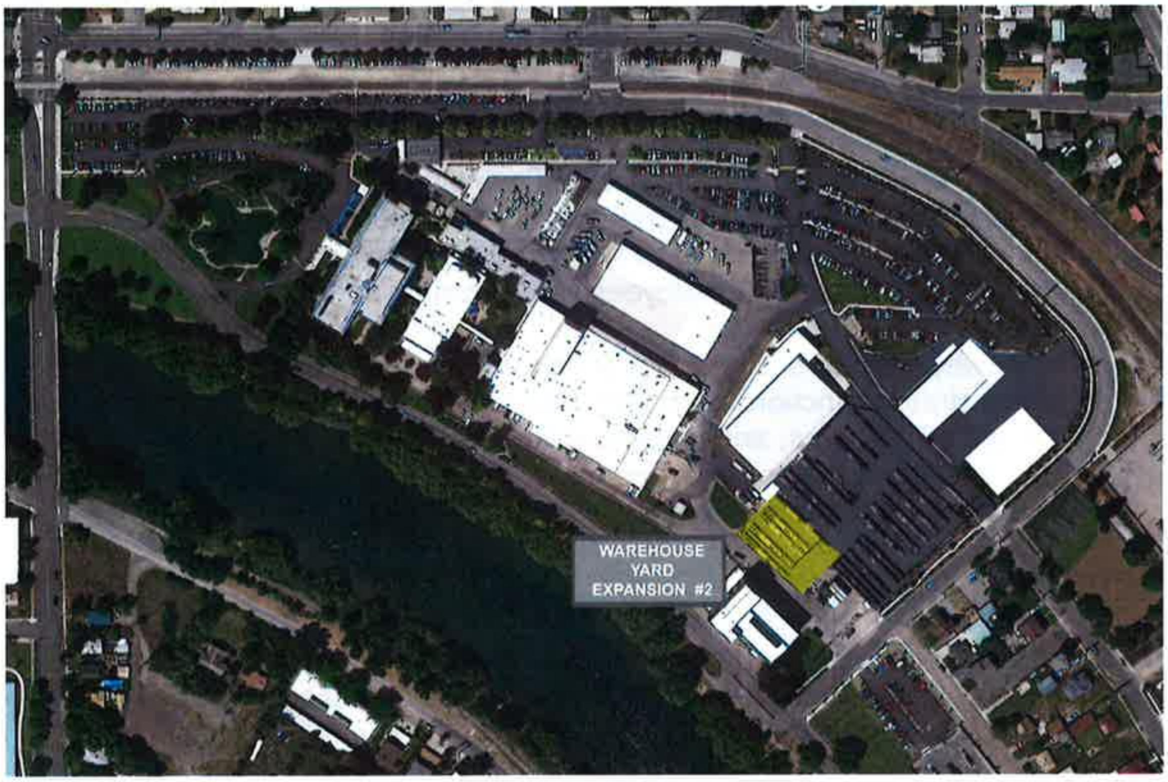
- Warehouse employees on forklifts will no longer need to cross N. North Center to get materials from storage yard across the street.
- Since crew trucks will no longer need to enter gate 5, drop off at IR, exit gate 6, go back out on N. North Center, and re-enter gate 5, the potential for costly accidents on N. North Center will reduce.
- IR crews will no longer work in the main service truck travel path, reducing the risk for a costly accident.

Campus Repurposing Phase 1

Projects 7 and 8: Spokane Construction and GPSS Office Remodels

The Spokane Construction and Avista Generation, Production and Substation Support (GPSS) office remodels were completed in 2016. A denser cubicle arrangement created new employee workspaces, and the existing 30+-year-old HVAC and electrical systems were replaced with newer, more efficient equipment. The customer benefits for this remodel include increased efficiency due to allowing administrative functions to remain consolidated on one campus, rather than being scattered amongst multiple buildings around the region. Upon completion, these projects provided quantifiable and non-quantifiable benefits in additional space and facilities energy and maintenance savings.

Project 9: Warehouse Storage Yard Expansion #2



The Warehouse Yard Expansion #2 project is schedule to complete in the first half of 2017. It will increase the size of our current warehouse exterior storage yard and consolidate many materials and equipment that were previously stored in inconvenient, inefficient "pockets" on the corporate campus. The customer benefits for this facility include better response time and reliability due to enhanced and efficient storage and material handling of products currently within the Avista electric and gas field infrastructure. Upon completion, this project is expected to provide quantifiable and non-quantifiable benefits in employee efficiency warehouse storage.

OPTION 2 – PURCHASE ALTERNATE SITES ELSEWHERE FOR VARIOUS NEEDS

Due to the issues outlined in the "Business Problem," another possible option would be to move some functions currently taking place at the corporate campus and relocating them elsewhere, thus freeing up space. However, this would be disadvantageous and create several possible risks.

Any new site purchased should be large enough to create another campus, so that Avista facilities can be secured and maintained at one site. This would require a lot possibly around 10 – 20 acres in size. As such, an available lot that size would probably need to be procured outside of Spokane city limits, and possibly in undeveloped county land. The capital costs to purchase a lot and address basic infrastructure needs (paved street access, water, sewer, electric, gas, etc.) could run into several million dollars. Any new facilities on the new site would come at an additional cost, which could vary based on design. For the projects mentioned in Option 1, it can be assumed that approximately the same $25 million cost could be expected at the new site.

However, there would be strong internal resistance to this “alternate site” model due to the fact that inefficiencies of work crews, deliveries, material handling, drop-off’s, etc. would be conducted at two different sites, with travel times for crews unknown. In addition, there are definitive efficiencies with field crews being adjacent to their administrative support employees. In this option, all administrative support employees would remain at the corporate campus.

However, to solve this, another option is if the ENTIRE corporate campus (field & administrative functions) were to move to a new site. This would require a site of at least 30-35 acres, and would require rebuilding ALL buildings and facilities that are currently at the corporate campus. The cost estimate for this option, at a very high level, would approach $400 million.

OPTION 3 – DO NOTHING

If none of the projects outlined in Option 1 were started, then all of the issues outlined in the “Business Needs” section would still need to be addressed over time. At a very high level, the list below brainstorms possible ideas to accommodate the issues.

- Employee space needs
  - Renting office space, purchasing off-site offices?
  - Risks: Decreased adjacency efficiencies, rental or purchase market costs, new maintenance at a new facility.
- Improving safety and efficiency of campus traffic flow
  - Build new roads, pathways, fence and gate systems, and controlled access points throughout the campus that would help separate these traffic patterns?
  - Risks: Increase in accidents - vehicular, pedestrian, or other.
- Outdated warehouse / stores space and processes
- Outdated Hazardous waste & materials space and processes
- Outdated transformer oil recovery space and processes
- Outdated investment recovery space and processes
  - For all four above: no building changes, keep their spaces as-is. Year-by-year increase in capital and maintenance costs to keep their spaces as functional as possible.
  - Risks: Catastrophic failure of any one of these structures would require a spike in capital or maintenance costs in any given year.
- Lack of materials storage yards, no short-term flexibility.
  - Materials would continue to be scattered around the corporate campus. Eventually materials may need to be shipped and stored off-site at a rented or purchased site.
  - Risks: Forklift traffic accidents crossing public streets. Material needed in an outage may be off-site. Decreased efficiency due to off-site travel.

Campus Repurposing Phase 1

- Alignment of campus parking and number of employees based at main campus
  - Rental of office space or purchase of off-site offices would hopefully include additional parking.
  - Purchase additional land off-site and develop into a parking lot. May need to look at an "employee shuttle" situation at a one-off parking lot since it may be too far away from the corporate campus.
  - Risks: Supply will continue to not meet demand. Employees may not use parking options, may continue to park in adjacent residential neighborhood. Additional maintenance costs of additional asphalt parking lots.

Campus Repurposing Phase 1

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: Date: 5/1/17

Print Name: Eric Bowles

Title: Manager, Facilities

Role: Business Case Owner

Signature: Ann 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

VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1	Vance Ruppert	4/18/2017	Heather Rosentrater	04/25/17	New template

Template Version: 02/24/2017

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

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:




3 PROPOSAL AND RECOMMENDED SOLUTION

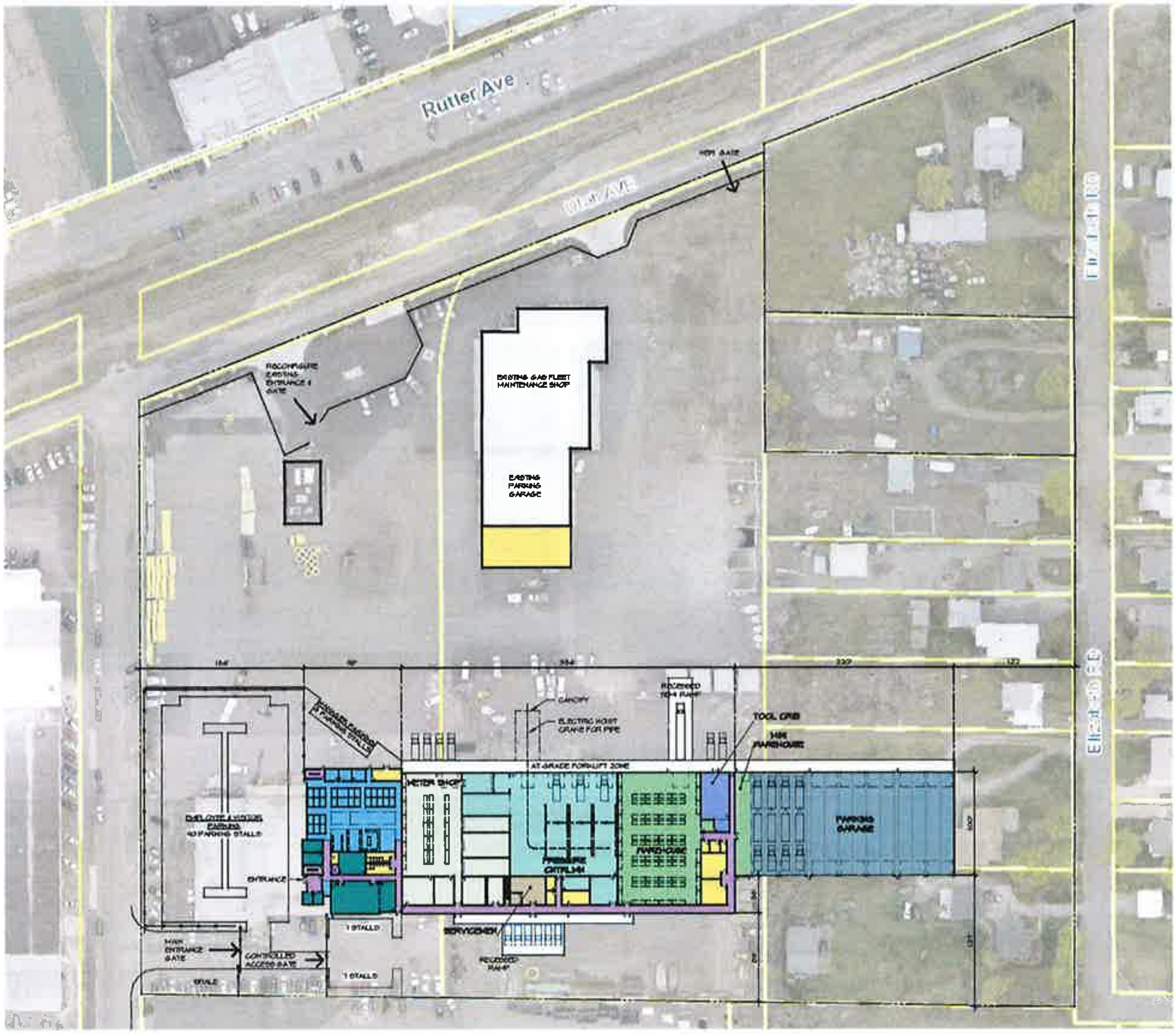
Option	Capital Cost	Start	Complete
Option 1 (Recommended) – Demolish existing building and build new Service Center on existing property.	$24,000,000	01/2016	12/2018
Option 2 – Purchase new property/site and build new Service Center.	$37,000,000 (approx.)	01/2016	12/2018
Option 3 – Do nothing, keep using 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 <u>all</u> three options.

<u>Option 1 – Demolish existing building and build new Service Center on existing property</u>

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.

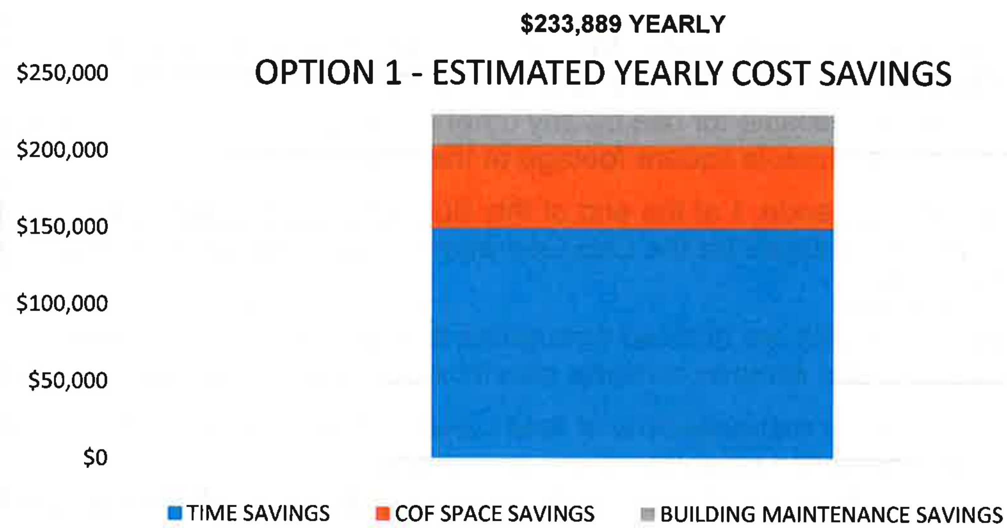
New Dollar Road Service Center



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

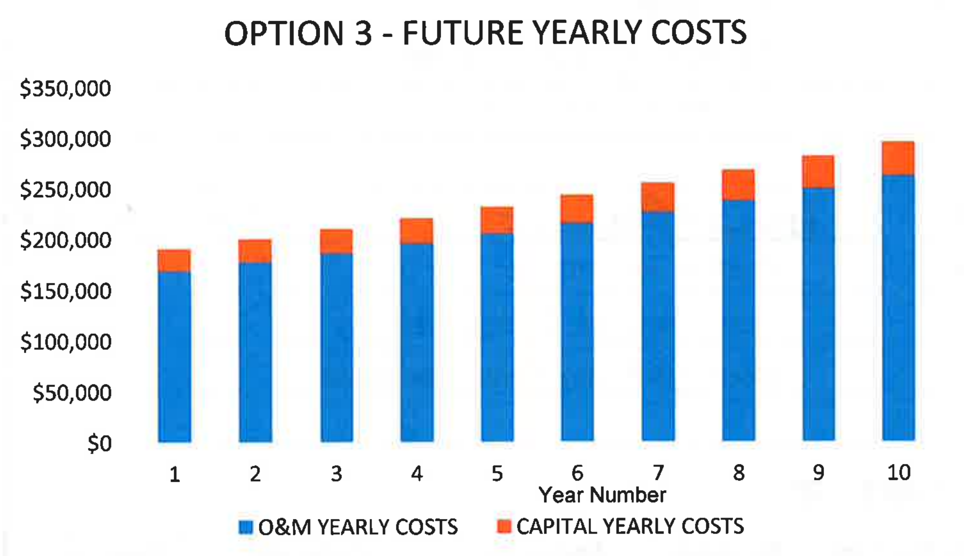
Facilities explored relocating the gas operations to an alternate sites, with the intent to build a facility similar to Option 1 above. In addition, the new site would have to build a new Fleet Maintenance Building and Vehicle Storage Building to replace their uses currently on the existing site. The 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.

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

Signature:	A Scarlett	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		

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.)

- 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.

Davenport Service Center

1 GENERAL INFORMATION

Requested Spend Amount	$6,500,000
Requesting Organization/Department	Facilities Management
Business Case Owner	Eric Bowles
Business Case Sponsor	Bryan Cox
Sponsor Organization/Department	Electric Operations
Category	Project
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The Facilities Department engaged with our Electric Operations and Environmental groups to determine the future of some of our legacy sites. They looked at a large number of items before determining the future of the Davenport Service Center. The team reviewed environmental impacts and regulations, future service center needs and the growth and needs of the Davenport Community.

Eric Bowles, Facilities Manager

Kevin Booth, Sr. Environmental Scientist

Bryan Cox, Dir. Transmission and West Electric Operations

Greg Gfeller, Director of East Electric Operations

Laurie Heagle, Materials Management Manager

Steve Aubuchon, Past Davenport Manager

Kelly Donohue, Current Davenport Manager

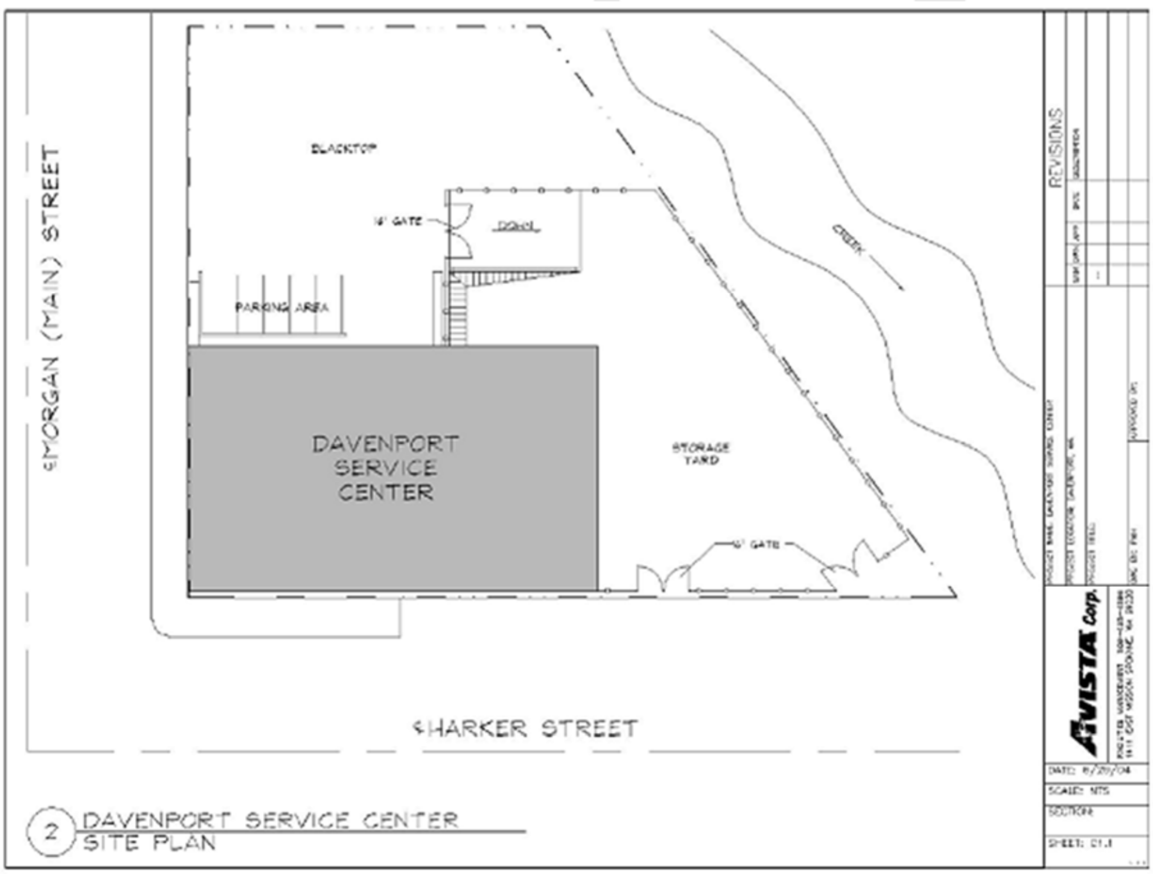
2 BUSINESS PROBLEM

The existing Davenport Service Center was purchased in 1966 for $23,000 from a local car dealer. A major remodel was completed in 1969-1970. Since 1966 Avista has invested $480,000 in the Davenport facility. Some of the upgrades include additional lighting and the installation of a corporate network as well as a roof replacement HVAC upgrade. The last of these upgrades were completed back in 2000. The pole storage area on site was removed in 1981 and relocated to a yard northeast of Davenport. A metal building was constructed at that location in 1989 and a concrete floor was added to the building in 1990. The majority of large storage items are stored at the Pole Yard site now.

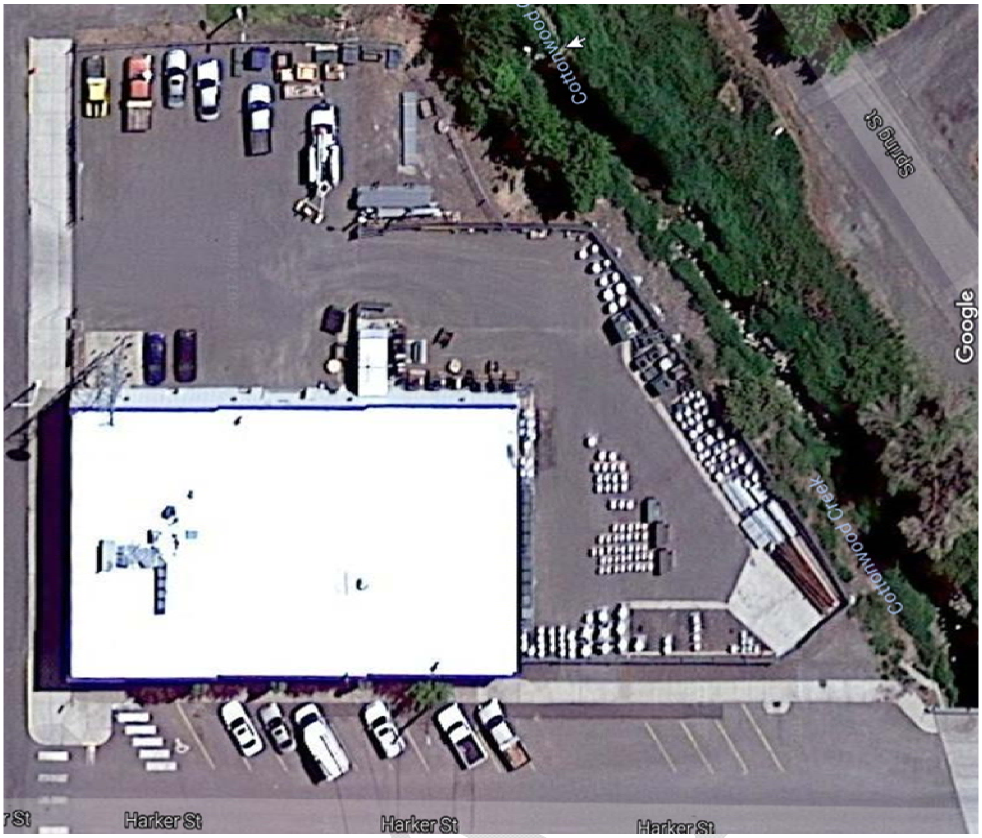
The crew currently travels to the pole yard each morning to get their line trucks, as the vehicles will not fit in the existing service center building. The current garage bay is too small for today's vehicles and would need extensive renovation to be useable. There is also not enough storage for them on site as the current property is limited an only 0.69 acres. Poles and other large vehicles are also stored at the pole yard due to the lack of storage space. The pole yard is located just under two miles from the Service Center. There are continual trips back and forth between the pole yard and the Service Center daily. These constant trips impact crew's ability to get out into the field in a timely fashion.

The Avista Environmental Department has determined that transformers should not be stored at the Davenport Service Center due to the bio-infiltration array behind the facility, adjacent to a local creek. To store all the transformers at the existing location additional environmental controls would need to be installed to protect the existing creek that runs behind the building. These materials are currently stored in the metal building at the pole yard location. Crews travel to and from the pole yard to get these larger materials, while the smaller items they need to do their work are stored at the service center.

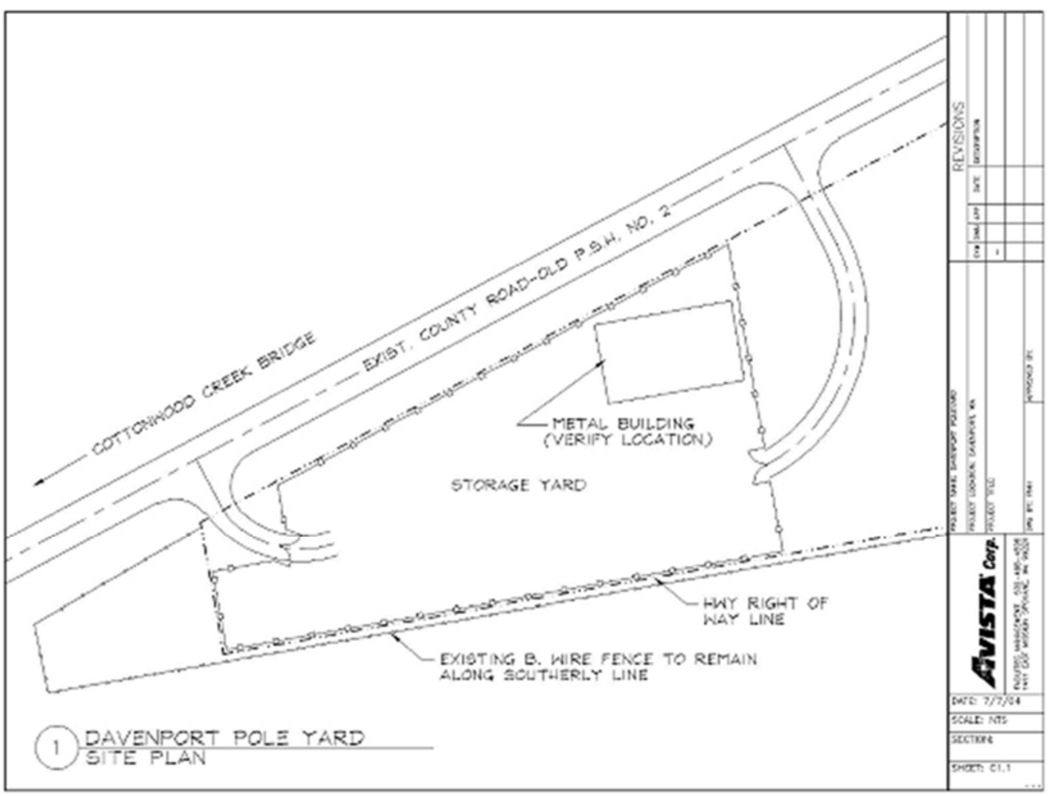
Davenport Service Center



Davenport Service Center



Davenport Pole Yard



Davenport Service Center

The building had a complete survey completed in 2012. In that survey many items were identified that needed immediate replacement or repair. A new survey is to be completed in 2017 and the business case will be updated with the most current information as it is available. A few of the larger items are noted below.

The Site has damage to the concrete sidewalks and paving and needs replacement. There is also extensive damage to the fencing that needs repair and replacement.

Davenport Service Center


Structurally there is damage to a support beam in the garage area where a line truck hit. It has been confirmed to be safe but needs repair. The new trucks are much larger than the building was designed for and damage like this will continue as there is no way to remove the structural element.

The exterior of the building needs extensive work. The building is in need of paint and the roll up doors and old inefficient windows need to be replaced. The exterior lighting is inefficient and need to be improved.


The interior of the building is in disrepair. There is a large amount of drywall work that needs repair and paint. The lighting needs to be updates to either T-8 or LED's. The Hot Water heater is in need of replacement. There is no Fire Safety System at the Davenport Service center, this is considered a critical failure and would need to be rectified if a new building is not built.





3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
New Davenport Service Center	$6,500,000	03 2019	12 2019
Davenport Renovation Project	$850,000	03 2019	08 2019

The proposed solution to the business problems identified above is to build a new Service Center. The New Service Center will possibly be located at the pole yard property which Avista currently owns approximately 2 miles to the east. We would also like to research purchasing a new vacant property that we could locate both the new service center and the pole yard. This option would allow us to find a property that could allow for any future growth needed.

The New Service Center, regardless of location, will include environmentally protected transformer storage areas and adequate storm water protection. This includes oil water separators for the entire facility. This is the new Environmental standard for design for Avista and meets the legal requirements as well. The new facility will centralize all of Avista crew functions into one location, saving windshield time each day for the crew.

The new service center would be designed to meet the needs of today's employees and would meet current code requirements. All the building systems would be designed to today's technology and planned to be more efficient than the existing location.

The current building could be sold to offset some of the cost of building new.

Alternatives:

In order to avoid constructing a new Davenport Service Center Avista would need to continue upgrading the existing Service Center building. The existing Service Center was formerly a car dealership and we guess the building was constructed in 1940's. In order to get line trucks inside the existing facility substantial structural remodeling would be in order. We would need to restructure the trusses of the building and make substantial structural changes to account for the truck height to store them in the building.

Cost to renovate the existing Facility for line trucks to fit and install adequate environmental controls to protect the creek and make structural changes to make use of the basement storage area would be at least $850,000. It seems much more desirable to invest the money in a new facility that will be functional for the next 50 years. O&M expenses could be greatly reduced by constructing an energy efficient facility with digital controls.

We would possibly need to purchase the adjacent Car Wash property to provide more yard space for storage to reduce the need to travel to the pole yard location. The property is currently not available but would provide an additional 0.25 acres to the lot.

4 APPROVAL AND AUTHORIZATION

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

Signature: ______________________ Date: __________

Print Name: Eric Bowles

Title: Facilities Manager

Role: Business Case Owner

Signature: ______________________ Date: __________

Print Name: ______________________

Title: ______________________

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	*Lindsay Miller*	*03/14/2017*	*Eric Bowles*	*03/17/2017*	*Initial version*

Template Version: 03/07/2017

Noxon and Clark Fork Living Facilities Renovation

1 GENERAL INFORMATION

Requested Spend Amount	$2,950,200
Requesting Organization/Department	Facilities
Business Case Owner	Rod Staton/ Eric Bowles
Business Case Sponsor	Anna Scarlett
Sponsor Organization/Department	Shared Services
Category	Project
Driver	Asset Condition

2 STEERING COMMITTEE OR ADVISORY GROUP INFORMATION

2.1 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 Generation Production Substation Support
- Manager of Shared Services
- Manager of Project Delivery
- Manager of IT Delivery
- Manager of Facilities

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

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

- Vice President of Energy Delivery
- End Users

3 BUSINESS PROBLEM

The Clark Fork and Noxon Living Facilities were constructed in 1983 and 1984 and have been in use for more than 30 years. The facilities are 16-room bunkhouses designed in a similar fashion to a motel with two wings, with each wing containing 8 rooms and a central common space containing a kitchen, dining hall and laundry facility.

Because of the limited availability of lodging in this rural area, Avista crews and personnel lodge at these facilities when performing work at Noxon Rapids Dam, Cabinet Gorge Dam, or on other Avista equipment in the area. Employees who perform work on the dams during the work week reside in the bunkhouse during the evenings. The living facilities are strategically located adjacent to the dam to maximize the time spent doing critical maintenance work.

With our aging infrastructure, work is currently ongoing at both dams and is planned to continue for the foreseeable future in the form of maintenance and upgrade projects. This work is essential to maintaining the reliability of our power generation and associated infrastructure in the region.

In 2015, Facilities Management was asked to evaluate the condition of the Clark Fork and Noxon Living Facilities by the GPSS department. Eric Bowles (Corporate Facilities Manager) and Rod Staton (Facilities Project Manager) traveled to the two sites and stayed in the rooms to evaluate the overall condition of the facilities and to experience the conditions first hand. Interviews were conducted with employees that were staying in the rooms to receive feedback. Photographs were taken of the facilities and a list of possibilities was put together to discuss with sponsors and stakeholders. (See Appendix).

During these inspections, extensive issues were found, including structural and water damage to the siding and framing due to faulty construction and subsequent water penetration, inadequate and antiquated electric heating systems, HVAC deficiencies, non-compliant electric breaker panels and inadequate insulation. Subsequent inspections exposed black mold and mildew caused by water penetration in parts of both facilities.

Upon sharing the facilities assessment with the sponsors and stakeholders it was decided that the next logical step would be to create a project to address the problems discovered at the living facilities. Bernardo Wills Architects of Spokane was hired to recommend the level of modernization needed to address the concerns found during the site assessment, and create the scope of work needed to renovate the facility. (See Appendix for concerns raised during the site assessment.)

4 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 (Recommended) – Remodel & correct all issues at both existing facilities at one time.	$2.95M	April 2016	Dec 2017
Option 2 – Address deferred maintenance issues individually over time as individual projects over a five year period.	$2.95M	April 2016	Dec 2021
Option 3 – Do Nothing	$0	-	-

Option 1 (Recommended) – Remodel & correct issues at both facilities.

The selected alternative includes the significant renovation of the living facilities at Clark Fork and Noxon to address the identified problems and components to extend the life of the facilities and update the facility to a more modern and energy efficient state. This alternative combines the required repair work with the facility renovation to avoid duplicating efforts and saving costs on contractor mobilization and re-work. The completed facilities would provide years of additional service, increase the efficiency of energy usage, reduce annual O&M costs to maintain the structures, and provide a suitable environment for housing our workforce at these remote sites.

With a centralized workforce based out of Spokane, it is critical to provide lodging near our worksites to best utilize available working hours. These living facilities are utilized by Avista maintenance crews and engineering personnel when performing work at Noxon Rapids Dam, Cabinet Gorge Dam, or other Avista equipment in the region. Both Noxon Rapids Dam and Cabinet Gorge Dam are in very rural and isolated areas. Options for lodging are extremely limited, with Sandpoint or Thompson Falls being the nearest towns. Travel time from these towns would limit the efficient use of crews for work at these facilities. Without the continued availability of the living facilities, it's estimated that it would cost $316,200 annually to procure lodging at alternate sites for work at the plants. Over a 20-year period, the annual cost to procure alternative lodging would exceed the total cost of the project by more than double.

The scope of the remodel project includes each of the 16 individual guest rooms, bathrooms, kitchen, dining room, activity room, lobby, laundry room, office, basement and building exterior. This work would extend the life of these facilities and update them to a more modern and efficient state. Interior scope work includes: full bathroom remodels, HVAC replacements/installs, window trim replacements, lighting upgrades, new flooring/trim/paint, new cabinets, countertops, & furniture, replacement of hot water heaters, new door handles & locks, and more. The exterior scope of work includes repair of termite/rot damage, re-siding, new paint, installation of snow guards & gutters, replacement of exhaust fans/vents, and more.

During each construction period, the facility being worked on will be unavailable for use until the first wing of eight rooms and the common areas are completed. Once constructions moves to the second wing of eight rooms, the facility will become available at half capacity. Crews working in the region will be required to utilize the other living facility until capacity is reached and make other arrangements after that point.

Option 2 – Address issues with multiple projects over 5 years.

This option spreads the cost of correction over a 5-year period. The mold and mildew issues would be addressed first and the additional items would be addressed systemically over time. The major argument against this approach is the down time in room availability while the work is occurring. Each discovered issue needs time to be addressed in both facilities, requiring prolonged periods of time where the rooms would unavailable to the crews. This option would drive up hotel room costs to accommodate work at the living facilities. The other major issue with this option is the staging of the work. Many of the discovered issues require substantial demolition to complete the work. There is a cascading effect and a logical order to trade stacking, creating logical work flow, this option does not afford the stacking of trades to create efficiency.

Option 3 – Do Nothing.

Disregarding the water penetration is not an option as this would render portions of, and eventually the entire facility, uninhabitable over time. The lack of available living facilities would inhibit plant maintenance and upgrade work resulting in increased project costs and customer rates.

This option is unacceptable due to health issues associated with mold and mildew.

Noxon and Clark Fork Living Facilities Renovation

The discovery of significant design flaws and inadequate construction materials increases the need to respond immediately. Facility assessment provided by Facilities Management and Bernardo Wills Architecture note significant issues that must be addressed to halt further decline of the facilities and to meet the current (UBC) Uniformed Building Code requirements. The level of deferred maintenance must be addressed to prevent additional cost to repair in future years. The damage increases over time and cost to address the concerns will increase with inflation.

5 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Jack Stewart Training Center Expansion & Enhancement 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: 5/23/17

Print Name: Eric Bowles

Title: Manager, Facilities

Role: Business Case Owner

Signature: A Scarlett Date: 5/23/17

Print Name: Anna Scarlett

Title: Manager, Shared Services

Role: Business Case Sponsor

Signature: Date: 5/23/17

Print Name: Heather Rosentrater

Title: Vice President, Energy Delivery

Role: Steering/Advisory Committee Review

6 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Rod Staton	5/19/2017	<name>	mm/dd/yy	Initial version

Template Version: 03/07/2017

APPENDIX

- Major structural damage to the siding and framing members due to faulty roof flashings installed at time of construction. Demolish lower room exterior walls, check for black mold, remediate black mold, repair damage, and replace materials.
- Inadequate and antiquated electric resistance wall mounted heating systems in each bathroom (manual controls only) and no GFI Receptacles.
- Air conditioning was not installed in the rooms at the time of construction, which is particularly difficult for crews during hot summer months.
- Electric breaker panels serving the facility are grossly undersized and must be replaced with code compliant panels.
- Highly undesirable shared hot water tanks installed in the upstairs rooms in hidden closets causing major water damage in the ground floor units due to tank leaks.
- Inadequate insulation (sound bats) between each unit producing high levels of sound transmission between the units.
- Life cycle failure (age) found in faucets, mixing valves and toilet hardware due to water alkalinity and mineral build up.
- R-19 insulation found in the ceilings of the entire facility, should be R-38 by energy code.
- Poor to no cell phone reception in individual rooms, limiting contact with family members during the week.
- 19" televisions in each room with terrible picture quality and audio.
- Metal Roofing panels that have reached the end of their expected life cycle, resulting in leak points due to product failure.
- ¾ inch X 4' X 8' vertical grain fir plywood siding that has failed at each gable end, with numerous intermittent panels failing on the front and rear of the building. Substantial damage occurring in 30% of the siding structure. Siding has exceeded expected life cycle, must be replaced. Original siding design was not compatible to local climate and moisture content.
- Numerous dings and chips in drywall, door trim and base moldings.
- Extreme water damage to front and rear fascia boards, must be replaced.
- Soffit material water damaged due to exhaust fans from individual units being inadequately vented to the exterior gable end wall.
- Tile and grout in each room showing considerable age and replacement is warranted due to wear.
- Bed frames of original vintage; highly uncomfortable and noisy.
- 1/2" copper plumbing runs have significant constriction due to mineral build up, replace all plumbing lines with new runs.
- Light fixtures are original era and should be replaced with energy efficient LED fixtures for energy savings.
- Replace exhaust fans with properly vented pipes exiting at gable ends; currently piped into the soffits and vented onto public walkway.
- Carpet has exceeded useful life. Replace carpet in each room.

- Kitchen countertops are chipped, broken and many have separated from the cabinet substrate. Replace all counter tops with commercial grade material.
- Cabinet hinges are broken and in disrepair, particle board cannot be repaired, replace cabinetry.
- Kitchen flooring material is vinyl sheet goods. Torn and tattered beyond useful life, replace with commercial grade tile for longevity.
- Snow sheds from roof falling 18' to the ground level entrances to lower rooms. Construct a retaining wall to protect employees from falling snow.
- 14' x 18' rear deck adjacent to dining hall is rotten and must be demolished. Replace with roof covering and install concrete pavers at ground level.

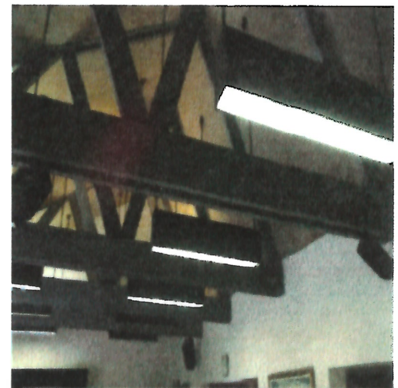
PHOTOGRAPHIC ASSESSMENT

Noxon and Clark Fork Living Facilities Renovation








Sandpoint Service Center

1 GENERAL INFORMATION

Requested Spend Amount	$5,500,000
Requesting Organization/Department	Facilities
Business Case Owner	Eric Bowles
Business Case Sponsor	Bryan Cox
Sponsor Organization/Department	Electric Operations
Category	Project
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

The Facilities Department engaged with our Electric Operations and Environmental groups to determine the future of some of our legacy sites. They looked at a large number of items before determining the future of the Sandpoint Service Center. The team reviewed environmental impacts and regulations, future service center needs and the growth and needs of the Sandpoint Community.

Eric Bowles, Facilities Manager

Kevin Booth, Sr. Environmental Scientist

Bryan Cox, Director of Transmission and West Electric Operations

Greg Gfeller, Director of East Electric Operations

Laurie Heagle, Materials Management Manager

Jim Kane, Sandpoint Manager

2 BUSINESS PROBLEM

The Sandpoint Service Center Facility was acquired in 1995 for $181,483. We are unsure of the original construction date. Since that time Avista has invested $514,423 in capital improvements to the Facility. Major maintenance upgrades include a new roof and an asphalt overlay in the service yard. The site has many issues and concerns that are forcing us to make an investment in the site or a new location.

The building had a complete survey done in 2012. In that survey many items were identified that needed immediate replacement or repair. A new survey is to be completed in 2017 and the business case will be updated with the most current information as it is available. A few of the larger items are noted below.

The Site has extensive damage to the concrete sidewalks and paving and needs replacement. The fencing requires extensive work and has a lot of damage.

Sandpoint Service Center

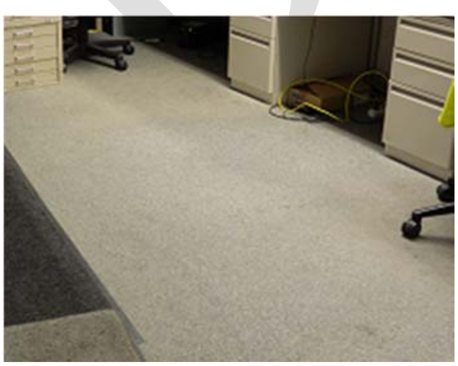





The roll up doors are in need of extensive work. They are damaged and some are in need of replacement.



The interior flooring is in need of replacement and is beyond repair.



Emergency exit lighting and a smoke detection systems are missing from the building. This is a critical failure and would need to be rectified if a new building is not built.

The existing building has minor code compliance and security issues. The interior of the main building is in need of an update and possibly a large reconstruction or renovation. The layout is no longer conducive to today's business needs. There a many ADA issues and much of the construction does not comply with current code. Many of the building systems are antiquated and have reached the end of their useful life.

The existing storage yard is becoming too small for ever-growing inventory. Currently we have done everything we can to capitalize on the existing storage space available. The property is too small for our needs and we are unable to purchase any additional land adjacent to the existing property.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete	Risk Mitigation
Do nothing	$0	N/A		
New Sandpoint Service Center	$5,500,000	03 2019	12 2020	
Sandpoint Renovation	$550,000	03 2019	08 2020	

In order to prepare the area for the next 50 years of service, we are asking to invest $5,500,000 for a new lot and building. We propose constructing a new line dock facility, covered storage buildings for expensive equipment. Provide modernized offices, meeting rooms, and mini warehouse. The entire Facility will be fenced and card reader access gates installed. The HVAC systems will be modernized and this should result in significant energy savings.

The proposed solution to the business problems identified above is to build a new Service Center. The New Service Center will be located on a new vacant property that we could locate both the new service center, the pole yard and warehouse. This option would allow us to find a property that could allow for any future growth needed.

The New Service Center, regardless of location, will include environmentally protected transformer storage areas and adequate storm water protection. This includes oil water separators for the entire facility. This is the new Environmental standard for design for Avista and meets the legal requirements as well. The new facility will centralize all of Avista crew functions into one location, saving windshield time each day for the crew.

The new service center would be designed to meet the needs of today's employees and would meet current code requirements. All the building systems would be designed to today's technology and planned to be more efficient than the existing location.

Sandpoint Service Center

The current building could be sold to offset some of the cost of building new.

Alternatives:

In order to avoid constructing a new Pullman Service Center Avista would need to continue upgrading the existing Service Center building. This would include several hundred thousand dollars' worth of upgrades and improvements. Purchasing additional properties and expanding the service center is not an option. Hills and grading difficulties will cost hundreds of thousands of dollars any time we were to increase the yard by even a little bit. We would need to purchase land in another area of town and create an additional storage yard. This would require that crews drive to and from this new storage yard several times a day and does not seem like a good business decision.

4 APPROVAL AND AUTHORIZATION

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

Signature: ______________________ Date: __________

Print Name: Eric Bowles

Title: Facilities Manager

Role: Business Case Owner

Signature: ______________________ Date: __________

Print Name: ______________________

Title: ______________________

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	*Lindsay Miller*	*03/14/2017*	*Eric Bowles*	*03/17/2017*	*Initial version*

Template Version: 02/24/2017

Facilities Structures and Improvement

1 GENERAL INFORMATION

Requested Spend Amount	$3,000,000
Requesting Organization/Department	Facilities
Business Case Owner	Eric Bowles, Facilities Manager
Business Case Sponsor	Anna Scarlett, Shared Services Manager
Sponsor Organization/Department	Shared Services
Category	Program
Driver	Asset Condition

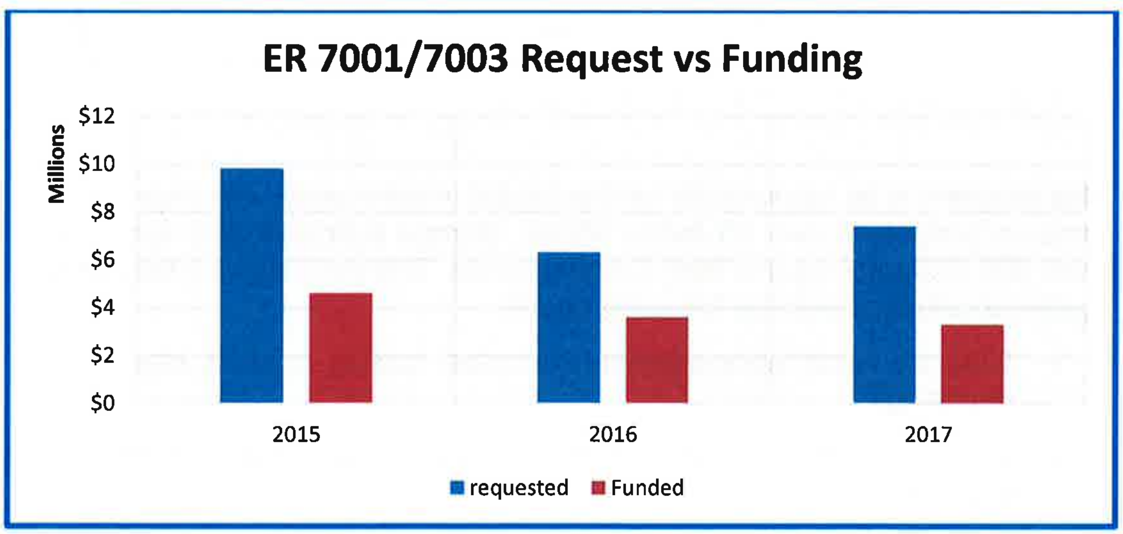
1.1 Steering Committee or Advisory Group Information

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.

In 2011, Facilities prepared a survey of several of our existing sites that created an Asset Condition score. This survey is the basis for prioritizing asset lifecycle replacements and site improvement projects (See attached for survey results).

A new site assessment survey is currently underway with an independent contractor and should be completed in 2017. This will be the basis for the asset replacement program over the next 10 years.

Total combined requests have been considerably higher each year than funding, and valid projects are often times backlogged.



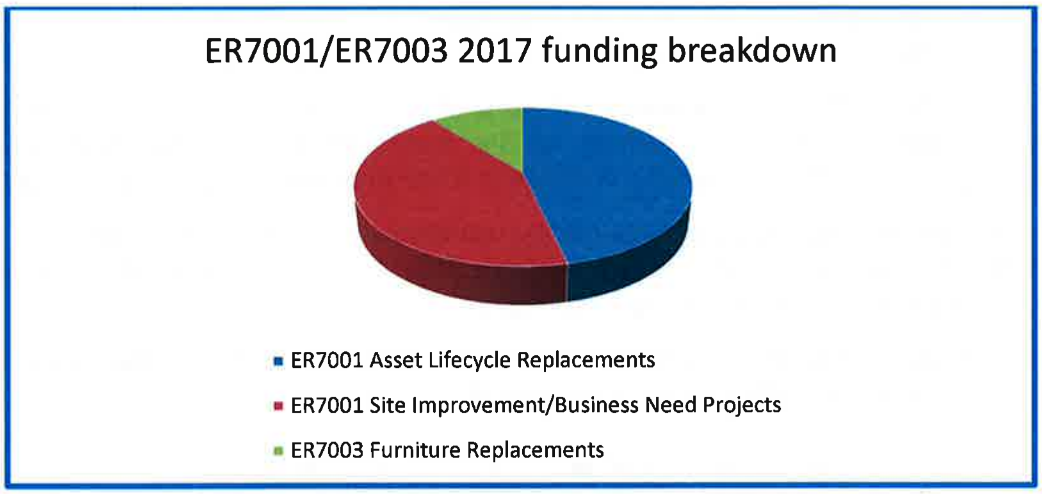
Funding backlog

Once the project list is assembled, it is vetted for approval by a stakeholder group at the next level of management familiar with the individual requests, (usually at the Director level). In the past this has most often been:

- Director of Facilities,
- Directors of East and West Operations,
- Directors of Generation, Transmission, and Gas (when applicable).

2 BUSINESS PROBLEM

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. 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.



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.)

Facilities Structures and Improvement

This program would encompass capital projects in all construction disciplines (roofing, asphalt, electrical, plumbing, HVAC, landscaping, expansions, remodels, energy efficiency projects).

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete	Risk Mitigation
Option 1 (Recommended) – Fund at existing levels.	$3M	01 / 2017	01/2022	Many of the issues on the list can quickly become safety issues if not addressed, exposing the company to risk.
Option 2 – Partially Fund Program	$1M Capital and $1M O&M	01 / 2018	01/2022	Capital investments can be limited with a corresponding increase in O&M dollars. As building systems continue to decline O&M burden will increase.
Option 3 – Do nothing	$0	Sites will continue to decline due to normal wear and tear. Certain systems (ex: roofing) failing can cause major damage to other areas of the building. Safety issues due to walkways and structural issues not being addressed.		

Option 1 – Fund Program at Current Level (Recommended)

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.

This Structures and Improvements program will be made up of 3 main parts:

1. Capital 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.

Facilities Structures and Improvement

Examples (asphalt and structural issues):

2. 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.

Examples:

3. 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.

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.

Option 2 – Partially Fund Program based on priority

This option would decrease the capital program and increase existing O&M budgets to prolong structures' lifecycles beyond rated life, and reduce capital needs. This option is not the preferred approach 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.

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.

Option 3 – Do nothing

This option is not recommended. 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.

4 APPROVAL AND AUTHORIZATION

Facilities Structures & Improvement

The undersigned acknowledge they have reviewed the ~~Airport Hangar~~ 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:	Facilities Manager		
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 member		

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: 02/24/2017

Capital Tools & Stores

1 GENERAL INFORMATION

Requested Spend Amount	$2,400,000
Requesting Organization/Department	Supply Chain
Business Case Owner	Glenn Madden, Manager, Supply Chain
Business Case Sponsor	Anna Scarlett, Manager, Shared Services
Sponsor Organization/Department	Shared Services
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

Budgeting for Avista's Capital Tool Program is projected for five years based on historical spends and prioritized against other company budget needs by Avista's Capital Planning Group (CPG). Midway through every year, business units analyze their need for tools and equipment to be purchased during the next fiscal year. Each year the Capital Tool Program has more requests for tools and equipment than can be funded (see Figure 1). The requests are prioritized by Safety and Compliance, Replacement, or Enhanced Productivity categories. Cuts to the requests are made by the business units to bring the projected cost of the list of equipment and tools into line with the budgeted amount. Review of the request is performed by Avista's CPG who may modify the funding level for the program in concert with other business budget needs. Additional cuts by the business units to the Tools and Equipment budget may be needed to meet the revised budget.

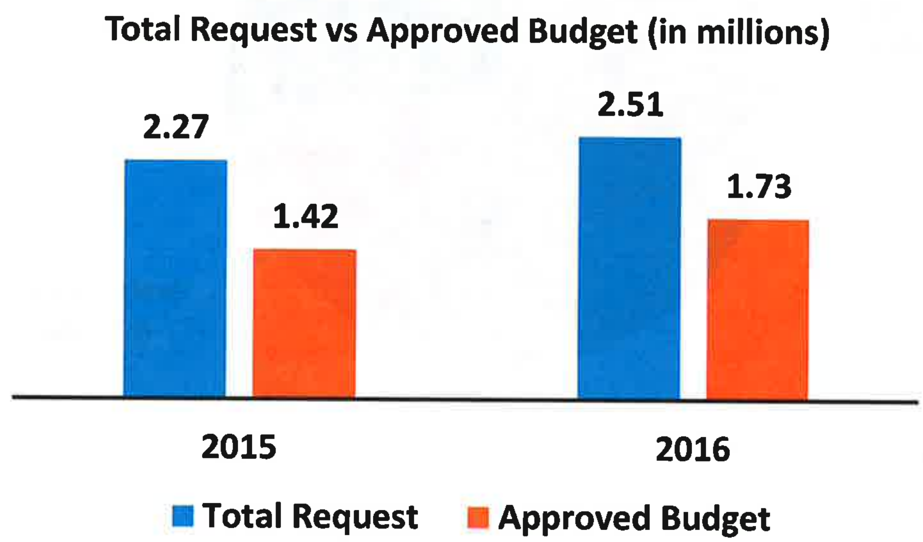


Figure 1

Capital Tools & Stores

Purchasing and oversight of this program is by the Supply Chain Department. The approval process follows the management chain of Supply Chain Manager, Manager of Shared Services, Vice-President of Energy Delivery, and President of Avista Utilities. The Capital Tools Program does not have a steering committee but does have stakeholders who are the managers and directors of all departments.

2 BUSINESS PROBLEM

Avista's Capital Tool Program provides all departments the proper tooling and equipment to perform work safely and efficiently. This equipment is necessary to safely construct, monitor, ensure system integrity, and properly repair and maintain the Avista systems (electric, gas, communications, fleet, facilities, and generation). Tool and equipment purchases are prioritized based on three categories:

1. Safety and Compliance
2. Replacements
3. Enhanced Productivity (see Figure 2)

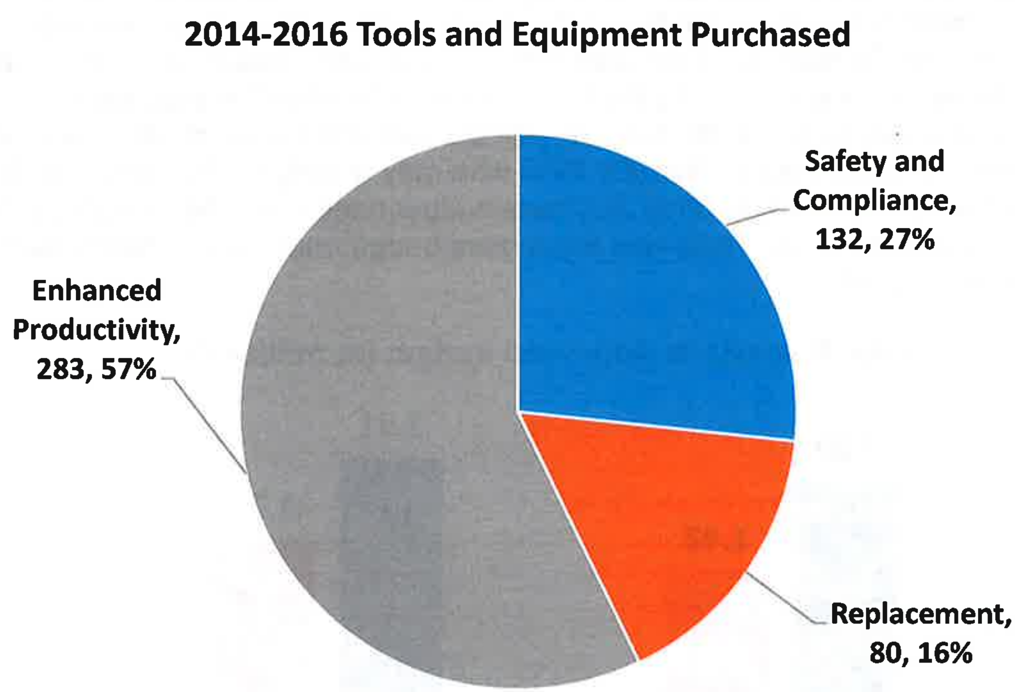


Figure 2

The highest priority tool and equipment purchases help ensure that Avista meets all safety and compliance requirements. Changes to safety standards and new compliance mandates may require purchasing new tools. Examples of tools and equipment purchased for safety and compliance reasons are:

- Ergonomic tooling such as battery cutters/presses/pole grounding staplers, vibration reduction pole tamps
- Manhole extrication devices, rescue mannequins and Automatic External Defibrillators (AEDs)
- Grounding equipment - such as mechanical grounding jumpers, equipotential grounding mats, and voltage indicators needed to support Avista's new Electro Potential Zone (EPZ) grounding program
- Groundhound site safety device - measures variances in ground voltage, alarming workers of hazardous ground potential rises preventing shock hazards

The next highest priority tool and equipment purchases are to replace existing tools that have reached their end of life. 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 can lead to hazardous conditions for the operators, potentially causing injury or death.

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 cause slowdowns in work performance. Examples of tools and equipment purchased for replacement reasons are:

- Replacement of telecommunications equipment when the current platform is no longer supported
- Aged gas boring moles that can no longer be rebuilt
- Underground locating equipment when replacement parts are no longer available for repairs

The third and last category for prioritizing tool and equipment purchases is enhanced productivity. Capital tooling and equipment is used to perform new construction work or repair work for unplanned failures. Often this work can take less time or be completed with better results by using tools.

This category also includes material handling and storage equipment for company storerooms (forklift, storage cabinets, racking, etc.) Equipment for storerooms increases warehouse response and efficiency to crews in providing the needed material or tool in a timely manner.

Examples of tools and equipment purchased for enhanced productivity are:

- Purchase of new underground locators, which serve as a cable locator and fault finder – previously these were separate pieces of equipment
- Plasma metal cutting table so Generation can machine their own parts onsite
- IKE field data collection device used to efficiently design, capture mapping information, and field audit overhead assets
- Fiber optic fusion splicing trailer to allow technicians to splice in all climates/conditions

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Requested Start	Requested Complete	Risk Mitigation
Option 1 (Recommended): Fund program at current levels.	*$2.4M*	*1/2018*		*Low Risk*
Option 2: Partially fund (based on priority)	*Varies*	*1/2018*		*Medium Risk*
Option 3: Rent 4% of total equipment and purchase the rest	*$2.3M*	*1/2018*	*12/2020*	*High Risk*
Option 4: Do nothing	*$0*	*N/A*	*12/2020*	*Extremely High Risk*

Option 1 – Fund Program at Current Level (Recommended)

It is recommended that this program be funded annually at its current level to ensure Avista has the proper capital equipment necessary to safely and efficiently perform all required work. 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 Capital Tool 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 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 could lead to reduced efficiency and have safety impacts.

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-serve 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.

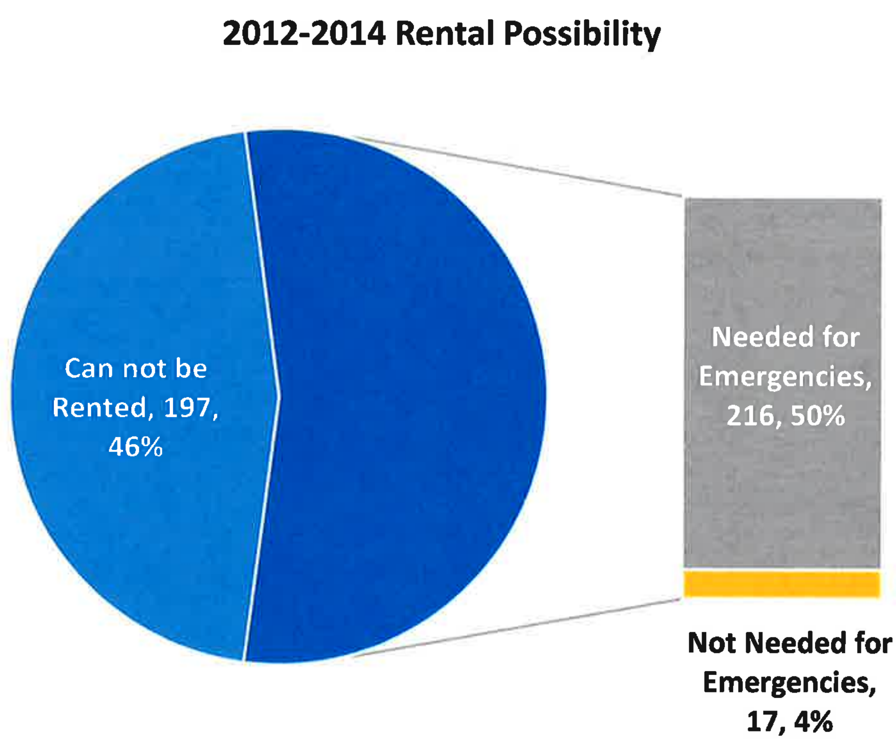


Figure 3

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.

Option 4 – Do Nothing

All construction, maintenance, and repair work performed at Avista is dependent on the use of capital tools and equipment. If proper tools and equipment are not available, work would cease. Without the necessary equipment, workers cannot perform their duties safely or efficiently, and Avista facilities and equipment could no longer be maintained.

Capital Tools & Stores

1 APPROVAL AND AUTHORIZATION

Capital Tools & Stores

The undersigned acknowledge they have reviewed the ~~Airport Hangar~~ 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: Gl Madd Date: 5/2/17

Print Name: Glenn Madden

Title: Manager, Supply Chain

Role: Business Case Owner

Signature: A 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 member

2 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1	*Gary Shrope*	*4-7-2017*	*Heather Rosentrater*	*04/25/17*	*New template*

Template Version: 02/24/2017

Apprentice/Craft Training

1 GENERAL INFORMATION

Requested Spend Amount	$300,000 over 5 years ($60,000 annual)
Requesting Organization/Department	Human Resources/Craft Training
Business Case Owner	Eric Rosentrater
Business Case Sponsor	George Brown
Sponsor Organization/Department	Human Resources
Category	Mandatory
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

The Joint Apprenticeship Training Committee (JATC) is the group identified by Avista to oversee the administration of the company's apprenticeship programs. The JATC will, as outlined in the Avista Standards of Apprenticeship, secure the instructional aides and equipment it deems necessary to provide quality instruction. To the extent possible, related instruction will be closely correlated with the practical experience and training received on the job.

2 BUSINESS PROBLEM

The capital allowance allotted to the Training Department through the Apprentice Training Business Case provides for tools, materials and equipment for training apprentices and journey workers across eleven skilled crafts or trades. This training consists of hands-on skills development that builds competency in a safe learning environment that may not always be available or controllable in the field. A well trained and competent workforce ensures reliable delivery of energy to Avista's customers and maintains a safe environment for employees, customers and the general public in all of Avista Utilities service territories.

In addition to creating a safe and skilled workforce, this training helps Avista to deliver timely training on new and emerging technologies as well as meet several federal and state mandated regulations including:

- Department of Labor, Standards of Apprenticeship – Title 29 CFR 29.5 (b)(4) and (b)(9) – Apprentice on the job training and related instruction
- Department of Labor, Occupational Safety and Health Standards – Title 29 CFR 1910.269 (a)(2) – Electric Power Generation, Transmission, and Distribution training
- Department of Transportation, Transportation of Natural Gas and Gas by Pipeline: Minimum Federal Safety Standards - Title 49 CFR 192.805 (h) – Qualification of Pipeline Personnel, Qualification Program training
- State of Washington – WAC 480-93-013 (4) – Covered Tasks: Equipment and facilities used by pipeline company for training and qualification of employees

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
On-going Capital Improvements	$300,000	01 2015	12 2019
Conduct Training Externally (No Training Facility)	$1,400,000 O&M	Annual	Annual

Capital expenditures under this program could include items such as building new facilities or expanding existing facilities, purchase of equipment needed, or build out of realistic utility field infrastructure used to train employees. Examples include: new or expanded shops, truck canopy, classrooms, backhoes and other equipment, build out of "Safe City"- commercial and residential building replicas, and distribution, transmission, smart grid, metering, gas and substation infrastructure.

Without the ability to provide specific hands-on operational training in-house, the company takes on several risks which include the inability to successfully fill critical craft positions with the necessary knowledge, skills and abilities specific to Avista's operations. This would have a direct and significant negative impact on system reliability, customer response times, as well as employee and public safety. Regulating bodies may also de-certify our apprentice program due to not meeting mandatory requirements for adequate training. As a result, the inability to train in-house would require extensive travel to fulfill our training obligations.

The cost to outsource hands-on-training and field simulations would be approximately $473,000 a year for facility rental alone. This is based on current training programs that have averaged over 530 hours per year at the training center. The overall annual costs including travel, lodging, meals and registration are estimated to more than triple this rental cost and be classified as operations and maintenance costs. Again this would result in a negative impact to Avista's customers.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the **Apprentice/Craft Training** 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:	4/14/17
Print Name:	Eric Rosentrater		
Title:	Safety, Training, and Labor Relations Manager		
Role:	Business Case Owner		

Signature:	George W Brown	Date:	4/14/2017
Print Name:	George Brown		
Title:	Director of HR, Shared Services, Benefits, Craft Training, Occupational Health and Safety & Union Labor Relations		
Role:	Business Case Sponsor		

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeremy Gall	04/04/2017	George Brown	04/14/2017	Initial version

Template Version: 03/07/2017

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

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

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.

Campus Repurposing Phase 2

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.		

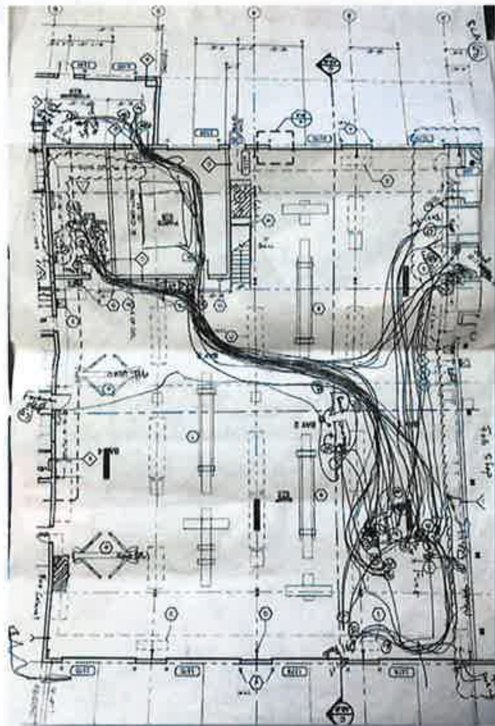
Option 1 (recommended): Construct a new fleet operations facility at the north end of the campus.

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

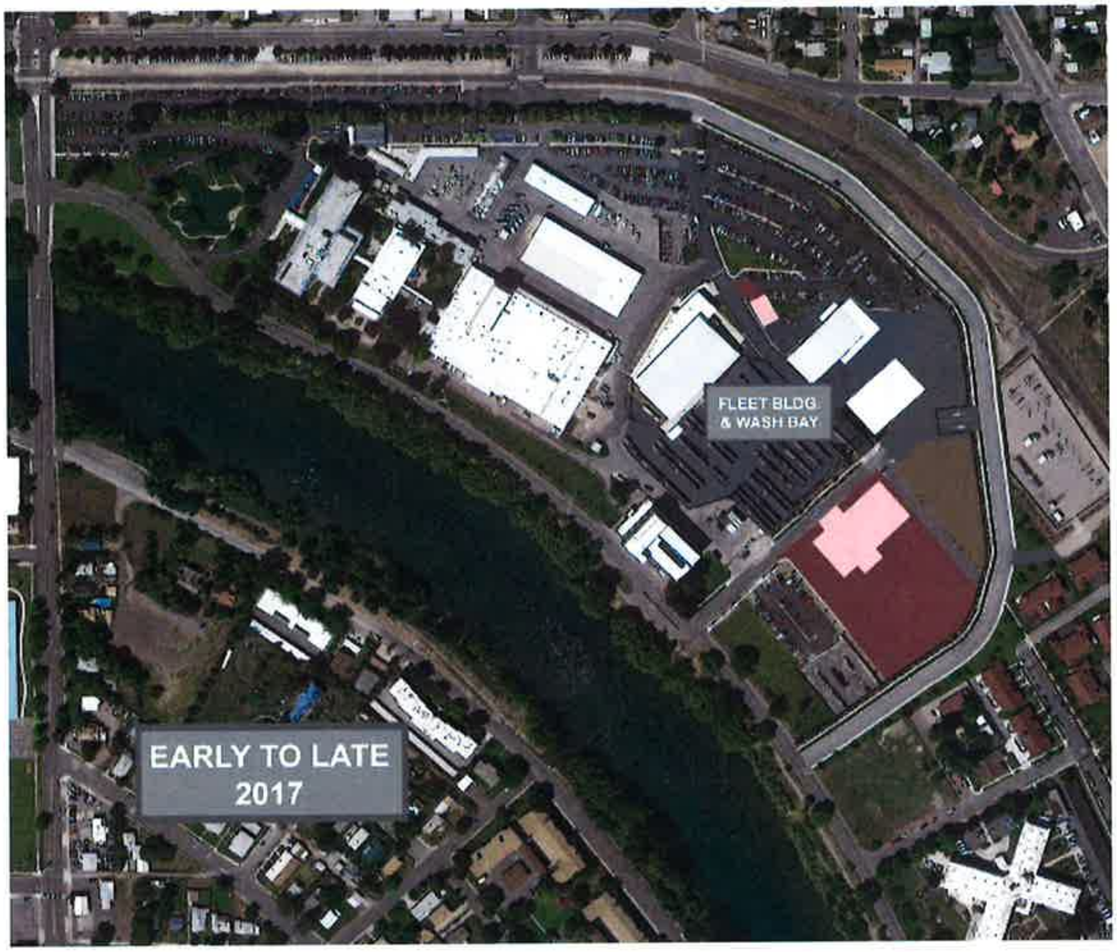


BPI Spaghetti workflow diagram

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.

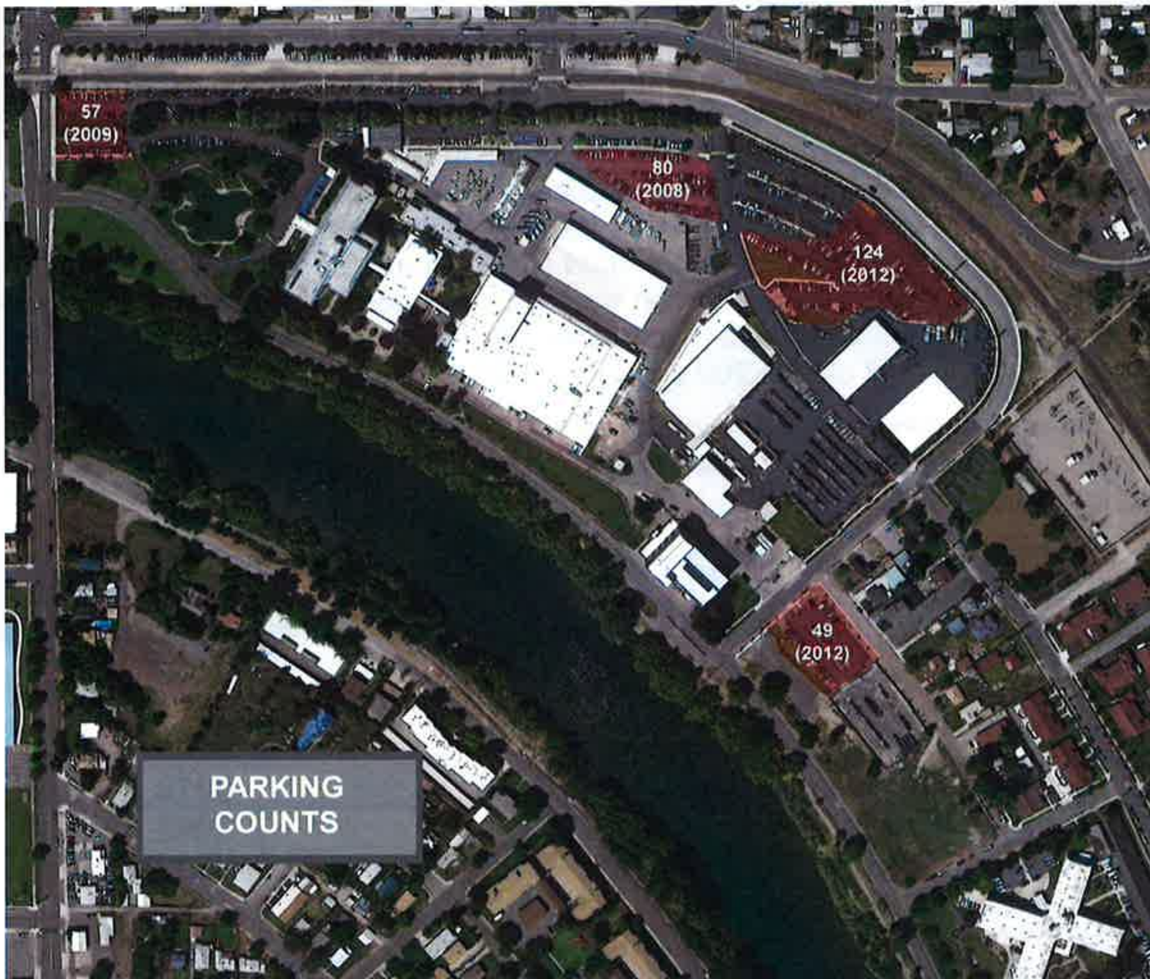
Project 3: Parking Garage

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

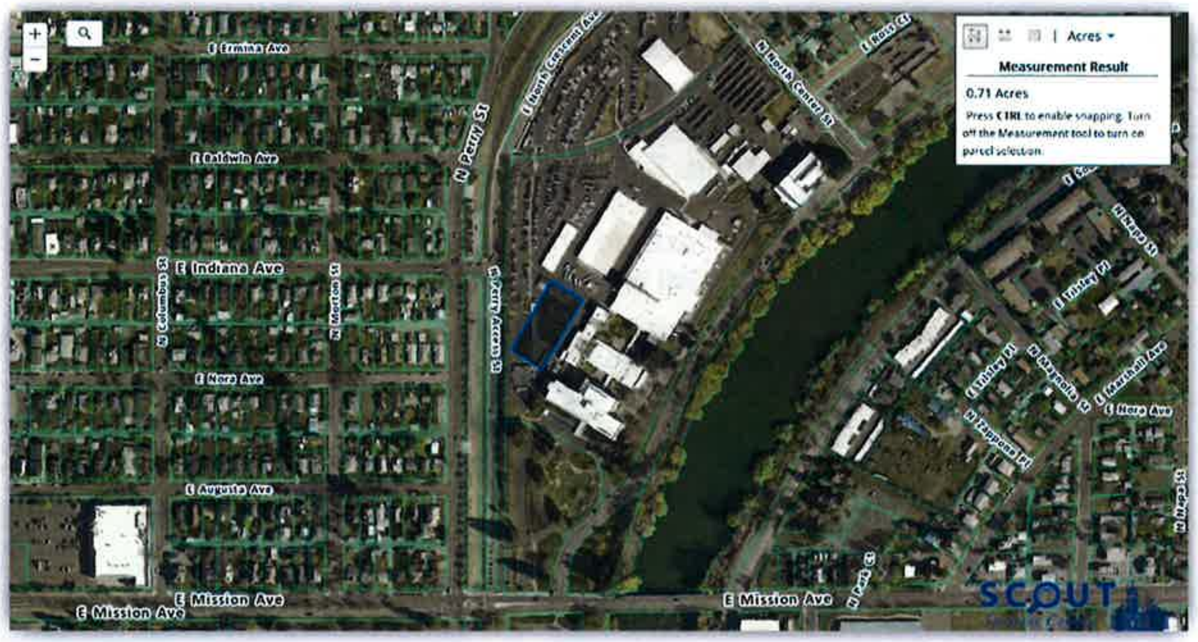
- **Option 2** – Convert property at the north end of campus (Ross Court) into parking lots.
- **Option 3** – Purchase properties to the east of campus, across Perry Street, and develop parking lots.

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.	

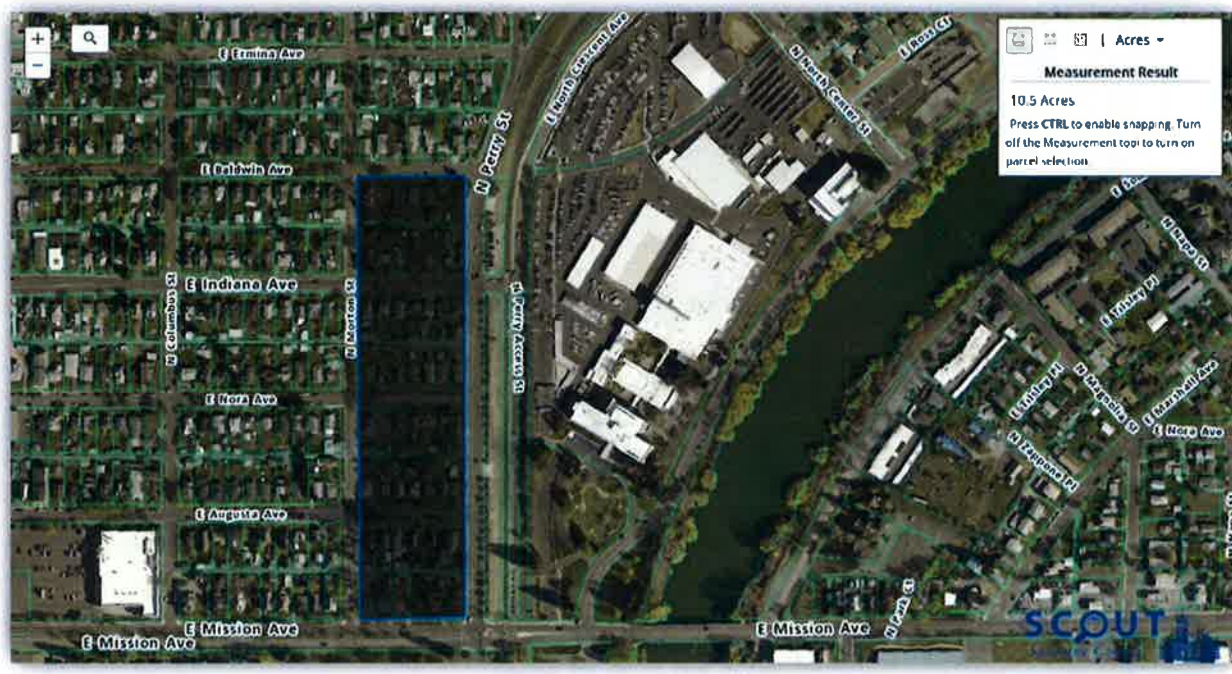
Option 2: Convert Ross Court property into parking to address current deficit

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.

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).

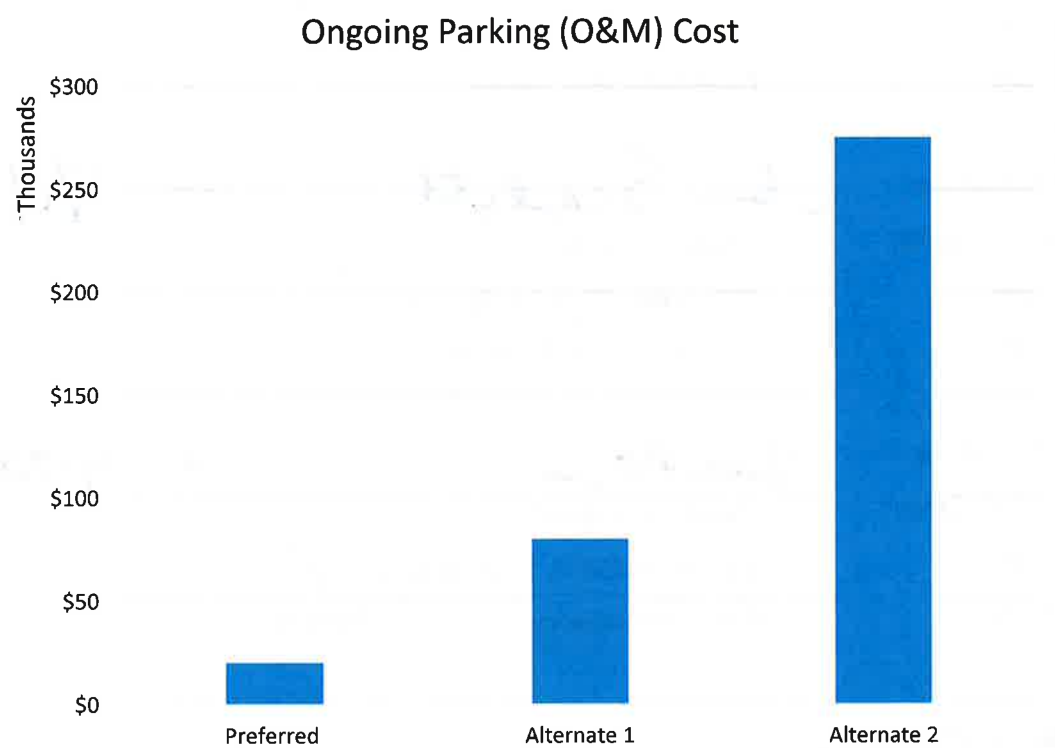
Option 4: Do Nothing

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.

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

Signature: A 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

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

Company Aircraft Capital

1 GENERAL INFORMATION

Requested Spend Amount	$3,000,000
Requesting Organization/Department	Travel & Flight
Business Case Owner	David Robinson, Chief Pilot
Business Case Sponsor	Anna Scarlett, Manager of Shared Services
Sponsor Organization/Department	Shared Services
Category	Project
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

Steering Committee:

- Manager of Shared Services
- Chief Pilot
- Captain
- Director of Finance
- Legal Counsel

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

- Vice President of Energy Delivery
- Financial Planning and Analysis
- Executive travelers

2 BUSINESS PROBLEM

Avista currently operates a 1999 Cessna Citation VII aircraft in support of all company business units and subsidiaries. Approximately 50% of legs flown are in direct support of utility regulatory activities with the remainder in support of regional Avista offices and various business undertakings. A large portion of these destinations are not served by an airline.

Avista has leased the company aircraft from PNC Aviation Finance since February 2000. In March 2018, the current 3-year lease of the company aircraft expires. The lease contains an end-of-term purchase option that applies lease payments made towards the purchase in a lump-sum amount.

The current lease requires 360 days' notice of intent to purchase or return the aircraft. Avista was granted a 30-day extension by PNC to this requirement. This extension expires on or about April 5, 2017.

The current lease requires Avista to carry an engine and auxiliary maintenance service plan, which expires at the end of 2018 and will cover major overhauls of both engines. One engine received this overhaul in March 2017 and the other engine is expected to be due for overhaul in the next two years. Avista also carries a separate ProParts parts plan, which we can terminate without penalty with 30 days notice.

Avista will be required to upgrade the avionics to comply with Federal Aviation Administration (FAA) ADSB-Out mandate before January 1, 2020.

Usage	Number of Trips	Hours	Top 3 Destinations
2014	216	234	1.Olympia 2.Medford 3.Seattle
2015	222	253	1.Olympia 2.Boise 3.Seattle
2016	215	226	1.Olympia 2.Salem 3.Medford

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete	Risk Mitigation
1. **Recommended:** Purchase/Upgrade Current Aircraft	$3M	01/2018	04/2018	
2. New 3 -year lease	$0	03/2018	03/2021	
3. Alternate transportation	$0	03/2018		$1.5-2.2M Return Payment costs
4. Purchase new aircraft	$15M	01/2018	12/2018	$1.5-2.2M Return Payment costs

A work group was convened in 2016 to complete a cost and revenue analysis of four option. Data and conclusions were updated March 2017 (see attachments). The cost of the current lease is approximately $1.2 million per year.

Option 1 (Recommended) – Purchase current aircraft:

This includes purchasing the aircraft at a cost of approximately $2.5 million, modifying the avionics to comply with the FAA ADSB-Out mandate at a cost of approximately $500k, and self-funding the parts plan. This option would save $1.1 million O&M annually by eliminating the lease payments, assuming we self-fund the parts plan beginning in 2018 and discontinue the engine and auxiliary MSPs at the end of 2018.

Timeline

- January 2018: Avionics upgrade to comply with FAA mandate.
- March/April 2018: Complete aircraft purchase.

Company Aircraft Capital

Option 2 – New 3 year lease:

Renegotiation of the lease is not provided as an end of term option, but presumably a lease could be negotiated such that it supersedes or otherwise cancels the existing lease.

If we renew the existing lease for a term of three years, the cost would be $1.79 million O&M in years 1 thru 3. The cost analysis assumes Avista would purchase the aircraft at the end of the lease term and operate it seven additional years. The same condition regarding parts and engine programs as in Option 1 apply.

Option 3 – Return aircraft and use alternate transportation:

Avista could end the current lease and, rather than extend or exercise the purchase option, we could choose to return the aircraft at the end of the lease. The cost of ending the current lease and returning or selling the aircraft would be between $1.5 million and $2.2 million as detailed below:

- Exercising this option would require Avista to pay an "aircraft return payment" of $2,185,008 (per Schedule No. 2-A to lease supplement.)
- Avista may attempt to sell the aircraft and reduce the aircraft return payment by any proceeds in excess of the "maximum lessee amount" of $1,659,984.
- At an estimated market value $2.3 million, Avista could reduce the aircraft return payment by approximately $640,000, to a net cost to Avista of $1,545,000, less selling costs.

Should Avista exercise the option to return the aircraft, travel would be through one of the alternatives below:

4.1 Airline

Most legs flown are to destinations that don't have regular airline service. This would require flying to the nearest airline airport and driving, sometimes a considerable distance.

4.2 Charter

There are currently no charter aircraft available in the Spokane area. Aircraft would need to come from outside the area (Seattle). These empty legs are usually charged at the full rate to the customer. Charter is also not usually available on short notice. Cost per flight hour is approximately the same as ownership.

4.3 Fractional

Fractional ownership is owning a part (usually ¼) of an aircraft. Shares are usually sold in 50 hour blocks. At Avista's current usage rates would require 4 shares or full ownership. Cost per share information is hard to come by. Fractional operators want you to show serious interest before they will talk specific dollar amounts. The assumption is that for similar aircraft flying Avista's typical missions, the cost per flight hour would be approximately the same as sole ownership of an aircraft. Aircraft are controlled by the managing company and would have to come from outside the area.

Company Aircraft Capital

Option 4 - Purchase new aircraft:

Avista could elect to return the existing aircraft (subject to return costs described above) and purchase a new aircraft with comparable capabilities. The plane considered has added fuel efficiency and a longer range (Gulfstream 150) would cost $15M capital in 2018. O&M costs would be approximately $0.63M in year 1 and would increase as items come off warranty. A new aircraft would have a minimum life of 20 years. This option has the highest revenue requirement over time.

Existing Lease	
Lease Payments	$1.26
Operating costs	0.95
Total	$2.21

$ In Millions

Annual Budget	Renew Lease			Purchase Exist. Plane			Purchase New Plane		
	Capital	O&M	RevReq	Capital	O&M	RevReq	Capital	O&M	RevReq
Year 1	$ 0	$1.79	$1.91	$2.75	$0.53	$1.15	$11.00	$0.53	$2.30
2		1.79	1.90		0.54	1.12		0.55	2.19
3		1.79	1.88		0.66	1.20		0.66	2.19
4		0.59	0.62		0.57	1.07		0.58	2.00
5		0.6	0.63		0.59	1.05		0.59	1.94
6		0.71	0.74		0.7	1.14		0.7	1.98
7		0.63	0.65		0.62	1.02		0.62	1.82
8		0.64	0.67		0.63	1.00		0.63	1.77
9		0.46	0.79		0.75	1.11		0.75	1.85
10		0.67	0.70		0.67	1.00		0.66	1.72
Present Value		9.66			7.91				22.8

See attachments; Corporate Aircraft Analysis 2016 and Aircraft Analysis-March 2017 for supporting documentation.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the ~~Airport Hangar~~ Aircraft Capital 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: 5-2-17
Print Name: David Robinson
Title: Chief Pilot
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 member

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1	David Robinson	04/25/17	Heather Rosentrater	04/25/17	New Template

Template Version: 02/24/2017

Ergonomic Equipment

1 GENERAL INFORMATION

Requested Spend Amount	$900,000 over 3 years
Requesting Organization/Department	Facilities
Business Case Owner	Lindsay Miller, Facilities Project Manager
Business Case Sponsor	Anna Scarlett, Shared Services Manager
Sponsor Organization/Department	Shared Services
Category	Project
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

A stakeholder group was formed in 2015 to evaluate this program. Stakeholders were George Brown, Eric Bowles, Mark Gustafson and Mike McAllister. They reviewed materials and made recommendations to leadership regarding the direction moving forward. They approved submission of the business case for the initial roll out of equipment. This initial roll out will cover the cost of new ergonomic equipment. Beginning in 2018, the subsequent equipment will be funded out of the furniture business case.

Steering Committee

- Eric Bowles, Facilities Manager
- Lindsay Miller, Project Manager
- Oona Timmons, Nursing Services Supervisor

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

- Vice President of Energy Delivery
- End Users

2 BUSINESS PROBLEM

Research from the Texas A&M Health Science Center School of Public Health indicates that standing desks as ergonomic interventions can improve physical health among employees and may also positively impact their work productivity.

More from the study:

http://www.tandfonline.com/doi/abs/10.1080/21577323.2016.1183534?tokenDomain=eprints&tokenAccess=km4nB428SqEGEqw7Bwjz&forwardService=showFullText&doi=10.1080%2F21577323.2016.1183534&doi=10.1080%2F21577323.2016.1183534&journalCode=uehf20

90% of Avista's ergonomic requests have been for sit/stand workstations. Avista previously had an ergonomic program that required employees to complete a symptom survey and demonstrate need when making a request for ergonomic additions to work stations. We only provided ergonomic equipment once it had been proven through an ergonomic evaluation that the employee was in need of intervention, often after an employee had already begun experiencing issues.

Ergonomic Equipment

Employees have sought services at our clinic and outside to help reduce symptoms associated with a variety of injuries exacerbated by their work station. Treatments include surgery, physical therapy and massage therapy.

Avista is self-insured, and healthcare costs are directly impacted by employee health and wellness. Between 2011 and 2014 we saw an average of 4.5 recordable injuries each year, under our self-insured workers compensation program, that were specifically related to an ergonomic issue. The average cost of those claims was $4,066 per claim. Each claim, from start to finish, takes an average of 8 hours of labor for Oona Timmons, Nursing Services Supervisor, and one hour of labor for Melanie Steele to complete. Total cost per claim, in labor, is $599.40.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete	Risk Mitigation
1. **Recommended:** Proactive Ergonomic Program (as-requested) Costs for new Ergonomic equipment	$900,000	07/2016	12 2018	
2. Use a less expensive product list and respond to ergonomic issues once they arise. Costs for new Ergonomic equipment	$600,000	07/2016	12/2018	
3. Return to previous process of responding to requests with ergonomic evaluations (as-needed)	$0	N/A		

Option 1 (Recommended) – Implement a proactive ergonomic program

Ergonomic Equipment

This option proposes to implement an ongoing program where all employees requesting ergonomic equipment will receive it, with no requirement of an ergonomic assessment or other proof of need. A proactive program has the following benefits:

- Increased employee engagement in ergonomic programs and education, by encouraging employees to take responsibility for maintaining their health and wellness at their workplace.
- Decreased time and cost of ergonomic equipment deployment by removing evaluations and approvals and standardizing equipment and installation.
- Prevention of workplace injuries and health impacts and reduction of the costs to the company and our customers, as well as to employees, associated with these.

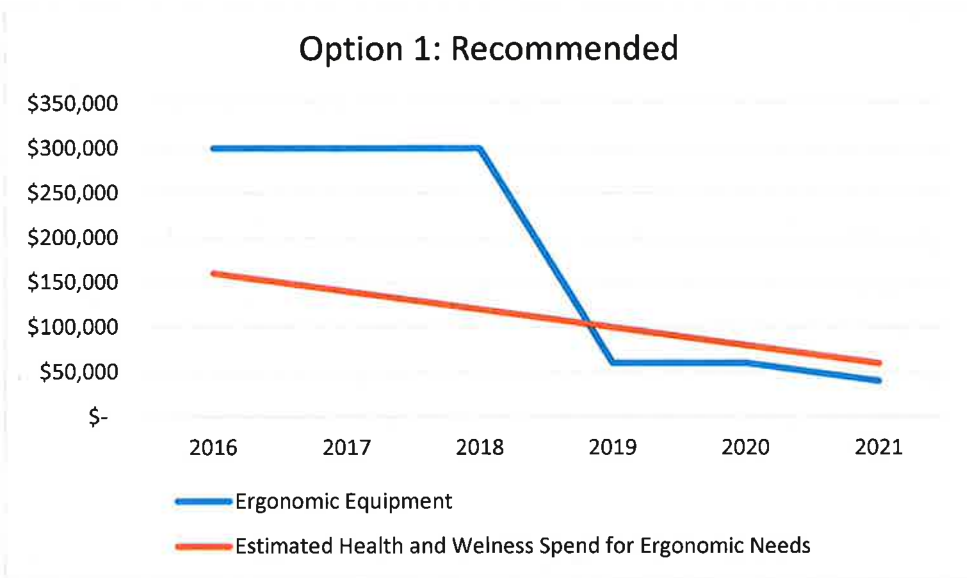
Cost/resources:

The newest option to be funded out of this project is the Vari-Desk, which costs under $400 and takes up to an hour of facilities labor and about 30 minutes of IT labor to install. Included in the program are ergonomic chairs, monitor arms and ergonomic IT hardware. The overall costs of the program are higher up front, but the program is expected to reduce long-term costs of health and wellness programs and services.

Other program benefits:

- Participants of the program receive tools including the *Ergonomic Reference Guide*. Employees can use this document as a starting off point for their ergonomic self-assessment. The guide identifies various areas of ergonomics that employees can pinpoint and implement on their own and can also help them recognize areas where our other tools may help.
- When employees receive new equipment they are provided with the *New Workstation Handout,* which provides tips and tricks to make better use of their new equipment.
- Avista provides a location for resources on our Intranet that employees can access. This includes videos on how to adjust our standard chairs and additional documentation and case studies regarding ergonomics.
- Education is ongoing included in a TED talk series we provide once a month as a "lunch and learn".
- After ergonomic deployment, employees receive a follow up survey at the 3 month, 6 month and 1 year mark. This is to ensure they are still using the equipment and that the equipment is working for them. This survey also includes reminders and tips and tricks to help keep employees engaged.

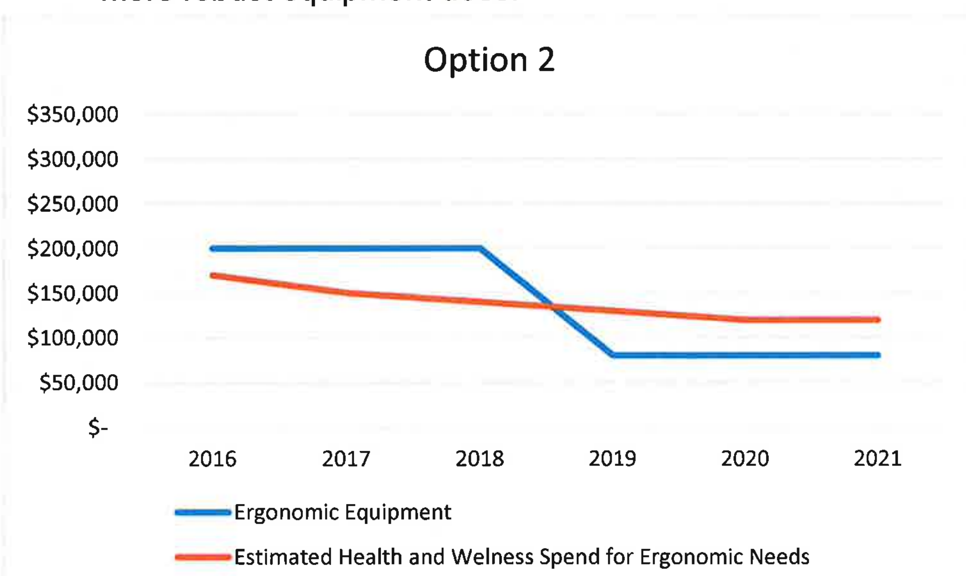
Ergonomic Equipment



Option 2 – Less expensive equipment

The team researched less expensive products, including chairs and sit/ stand stations. This option was not preferred for the following reasons:

- The sit/ stand products do not have the same weight capacity that the Vari-Desk does.
- The equipment options were less expensive but also less durable. Units would require more frequent replacement over time.
- The less expensive seating options have fewer functions that provide ergonomic relief and would not provide the benefit to employees that the more robust equipment does.



Option 3 – Respond to requests with ergonomic evaluations (as-needed)

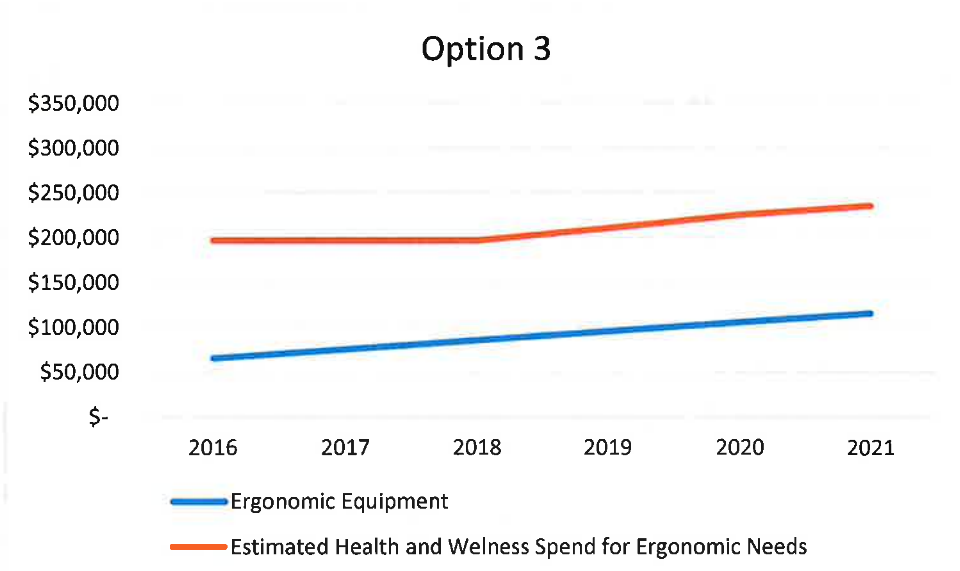
Ergonomic Equipment

From 2013-2015, new ergonomic requests required an ergonomic evaluation to determine the need for a sit/stand station. Each evaluation cost $150 and was charged back to the employees department. We required the manager to approve all recommended ergonomic evaluations prior to proceeding with the evaluation. Between 2013 and 2015, we spent $11,250 on Ergonomic Evaluations. Once it was determined that a sit/stand is necessary, we would then deploy the equipment.

Prior to 2015, we used either a motorized station or an elevated standing desk. The motorized station cost approximately $600 plus labor to install on the front end and, in the event of a move, another 5-6 hours for turn around. An elevated standing desk, which is just raising the original desk, had minimal costs from a material standpoint but much greater costs in labor. Labor for this install included roughly 5 hours with original set up then, if an employee had to be moved, it would take another 5 hours to set up and 2-3 hours to turn to other station back to the standard design.

We moved away from this approach to our proactive program (Option 1) approach because of the following considerations:

- Installations took longer and cost more under the previous program.
- Employees were forced through an evaluation and approval process, and often received ergonomic equipment only after they began experiencing issues.



4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Ergonomic Equipment 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: L Miller Date: 5/1/2017
Print Name: Lindsay Miller
Title: Facilities Project Manager
Role: Business Case Owner

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

Signature: H R 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	*Lindsay Miller*	*04/25/17*	*Heather Rosentrater*	*04/25/17*	*New template*

Template Version: 03/01/2017

1 GENERAL INFORMATION

Requested Spend Amount	$10,300,000
Requesting Organization/Department	Facilities Management
Business Case Owner	Vance Ruppert, Project Manager, 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

Two distinct groups assisted in shaping the Business Problem and the Proposal and Recommended Solution for this business case. The first consisted of the following stakeholders (hereafter referred to as the Director Team):

- Andy Vickers, Director, Generation, Production & Substation Support (GPSS)
- Bryan Cox, Director of Operations, West
- Mike Faulkenberry, Director of Gas Delivery
- David Howell, Director of Engineering
- Greg Gfeller, Director of Operations, East
- Laura Vickers, Senior Manager of Shared Services
- Diane Quincy, Director, Human Resources
- Jim Corder, Director of IT and Security
- Mike Broemeling, Director of Customer Service
- Linda Jones, Director, Human Resources Craft Training & Safety.

The Director Team selected the “Advisory Group” to refine the business case. This group included:

- Tony Klutz, Safety & Health
- Eric Rosentrater, Electric Operations
- Craig Buchannan, Gas Operations
- Mike Gonnella, GPSS
- Bill Magers, Avista/SCC Line School
- Latisha Hill, Compliance & Analytics
- Dave James, Distribution Engineering
- Vance Ruppert, Facilities
- Michael Busby, Enterprise Technology
- Jeremy Gall, Craft Training

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

- Vice President of Energy Delivery
- Executive Officers

2 BUSINESS PROBLEM

2.1 Current State

The Jack Stewart Training Center (JSTC) is located in north Spokane at one of Avista's generation facilities which includes the Northeast Combustion Turbine and Substation. JSTC is home to the Pre-Apprentice Line School, a partnership between Avista and Spokane Community College (SCC), and the facility is heavily used by multiple Avista departments, including electric operations, gas construction, and GPSS. These departments conduct numerous class types such as compliance and safety training, grid modernization and smart devices, leadership development, new employee training, and multiple other meeting space needs.

2.2 Previous Business Case

In early 2015, research into which Avista departments required dedicated training spaces was completed. The Director Team was assembled based upon the results of 1) if the Director had departmental reports requiring the training space, or 2) if the Director contributed to supplying the training space or programs. On June 29, 2015, the Director Team held a meeting to review the 2011 JSTC expansion plan and determine if an updated business case should be created. It was agreed that the modular buildings still needed to be replaced for continued operations of the line school. The Director Team further discussed building a gas training facility at the Dollar Road Service Center or including it as part of the JSTC expansion. The group agreed that gas training would be best accomplished at JSTC. The group also agreed to have the design include capacity for corporate-wide training, not just craft and technical training.

The 2011 JSTC expansion business case requested $4.5 million to expand and enhance the operational capability at JSTC by replacing modular training classrooms and existing shops in use by the line school with a flexible-use classroom/shop training building. The project would:

- Provide additional classroom space
- Replace outdated and deteriorated modular buildings
- Consolidate current shops for efficient use of space and better support training demands
- Make-up for the decreased availability of classrooms at the Mission campus
- Resolve parking issues at JSTC

2.3 Need for a Revised Business Case

The operational challenges the previous business case sought to address in 2011 have continued to increase since its original submission. Today that plan would not address the capacity needs of the facility, and would actually further compound problems, such as eliminating a small shop that supports the natural gas operator qualification program.

Thus, the Director Team identified representatives from each area (which became the Advisory Group outlined in Section 1.1) to provide input into a new facility design. The Advisory Group identified a list of capabilities a facility would need to have to meet training demands based on regulations and current operational practices (see appendix B). The training department collaborated with facilities to create a proposed facility design that would be capable of supporting the identified training. This design was reviewed and modified by the Advisory Group prior to being presented to the Director Team. The Director Team reviewed the updated expansion plan on January 26, 2016, and with a few minor recommended changes, requested the plan be used to submit an updated JSTC Expansion business case.

The updated business case accounts for current challenges by addressing the three key areas JSTC supports:

- Avista/SCC Pre-Apprentice Line School
- Natural Gas Training & Operator Qualification
- Avista Leadership Training & Development

Avista's line craft first began using JSTC for apprentice and journeyman training because of its close proximity to Avista's Mission campus and open terrain for building electric distribution lines for training. A surplus modular building from the construction of the Kettle Falls Generating Station was placed at JSTC between 1983 and 1984 for use as classrooms for the apprenticeship. In 1992, the Line School was established with grant funding and also began training out of this modular. In 2006 a second, already 10 year old, modular was added to the property to support the success and growth of the line school. Over its 24-year history the annual enrollment of students has more than tripled from an average of 24 each year to 86.

The heavy use of these modular buildings over 33 years has taken its toll and the need to replace them due to deterioration is immediate. Regular maintenance is no longer sufficient to sustain its proper condition. When these buildings become uninhabitable, the line school will have to relocate to the main training building on campus to sustain its operations (see Illustration 1 below).

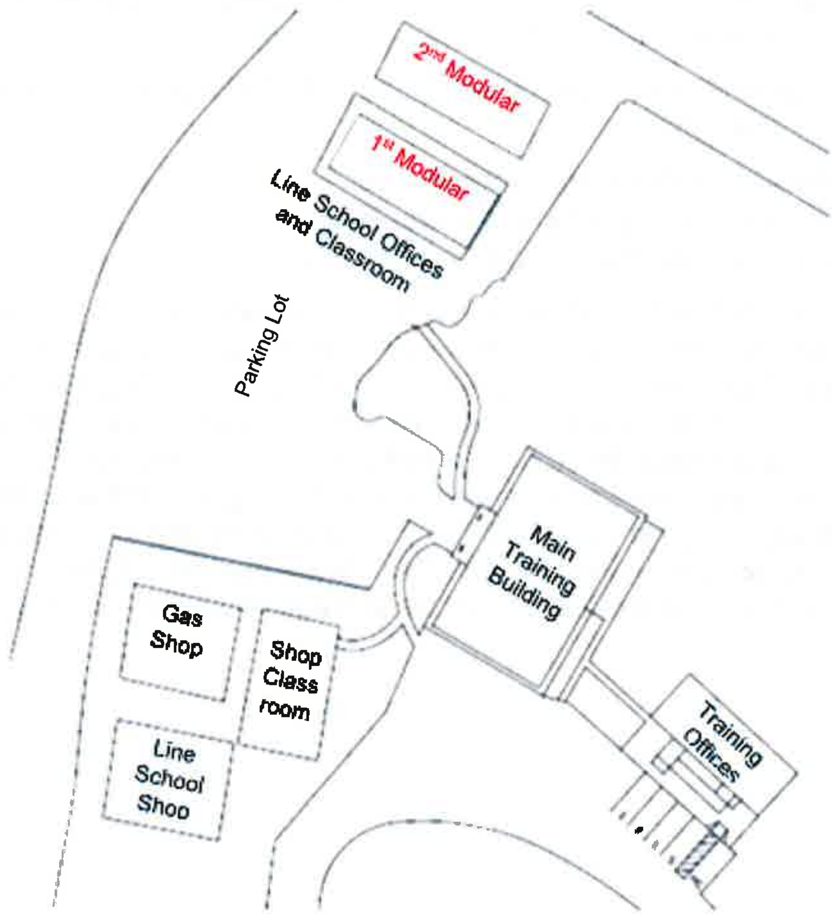


Illustration 1 - Existing JSTC Training Facilities

Moving the line school into the main training building would prohibit use of the facility for any other training or meeting. An alternate location would have to be found to accommodate Avista training. Initial costs of renting facilities and added travel based on historical use over the last four years is estimated at $604,873 (see cost estimate breakout in Appendix E).

In 2001 and 2002 the use of the facility was increased with the addition of Avista's leadership programs and new regulations requiring operator qualification (OQ) for natural gas workers. The smaller line shop first constructed at JSTC was designated for gas training and OQ performance evaluations. OQ also incorporates approximately 25 hours of computer-based training annually. Use of the facilities for natural gas training and OQ would be lost with either the approval of the originally proposed facility expansion or the relocation of the line school to the main training building. A natural gas training facility was not incorporated in the original 2011 expansion plan (see Illustration 2 below).

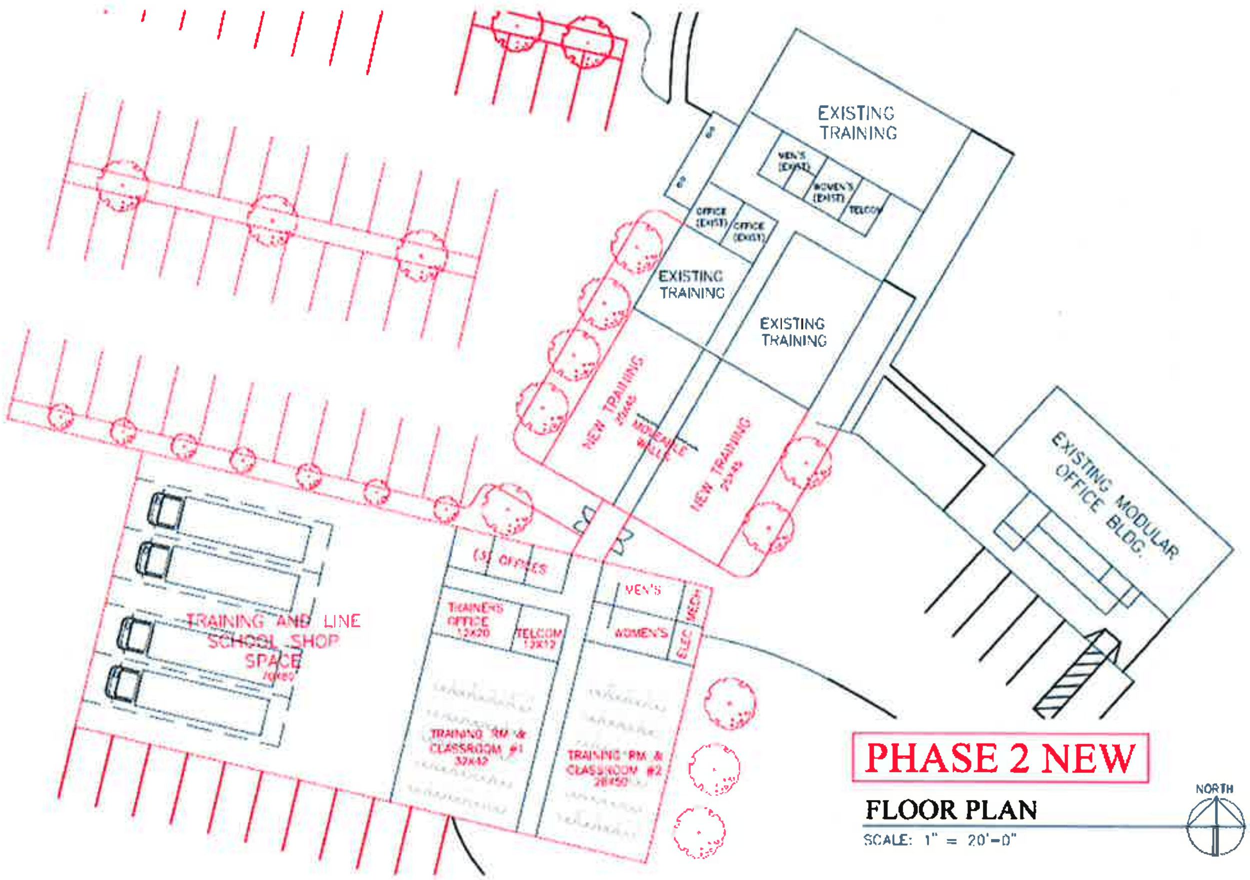


Illustration 2 – Original 2011 Proposed JSTC Training Facility Expansion

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – (Recommended) - Full Expansion (Line School & All Avista Training)	$10.3M	01 2018	12 2019
Option 2 - Partial Expansion (Line School & Craft Training)	$6.95M	01 2018	12 2018
Option 3 - Do Nothing	$0		

3.1 Option 1 – Full Expansion

Updated JSTC Expansion Business Case

The updated business case is designed to support multiple operations functions across the company with a primary focus on the Avista/SCC Pre-Apprentice Line School, Craft & Technical Training, and leadership development. The operational areas supported include:

- Avista/SCC Pre-Apprentice Line School
- Electric Operations
- Gas Operations
- Generation, Production, Substation Support (GPSS)
- Compliance & Safety
- Corporate Training (Leadership, Team Building, New Hire, Customer Service, etc.)
- Other Areas (Engineering, Dispatch, Control Room, Emergency Response, Business Continuity, Community, etc.)

The expansion plan provides for the construction of three additional training facilities within the currently used area at JSTC (see Appendix A for illustrations of proposed facilities). The three buildings would contain classrooms and hands-on laboratory environments:

- Pre-Apprentice Line & Electric Operations Facility
- Gas Training Facility
- Main Training Facility - GPSS, Compliance & Safety, Corporate, and other areas

Construction could be planned and completed across two years budgeting $4,000,000 for year one and $6,300,000 million in year two. A breakout of the estimated construction costs are found in Appendix D.

Regulations and operational needs across all technical areas has created a higher demand for training facilities year round. In many cases, operational departments' training schedules must remain flexible to accommodate customer needs and unplanned system events. Each operational area also has very specific and unique training needs that require a dedicated space for materials and equipment. To accommodate these needs, a dedicated classroom for each major operations department is included in the plan: electric, gas, GPSS, line school as well as a classroom for the multi-trade classes for switching and tagging and grid modernization. Examples of what these classrooms could look like are found in Appendix C.

Customer benefits are outlined within the Risk Assessment table in Section 3.2 below. Please pay particular attention to the Safety, Reliability, and Customer/Community items listed in the table. Each of these are explicitly related to ensuring that our work force has the proper qualifications to provide utility services to our entire service territory.

3.2 Risk Assessment – Consequences if not completed

Safety:	To employees, contractors, customers and public safety if work is performed by unqualified personnel
Reliability:	To system integrity and company reputation if work is performed by inadequately trained personnel
Customer/ Community:	To quality of life for residential customers and revenue for commercial/industrial customers
Financial:	For fines due to non-compliance, costs of system repair/restoration, community reparation, and shareholder value. Loss of revenue and increased operating costs for training new employees
Department:	Inability to staff department with qualified workers to adequately respond and support work in the field.

Lack of, or poor quality training presents many potential long-term risks to an organization's ability to maintain and sustain a safe and qualified workforce. These risks can negatively affect employee and public safety, system reliability and customer satisfaction.

More immediate financial and operational consequences are possible due to the risk of non-compliance with state and federal regulations. Most of these regulations outline requirements for conducting instructor-led training with a demonstration of proficiency at facilities simulating the environment in which the employee would be completing the trained task. Additional training requirements are outlined by Avista's Incident Prevention Manual and corporate policies.

The following regulations have a direct correlation to the training conducted at JSTC:

- Department of Labor, Standards of Apprenticeship – Title 29 CFR 29.5 (b)(4) and (b)(9) – Apprentice on the job training and related instruction
- Department of Transportation, Transportation of Natural Gas and Gas by Pipeline: Minimum Federal Safety Standards - Title 49 CFR 192.805 (h) – Qualification of Pipeline Personnel, Qualification Program Training

- State of Washington – WAC 480-93-013 (4) – Covered Tasks: Equipment and facilities used by pipeline company for training and qualification of employees
- Department of Labor, OSHA – Title 29 CFR 1910.269 (a)(2) – Electric Power Generation, Transmission, and Distribution training

Potential financial risks also exist in the event the line school could not operate due to a lack of adequate facilities. The impacts could include the loss of an average annual revenue of $650,718. It is also estimated that Avista could incur $331,546 in annual operating costs to train new employees basic skills previously gained as a student in the line school.

3.4 Alternative Solutions

<u>Option 2 – Partial Expansion</u>

An alternative solution would be to scale back the project to only address line school, natural gas and craft and technical training as required by state and federal regulations. This would prohibit corporate training and other uses of the facility which are more easily accommodated in local rental facilities that provide classroom space. The approach would reduce the facility expansion estimated cost from $10.3 million to $6.95 million. This is a reduction of $3.3 million, but comes with a potential increase in annual operating costs to accommodate corporate training at one-half to two-thirds of the estimated $472,889 in Appendix E – Cost of Using Rented Rooms.

Additionally, the completion of the originally proposed business case to expand the facilities resolves the issues the line school currently faces, but creates a higher risk for natural gas operations training and OQ.

<u>Option 3 – Do Nothing</u>

The risks of not upgrading and expanding the JSTC facility at all (do nothing) could greatly impact Avista's operations as previously outlined.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the ~~Airport Hangar~~ Jack Stewart Training Center 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:	Vance Ruppert		
Title:	Project Manager, Facilities		
Role:	Business Case Owner		

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

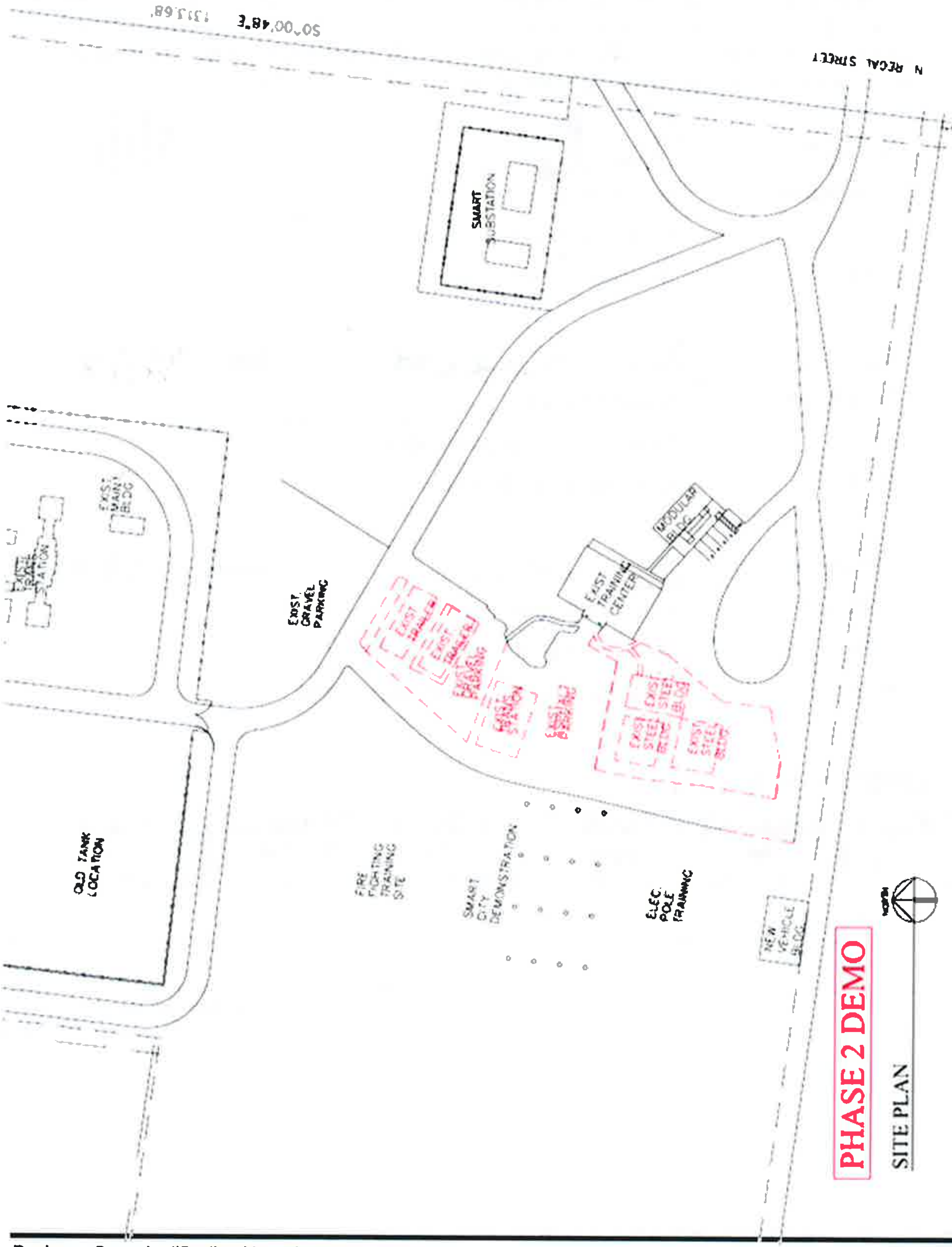
Signature:	[signature]	Date:	4-28-17
Print Name:	Heather Rosentrater		
Title:	Vice President, Energy Delivery		
Role:	Steering/Advisory Committee Review		

5 VERSION HISTORY

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

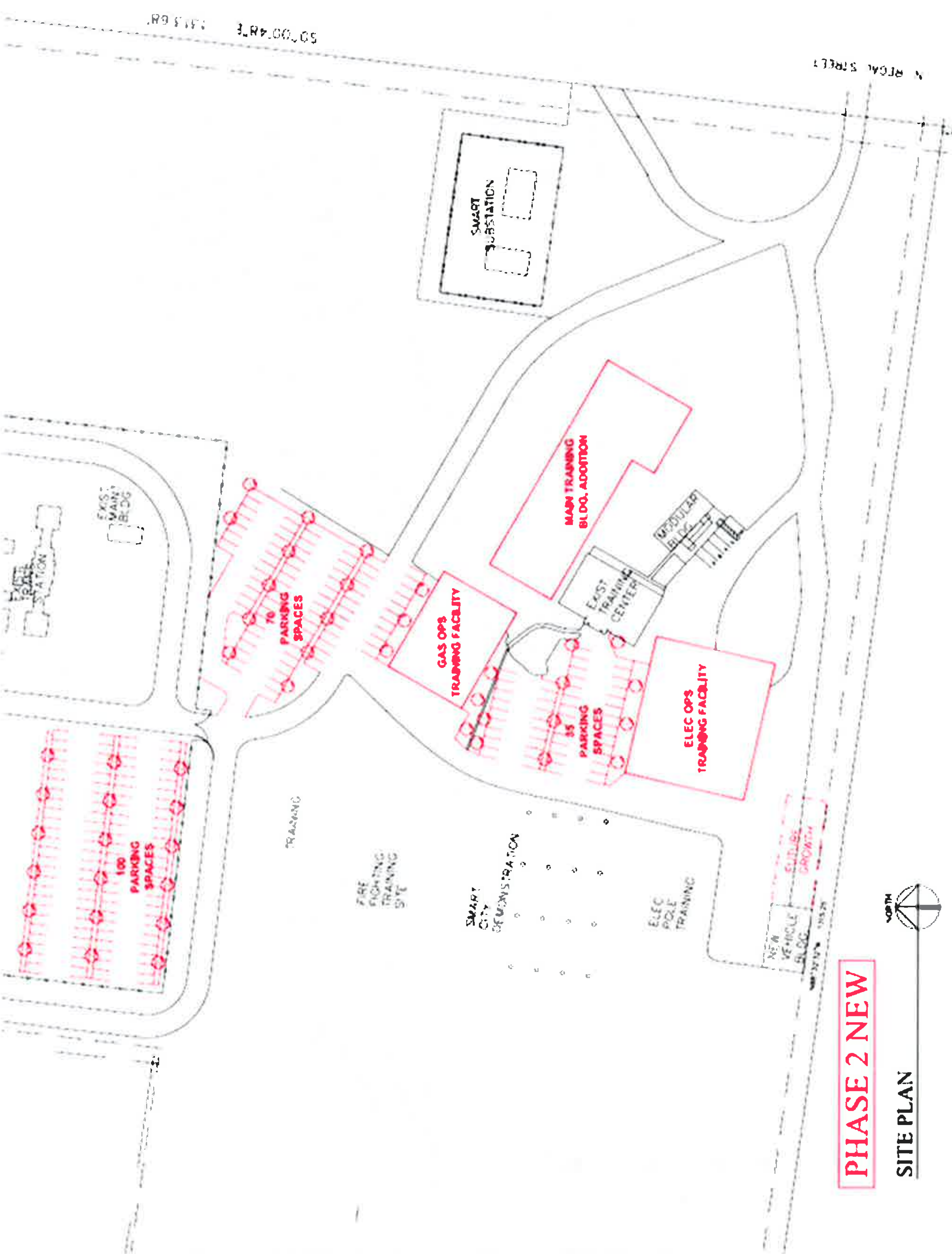
Template Version: 03/07/2017

Appendix A



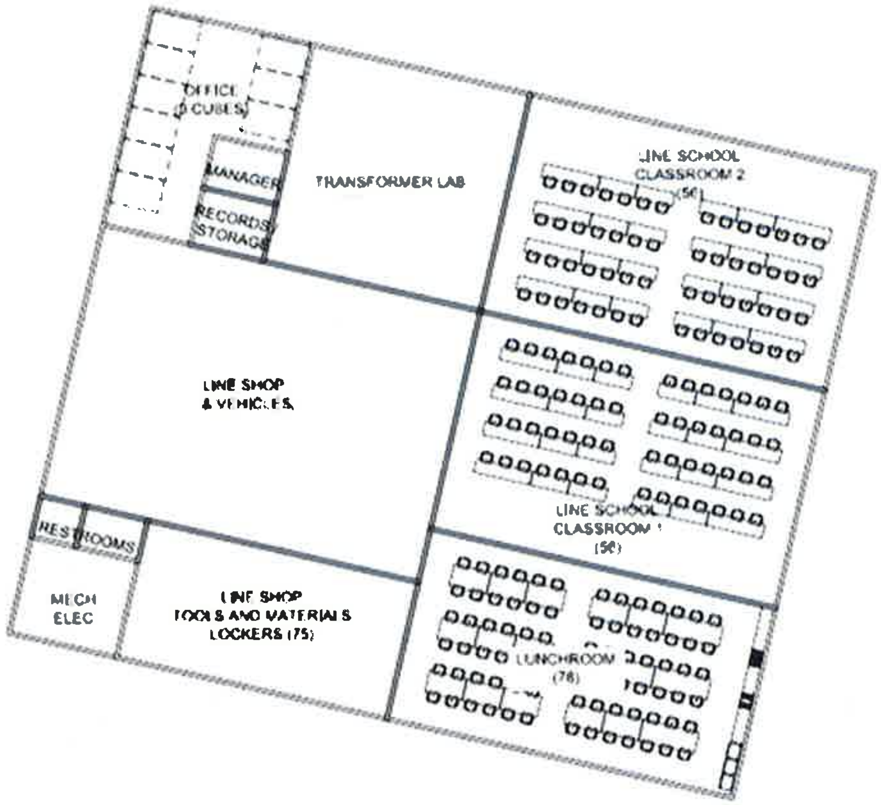
Location of New Line and Gas Training Facilities

Jack Stewart Training Center Expansion & Enhancement



Proposed New JSTC Facilities

Jack Stewart Training Center Expansion & Enhancement



ELEC OPS TRAINING BLDG.

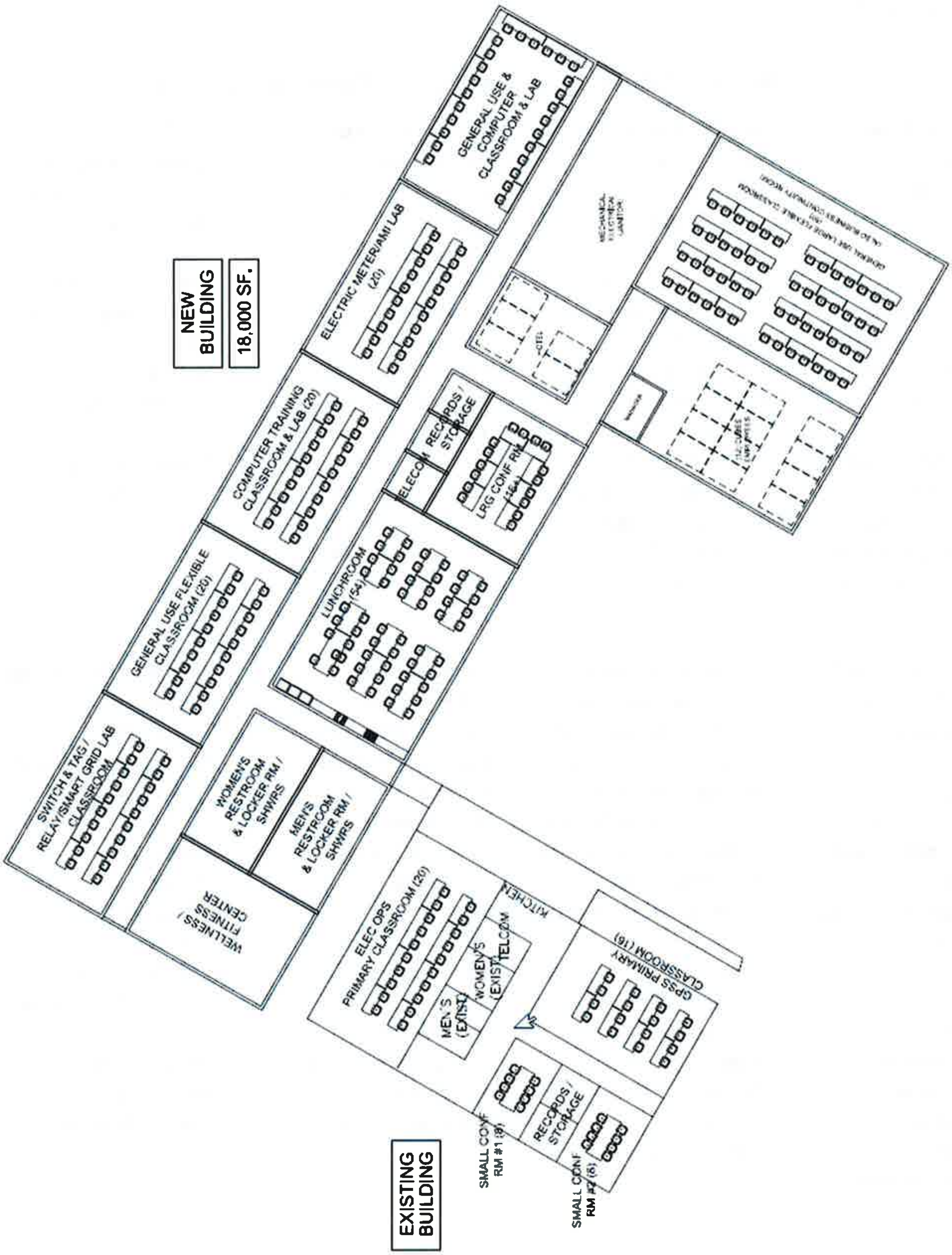
16,000 SF.

GAS OPS TRAINING BLDG.

8,700 SF.

Line School/Electric Ops and Gas Training Facilities

Jack Stewart Training Center Expansion & Enhancement



Expanded Main Training Facility

Jack Stewart Training Center Expansion & Enhancement

Appendix B

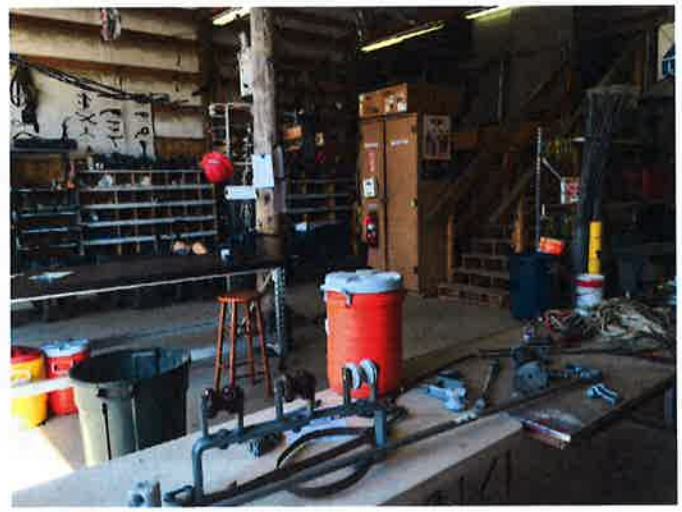
Jack Stewart Campus Training & Operational Capabilities

Compliance/Safety	Electric Operations	Gas Operations	GPSS
First Aid/CPR	Saturday School	OQ Refresher	Substation Equipment
Substation Entry	Cold School	Equipment Operator	Transmission Equipment
Arc Flash	Hot Secondary	Leak Survey	Battery Room
Flagging	Hot Stick	Pipe Joining	Relay Room
Forklift	Transformer Theory	Gas Worker	Transformer Theory
Trenching & Shoring	Solar Installation/Hazards	Locating	Motor/Generator Theory
Confined Space Entry/Rescue	Smart Grid	Welding	Welding
Respirator/SCBA Training	Adv Meter Infrastructure	Mechanics I & II	Hydraulics
Crane Certification	Fault Finding	Regulator Stations	Equipment Operator
Mock Drills	Bucket/Pole Top Rescue	Tapping & Stopping	Smart Grid
IPM Training/Refresher	Vault Safety/Rescue	Gas Meters	Clearance & Tagging
Lockout/Tagout	Ladder Safety/Rescue	Cathodic Protection	Digger/Derrick
Switching & Tagging	Tower Safety/Rescue	Appliance T-shooting	
Adv Switching & Tagging	Digger/Derrick	Valve Maintenance	
Equipotential Grounding	Equipment Operator	Gas Fire school	
RF Exposure			

Pre-App Line School	Corporate Training	Other Training	Facilities/Technology
Electric AC/DC Theory	Leadership Development	CDL/Refresher	Classrooms
Basic Math/Algebra	Communication Leadership	Elec Dist Stds Course	Training Offices
Climbing	Managing through Change	Const Proj Coordinator	Temporary Work Station
Tower Safety	New Hire Orientation	Dispatch	Lavatory/Showers
Overhead Distribution	Avista Community Academy	Gas Control Room	Locker Room
Underground Distribution	Customer Service/Experience	System Operations	Fitness Center
Transmission	Avista Project Deliver	Engineering	Storage
Commercial Driver's License	Avista Leadership Program	EOP	Vehicle Canopies
OSHA 10 T&D	BPI	Computer Training	Parking
Flagging	Team Building	Pre-Employment Testing	Web Conferencing
Forklift	Electric AC/DC Theory	Maximo	Recording/Broadcasting
First Aid/CPR	Gas Theory	GoBook	Kitchen/Dining
Equipment Operator	Utility Operations	ILT/OJT Train-the-Trainer	Computer Lab
Pole Top Rescue	Touchpoint	Industry Events	Transformer Room
Bucket Rescue	DISCOM	Innovation Groups	Business Continuity
Digger/Derrick	Community Education	Tryouts	
Interviewing/Resume Prep			

Appendix C

Examples of Line School & Electric Training Facilities



Examples of Gas Training Facilities

Appendix D

Jack Stewart Training Center

Budget Allocation:

Currently, $4.5 M is approved in budget year 2020.

ESTIMATED COSTS		Cost per SF (Low - $135)	Cost per SF (High - $185)
Elec Ops Training Bldg SF	16,000	$2,160,000	$2,960,000
Gas Ops Training Bldg SF	6,700	$904,500	$1,239,500
Main Training Bldg SF	18,000	$2,430,000	$3,330,000
2. Site Work		$450,000	$450,000
(91K SF Parking Lots, utilities, new septic and/or sewer)			
3. IS-IT		$750,000	$750,000
(New servers/switches, conf rm A/V, cabling)			
4. Furniture		$800,000	$800,000
(new chairs, desks, conference rooms, tool shelving)			
5. Professional / Consultant Fees		$150,000	$150,000
6. Overhead / Contingency		$600,000	$600,000
Total Capital Costs		$8,244,500	$10,279,500

Appendix E

Estimated Annual Cost of Using Rental Facilities					
Projected Rental Cost Based on Average Annual Use for All Activities					
JSTC Historical Usage by Classroom					
Classroom	**2016**	**2015**	**2014**	**2013**	**Average Days/Year**
Main	154	178	171	181	171
Large	159	171	141	169	160
Tech	149	102	95	100	112
Shop	110	95	105	76	96
Total Days	**573**	**546**	**512**	**526**	**539**
Annual Average Cost to Rent Rooms ($560/day with A/V)					$301,920.00
Estimated Added Travel to Rented Facility					
Locations (Round Trip)		**Time**	**Miles**	**Rate**	**Total**
Mission to Jack Stewart		24	10	$0.55	$5.50
Mission to Center Place		36	22	$0.55	$12.10
Difference between locations		12	12	$0.55	$6.60
Average 15 participants per class with 539 classes per year					
Additional hours spent traveling per year					1617
Cost of additional time per year ($45.44/hour loaded wage)					$117,593.53
Additional miles spent traveling per year					97,046
Cost of additional miles per year					$53,375.14
Annual Average Cost of Additional Travel to Rented Rooms					$170,968.67
Estimated Annual Total Cost of Using Rented Rooms					**$472,888.67**

Estimated Annual Cost to Train Gas Apprentices Using External Training Providers Due to Loss of Training Facilities		
Weeks	**Course**	**Total Cost**
3.6	Training at Regional Gas Utility	$2,760.00
3.6	Lodging during training	$1,800.00
3.6	Air Fare	$792.00
3.6	Rental Car	$925.20
3.6	Meals	$900.00
3.6	Travel Time	$1,520.64
Estimated Cost to Train One Gas Apprentice Externally		$8,697.84
Cost with Projected Gas Average of 8 Apprentices Per Year		**$69,582.72**

Estimated Annual Cost to Deliver Classroom Components of OQ Program to Gas Employees Due to Loss of Training Facilities	
Additional hours spent traveling per year	475
Cost of additional time per year	$28,842.00
Additional miles spent traveling per year	15200
Cost of additional miles per year	$8,360.00
Annual Average Cost of Additional Travel to Rented Rooms	$37,202.00
Annual Average Cost of renting rooms for Operator Qualification	$25,200.00
Annual Total Average Cost of for Operator Qualification	$62,402.00
Estimated annual cost of not having a gas training facility	**$131,984.72**

Estimated Annual Cost of Using Rental Facilities	**$604,873.39**

Airport Hangar

1 GENERAL INFORMATION

Requested Spend Amount	$1,500,000
Requesting Organization/Department	Facilities
Business Case Owner	Eric Bowles, Facilities Manager
Business Case Sponsor	Anna Scarlett, Manager of Shared Services
Sponsor Organization/Department	Shared Services
Category	Project
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

Steering Committee:

- Facilities Manager
- Manager of Shared Services
- Chief Pilot
- Captain
- Project Manager, Facilities
- Real Estate Manager

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

- Vice President of Energy Delivery
- Executive Officers

2 BUSINESS PROBLEM

Avista currently subleases a hangar owned by Spokane International Airport and leased by the airport to Merlin Enterprises, for secure storage and maintenance of our company aircraft and for daily operations by the flight crew. Avista will lose the sublease on the hangar after July 31, 2018, at which time Merlin's lease will end. At that time, airport management plans to demolish the existing hangar as part of a plan to reclaim the existing property and relocate private hangars to a different part of the airport. At that time, Avista will need to secure a new hangar for the aircraft.

3 PROPOSAL AND RECOMMENDED SOLUTION.

Option	Capital Cost	Start	Complete	Risk Mitigation
1. **Recommended**: Build a new Hangar at Spokane International Airport.	$1,500,000	01 2018	12 2018	
2. Extension of the existing sublease.	$0	8 2018	10 2019	
3. Co-Lease an existing structure with another plane.	$0	N/A		
4. Find a location at another Airport.	N/A	N/A		

Four options were considered for securing a hangar for the aircraft, including building a new hangar, extending use of the current hangar, relocating to another airport, and co-use of an existing hangar.

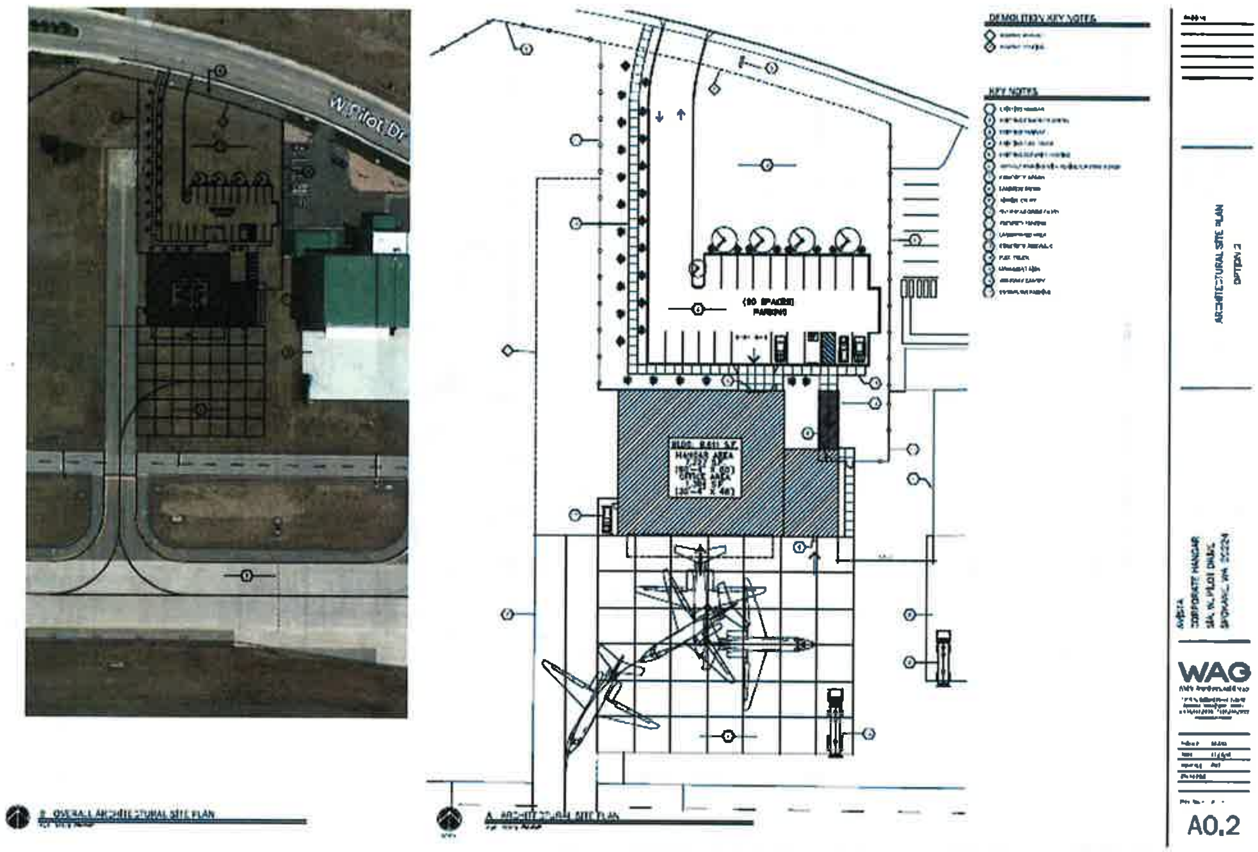
Option 1 (Recommended): Build a new Avista-owned hangar on land leased directly from Spokane International Airport.

This solution is recommended for the following reasons:

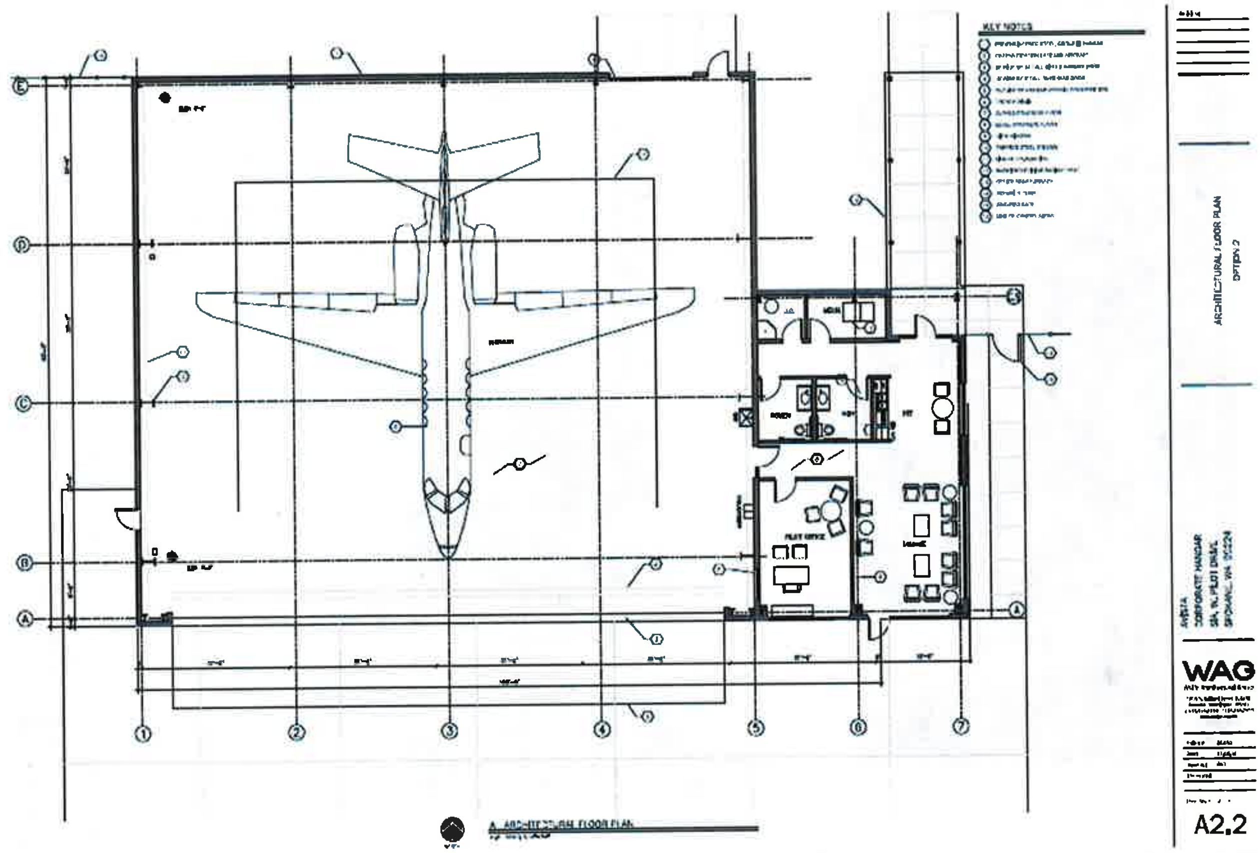
- Spokane International Airport is convenient to headquarters.
- The airport is currently offering a good selection of plots, with good approaches and footprints that would allow easier separation of the public entrance from the secured part of the airport.
- We could secure a long-term lease with the airport and lock in lease payments. Current discussions include a lease term of up to 50 years.
- Construction in 2018 would allow us to take advantage of lower interest rates and construction costs than what we would likely get in 2019 or 2020.
- Leasing directly from the airport will allow us to de-ice and fuel the aircraft ourselves or through a contractor we select, rather than having to use the airport's services exclusively, saving costs and increasing efficiency.
- Constructing the hangar would allow us to design a structure with the future in mind. The current aircraft has an expected life of up to 20 years, and a new aircraft would change the required size of height and width of the hangar. A new hangar would include the following elements (see schematics):
    - Ample plane storage and room for maintenance and maneuvering
    - Minimal parts storage
    - Restrooms
    - Offices for flight staff
    - Secure parking with Avista access
    - Separate unsecured and secured areas for travelers

Airport Hangar

Schematic Option:



Airport Hangar



Option 2 – Direct lease from Spokane airport

We looked into pursuing an extension of the existing sublease, and confirmed that we can convert our sublease into a direct lease with the airport and stay in the existing hangar temporarily. However, because of airport management's plans for vacating the land the current hangar is on, we would be able to do this for a maximum of 6-12 months, and we would need to be in negotiations with the airport on a long term solution.

Option 3 – Share existing hangar

There is currently one hangar at the Spokane International Airport large enough and with owners who would consider co-leasing with Avista. Avista would not have ownership of this building, which presents several challenges:

- Sharing space with co-lessor(s) would require additional security measures to protect our aircraft and ensure the security of our network (located in the office of the flight crew). These measures could require additional construction of secured entrances and areas and/or hiring security personnel, and would need to be coordinated with and approved of by any co-lessors, at Avista's cost.
- There is also a concern about damage to the airplane. The plane would be stored in tight quarters alongside another aircraft, and damage is more likely to occur as planes are maneuvered in and out of the hangar.

Maintaining the aircraft and keeping it secure from co-lessor's employees and/or mechanics would present a security logistical challenges as well.

- Currently we do not have to coordinate departures or arrivals with another entity. Co-leasing would require us to share flight information and coordinate our departures and arrivals with our co-lessor.
- Additional future co-occupants could be brought in and affect Avista's use of the hangar.

Option 4 – Store at another airport

A. Felts Field was looked into as an option to move the plane but the runway is not long enough. A 7,000-ft runway minimum is required to safely land and takeoff with our current aircraft.

B. The Coeur d'Alene airport was researched as a solution. There are no options to lease an existing hangar available; however there is the possibility of building a hangar at that location. The cost of building a hangar at the Coeur d'Alene Airport would be the same or comparable as building a hangar at the Spokane International Airport, but would increase overall travel time and cost for employees having to drive to Coeur d'Alene for flights.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Airport Hangar 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:	Facilities Manager		
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 member		

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: 02/24/2017

New Deer Park Service Center

1 GENERAL INFORMATION

Requested Spend Amount	$6,500,000
Requesting Organization/Department	Facilities
Business Case Owner	Eric Bowles / Vance Ruppert
Business Case Sponsor	Anna Scarlett
Sponsor Organization/Department	H07
Category	Project
Driver	Asset Condition, Performance & Capacity

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

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

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

- Deer Park Operations: Frank Binder. Previous stakeholder included Bryan Cox.
- Real Estate: Rod Price, Dave Atherton, Ron McGregor.
- Warehouse: Laurie Heagle. Previous stakeholder included April Spacek.
- 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

2 BUSINESS PROBLEM

The Deer Park Service Center serves as the main electrical and gas operations facility for approximately 16,500 customers in the Deer Park and surrounding area, such as Colbert, Chattaroy, Elk, and Loon Lake. Approximately 10 Avista field crew and administrative support employees are based out of the site. This facility also supports our local operations during storms and power outages in the north Spokane County and Stevens County regions to help serve an additional approximately 34,000 customers.

The existing Deer Park Service Center was constructed in approximately 1971, and many of its building components, systems, and equipment have deteriorated over time. Over the decades, previous capital projects included new and replacement asphalt for exterior storage yards, re-roofing, a vestibule addition, a new pole building for service vehicle truck parking, etc.

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

As part of the survey, the following images were captured and are representative of current conditions:

In addition to the low-scoring facility conditions, the original 1971 design of the service center was meant to accommodate a customer base half of what it is now currently serving. In just the city of Deer Park alone, the U.S. Census registered a 282% increase in population between 1970 and 2010. Please see table below for additional representative growth rates within the service center's overall territory from 1995 – 2013.

	1995	2013
Number of Employees Reporting to Site	6	10
Number of Electric Customers	4141	9477
Number of Gas Customers	3506	5040
Number of Electrical Poles	3200	5991
Number of Transformers	1500	2987
Miles of Conductor	1101	1550

With this growth increase, two additional meter readers, one lineman, and one groundman were added to the employee count in this facility since 1995. However, this in turn added three new Avista service vehicles as well as increased personal employee vehicle parking, further encroaching on the available square footage of the 1971 facility.

In addition, more materials, equipment, and vehicles are necessary to maintain the electric and gas systems for the growing customer base. As such, the existing exterior storage yard and the interior warehouse/stores space is becoming too small for these increasing amounts of inventory.

There are also environmental concerns with the existing site located near railroad tracks, and close proximity to a city water well. In 2013-14, during a routine asphalt replacement project, contaminated soil and debris were discovered which required remediation and proper removal and clean up. There could be additional areas of costly contamination if future projects expose them.

The existing service building is tight for modern line truck and service vehicle sizes, which have grown considerably in length since Avista's 1970 fleet. Currently several trucks must be parked outside due to not being able to fit inside the building.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 **(Recommended)** –	$6,500,000	01/2015	12/2018

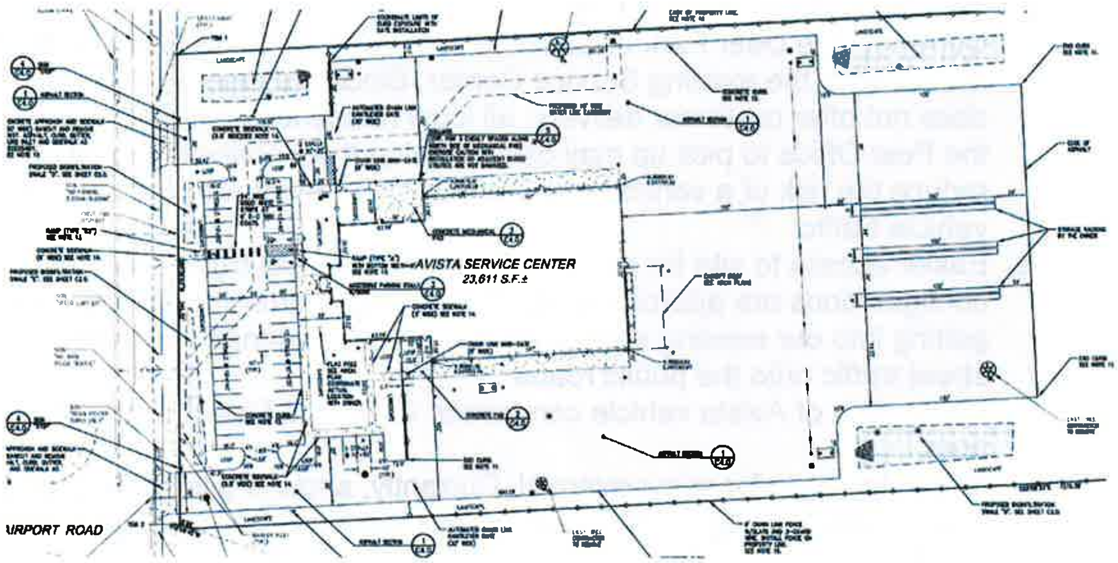
Purchase new site and construct new service center			
Option 2 – Purchase neighboring land next to existing site and build new / expand as needed.	~ $4,000,000	01/2015	12/2018
Option 3 – Do nothing.	$49K capital yearly. $54K O&M yearly. (Both values are approximate averages from the last 5 years)		

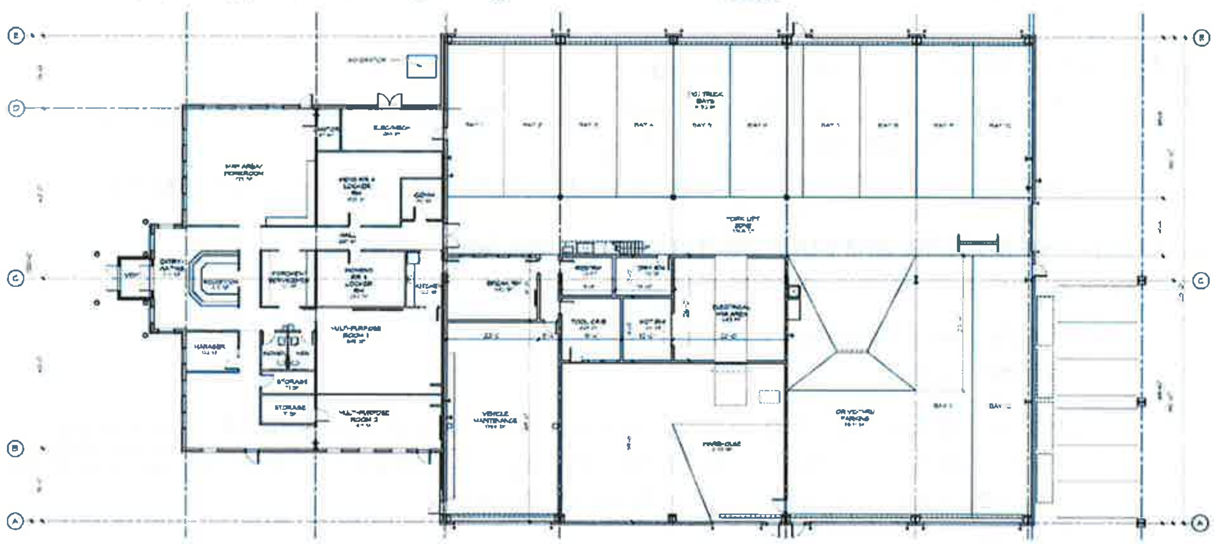
The three above options were produced with input from the Advisory Group listed above in Section 1, Item 1.1. Please note, individual stakeholders from the Advisory Group may not have been involved in producing all three options.

New Deer Park Service Center

Option 1 – Purchase new site and construct new service center ($6.5 million).

The recommended design solution is shown in the two drawings on the next page. Avista's Real Estate Department has located a vacant 10-acre lot in a new road extension and Local Improvement District (LID) created by the city of Deer Park, to promote industry and business within city limits. As part of the partially Federal-funded LID, the city installed sewer and water utilities to the site. Avista would develop and asphalt the street-side five acres of the lot and build a new 24,000-square-foot building.





The benefits this proposed design will provide include the following Items 1 through 4:

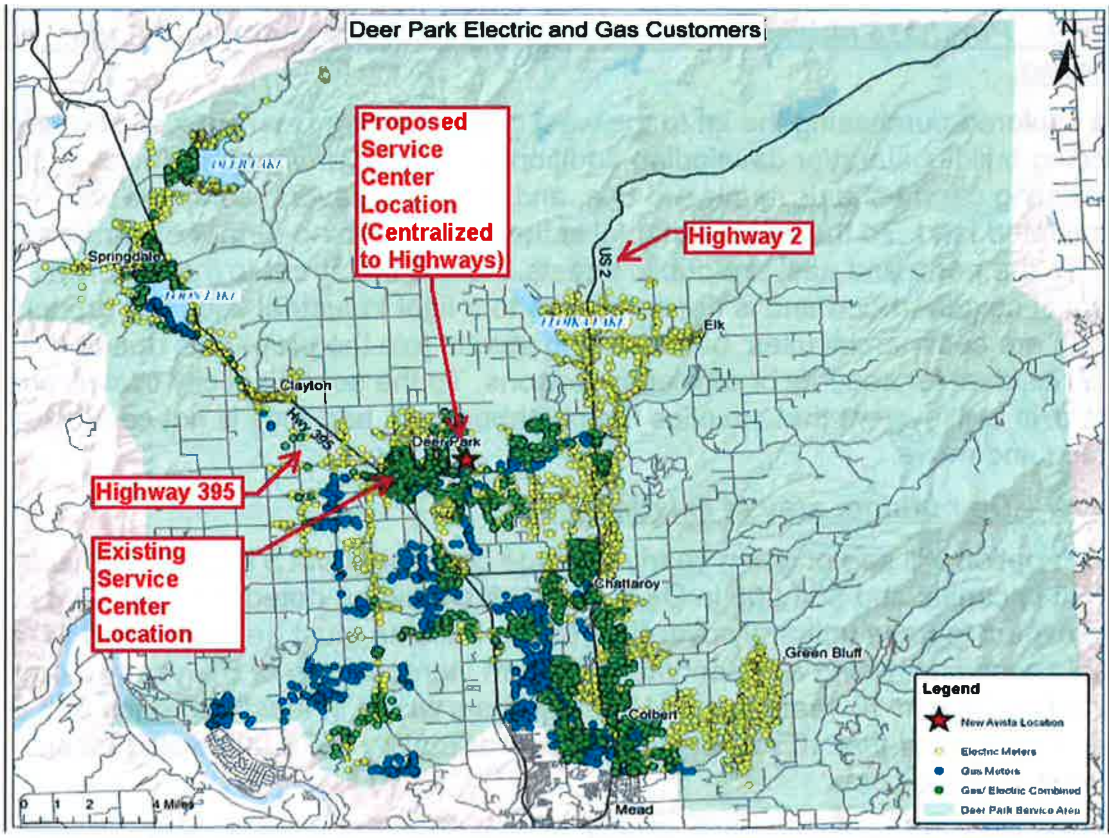
1. Estimated Cost Savings. The total cost savings, resulting from increased efficiency and production capabilities of Avista employees leading to direct cost savings, is estimated to be $59,046 yearly going forward.
2. Non-quantifiable improvements in safety of Avista employees, including but not limited to:
    - o Reduced risk of service truck backing accidents.
    - o Clearly articulated paths of service vehicle traffic on site.
    - o Separate employee and visitor parking from service yard traffic and

parking.
- Better clearances for employees that work with interior shelving and forklifts, and pick materials in the storage yard.
- Cranes to prevent lost time accidents resulting from manual lifting and moving of equipment and materials.
- Covered and heated parking areas to reduce the risk of lost time accidents or injuries from slips, trips, and falls.
- Security for lone workers in the office.
- Currently, the Deer Park Post Office and its 3,800 mailboxes are directly northeast of the existing Service Center. Since the Deer Park Post Office does not offer customer delivery, all local residents drive and/or walk to the Post Office to pick up mail daily. Moving the Service Center would reduce the risk of a vehicular or pedestrian accident with our service vehicle traffic.
- Easier access to site for operations vehicles. Avista truck and trailer configurations are approximately 70 feet long. Currently there is difficultly getting into our existing service center, and occasionally Avista blocks street traffic onto the public roads.
- Elimination of Avista vehicle congestion within the Deer Park downtown area.
- Dedicated area for snow removal. Currently, snow is piled near public streets, and melting snow occasionally floods the existing storage building on site.

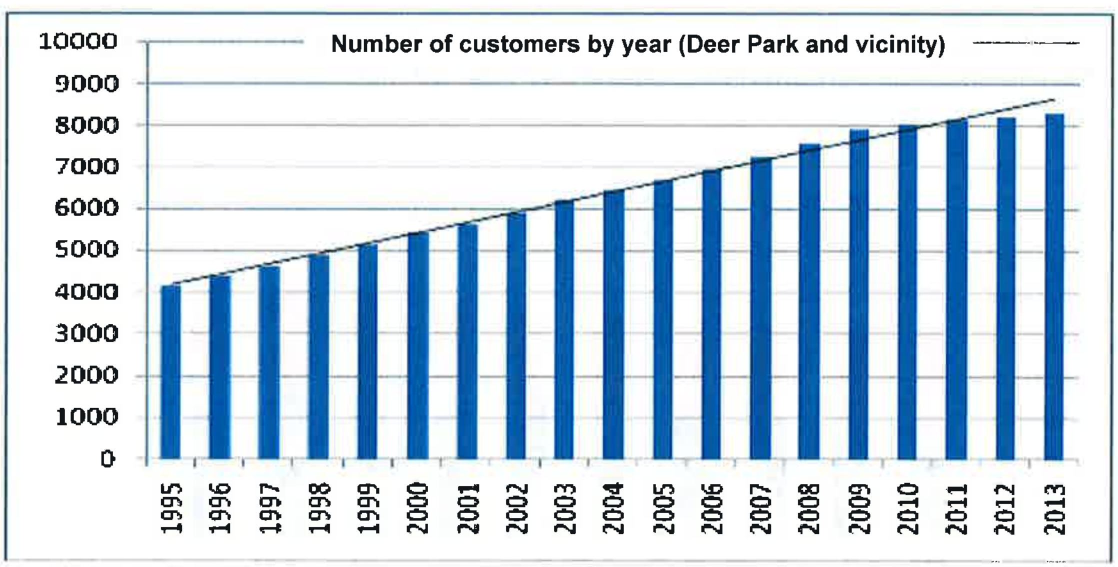
3. Non-Quantifiable Equipment Savings
   - Potential increased longevity of service vehicles/trucks due to being covered and/or in heated parking.
   - Better deterrent for theft concerns of materials, vehicles, or equipment.

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 employee efficiencies.
   - Faster response time of field crews due to centralized location between Hwy 2 and 395, especially during outages. Please see territory map below to show location, and proximity to customers.

New Deer Park Service Center



- Increased reliability of electric and gas operations.
- Increased customer safety due to the above three items, especially during a safety event such as an electric outage.
- Accommodating future customers and growth within the Deer Park and vicinity territory, assuming growth rates shown on historical data mentioned in "Business Problem" section, and graphically shown below.



- Ability to accommodate and assist additional customers south to Spokane or north to Colville in the event of an electric outage.

New Deer Park Service Center

Option 2 – Purchase neighboring land next to existing site and build new / expand as needed.

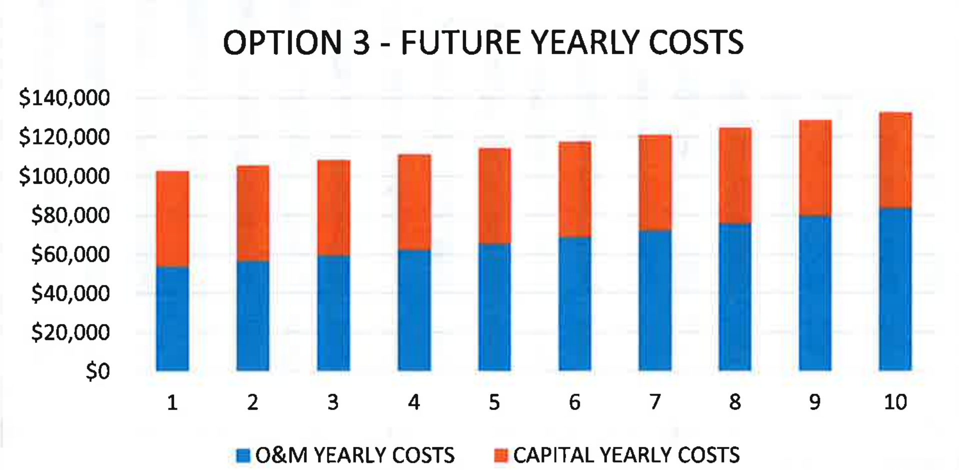
Avista explored purchasing the lot to the west of the existing Deer Park site, in hopes of expanding buildings and/or developing additional storage yard space. However, the lot is an existing car mechanic / junkyard use, and there are several concerns with contaminated land. To the west of that lot is the railroad, so no further expansion could occur. To the north and east are public streets. Across the street to the east is a residential neighborhood and is not conducive to a light industrial use. The properties to the north are commercial uses, but not being able to join the properties due to the public road is not ideal for security or efficiency reasons. To the south is a city owned property with its own well system that supplies the neighborhood, and thus is not conducive to purchase and move.

Option 3 – Do nothing, stay at existing site.

The third option will see ongoing yearly average costs at about $103,000 per year ($49,000 in capital and $54,000 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 $83,000. At the same time, over that 10 years a total of approximately $678,000 would be spent on O&M maintenance costs.

In regards to future capital costs, it should be expected that yearly spend will be roughly half of the 5 year average ($49,000 yearly) as building, site, and building systems are systematically replaced due to age or condition. Using this figure, a total of approximately $486,000 would be spent on capital costs over 10 years. However, it must be noted that 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 the failure.

This option also does not address proximity to railroad tracks and the city water well or potential residual soil contamination from the adjacent site.



4 APPROVAL AND AUTHORIZATION

Deer Park 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:		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	Vance Ruppert	04/25/17	Heather Rosentrater	04/25/17	New template

Template Version: 03/07/2017

Pullman Service Center

1 GENERAL INFORMATION

Requested Spend Amount	$7,600,000
Requesting Organization/Department	Facilities
Business Case Owner	Eric Bowles
Business Case Sponsor	Greg Gfeller
Sponsor Organization/Department	Electric Operations
Category	Project
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

The Facilities Department engaged with our Electric Operations and Environmental groups to determine the future of some of our legacy sites. They looked at a large number of items before determining the future of the Pullman Service Center. The team reviewed environmental impacts and regulations, future service center needs and the growth and needs of the Pullman Community.

Eric Bowles, Facilities Manager

Kevin Booth, Sr. Environmental Scientist

Bryan Cox, Director of Transmission and West Electric Operations

Greg Gfeller, Director of East Electric Operations

Laurie Heagle, Materials Management Manager

Jenny Blaylock, Pullman Manager

2 BUSINESS PROBLEM

The Pullman Service Center Facility was constructed in 1959, with various upgrades, remodels and additions since then. Some of the upgrades included the construction of an addition to the west side of the service center in 1979, the construction of a storage canopy and meter shop area, offices, a parking canopy and an office addition to the East side of the building in 2009.

The existing Pullman Service Center has a number of concerns. The existing storage yard is becoming too small for the ever-growing inventory. Currently we have done everything we can to capitalize on the existing storage space available. Also, added smart grid inventory will soon overwhelm storage yard. The property is too small for our needs and we are unable to purchase any additional land adjacent to the existing property. There is a hillside to the North and East of the property that would not be usable as it would require extensive excavation to bring it down to the same plane as the existing property. This is not feasible based on the elevation changes. To the Wes, the land is part of the highway drainage system so we are unable to purchase the land to add to our property.

Pullman Service Center

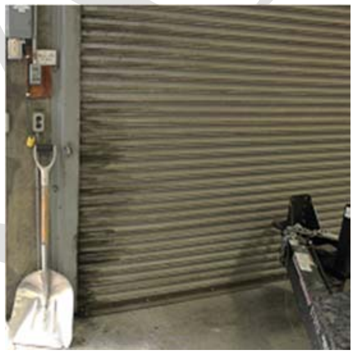
There are environmental concerns with poor storm water treatment and public highway runoff. The state has made some changes to the highway runoff but there are still concerns with the runoff and its impact and maintenance on our site. We have added a large amount of storm water mitigation but the entire site needs to have a review of the water run off plain and upgrades made. There are also concerns regarding run off from washing vehicles on the site, currently we are not properly mitigating our line truck washing runoff.

The existing building has minor code compliance and security issues. The interior of the main building is in need of an update and possibly a large reconstruction or renovation. The layout is no longer conducive to today's business needs. There a many ADA issues and much of the construction does not comply with current code. Many of the building systems are antiquated and have reached the end of their useful life.

The building had a complete survey completed in 2012. In that survey many items were identified that needed immediate replacement or repair. A new survey is to be completed in 2017 and the business case will be updated with the most current information as it is available. A few of the larger items are noted below.

The existing site septic tank has multiple issues with the system backing up. The sump pump also has issues and has needed continual maintenance.

All the roll up doors need to be replaced at the site. Many are damaged and beyond repair.


The built- up roof requires a lot of maintenance and has a number of cracks and flashing that needs repair.


Pullman Service Center

In the interior there are needs for flooring replacements, furniture changes and ceiling grid improvements.

The HVAC system is in need of replacement.

There is no existing fire safety systems currently at the Pullman location. This is considered a critical failure and would need to be rectified immediately if we do not move forward with building a new location.

Current Pullman Service Center

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete	Risk Mitigation
Do nothing	$0	N/A		
New Pullman Service Center	$7,600,000	08 2019	12 2020	
Pullman Renovation/ Storage Yard Land	$750,000	08 2019	08 2020	

The proposed solution to the business problems identified above is to build a new Service Center. The New Service Center will be located on a new vacant property that we could locate both the new service center, the pole yard and warehouse. This option would allow us to find a property that could allow for any future growth needed.

The New Service Center, regardless of location, will include environmentally protected transformer storage areas and adequate storm water protection. This includes oil water separators for the entire facility. This is the new Environmental standard for design for Avista and meets the legal requirements as well. The new facility will centralize all of Avista crew functions into one location, saving windshield time each day for the crew.

The new service center would be designed to meet the needs of today's employees and would meet current code requirements. All the building systems would be designed to today's technology and planned to be more efficient than the existing location.

The current building could be sold to offset some of the cost of building new.

Alternatives:

In order to avoid constructing a new Pullman Service Center Avista would need to continue upgrading the existing Service Center building. This would include several hundred thousand dollars' worth of upgrades and improvements. Purchasing additional properties and expanding the service center is not an option. Hills and grading difficulties will cost hundreds of thousands of dollars any time we were to increase the yard by even a little bit.

We would need to purchase land in another area of town and create an additional storage yard. This would require that crews drive to and from this new storage yard several times a day.

4 APPROVAL AND AUTHORIZATION

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

Signature:		Date:	
Print Name:	Eric Bowles		
Title:	Facilities Manager		
Role:	Business Case Owner		

Signature:		Date:	
Print Name:			
Title:			
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	*Lindsay Miller*	*03/14/2017*	*Eric Bowles*	*03/17/2017*	*Initial version*

Template Version: 02/24/2017

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	Anna Scarlett, 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 meet 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*
AVA Avg Age	*8.03*	*7.81*	*7.59*	*6.81*	*6.55*	*6.23*
Industry Avg Age	*6.11*	*6.27*	*6.27*	*6.56*	*6.53*	*6.38*
Avg Op Cost / Unit	*$10,924*	*$11,558*	*$11,534*	*$10,845*	*$9,739*	*$9,285*

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.

Fleet Services Capital Plan

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
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

Fleet Services Capital Plan

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 $7,811. 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 $5,810. 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 $6,913. Over the 14-year period, this strategy will cost fleet 14 x $5,816 = $81,424

Fleet Services Capital Plan

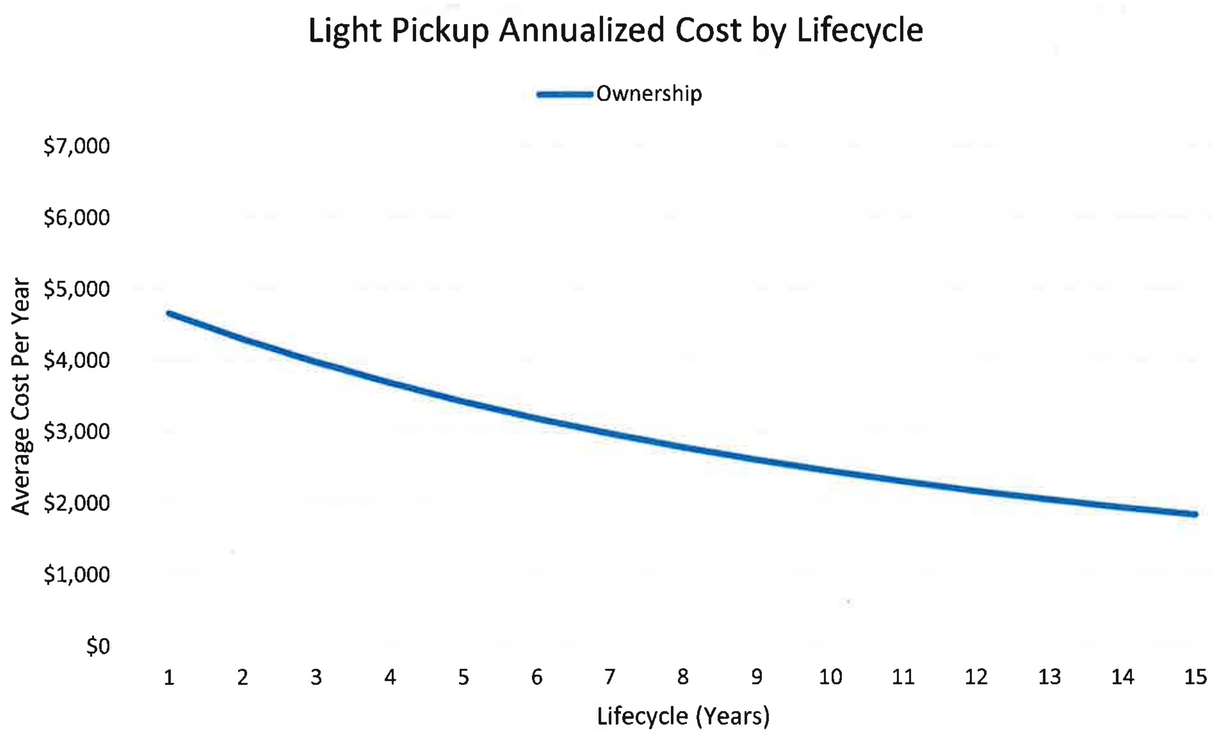
The table below summarizes the calculations in the previous example.

	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.

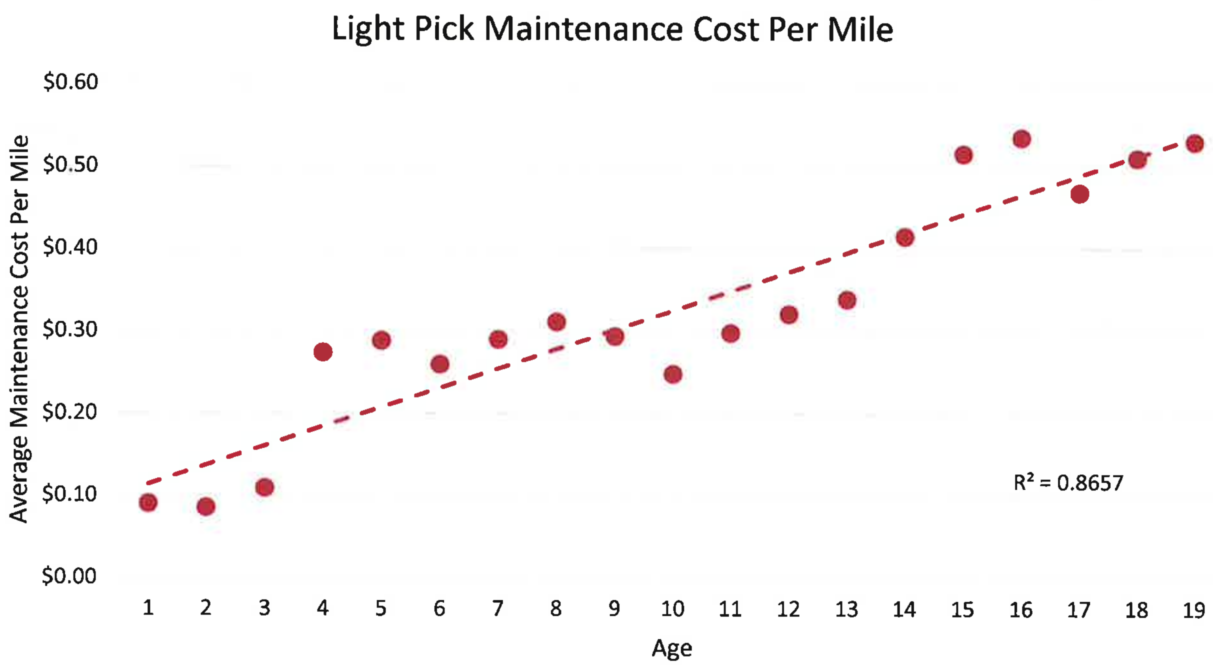
Modeling Ownership Cost

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.



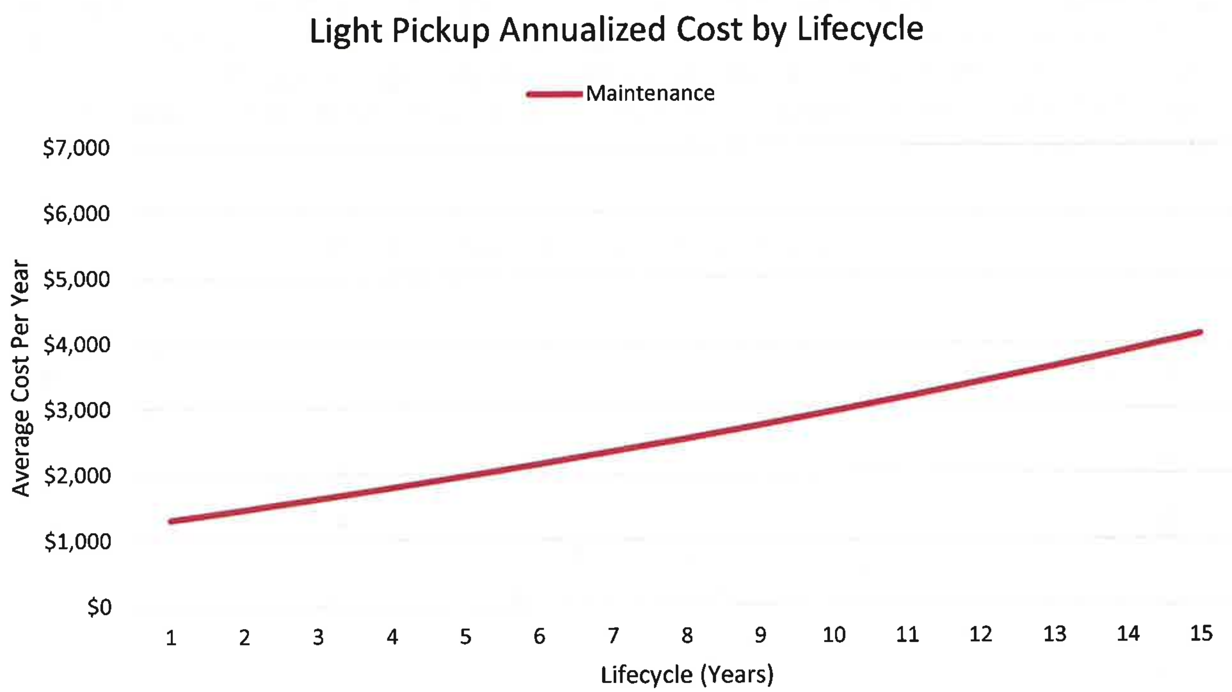
Modeling Maintenance Cost

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.



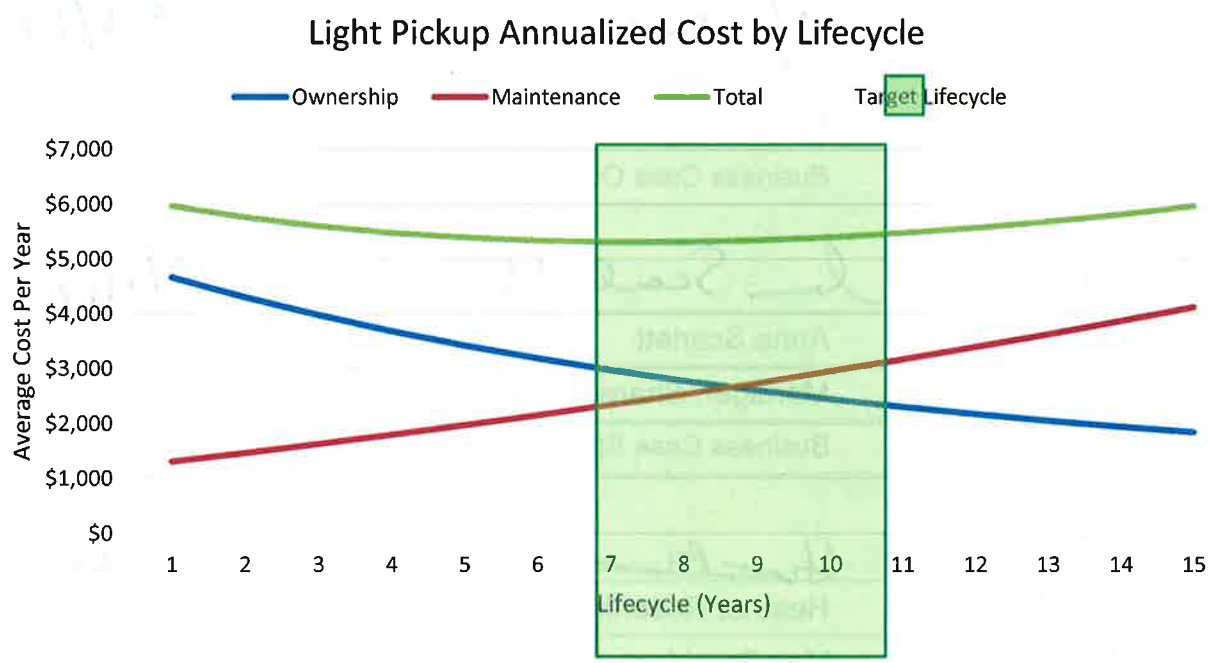
Fleet Services Capital Plan

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.



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: [signature] Date: 5/1/17
Print Name: Greg Loew
Title: Manager, Fleet Services
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

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*

Template Version: 03/07/2017

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: Date: 4-13-2017

Print Name: Jody Morehouse

Title: Director Gas Supply

Role: Business Case Owner

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