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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-17-01
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-17-01
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	EXHIBIT NO. 8
AND NATURAL GAS CUSTOMERS IN THE	)	
STATE OF IDAHO	)	HEATHER L. ROSENTRATER
	)	

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

Customer Usage
State of Washington - Electric & Gas
As of December 31, 2016*

Electric Schedule	**No. of Customers**	**kwh (000s)**	**% of Total kwh**
Residential Schedule 1	104,843	1,098,331	38%
General Schedules 11 & 12	21,012	357,654	12%
Large General Schedules 21 & 22	1,139	657,407	23%
Extra Large General Schedules 25 & 25P	11	729,402	25%
Pumping Schedules 30, 31 & 32	1,406	60,737	2%
Street & Area Lights Schedules 41-49	149	13,345	0%
	128,560	2,916,876	100%

Natural Gas Schedule	**No. of Customers**	**Therms (000s)**	**% of Total Therms**
General Service Schedule 101	78,604	50,611	40%
Large General Service Schedules 111 & 112	1,421	21,041	17%
Interruptible Service Schedules 131 & 132	-	-	0%
Transportation Service & Other	8	55,784	44%
	80,033	127,436	100%

Total Electric & Gas Customers	208,593

* Average Customers and Billed Usage

2016

Electric Distribution System 2016 Asset Management Plan

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Avista Corp
02-05-2016

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Purpose

This report documents the asset plans for Electrical Distribution System for Avista. The plans discussed here represent what we believe to be the best approach to managing Avista's Distribution assets and provides the Key Performance Indicators (KPIs) and metrics Asset Management (AM) to support the plans and demonstrate the effectiveness of those plans implemented. The report also helps identify areas for improvement or opportunities to improve the value we receive from our assets.

Some of the metrics provide a basis for comparing how an asset performed with a program and how it would have performed without a program. The difference in performance provides an estimate of the cost saving of the program. The estimated savings is only a snapshot in time and may not represent the exact savings; it provides a relative comparison and supporting justification for AM decisions made in the past. Other KPIs and metrics provide indications of how well an asset is performing and helps determine when further work is required. KPIs and metrics tracking also help evaluate the accuracy of different AM models and determine when or if a model should be revised.

Executive Summary

The primary message of this asset management plan is that the programs in place have been positively impacting the number of outages and decreasing the cost to mitigate these failures. Continuous improvement upon these programs is necessary to maintain reliability and efficiency. Assets are aging faster than our current programs and plans can alleviate. However, programs are continually being analyzed and updated to continue to improve our overall management of the distribution assets.

If available, each of the below summaries include a ranking criteria table. This table includes the Customer IRR from the business case, the Benefit to Cost Ratio from our IRR calculation analysis and the Risk Reduction Ratio from the supporting business case.

Current Programs:

1. **Grid Modernization** – includes replacing poles, transformers (Pad Mount, Overhead & Submersible), cross arms, arresters, air switches, grounds, cutouts, riser wire, insulators, conduit and conductors in order to address concerns related to age, capacity, high electrical resistance, strength, and mechanical ability. The program also includes the addition of wildlife guards, smart grid devices and switched capacitor banks, balancing feeders, removing unauthorized attachments, replacing open wire secondary, and reconfigurations. Although this is a new program it does appear to be reducing outages for the feeders worked on. The program has slowly shifted from "Feeder Upgrade" to this new larger scoped Grid Modernization program. With only a few years of data since completion of the earliest feeders, this program needs time to mature, so the full value of the program can be realized.

Customer IRR	Benefit/Cost	Risk Reduction Ratio
6.4%	-	0.7293

2. **Transformer Change-Out Program** – has run smoothly for the past few years with the targets and KPIs being met regularly. This program was largely implemented to reduce the environmental concern of Polychlorinated biphenyls (PCBs) in some Pre-81 transformers. The environmental risks have been heavily decreased, with a focus in areas that have a greater potential to impact our waterways. Since these are also old and inefficient transformers, our efficiency has increased. However, this program is about to switch over to the second phase. With this switchover the program will "piggy back" on Wood Pole Management for a complete cycle to finish removing the non-PCB Pre-81 transformers from our system. The effectiveness and efficiency of this second phase is yet to be determined.

Customer IRR	Benefit/Cost	Risk Reduction Ratio
5% < 9%	-	0.0670

3. **URD Cable Replacement** – is the programmatic replacement of the pre 1982 unjacketed Underground Residential District (URD) cable. Originally the removal of all of the pre 1982 cable was to be completed in 5 years; however, funding didn't match the original target and some cable remains in use today. To date the program has paid great dividends towards reducing URD Cable-Pri events when compared to where it would have been without taking action. Although many feet of this type of cable remain in use, the outages have been greatly reduced and we are seeing few outages due to this early generation of cable.

Customer IRR	Benefit/Cost	Risk Reduction Ratio
9% < 12%	-	0.1958

4. **Vegetation Management** – maintains the distribution system clear of trees and other vegetation. This reduces outages caused by trees and to a lesser extent outages caused by squirrels. This program has had a big impact on reducing our number of unplanned outages. Reducing these outages improves our reliability, reduces our risk during storms and decreases safety hazards for our employees working on the distribution system. Tree related outages continue to decline and the cost per mile to do this program have continually decreased due to efficiency gains, improved processes and new methods such as per unit costing; which in turn drives up the value of this program.

Customer IRR	Benefit/Cost	Risk Reduction Ratio
63.39%	14.74	22.39

5. **Wood Pole Management** – inspects and maintains the existing distribution wood poles on a 20 year cycle. In addition to inspecting the poles, we inspect distribution transformers, cutouts, insulators, wildlife guards, lightning arresters, crossarms, pole guying, and pole grounds. The inspection of these other components on a pole drives additional action to replace bad or failed equipment along with replacing known problematic components. Overall, WPM has been effective at maintaining the current level of reliability to our customers, however, we will need to complete work on more feeder miles to control the impact on future reliability.

Customer IRR	Benefit/Cost	Risk Reduction Ratio
7.42%	2.283	0.6879

6. **Area and Street Light** – replaces non-decorative high pressure sodium and mercury vapor lights with equivalent LED lights. The initial year of the program changed out 100W and 200W HPS and MV non-decorative street lights in Washington only. The scope was changed and going forward all wattage types of non-decorative lights for both area and street lights will be replaced in both Washington and Idaho. The first year of the program finished on budget with more lights completed than anticipated. The scope change and potential budget cuts may push this 5 year program out, however, the impressive first year gives hope that with an intact budget the program may complete closer to the 5 year cycle than not.

Customer IRR	Benefit/Cost	Risk Reduction Ratio
7.92%	1.917	.0718

7. **Worst Feeder** – This program aims to improve the reliability of its most underperforming distribution circuits. Projects vary by individual circumstance but in many cases additional circuit reclosers are installed to reduce outage exposure and to automatically restore power to upstream customers or circuits in outage prone areas are converted from overhead to underground or circuits are effectively 'hardened' by shortening conductor span lengths or by increasing phase spacing. This programs goal is to selectively improve the feeders with the worst SAIFI and so far this program seems to be producing as planned. Not all feeders drop off the list after work is done but most have a large reduction in outages after work is done.

Customer IRR	Benefit/Cost	Risk Reduction Ratio
5% < 9%	-	0.2062

8. **Segment Reconductor and Feeder Tie** – addresses specific congestion issues in the distribution system. The purpose of the program is to reconductor portions of circuits or to install additional 'tie' points to enable load shifts and transfers. In most situations, this involves that poles be replaced and that existing conductors remain in service during the majority of the work. Transformers, customer service wires, and other equipment including crossarms, insulators, guy wires, brackets, communication circuits, fuse holders, and other hardware must be installed new or transferred to new poles. This program helps maintain operational flexibility and circuit reserve capacity for our distribution system.

Customer IRR	Benefit/Cost	Risk Reduction Ratio
0%	-	1.489

9. **Network** – Major network equipment falls into four categories: network transformers, network protectors, cable (primary and secondary), and physical facilities – duct banks, vaults, manholes, and handholes. There are no established performance metrics for this program. The network is designed with redundancies to prevent outages and our current outage management tool does not "see" network events, making it difficult to keep track of the typical metrics used in other programs.

Customer IRR	Benefit/Cost	Risk Reduction Ratio
9% < 12%	-	1.285

10. **Protection** – Avista's Electric Distribution system is configured into a trunk and lateral system. Lateral circuits are protected via fuse-links and operate under fault conditions to isolate the

lateral in order to minimize the number of affected customers in an outage. Engineering recommends installation of cut-outs on un-fused lateral circuits and the replacement of obsolete fuse equipment (e.g. Chance, Durabute/V-shaped, Open Fuse Link/Grasshopper, Q-Q, Load Break/Elephant Ear, and Porcelain Box Cutouts). As part of the program, sizing of fuses will be reviewed to assure protection of facilities, as well as coordination with upstream/downstream protective devices. This program began as an obsolete replacement program but has grown to incorporate un-fused and wrong fused laterals. Cutout outages have decreased through this program but with the added scope a new metric will need to be made. This is a targeted program to ensure adequate protection of lateral circuits and to replace known defective equipment.

Customer IRR	Benefit/Cost	Risk Reduction Ratio
9% <12%*	-	0.0990*

*Original scope

To date the programs developed have made a huge impact in the number of outages on the distribution system. The cyclic programs need to continue to be analyzed and updated to maintain the improved reliability, reduced risk and decreased O&M costs. Since the assets continue to age faster than the current programs can mitigate, new programs or scope changes will be required going forward to continue to provide our customers with safe and reliable service.

Data Sources

Much of the information used in this report's metrics comes from three sources: Annual Sustained and Momentary outage data; Outage Management Tool (OMT) events; and Oracle (financial and supply chain database). The annual Sustained and Momentary outage data is generated by the Distribution Dispatch Engineer each month in a spreadsheet. The Sustained and Momentary outage data for years 2001 – 2007 was modified by AM to align the reasons and sub-reasons to coincide with the current descriptions. While the Sustained and Momentary outage data comes from OMT data and is a subset of OMT data, this data has been scrubbed by the Distribution Dispatch Engineer to improve its accuracy.

The OMT tracks outages and customer reports of problems on the Distribution system, Substations, and Transmission events that cause outages on the Distribution system. This data includes sustained outages, momentary outages, and events without outages. Events that only cause a partial outage or no outage at all do not show up in the Sustained and Momentary outage data, because the data does not fit the definition of a sustained outage or a momentary outage. However, the OMT data is sometimes subject to reporting an event more than once. The Distribution Dispatch Engineer reviews the data and strives to prevent duplication by rolling events up and editing the data. However, some duplication still occurs. OMT data is used to calculate number of outages, number of OMT events (outages, partial outages, and non-outage events), outage duration, number of customers impacted, response times, System Average Interruption Frequency Index (SAIFI) impacts, and System Average Interruption Duration Index (SAIDI) impacts.

Discoverer provides financial, customer information, and material usage information from our warehouse and financial systems. Spending and material can be tracked to the ER and BI level for capital work and the Master Activity Code (MAC) and Task for Operations and Maintenance (O&M) work.

Standard Calculations

See reference the "2010 General Metrics Data Collection and Analysis for System Reviews" for the details and examples of how different measures and metrics are calculated.

Review of OMT Data and Trends

Examining the data in OMT reveals a lot of information which helps Avista understand the condition of our assets and shows some trends we can address. Below, we will examine various trends within OMT Events per Year, SAIFI trends by OMT Sub-Reasons, and other measures.

OMT Events per Year

Table 1 shows the past seven years of data out of OMT by Sub-Reason and allows trend analysis. OMT Events represents cost and action for Avista, so it was selected as a basis for much of our trending. However, OMT Outage data (shown in Table 2) can have a different trend than OMT Events. Since the SAIFI analysis already includes outage data, AM selected to trend OMT Events and SAIFI contribution. Based on Table 1, we identified the top 10 increasing and decreasing trends in OMT Sub-Reasons. The Top 10 increasing trends in the number of OMT events by year is shown in Table 3 and the Top 10 decreasing trends in the number of OMT events by year is shown in Table 4.

Table 1, OMT Events by Sub-Reason and Year

OMT SUB-REASON	2009	2010	2011	2012	2013	2014	2015
Arrester	19	32	30	36	24	32	20
Bird	218	179	332	231	270	248	227
Capacitor	4	2	0	4	4	3	0
Car Hit Pad	139	105	98	105	117	104	88
Car Hit Pole	217	298	339	355	369	378	307
Conductor - Pri	42	64	81	110	142	135	83
Conductor - Sec	286	273	310	286	331	323	299
Connector - Pri	111	101	100	79	85	85	51
Connector - Sec	429	410	408	390	336	321	283
Crossarm-rotten	23	25	28	19	18	26	23
Customer Equipment	1626	1458	1384	1434	1368	1328	1200
Cutout/Fuse	197	217	176	209	171	196	109
Dig In	164	149	123	109	103	104	96
Elbow	7	5	8	2	10	6	5
Fire	157	203	234	230	282	200	206
Forced	51	63	67	33	63	68	29
Foreign Utility	724	894	720	734	720	602	765

OMT SUB-REASON	2009	2010	2011	2012	2013	2014	2015
Insulator	32	49	36	32	47	34	37
Insulator Pin	28	24	30	25	23	16	19
Junctions	2	2	1	4	6	7	2
Lightning	598	163	179	635	453	297	200
Maint/Upgrade	539	1571	3334	2589	1840	1880	1566
Other	394	414	426	483	472	467	344
Pole Fire	116	102	117	113	152	134	153
Pole-rotten	44	37	35	52	34	55	43
Primary Splice	0	1	1	0	0	0	0
Protected	18	10	4	5	5	3	4
Recloser	4	11	3	2	3	11	2
Regulator	14	20	17	13	17	18	13
SEE REMARKS	821	892	543	487	463	508	518
Service	123	188	197	230	191	124	172
Snow/Ice	988	565	167	352	122	243	1882
Squirrel	700	390	395	358	215	279	272
Switch/Disconnect	9	3	0	3	6	16	8
Termination	7	7	9	12	21	19	8
Transformer - OH	158	128	156	167	132	133	84
Transformer UG	57	53	51	50	71	60	62
Tree	55	53	51	56	46	60	47
Tree Fell	390	506	392	377	298	393	340
Tree Growth	375	330	335	335	349	400	280
Underground	0	3	1	3	2	2	0
Undetermined	1145	948	861	783	765	723	728
URD Cable - Pri	136	93	95	72	93	88	64
URD Cable - Sec	212	190	248	219	208	188	153
Weather	357	895	325	314	216	166	208
Wildlife Guard	3	0	1	2	0	0	0
Wind	294	1309	256	1042	1126	3238	6465

Table 2, OMT Outages and Partial Outages by Sub-Reason and Year

OMT SUB-REASON	2009	2010	2011	2012	2013	2014	2015
Arrester	18	31	30	32	21	29	19
Bird	213	175	322	225	259	244	216
Capacitor	4	1	0	3	2	0	0
Car Hit Pad	41	30	31	45	36	37	40
Car Hit Pole	104	135	131	158	152	164	159
Conductor - Pri	31	49	61	70	113	98	65
Conductor - Sec	117	104	126	124	147	148	151
Connector - Pri	102	84	82	59	68	70	44
Connector - Sec	272	263	270	267	227	227	211
Crossarm-rotten	11	20	24	17	15	21	18
Customer Equipment	1205	1121	1034	1099	1037	1011	932
Cutout/Fuse	175	194	161	185	155	180	98
Dig In	104	88	75	64	62	69	60
Elbow	7	5	7	2	10	6	5
Fire	8	69	72	82	102	74	108
Forced	51	63	67	33	63	66	29
Foreign Utility	78	103	61	62	90	66	175
Insulator	23	31	26	19	27	22	28
Insulator Pin	16	15	18	19	13	11	12
Junctions	0	1	0	2	2	5	0
Lightning	572	159	174	562	417	284	197
Maint/Upgrade	534	1566	3331	2587	1834	1873	1563
Other	247	275	261	282	282	258	202
Pole Fire	101	87	93	95	128	114	138
Pole-rotten	14	11	10	9	7	14	18
Primary Splice	0	1	1	0	0	0	0
Protected	17	7	4	5	5	3	4
Recloser	3	9	1	2	3	11	2
Regulator	10	16	14	10	10	13	13
SEE REMARKS	420	443	286	255	262	217	243
Service	59	89	86	59	55	44	62
Snow/Ice	592	347	135	291	103	202	1281
Squirrel	694	380	389	351	210	274	263
Switch/Disconnect	7	3	0	1	5	14	8
Termination	7	6	8	12	18	16	7
Transformer - OH	143	107	138	150	117	118	78
Transformer UG	42	44	36	42	59	49	54
Tree	42	39	36	39	35	43	40
Tree Fell	186	234	215	229	183	223	219
Tree Growth	101	77	71	93	90	123	87
Underground	0	1	1	3	2	2	0
Undetermined	1023	855	799	684	669	634	641
URD Cable - Pri	132	89	92	71	89	84	59

OMT SUB-REASON	2009	2010	2011	2012	2013	2014	2015
URD Cable - Sec	201	175	227	202	190	173	145
Weather	273	620	178	170	137	101	122
Wildlife Guard	3	0	0	2	0	0	0
Wind	229	982	195	802	840	2345	5721

Table 3, Top Ten Trends Upward in OMT Data by Sub-Reason based on 2009-2015 data

Top Ten Upward Trends	
OMT Sub-Reason	Slope Change per Year
Wind	709
Maint/Upgrade	79
Snow/Ice	62
Fire	12
Conductor - Pri	9
Foreign Utility	9
Car Hit Pole	9
Conductor - Sec	8
Pole Fire	7
Bird	3

Table 3 shows that the largest upward trend changed this year to Wind. This change was due to the large wind storm that impacted our service territory in November. Snow/Ice is also very high on the list and is mostly due to the snow storm in December. Without these major events then Maintenance and Upgrade would continue to be the largest trend upward. We have implemented many programs that increase our outages due to maintenance but decrease the number of outages due to failures. Bird has always been on this list but has slowly dropped to the number 10 spot with a much smaller trend upward suggesting the increase in wildlife guard installation has had a positive impact. Car Hit Pole remains pretty steady trending upward and will continue to be monitored. Both Primary and Secondary Conductor are both increasing at a steady pace and may need to be reevaluated. Primary Conductor is only addressed with our Grid Modernization and Segment Reconductor and Feeder Tie program. Fire has consistently been on the top 10 list but is a customer issue and not an Avista issue so this is not something Avista can mitigate. Foreign Utility is also a non Avista issue and does not need to be addressed within this document.

Table 4 shows the Top 10 OMT Sub-Reasons with a downward trend. The largest downward trend is in Undetermined. This Sub-Reason, as well as SEE REMARKS, have been trending downwards for a few years and is believed to be due to an increased focus on the importance of accurate and standardized outage data. Squirrel events continue to decline, as well. This is probably largely due to adding Wildlife Guards (WLG) on new installs and adding them to existing transformers as part of Wood Pole Management and Grid Modernization. The URD cable Replacement program for the first generation of unjacketed cable has paid great dividends when compared to where it could have been without taking action at reducing URD Cable – Pri events. Reduction in lighting strikes may simply be due to nature, however, the Wood Pole Management (WPM), Grid Modernization and Transformer Change-out Program (TCOP) may also be helping to mitigate this issue by adding lightning arrestors to new install transformers. The decrease in Cutout/Fuse Sub-Reasons can likely be attributed to Wood Pole Management, TCOP and Grid Modernization programs along with some contribution from other programs. The remaining Sub Reasons in the table have trend downward but the changes are not material at this point in time or are outside of Asset Management's control.

Table 4, Top Ten Trends Downward in OMT Data by Sub-Reason based on 2009-2015 data

Top Ten Downward Trends	
OMT Sub-Reason	Slope Change per Year
Undetermined	-61
Squirrel	-60
Weather	-55
Customer Equipment	-37
SEE REMARKS	-36
Lightning	-23
Connector - Sec	-11
Cutout/Fuse	-9
URD Cable - Pri	-8
Connector - Pri	-8

The overall trends in OMT Events are shown in Figure 1 along with the trends in AM related OMT Events (see Appendix A of the "2010 Asset Management Electrical Distribution Program Review and Metrics" and the table titled "List of AM Related OMT Sub-Reasons" to see which OMT Sub-Reasons are considered AM Related). Based on Figure 1, Avista sees the trend in the number of events decreasing over the past 5 years.

AM related OMT events are actually decreasing at a rate around 4%. Since the regional growth rates are less than 2%, the decrease is most probably due to the increase in maintenance in the system and replacement of aged infrastructure.

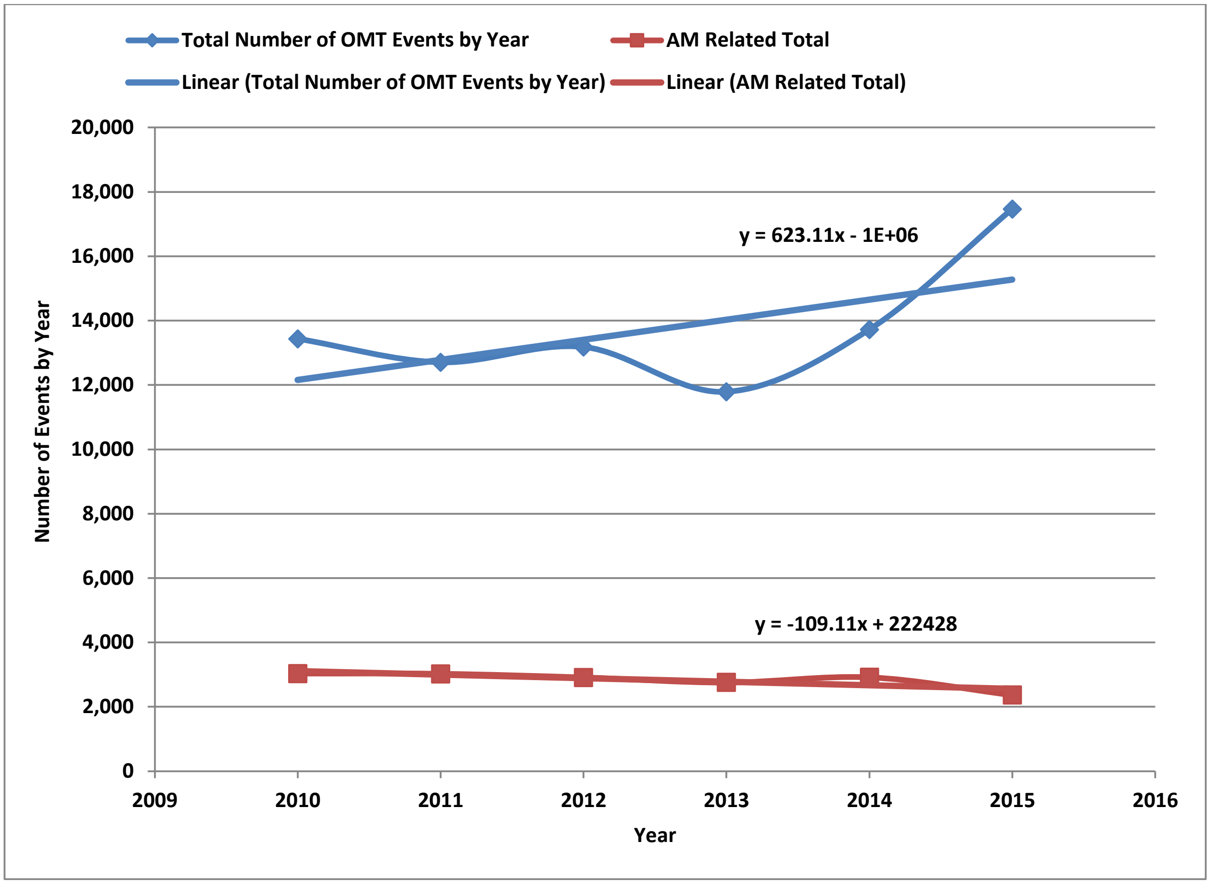


Figure 1, OMT Annual Number of Events and AM Related Event Trends and Trend Lines

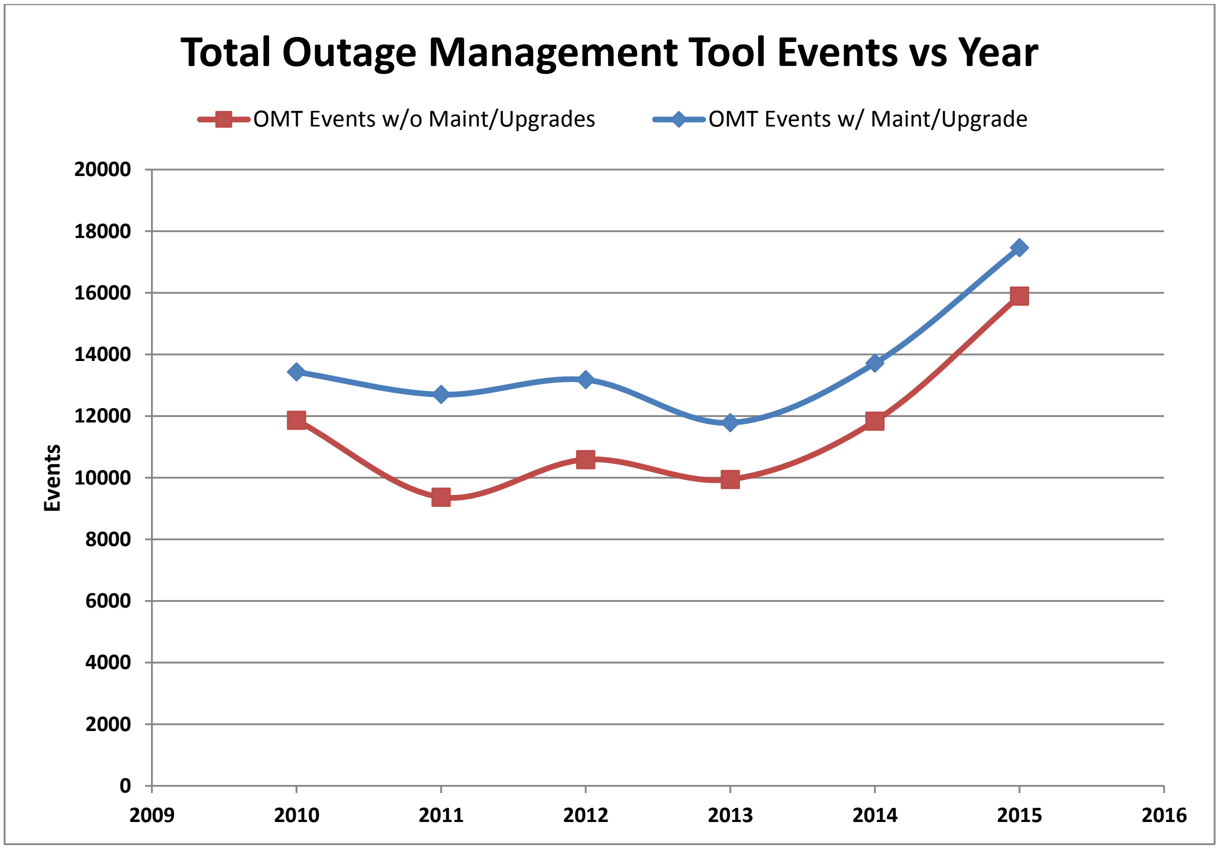


Figure 2, OMT Events with and without Planned Maintenance or Upgrades

SAIFI Trends by OMT Sub-Reasons

Examining how SAIFI changes each year is shown in Table 5. SAIFI values in Table 5 represent the annual value each event contributes to the overall SAIFI number. For example, in 2011, the average Arrester event in OMT added 0.003380523 to the overall SAIFI number for the year. While the number of electrical customers does typically grow each year, the main driver for changes in the average SAIFI number per event comes from the average numbers of customers affected by the event. Continuing our example with Arresters, in 2010 Avista had 356,777 electrical customers and the average Arrester outage event affected 102 customers, so the average SAIFI impact per event was 0.009230266. In 2011, our electrical customer count increased to 358,443 and the average number of customers affected by an Arrester related outage dropped to 40, and the average SAIFI impact due to Arrester events dropped to 0.003380523. The result for SAIFI was an increase in the average impact to SAIFI in 2010 compared to 2011.

While most Sub-Reasons in OMT have fluctuating value around an average value over the past five years, some Sub-Reasons have demonstrated a definite trend upward as shown in Figure 4. Figure 4 shows the top 10 Sub-Reasons based on the percentage change in 2015. Some of the Sub-Reasons in Figure 4 do not have a significant impact on the SAIFI number, however, the trend for all of these Sub-

Reasons are the top increasing SAIFI trends over 5 years which could eventually move them into the top SAIFI contributors over time.

Figure 5 and Figure 6 illustrate the makeup of the overall SAIFI value and overall OMT Sustained Outages. Figure 5 and Figure 6 show a different result because the number of customers impacted by each Sub-Reason is different. For example, we have very few Pole Fire caused outages, but they affect a large number of customers. So, Pole Fire shows a significant impact to SAIFI in Figure 5 but is insignificant on Figure 6.

Table 5, SAIFI Trends by OMT Sub-Reason Average per Outage

Average SAIFI by Sub-Reason Event						
OMT Sub-Reason	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Arrester	0.009230266	0.003380523	0.015245676	0.003562297	0.009598559	0.001364179
Bird	0.026835343	0.050143556	0.015659978	0.064285794	0.021842454	0.026664936
Capacitor	0.002842798	0	0.006147101	8.27074E-06	0	0
Car Hit Pad	0.001972404	0.00315424	0.004171572	0.004940524	0.003134	0.0051936
Car Hit Pole	0.055741604	0.034563763	0.078829605	0.061689509	0.07509589	0.042359382
Conductor - Pri	0.013459389	0.025213018	0.024181701	0.036457655	0.029884932	0.020986851
Conductor - Sec	0.001923463	0.001952154	0.003857768	0.002491023	0.003821952	0.004026636
Connector - Pri	0.029390854	0.022841718	0.023941651	0.01912657	0.023079128	0.00541549
Connector - Sec	0.001764569	0.001927718	0.002095065	0.001612901	0.001526051	0.002468959
Crossarm-rotten	0.010791352	0.017452881	0.004106797	0.001059746	0.015222287	0.000560328
Customer Equipment	8.43629E-05	4.18879E-05	0	4.96037E-05	0	3.39306E-05
Cutout/Fuse	0.029472485	0.014918168	0.027484801	0.01707108	0.018776702	0.009920028
Dig In	0.002911047	0.007751271	0.001543001	0.001766282	0.006145152	0.001637209
Elbow	9.54113E-05	0.000737521	2.50685E-05	0.001158911	0.000444984	0.000469738
Fire	0.000916016	0.001765849	0.004579849	0.012299424	0.001239404	0.007950852
Forced	0.026724006	0.011341762	0.01007956	0.035479695	0.010119982	0.019996134
Foreign Utility	0.06415389	1.9551E-05	1.10385E-05	3.04099E-05	0	0.006688417
Insulator	0.00947135	0.00767475	0.001619894	0.018937297	0.020106196	0.011789959
Insulator Pin	0.00609977	0.012718209	0.002646432	0.004556295	0.008017909	0.001082908
Junctions	5.63488E-06	0	0.002791077	0.000475014	0.000657922	0
Lightning	0.05153771	0.029986357	0.107700751	0.152792603	0.10038083	0.050646543
Maint/Upgrade	0.115272977	0.131045664	0.093958391	0.118799625	0.097069382	0.104791239
Other	0.177318475	0.156583826	0.114257941	0.085502603	0.082302999	0.115450196
Pole Fire	0.108242728	0.087722138	0.058825288	0.078650039	0.096520659	0.160560667
Pole-rotten	0.002027401	0.002475849	0.001111378	0.002186058	0.007843191	0.000477747
Primary Splice	1.40872E-05	0.000227493	0	0	0	0
Protected	0.005438117	0.000105902	0.000523814	0.000524546	0.000303026	0.00239954
Recloser	0.002520587	0.000212125	8.36386E-06	0.001310323	0.01501481	0.001838003
Regulator	0.019517299	0.003012273	0.020486437	0.010292094	0.015208638	0.011244625
SEE REMARKS	0.0263254	0.022946333	0.024001629	0.035782952	0.030523744	0.024167276
Service	0.001512913	0.001254413	0.001425234	0.001116933	0.00158065	0.001204447
Snow/Ice	0.091003627	0.039682871	0.109703932	0.035007006	0.078612086	0.304018091
Squirrel	0.021425719	0.039013725	0.050207568	0.026293232	0.039139515	0.030862207

OMT Sub-Reason	2010	2011	2012	2013	2014	2015
Switch/Disconnect	0.004582077	0	4.14971E-05	0.020930465	0.036865454	0.008279847
Termination	0.000152009	0.000173439	0.000637191	0.003063515	0.002290441	0.001269524
Transformer - OH	0.002407314	0.017106495	0.004874802	0.004093373	0.026346897	0.008655826
Transformer UG	0.001704189	0.001165537	0.001438726	0.006231495	0.009683188	0.001587665
Tree	0.013288743	0.000938339	0.011356792	0.002750215	0.015326026	0.002845582
Tree Fell	0.092136448	0.062998204	0.067319172	0.054556299	0.057820669	0.084106127
Tree Growth	0.007012046	0.003838547	0.005569335	0.005691876	0.009617668	0.003505633
Underground	2.81744E-06	2.80426E-06	3.87453E-05	5.48895E-06	5.45993E-06	0
Undetermined	0.110134471	0.234672203	0.177748096	0.157264023	0.14781125	0.119112398
URD Cable - Pri	0.005903606	0.008770789	0.002422167	0.006080464	0.005855776	0.0069458
URD Cable - Sec	0.000953008	0.001467391	0.001544569	0.001409578	0.000980058	0.001315704
Weather	0.195547002	0.051231256	0.053674679	0.033680951	0.041372627	0.025389892
Wildlife Guard	0	0	8.35232E-06	0	0	0
Wind	0.291134088	0.089836161	0.195492335	0.209669949	0.517115518	1.128419475

OMT Sub-Reason Events High Limit

The second metric used to determine if we must examine a problem is the deviation from the established mean discussed above for each OMT Sub-Reason. If the number of OMT events for a specific Sub-Reason exceeds the OMT Sub-Reason Events High Limit (High Limit) AM may need to conduct an investigation and try to explain why the annual values are exceeding the limit (see Appendix D of the "2010 Asset Management Electrical Distribution Program Review and Metrics"). The High Limit is based on the average of annual values for each Sub-Reason plus two standard deviations. This method is also used to calculate the quarterly High Limit as well. The data for the average is the OMT Data for 2005 through 2009. For 2015, the following OMT Sub-Reasons exceeded their High Limit are shown in Table 6. We anticipated that Avista would exceed these limits due to natural deviations for events outside our control and due to some cyclical nature we observe in our data. Our goal here is to help identify trends in time to potentially address them if possible.

Table 6, OMT Sub-Reasons Exceeding Annual High Limit

OMT Sub-Reasons Exceeding their associated OMT High Limit	Number of Years High Limit Exceeded
Car Hit Pole	6
Conductor – Pri	5
Wind	3

Based on Table 6, presently there are no issues requiring changes to our current plans. We will continue to monitor Conductor – Pri, as this may call for some kind of action in the future. Car Hit Pole is being analyzed by another group. If a program is implemented from this analysis then we should see that issue drop off the High Limit Exceeded chart. Wind has popped up on this chart due to a couple of fourth quarter large storms the past couple of years. We will continue to monitor all of these issues.

Figure 3 shows the quarterly trends that feed into the annual trends for the OMT High Limit. For all OMT Sub-Reasons since 2006, only five Sub-Reasons have had more than five quarters where they exceeded the High Limit, Car Hit Pole with 17 quarters above the limit, Conductor – Pri with 8 quarters above the limit, Fire with 6 quarters above the limit and Service with 9 quarters above the limit. This information is consistent with Table 6 above. We will continue to monitor Service for potential future action, but it currently does not warrant a maintenance or replacement strategy.

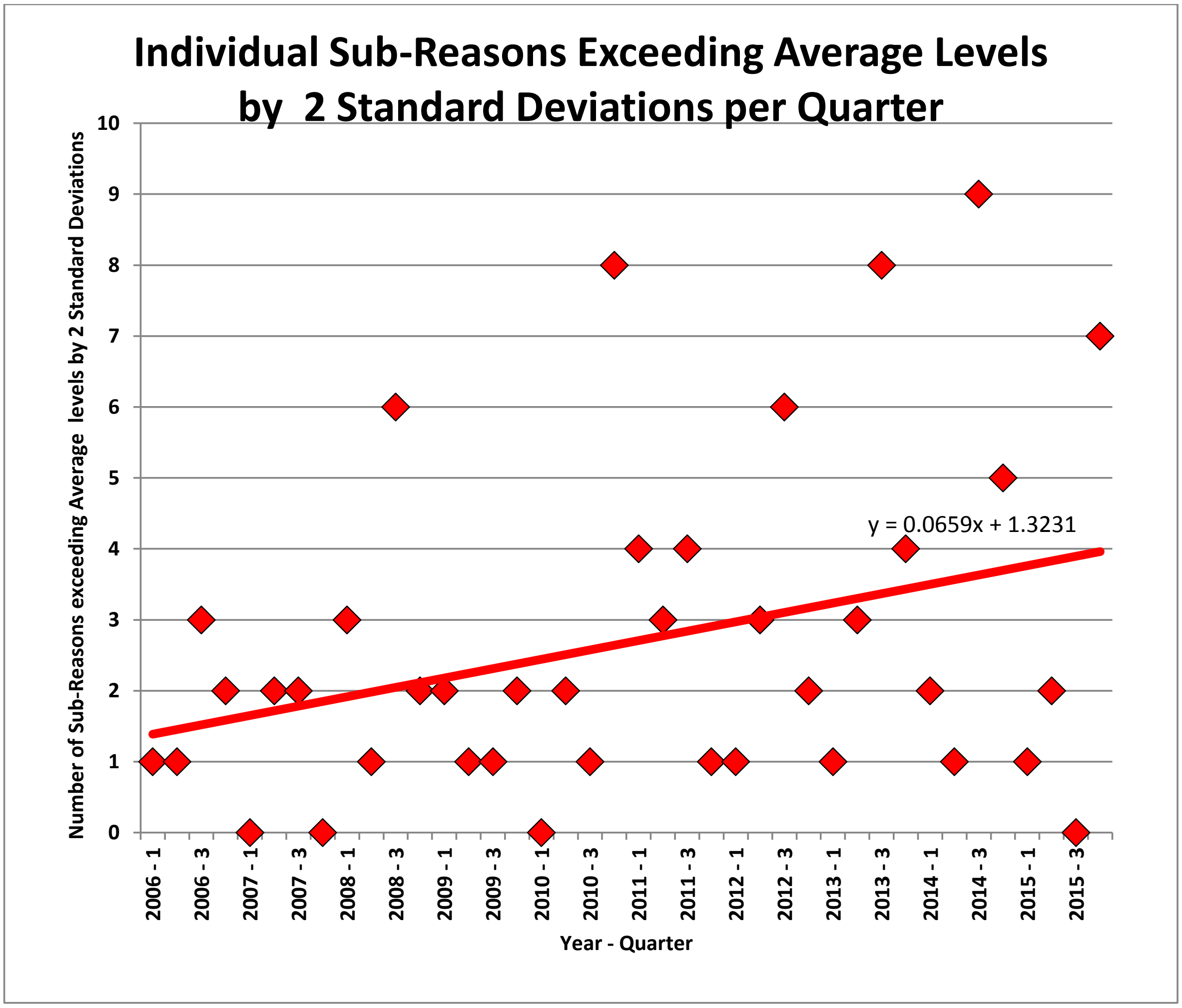


Figure 3, Individual Sub-Reasons exceeding Quarterly High Limits

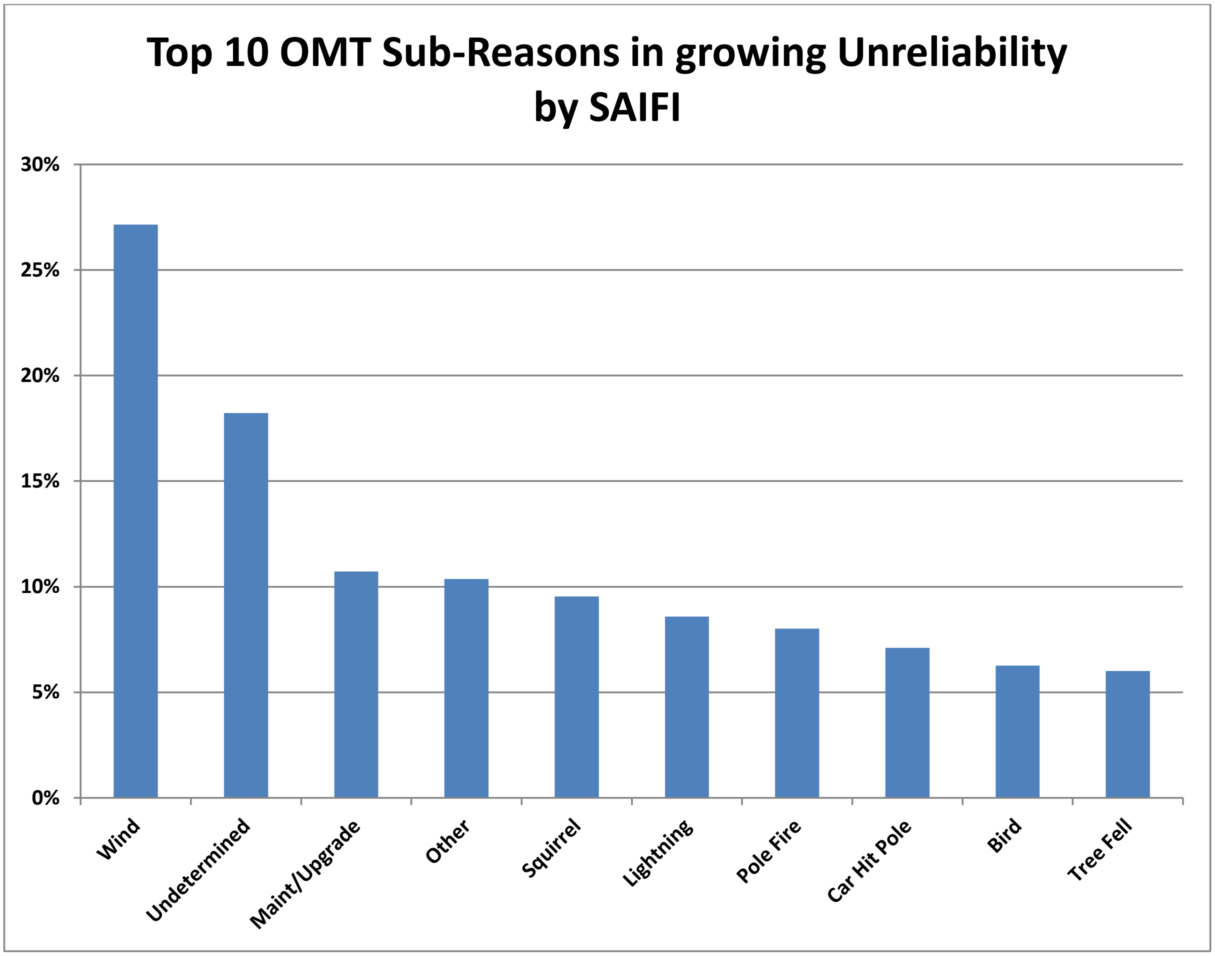


Figure 4, Top 10 Sub-Reasons with the Value of SAIFI Rising over Time

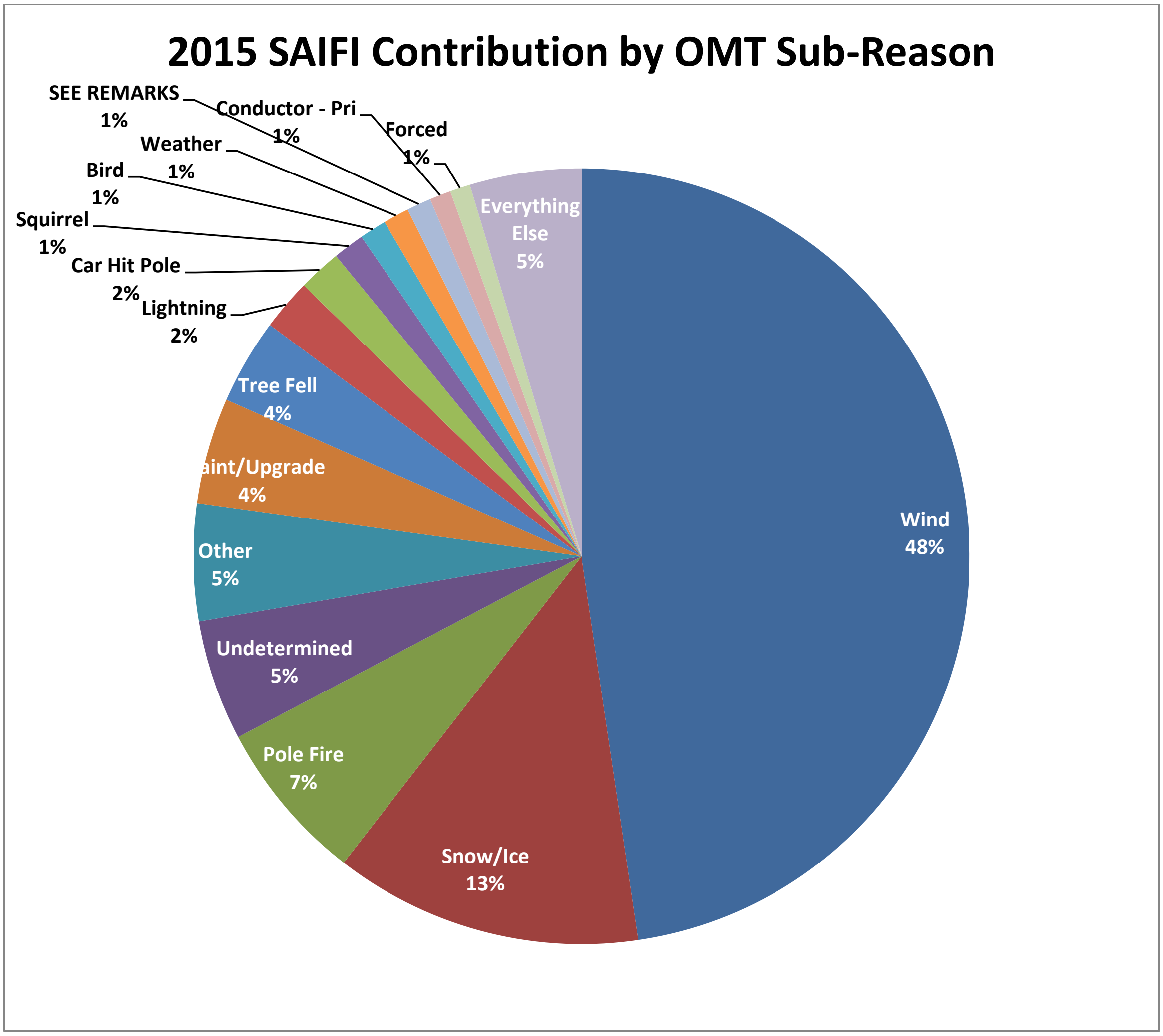


Figure 5, 2015 OMT SAIFI Contribution by Sub-Reason

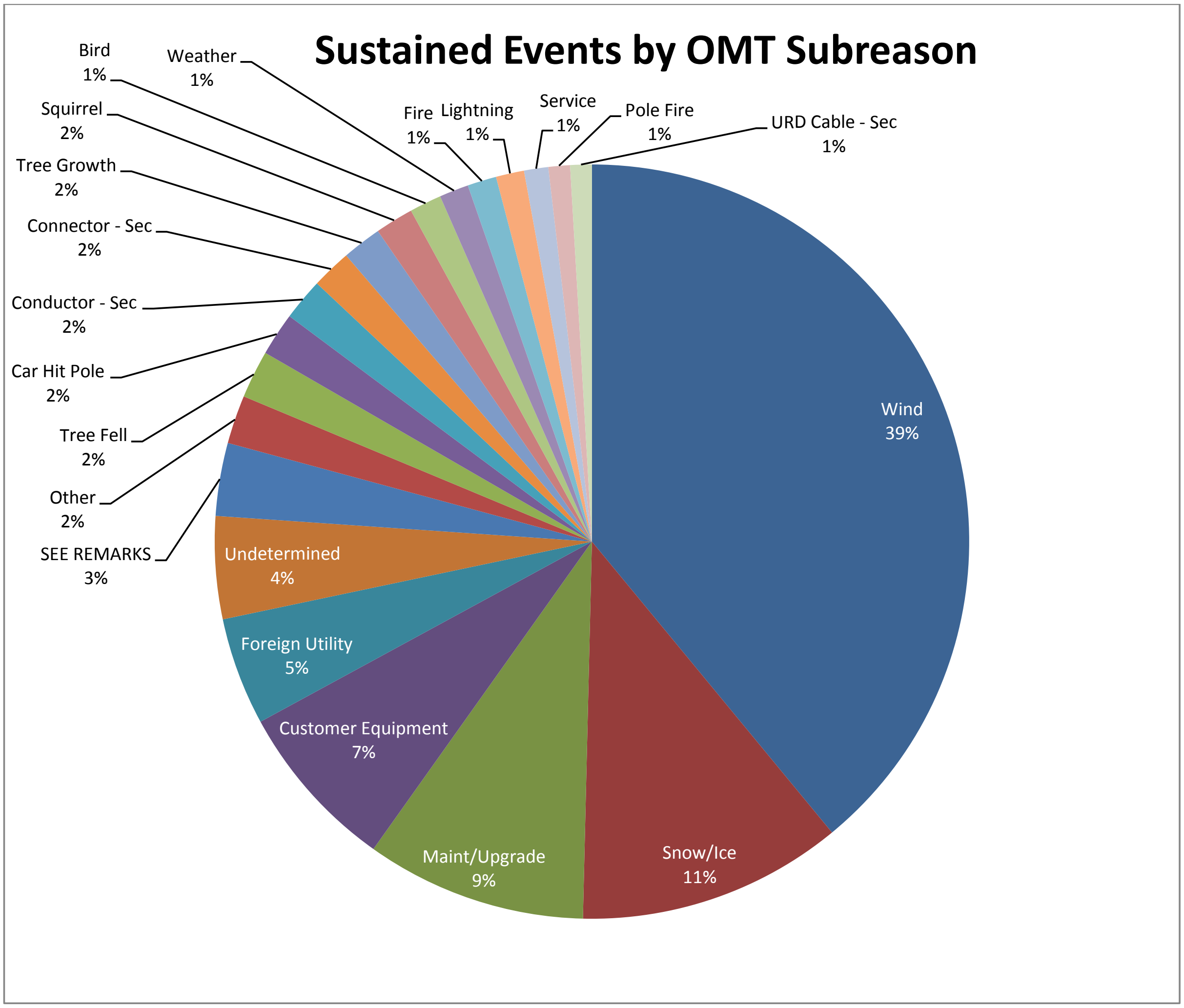


Figure 6, 2015 OMT Sustained Outage Comparisons

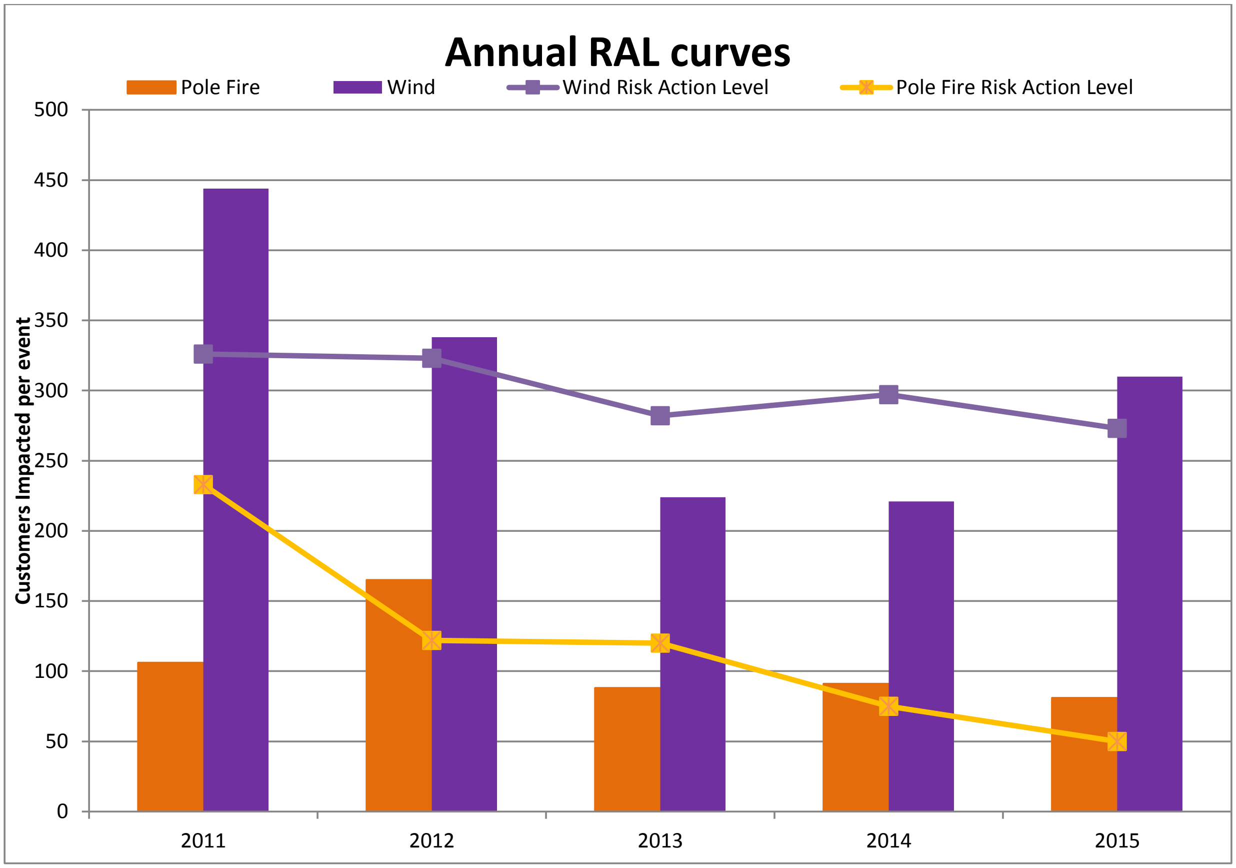


Figure 7, Customers Affected Per Event Exceeding Risk Action Levels

System

The distribution system has an equipment average life of 55 years with the replacement value of a little over $2 billion dollars. For Avista to maintain the system at its current level, just under $37 million a year would need to be spent on replacing aging infrastructure. The overall capital spending for the distribution was just over $85.5 million (this includes the large storm and growth). The total capital spending on just replacement work (with the large storm) was just over $83.5 million. Our replacement work, without the storm, still exceed our levelized spending required to keep the system at its current state. Avista also spent around $14 million in O&M on the distribution system.

Network

The downtown network has an equipment average life of 50 years with the replacement value of a little over $93.7 million. For Avista to maintain the system at its current level, just under $1.9 million a year would need to be spent on replacing aging infrastructure. The overall capital spending for the network was $2.7 million (this includes growth). The total capital spending on just replacement work was $1.3 million. Our replacement work last year did not meet our levelized spending required to keep the system at its current state.

Major Changes

The distribution system is a fairly constant system. Most programs are in place to maintain or improve infrastructure for current customers or build new to support new customers. Currently there is a program set to be completed next year that will change out the last area that Avista serves at the legacy 4kV voltage. This voltage is obsolete for serving utility distributions systems and we have very limited spare equipment to continue service at this voltage. This is a needed upgrade to our standard distribution class voltage and equipment that was delayed in 2014 due to resources, and was pushed into 2015 and 2016. This is also the first year that Avista has installed LED street lights. This marks the beginning of a complete system conversion from the more inefficient high pressure sodium and legacy mercury vapor lighting to LED lights for both Area and Street Lighting.

Specific Distribution Programs and Assets

In the following sections, AM reviews the different programs and work done to determine an AM action plan for particular assets. Some plans indicated the current case or no action was the best approach and others indicated there was an appropriate action for managing an asset. If a plan was implemented, then the available information will be reviewed to determine how the plan has impacted the system.

Distribution Wood Pole Management (WPM)

The current WPM program inspects and maintains the existing distribution wood poles on a 20 year cycle. Avista has 7,702 overhead circuit miles. The average age of a wood pole is 28 years with a standard deviation of 21 years. Nearly 20% of all poles are over 50 years old and we have an estimated 240,000 Distribution poles in the system. This means that about 48,000 poles are currently over 50 years old. Our 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 inspection of these other components on a pole drives additional action to replace bad or failed equipment along with replacing known problematic components. These additional inspection items have expanded the current program beyond the original scope, but have proven to be a cost effective way of addressing more than just wood pole issues. The 2016 budget is set to be cut for this program and many others. The goals of this program would be to remain on the same 20 year cycle. The inspections would remain identical to the current scope, however, the follow-up work done through the WPM program would be a subset of the items above. WPM would no longer replace arresters, cutouts, wildlife guards or do any guying repairs, this work would be left up to the offices to complete at within their work plan.

Selected KPIs and Metrics

AM selected the number of OMT Events by Year related to WPM work and feeder miles of follow-up work completed verses miles of feeders inspected as KPIs to monitor WPM. These KPI relate to reliability performance, cost performance, and customer impacts. Our goal is to maintain or reduce the number of OMT events related to WPM. The current plan optimized the inspection cycle based on cost, so the impacts to reliability were addressed only as they relate to costs. The goal for these KPI is to stay below the number of events averaged over 2005 – 2009 for WPM Related OMT Events. See Table 7 for the goal and for the actual value for 2015. The OMT Events KPI is a lagging KPI and an indication of how well past work has impacted outages. The feeder miles of follow-up work completed verses miles of feeders inspected KPI is a leading indicator and reflects how outages in the future will be impacted by the work. The number of miles inspected is shown in Table 7 for the goal and actual values.

The feeder miles of follow-up work completed verses miles of feeders inspected KPI comes from the annual Distribution WPM inspection plan and is the sum of all miles of the feeders completed in that year. The completed number of miles for follow-up work on feeders comes from Asset Maintenance based on their tracking of the work as it is completed. The purpose of this metric is to evaluate how much backlog work is created each year in order to adjust future year's budgets. Asset Management has been working to increase the budget each year, with the goal of having no back log, by budgeting enough to inspect and follow up on a 20 year cycle.

Table 7, WPM KPI Goals by Year

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

*Note: Beginning with 2012, the Actual Miles Follow-up Work Completed will include WPM and Distribution Grid Modernization miles.
**To maintain a 20 year cycle the program only needs to complete 390 miles per year. The program is a little behind the targeted average of about 380 miles per year.

Metrics provide a more detailed review of WPM. WPM metrics involve more information and calculations than the KPIs and include: WPM contribution to the annual SAIFI number; number of distribution wood poles inspected; material usage for WPM by Electric Distribution Minor Blanket and Storms; number of Pole-Rotten OMT Events; Crossarms-Rotten OMT Events; and actual material use verses model predicted material use for WPM follow-up work (see

Table 8). The WPM contribution to the annual SAIFI number metric comes from data pulled out of OMT by Cognos and calculates the average impact to SAIFI per event by Sub-Reason.

The average impact to SAIFI per WPM event is the sum of the average impact to SAIFI for Arresters, Cutouts/Fuses, Crossarms, Insulators, Insulator Pins, Pole Fires, Poles – Rotten, Squirrels, Transformers-OH, and Wildlife Guards. The average impact to SAIFI for WPM events is then multiplied by the number of event causing an outage or partial outage (this is the sum of OMT events causing an outage or partial outage for Arresters, Cutouts/Fuses, Crossarms, Insulators, Insulator Pins, Pole Fires, Poles – Rotten, Squirrels, Transformers-OH, and Wildlife Guards). The goal for this metric is the five year average for 2005-2009. The purpose of this metric is to ensure WPM maintains the current reliability. Although the last two year's SAIFI goals were exceeded it was due in part to a couple large outages. Last year a couple of squirrel instances happened during Hot Line Holds causing a feeder lockout to occur. This year Pole Fire caused the biggest issue. There was a single event that required an entire feeder be taken off line to allow a cutout to be opened safely. This one occurrence impacted nearly 3000 customers. Removing these exceptions from the SAIFI drops the overall WPM SAIFI to an acceptable level.

The number of Distribution System poles inspected metric measures the annual plan for inspecting wood poles against how much work was actually completed. The AM plan calls for a 20 year inspection cycle which was originally estimated to be ~12,000 poles per year. The AM plan also represents inspecting 17.5 feeders a year. This metric ensures the WPM program meets the AM plan for Distribution Wood Poles.

The final metric, material use verses model predicted material use, tracks the actual number of key stock numbers (see Figure 12for assets monitored) against what the AM model predicted. Discoverer is used to pull stock number usage out for the applicable stock numbers and then they are compared to the AM model predictions. The purpose of this metric is to measure the performance of the model to predict the future outcomes.

Table 8, WPM Metric Goals by Year

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

*The SAIFI number without the exceptions is within the bounds of the projected SAIFI

Figure 8 shows the trends in OMT events for the Sub-Reasons associated with WPM and generally the trend in OMT events is downward. The major contributors (Cutouts/Fuses, Squirrel, and Transformer – OH) all showed a level trend or a general trend downward over the past 5 years. Pole Fire had a slight increase this year but we had a dry hot summer which could account for some of the increase. Overall, WPM is controlling the number of OMT events. The leading indicator, Miles Follow-up Work Completed, shows we were falling behind in addressing issues identified during the inspection. If this backlog continues to grow, it will begin to impact the number of OMT events into the future. Funding limitations are preventing us from clearing out the backlog. We continue to strive to get funding for the back log.

The KPI "Actual Miles Follow-up Work Completed" provides an indication of what could happen to the other metrics (see Table 7). Simply inspecting the poles does not improve the systems performance. The follow-up work to the inspection needs to be completed. This metric shows follow-up work carrying over into 2016. The driver for WPM is a 20 year inspection cycle and if allowed to fall behind, the WPM follow-up work could become a major financial issue and reliability risk for future years

Grid Modernization, discussed later in this document, also impacts some of the same metrics as WPM (see Table 22 for the actual comparisons). In 2012, we revised the metrics and now include the miles of completed Grid Modernization work in the Table 7 since the work is coordinated with WPM and intended to help address the backlog in WPM.

WPM Metric Performance

The annual contribution to SAIFI showed a slight incline in 2015 but the overall trend continues to show improvement and, if the exceptions are removed from this year's SAIFI then it remains below the five year average value as shown in

Table 8 and Figure 9. Overall, WPM has been effective at maintaining the current level of reliability to our customers.

The number of Distribution poles inspected measures how well the program is performing against a 20 year inspection cycle. The goal is to inspect every feeder once every 20 years. The work to perform the wood pole inspections is tracked based on the number of poles inspected. Using miles works, but different feeders have different pole densities per mile and the way the contractor bills for the inspection work makes using the number of poles inspected easier. WPM did not hit the planned number of inspections shown in

Table 8. This is largely due to a budget cut towards the end of the year. The completed inspections are following the AM plan for WPM very nicely. Figure 10 shows how Avista's use of Distribution Wood Poles changed with time. This graph supports a growing number of pole and WPM related issues. Based on poles lasting 74 years before they will be replaced on a planned basis, Avista would need to replace 3,200 poles per year at equilibrium. We finally reached and exceeded 3,200 poles per year in 2011 and although the replacement is not a steady number we have remained above the 3,200 threshold since then. Figure 11 shows how an increasing number of poles are reaching 74 years.

WPM Model Performance

The AM model for WPM provided a decent baseline for estimating the costs of the WPM follow-up work, however, AM is currently reanalyzing this program and so there will be a new baseline in the near future.

WPM Summary

The main message from the KPI and metrics for WPM is that we are moving in the right direction, but we are falling behind and will need to complete work on more feeder miles to control the impact on future reliability.

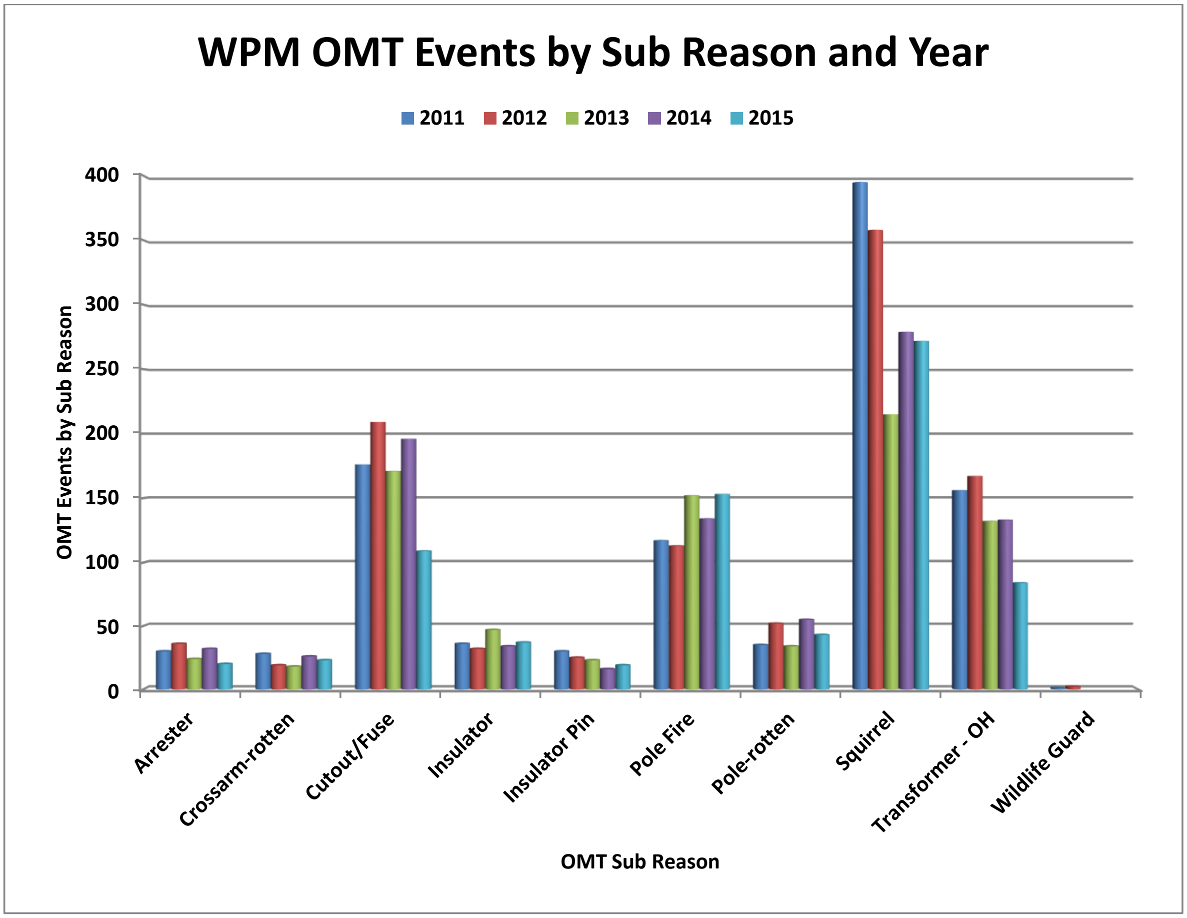


Figure 8, WPM OMT Event Trends

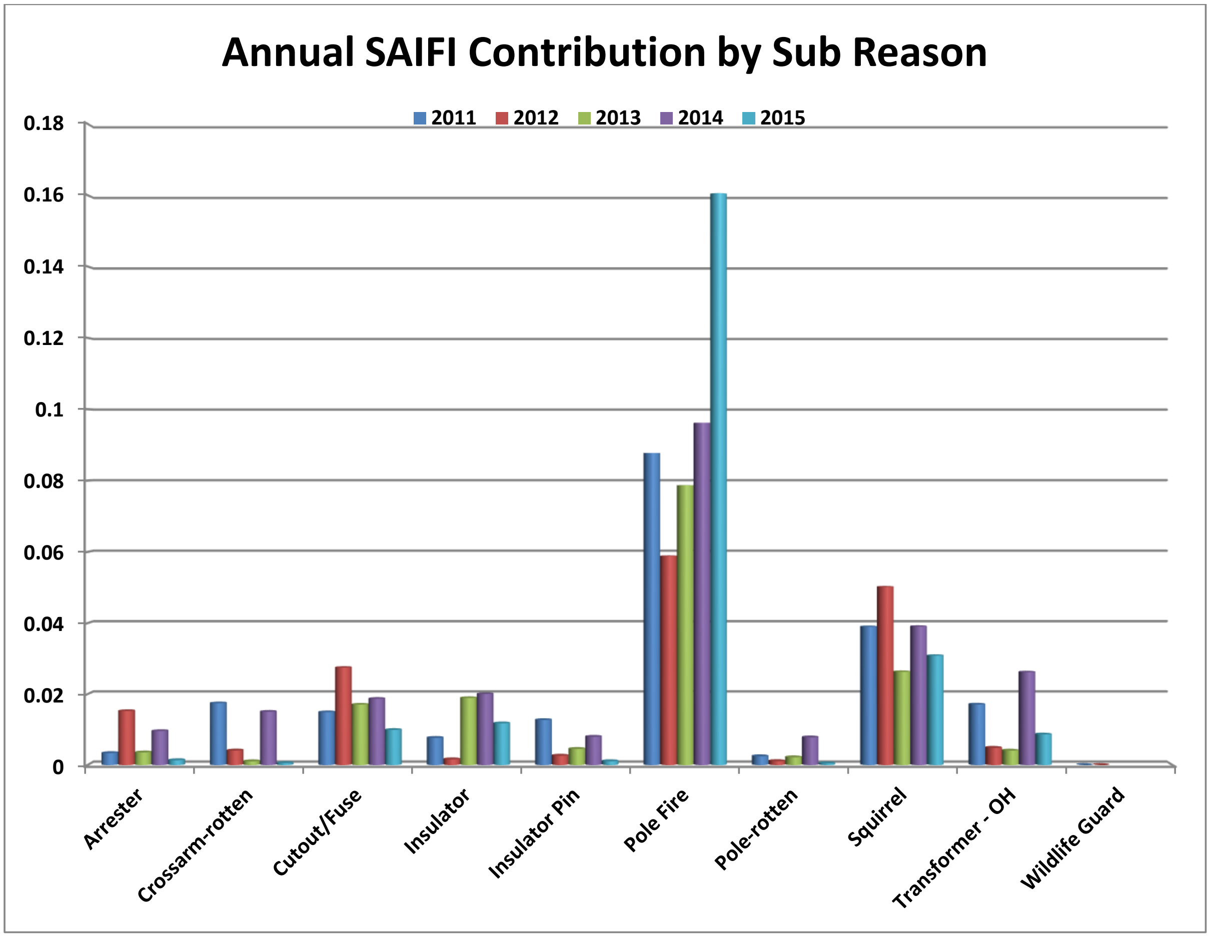


Figure 9, WPM Contribution to Annual SAIFI value by Sub-Reason and Year

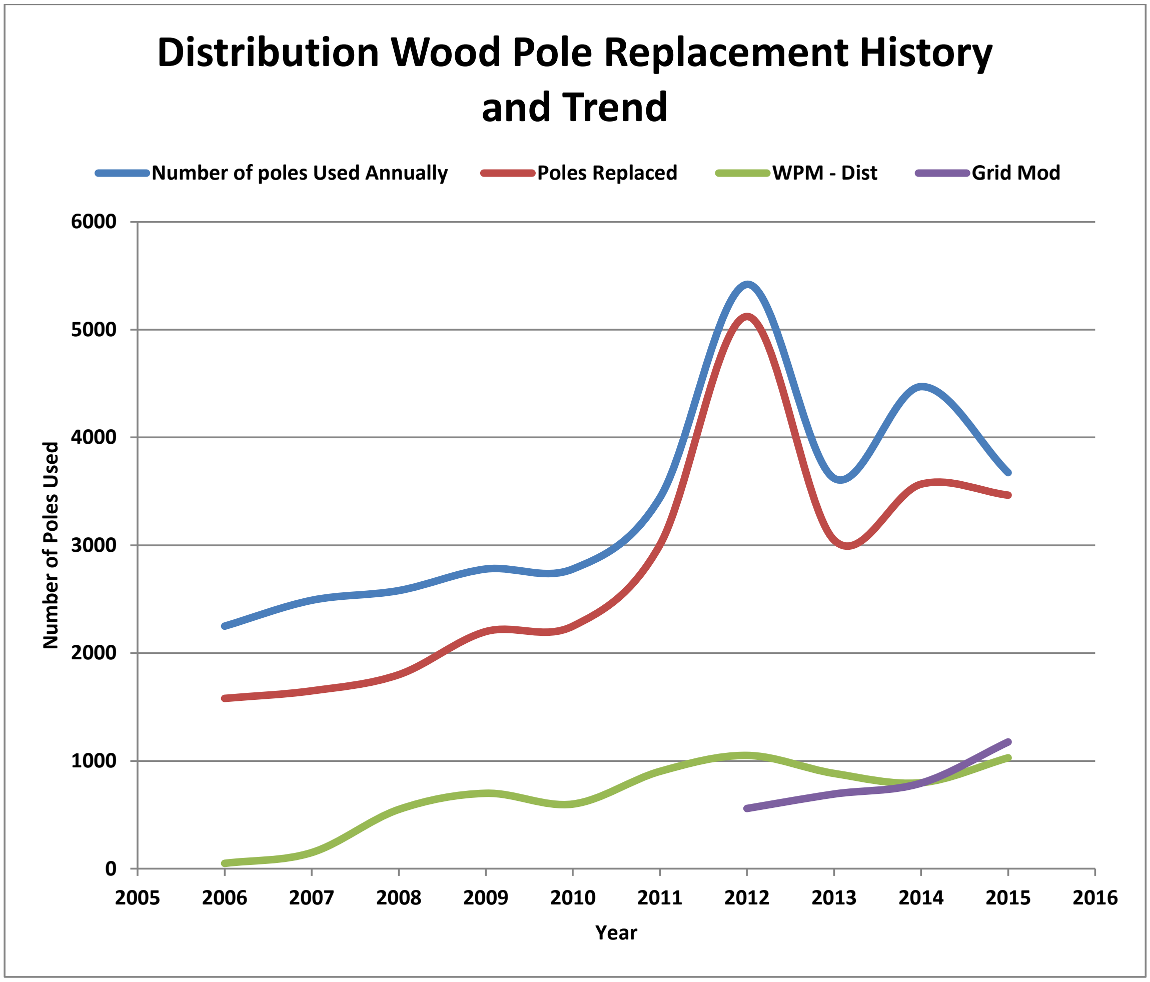


Figure 10, Wood Pole Used by Summarized Activity

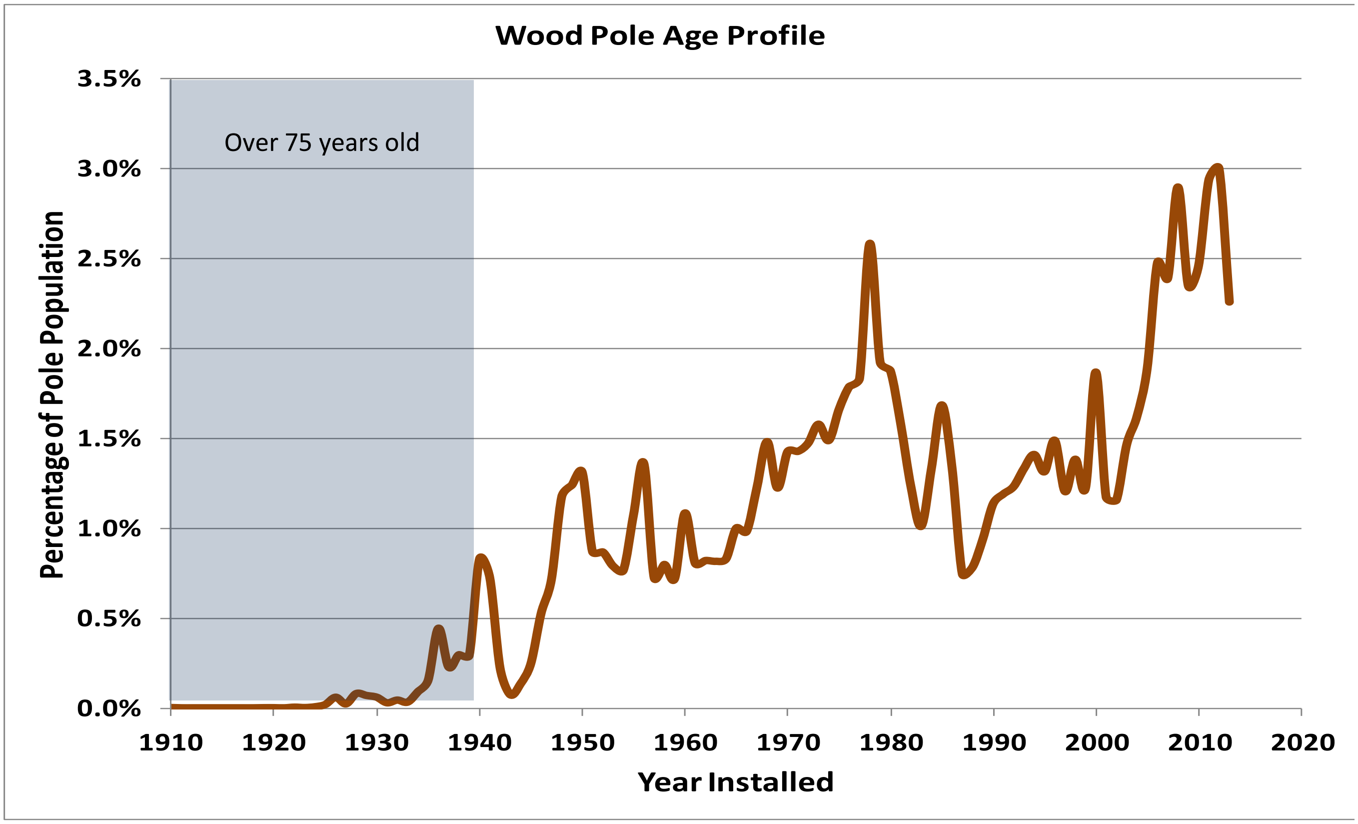


Figure 11, Distribution Wood Pole Age Profile
***Pole age data has not been updated in the past 4 years**

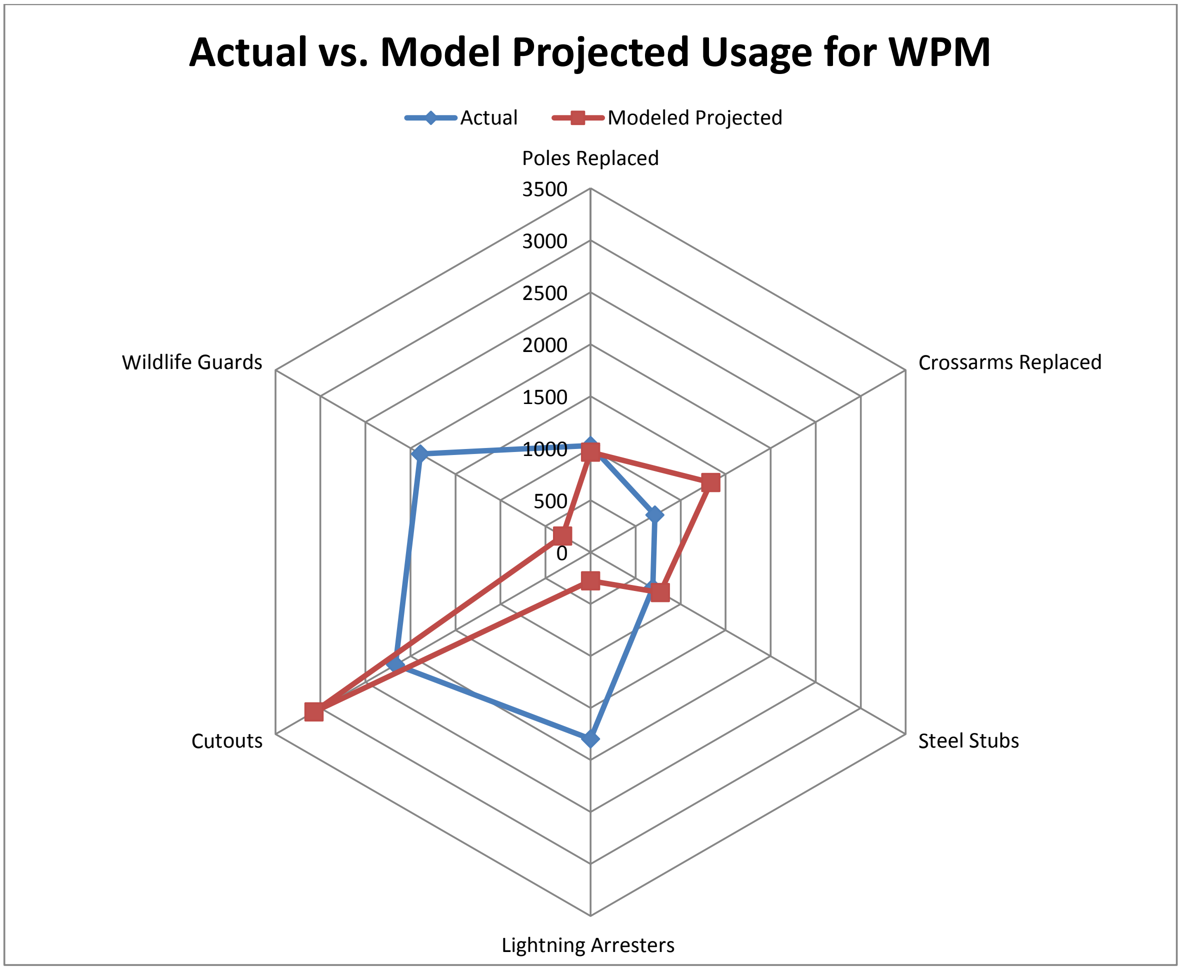


Figure 12, Actual vs. Projected Usage for WPM

Wildlife Guards

Wildlife caused outages have a significant impact on electric service reliability to customers. The improved outage tracking implemented in 2001 has consistently shown, within a percent or two either way, that animal's cause 19% of outages experienced by electric customers. While generally short in duration, labor impacts to respond are significant. In 2010, Squirrels accounted for only 6% of all sustained outages (see Table 9) which is a significant drop from 2009 value of 12%. This trend downward has continued and the percent of squirrel caused outages is now below 3%. We will continue to monitor this issue.

Selected KPIs and Metrics

The goal of the Wildlife Guards program is to reduce the number of Animal caused outages on the distribution system. More specifically, the program targets reducing the number of squirrel caused outages. The plan estimates that installing guards on the worst 60 feeders will reduce the number of Squirrel caused outages by 50%. 2006 was selected as the starting point, because the work performed that year was not influenced by the current AM plan. The final goal was a 50% reduction from the 2006 value of 902; however, this year's value of 272 exceeds the final goal and has for the past five years.

The second KPI used is the percentage of sustained outages caused by Squirrels. This KPI provides a relative impact that squirrel related outages are having on the system and represents the future value of installing Wildlife Guards on Distribution Transformers.

The only metric for Wildlife Guards is the annual avoided outage benefit from Squirrel related outages. We estimate approximately $82 in benefit for every outage avoided starting in 2011. Using this benefit per event, the projected avoided outage benefit by year is the difference between the projected number of events and the actual number of events for that year multiplied by the calculated cost per event for that year. The goals by year are shown in Table 10.

Table 9, Wildlife KPI Goals for 2010 - 2015

KPI Description	Projected Number of Squirrel OMT Events	Actual Number of Squirrel OMT Events	Percentage of sustained outages caused by Squirrels
2009	810	700	12.2%
2010	720	390	5.62%
2011	630	395	5.05%
2012	540	358	4.54%
2013	450	215	3.27%
2014	450	279	3.45%
2015	450	272	2.97%

Table 10, Wildlife Metric Goals for 2010 - 2015

Metric Description	Projected Avoided Outage Benefit due to Squirrel Caused Outages	Actual Avoided Outage Benefit due to Squirrel Caused Outages
2009	$36,000	$47,190
2010	$71,000	$157,466
2011	$22,000	$34,696
2012	$30,000	$37,935
2013	$37,000	$49,916
2014	$37,000	$46,045
2015	$37,000	$46,269

*Note: Avoided costs were revised from $390 per event to $82 for 2011 on. This change was based on a review of costs.

WILDLIFE GUARDS KPI Performance

Installing Wildlife Guards has exceeded expectations so far and has decreased the number of OMT events for Squirrels. The original model estimated costs were higher than actual costs because the model assumed more guards would be needed. So, the saved money has been used to work on more feeders than originally anticipated. This program officially ended a few years ago due to the quick pace of the work, however, the metrics are still being watched because other programs still have an indirect impact on the numbers. These other programs continue to add WLG into our system on a less programmatic basis. Based on Figure 13 and Figure 14 you can see that few WLG were installed this year with WPM continuing to install the bulk of the WLG. However, the value and original scope of the program were realized years ago and so this is not a concern. This is the last year that this programs metrics will be reported on but we do envision a continued value for years to come.

WILDLIFE GUARDS Metric Performance

The main purpose of the Avoided costs metric shown in Table 10 is to demonstrate the savings associated with the work from the original model. In 2010, Avista saw savings nearly triple the projected amount. Other work such as Electric Distribution Minor Blanket and WPM continue to install Wildlife Guards on Distribution Transformers. However, the large increase in savings is most likely due to the increase in the number of WLG installed in 2010.

WILDLIFE GUARDS Model Performance

The Wildlife Guard model under estimated the impact of the work performed (see Table 9), so our performance has exceeded our expectations. This exceeds the goal of being within +/- 30% of the actual value. However, since the program has accomplished its purpose, no further work is planned.

WILDLIFE GUARDS Summary

The Wildlife Guard program showed real cost savings over time. The program ended a few years ago and more than exceeded expectations. We continued to report on the established metrics to help realize a more complete value of the program. Although, we will no longer report on these metrics, work in WPM and other efforts to install wildlife guards on Distribution Transformers may continue to create even more value.

Table 11, Worst Feeders for Squirrel related Events for 2015

Feeder	Sustained Outages	Percentage of all Squirrel related Outages	Running Percentage
PIN443	14	3.80%	3.80%
SLW1358	9	2.45%	6.25%
PDL1203	9	2.45%	8.70%
CFD1211	7	1.90%	10.60%
OTH501	6	1.63%	12.23%
SIP12F4	5	1.36%	13.59%
TEN1256	5	1.36%	14.95%
BLU321	5	1.36%	16.31%
CDA124	5	1.36%	17.67%
BUN426	5	1.36%	19.03%
SLW1368	5	1.36%	20.39%
SLW1348	5	1.36%	21.75%
STM633	5	1.36%	23.11%
CHW12F3	5	1.36%	24.47%

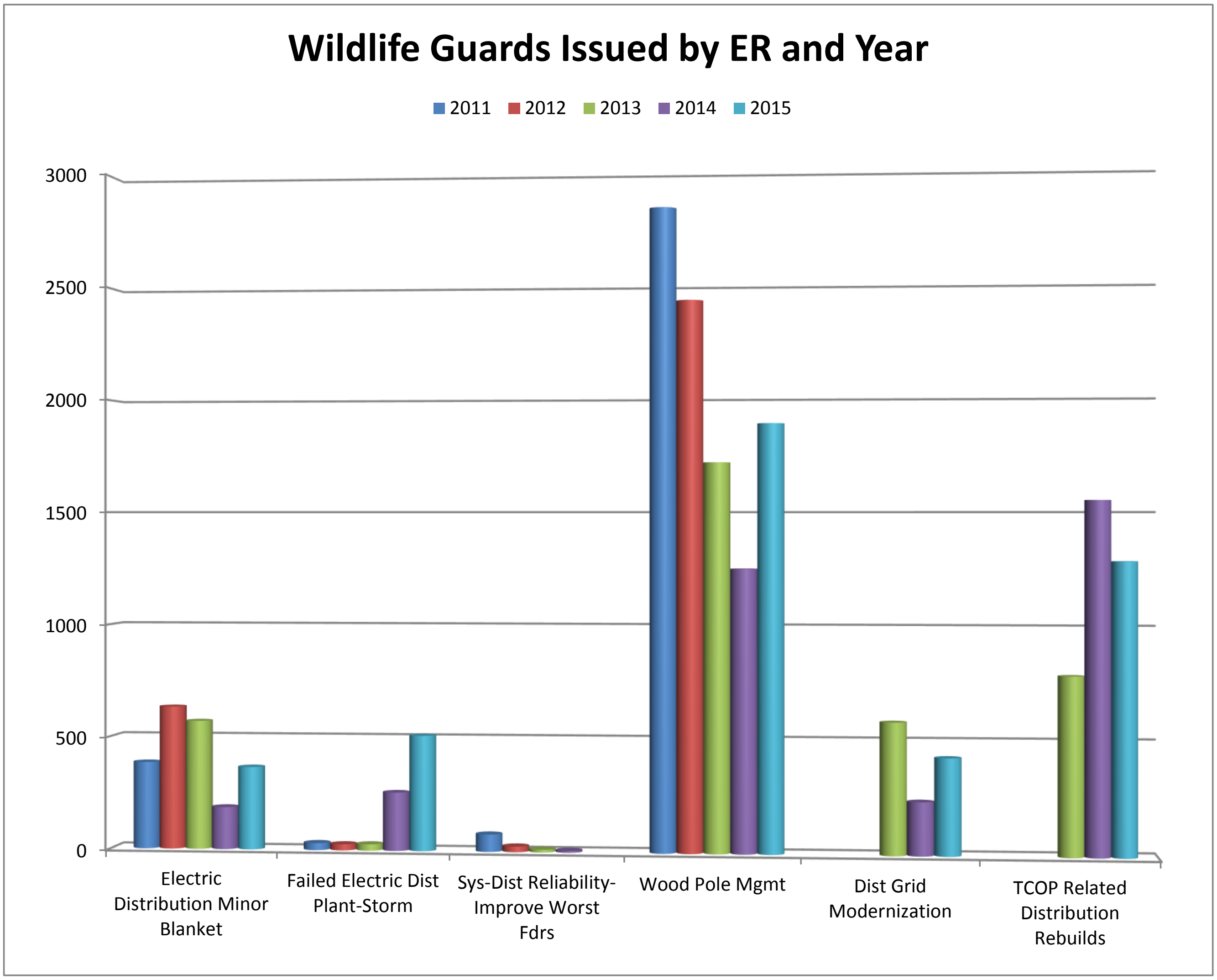


Figure 13, Wildlife Guards Installed by Year and Expenditure Request

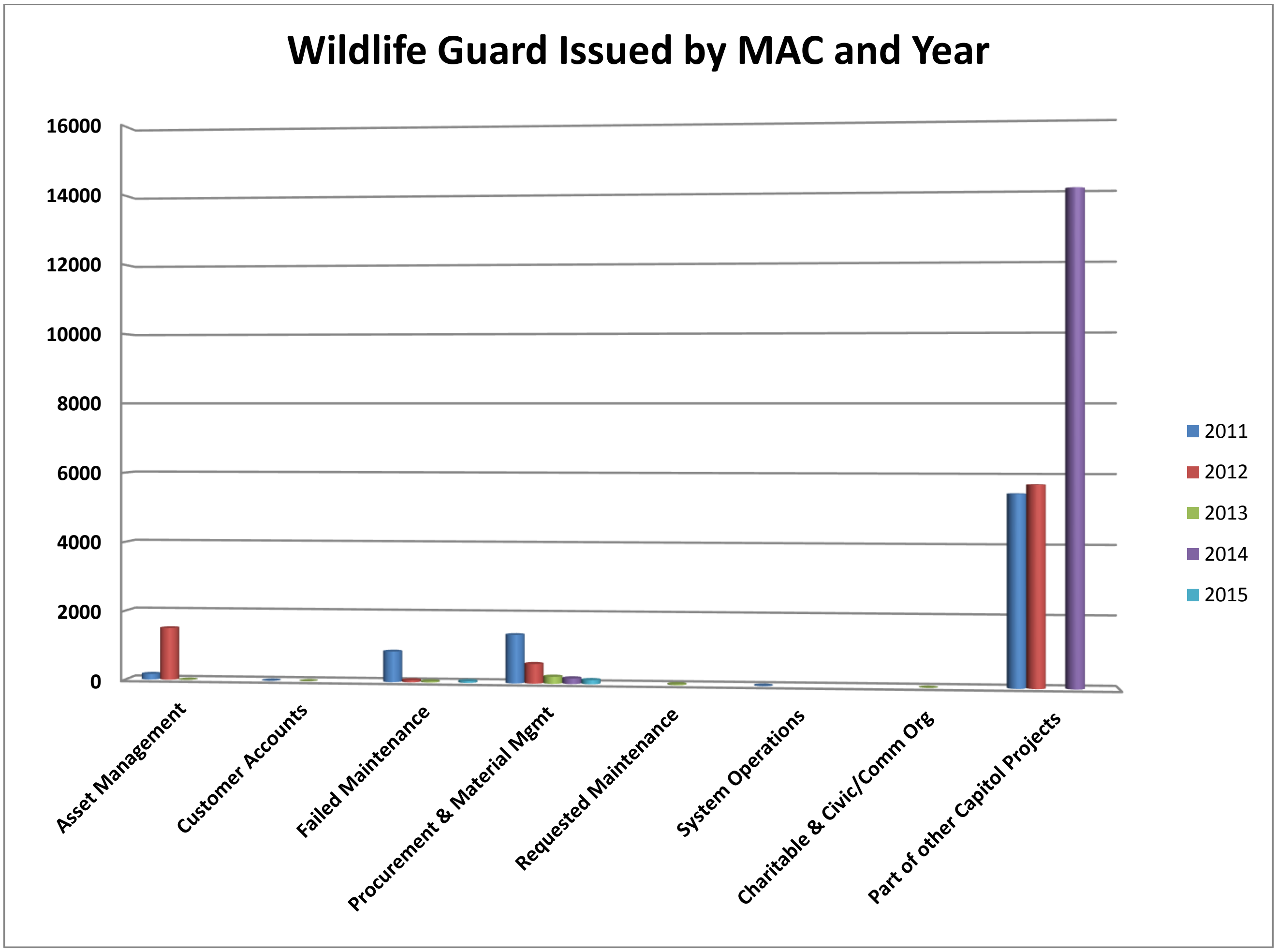


Figure 14, Wildlife Guards Usage by MAC for 2011-2015

URD Primary Cable

URD Primary Cable replacement addresses aging underground primary distribution cable. URD installation began in 1971. Over 6,000,000 feet of URD was installed before 1982. Outage problems exist on cable installed before 1982, cable installed after 1982 has not shown the high failure rate of the pre-1982 cable. Programmed replacement of the problem cable has been on-going at varying levels of funding since 1984. Emphasis is on the original vintage of URD. That cable was not jacketed with a protective layer of insulating material, neutral conductor was bare tinned copper concentric type construction on the outside of the cable. Insulating material was vulnerable to water intrusion.

Historically, over 200 faults of primary cable happen annually. There have been as many as 264 primary cable faults in 2003. During 2007 there were 168 primary faults. From 1992 faults increased from 2 per 10 miles of cable to 8 per 10 miles in 2005. The number of faults per mile has stabilized between 2005 – 2007 after steadily climbing between 1992 and 2005.

Funding for URD Primary Cable replacement was significantly increased in 2007 and began the current program. The program had an original estimate of 5 years to complete. Although the funding has not matched the original plan, almost all of the work was accomplished over six years. The year 2012 represents the last year of major funding for the program since the number of outages has significantly dropped and the worst feeder for URD Cable – Pri failures only had four outages. We anticipated some low level of funding for the remaining cable sections as they fail and are currently running this program on this smaller level.

Selected KPIs and Metrics

We selected two KPIs to track for URD Primary Cable replacement, URD Primary OMT Events and number of feet replaced each year. The goals for each of these KPIs came from the trends observed over the past few years and set a goal to complete the replacement of URD Primary cable in 2012. The program continued into 2015 but with a limited budget. Table 12 shows the goals for each KPI by year. The OMT events reflect the impact to our system of past work. The number of feet of URD Primary Cable replaced acts as a precursor to future OMT performance. After the first generation of URD Primary Cable has been replaced, the second generation will need to be monitored and plan may need to be established for addressing this vintage of cable.

Table 12, URD Cable - Pri KPI Goals

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	178000	213,000
2010	119	93	178000	217,883
2011	94	95	178000	225,823
2012	70	72	178000	117,247
2013	45	93	0	35,874
2014	45	88	0	35,515
2015	45	64	0	24,155

The selected metric for URD Primary Cable is the avoided costs due to cable faults. The benefits are based on a projected number of failures without the program that are projected to be around 670 events for 2015. Currently, each event on average costs ~$2,800 due to the duration of the outage and the number of people involved in correcting the fault. While this indicator is based on a projection, it provides a reasonable estimate of the return on investment for the money spent to replace this vintage of cable. Table 13 projects the anticipated avoided outage benefit by year for the estimated number of avoided outages.

Table 13, URD Cable - Pri Metric Goals

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

URD PRIMARY CABLE KPI Performance

For 2015, the performance for URD Primary Cable did not meet expectations but performed well. Table 12 shows that URD Cable – Pri events have not met expectations for the past couple years, however, the outages continue to have a downward trend. Figure 15 shows the downward trend in the number of events. The second generation of URD Primary Cable is also being analyzed. If it begins failing at an increasing rate, it would signal the next round of cable replacements. We have some faults in newer cables and anticipate that this will be true for several years to come. If these faults begin to significantly increase over time, we will have to begin replacement of this cable since the earliest of the second generation cable is now approaching 30 years old.

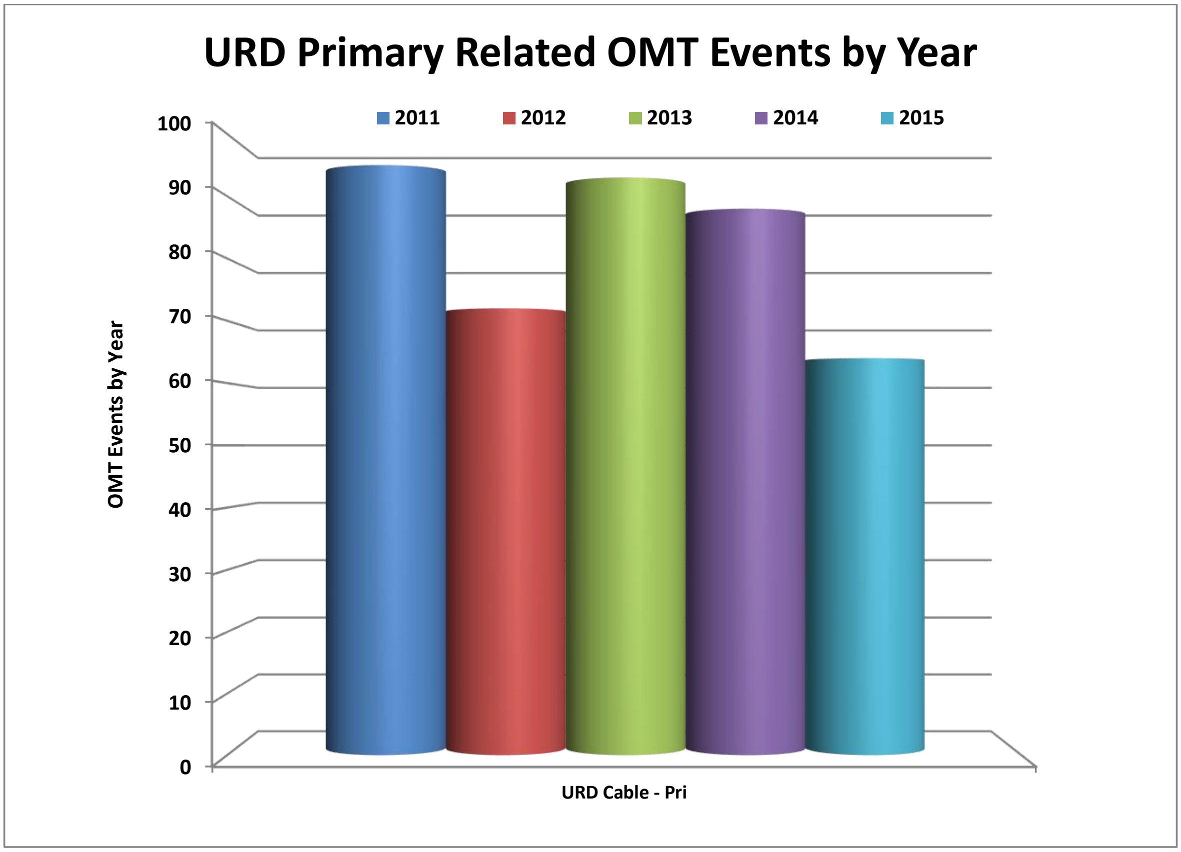


Figure 15, URD Primary Cable OMT Events by Year

URD PRIMARY CABLE Metric Performance

The projected savings and estimated savings due to avoided outage costs for Avista has typically come in very close as seen in Table 13. The avoided outage cost for this last few years has not performed as well as years past but overall the current program is performing as expected.

URD PRIMARY CABLE Model Performance

This AM model is an early vintage model and given the cash flow, did not match the model; but it has generally predicted performance reasonably well. Because of the good performance and limited remaining time for the program, the model will be retained as is and the program allowed to expire once all of the first generation URD Primary Cable has been replaced.

URD PRIMARY CABLE Summary

Several people have worked diligently on this program and it is now nearing completion. We anticipate another round of URD Cable replacements in the future, but we don't have any evidence indicating that the company has reached the end of life on the second generation of URD Cable. The program has succeeded in reducing O&M costs by avoiding long and costly outages. Since all of the work to replace the cable comes from capital spending, the program is a great example of how capital spending can reduce O&M. However, operations continue to find more cable than estimated remaining, so future funding is recommended to only cover planned work on known cable.

Distribution Transformers

In 2011, Avista implemented the Transformer Change Out Program (TCOP) to replace all Distribution Transformers containing PCB's followed by replacing all pre-1981 transformers. The driver for the program is to reduce the environmental risks associated with PCB's in transformers and improve the overall electric distribution system by eliminating higher loss transformers.

The program has two strategies associated with it. The first strategy is to eliminate all transformers containing or potentially containing PCB's. The initial focus was on areas near water sources. These transformers have specific work plans for removing them from the system. The second strategy uses the Wood Pole Management program to remove all pre-1981 transformers as part of their follow-up work on a feeder. The first strategy work should be completed in 2016 and the Wood Pole Management work should have all the pre-1981 transformers replaced by 2036.

Selected Metrics

Table 14 shows the metrics selected for TCOP. The number of transformers changed out represents the reduction of future risk from PCB's. It also provides a leading indicator of how many future transformer failures we may experience. The energy savings represents the value of changing out the less efficient transformers and quantifies the approximate amount of energy saved each year by replacing less efficient transformers with more efficient ones.

Table 14, TCOP Metrics

Year	Planned Number of Transformers Changed Out	Actual Number of Transformers Changed Out	Planned Energy Savings from Transformers (MWh)	Projected Energy Savings from Replaced 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	305	2,557	299	2,547
2015 – Pad/Subm	2,030	342	1,447	603
2016	1,419		1,265	
2016 – Pad/Subm	87		149	
2017	948		940	
2017 – Pad/Subm	259		466	
2018	347		330	
2018 – Pad/Subm	1,092		1,853	

- Note: values in red have missed the goal

***Conservative estimate based on no load loss**

Metric Performance

In 2015, we cut back the funding on the TCOP program but were still able to complete in total more transformer's than expected. Fewer padmount transformers were completed but many more overhead transformers were replaced instead. Budgeting for the last few years has had an effect on the expected program and will continue to impact the program going forward. New metrics have been developed to account for the extended program due to the decreased budget.

Summary

The TCOP is accomplishing it objectives and reducing Avista's and customer's risks associated with Distribution transformers containing PCB's and providing energy savings.

Area and Street Lights

Asset Management converted the existing area and street light data into our Geographical Information System (GIS) in 2012 and continued the work through 2014. This work updated and corrected the existing information and provided a platform to convert our High Pressure Sodium (HPS) lights to Light Emitting Diode (LED) fixtures beginning in 2015. The recent cost and reliability improvements in LED lights have made converting 100W HPS lights to LED fixtures cost effective. The rate schedule was approved for the state of Washington for 100W and 200W HPS street lights for 2015 and for all non-decorative wattage of both street and area lights for Washington and Idaho in 2016.

Selected Metrics

Table 15 shows the metrics selected for the Street light change out program. The number of lights changed out represents the reduction of maintenance costs due to the increased durability of LED lights. It also provides a leading indicator of how many future light failures we may experience. The energy savings represents the value of changing out the less efficient HPS lights and quantifies the approximate amount of energy saved each year by replacing less efficient HPS lights with more efficient LED ones.

Table 15, Area and Street Light Conversion Metrics

Year	Planned Number of Lights Changed Out	Number of Lights Changed Out	Planned Energy Savings from Lights (W)	Actual Energy Savings from Lights (W)
2015	3,500	4,166	262,500	312,450
2016	4,000		300,000	
2017	5,000		375,000	
2018	6,500		487,500	
2019	8,000		600,000	

Summary

This program is not unique, years ago a systematic change out of mercury vapor lights occurred. However, some of these lights remained well after the program ended. This program should have a better result due to the new technology in mapping being used for lights. This program may also expand to the remaining decorative lights in the future.

Distribution Vegetation Management (VM)

Our Vegetation Management program maintains the clearance zone free of vegetation for the distribution system clear of trees and other vegetation. This reduces outages caused by trees and to a lesser extent squirrel caused outages. Our Distribution System runs for 7,702 circuit miles in Washington, Idaho, and Montana. The Vegetation Management program also covers work on the Transmission System and the High Pressure Gas Pipeline system, however the purpose here is to only look at the Distribution System.

For the Distribution System, our analysis has shown that a pro-active maintenance program provides the best value to our customers. While our past practices were a four and seven year cycle based on vegetation type and had a reduced clearing diameter, our analysis has indicated a five year clearing cycle at a normal clearing distance has advantages. Our current goal is to be on a 5 year cycle, however, we don't always hit our target distance (Table 18) and are closer to a 6 year cycle.

The purpose of Vegetation Management is to meet regulatory compliance, provide the best value to our customers, and maintain current reliability. The Vegetation Management program continues herbicide spraying and enlarged the risk tree programs to further improve vegetation management. Both of these additions strive to improve the performance of the system by reducing vegetation related events.

Selected KPIs and Metrics

For VM, we selected one leading KPI and a lagging KPI. These KPIs were set for the old analysis and ended last year, we linearly progressed these numbers to buffer us until we can establish new KPI goals. The leading KPI is the number of Distribution Feeders miles managed each year. This indicates how well the actual work matches the planned work and the model. The results of the work in VM should directly impact the number of Tree Growth and Tree Fell events in OMT which is the lagging KPI. The number of Tree Growth events and Tree Fell events are summed for each year and compared to the AM models predictions if the plan is followed. The goals for each KPI by year are shown in Table 18. The AM model for Tree Growth events and Tree Fell events shows varying KPI's for each year due to the strict following of the 5 year cycle based on when the feeder was last done. For a VM metric, we selected the Tree-Weather OMT events by year. As seen in Figure 16, there is a relationship between weather events and VM. We assume that improvements in VM results should impact the number of Tree-Weather OMT events and set a goal shown in Table 18. The goal for Tree-Weather events is based on the AM models average value over a 10 year period. This metric was not included as a KPI, because weather events are very unpredictable and random in nature. Once the relationship has been better established, it may become a KPI.

Another metric selected for monitoring is the cost per mile for VM on the distribution feeders. While no goals have been established, this will measure how effective our AM spending gets the work done and how much work is required to clear the lines. The costs per mile should drop in future years, because the amount of work required to clear the feeders should decline after reaching a 5 year cycle. The total number of miles of all planned work was modified in 2011. Beginning in 2011, the costs per mile calculation includes all planned work and not just the miles cleared. So, the total number of miles for all planned work was included in the metrics.

Table 16, Vegetation Management Metric Goals

	Projected SAIFI - Tree Fall	Actual SAIFI - Tree Fall	Projected SAIFI - Tree Grow	Actual SAIFI - Tree Grow
2010	1.40E-07	0.092136448	8.84E-08	0.007012046
2011	1.40E-07	0.062998204	8.84E-08	0.003838547
2012	1.40E-07	0.067319172	8.84E-08	0.005569335
2013	1.40E-07	0.054556299	8.84E-08	0.005691876
2014	1.40E-07	0.057820669	8.84E-08	0.009617668
2015	1.40E-07	0.084106127	8.84E-08	0.003505633

Note: values in red missed the goal

VM KPI Performance

Both Figure 16 and Figure 17 show the same trends for Tree Growth, Tree Fell, and Tree Weather. Table 17 shows the results for Tree Growth and Tree Fell outages and how well these align with the projected outages. Table 17 shows the field confirmed outages due to Tree-Weather events. These are a subset of the OMT outages and only include outages that, after being field verified, were still deemed tree caused. For the last 5 years our average actual annual miles managed is just below the miles needed to remain on a 5 year cycle. Last year's missed goal was caused by budget cut late in the year and it is likely that the slightly less than anticipated average miles is due to this and other past budget cuts. It is important to keep the program funded at a 5 year pace to continue to achieve our anticipated Projected Tree Growth + Tree Fell OMT Events – 5 Year Cycle.

Table 17, VM KPI Performance

Year	Projected Tree Growth + Tree Fell OMT Events – 2009 Plan	Projected Tree Growth + Tree Fell OMT Events – 5 Year Cycle	Actual Number of OMT Events	Projected Annual Miles Managed	Actual Annual Miles Managed w/o Risk Tree or Spraying	Percent Model Error
2009	1120	556	765	1,220	790	136%
2010	620	540	836	1,560	1,304	155%
2011	790	500	727	1,560	1,747	145%
2012	1210	520	712	1,560	1,296	137%
2013	1390	630	647	1,560	1,459	103%
2014	1400	780	793	1,560	1,663	102%
2015	1730*	777*	620	1,560*	1,405	-

Note: values in red missed the goal
*Linear progression from previous metrics

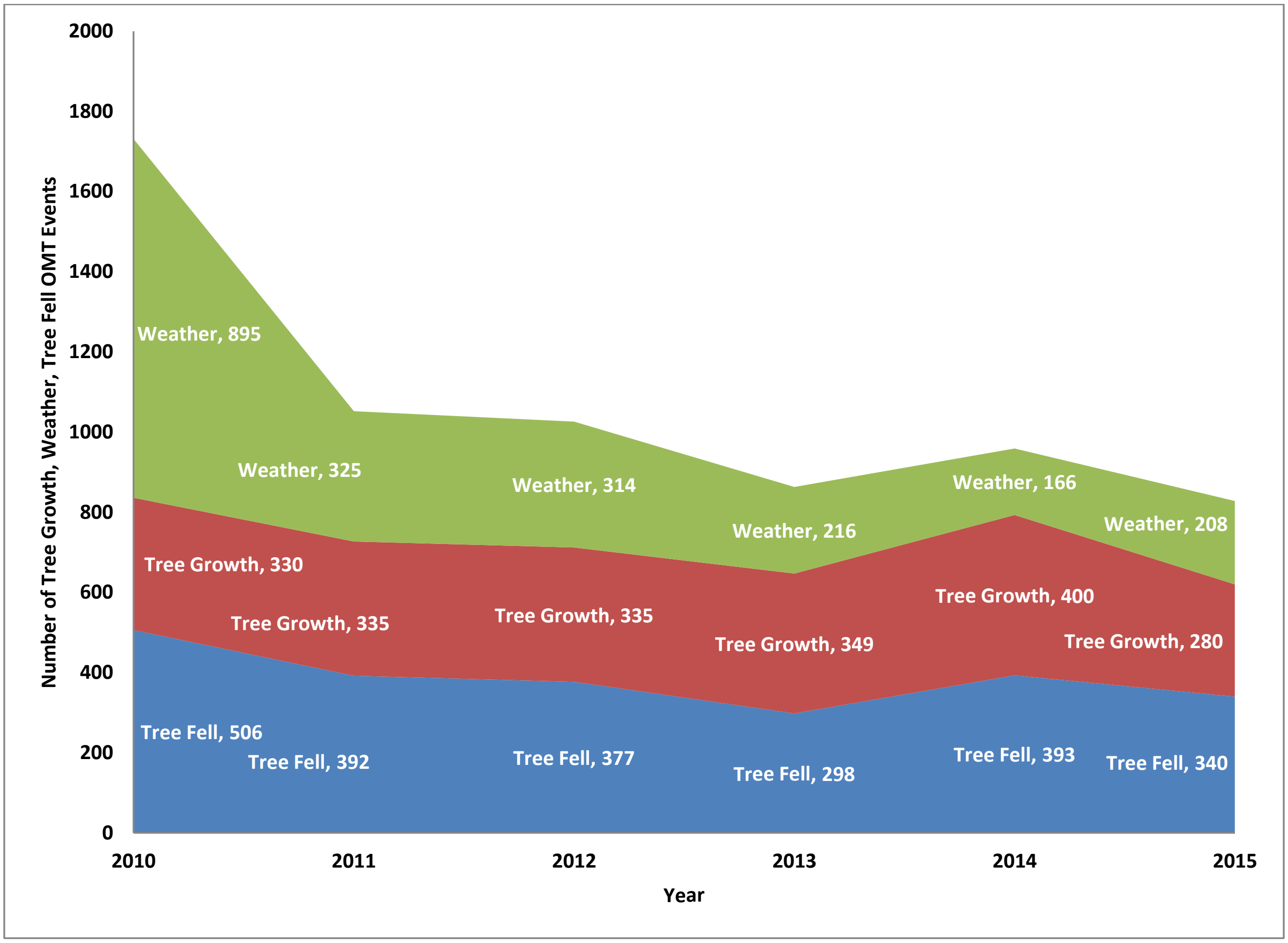


Figure 16, OMT Events Data Trends for Tree-Weather, Tree Growth, and Tree Fell Sub-Reasons

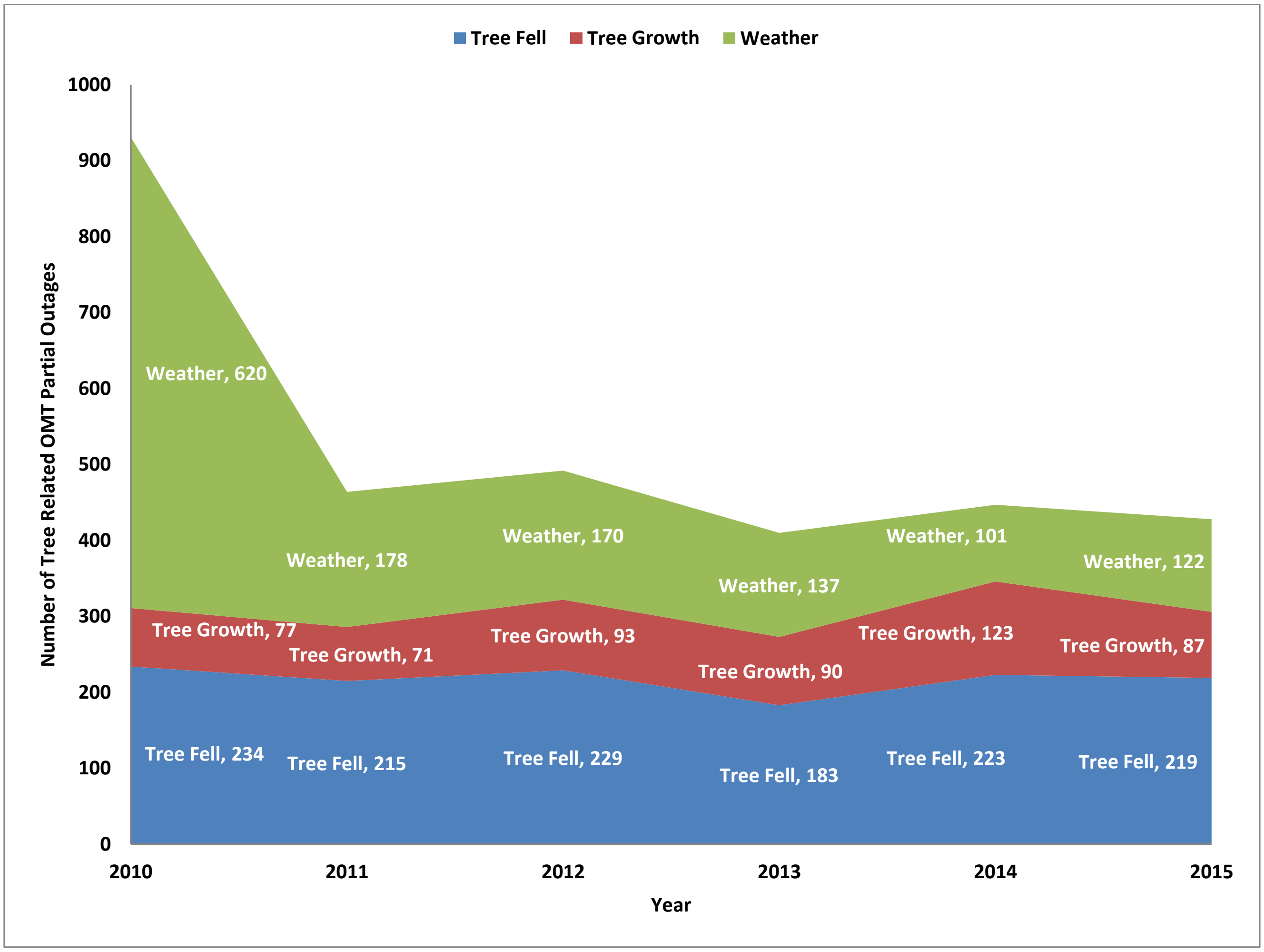


Figure 17, OMT Outage and Partial Outage Data Trends for Tree-Weather, Tree Growth, and Tree Fell Sub-Reasons

VM Metric Performance

The Tree OMT Events for 2015 continued to show improvement and were below the AM model projections (see Table 17). However, we must update the Vegetation Management models to improve projections and potentially update the program plan.

The cost per mile for VM in 2015 was $1,058 (see Table 19). This much lower than average. This is partially due to the large amount of miles of distribution that was inspected after the large storm in November of this year. We need to update the Vegetation Management model to address changes in the program which will help understand the impact to our system.

Table 18, Tree-Weather OMT Events Metric for Vegetation Management

Year	Projected Tree-Weather OMT Events – 2009 Plan	Projected Tree-Weather OMT Events – 5 Year Cycle	Actual Field Verified Tree Caused Weather Events	Actual Number of Tree-Weather OMT Events	Percent Model Error
2009	420	166	258	357	215%
2010	80	50	403	895	1790%
2011	220	70	159	325	464%
2012	580	70	150	314	449%
2013	800	170	121	216	127%
2014	1120	430	97	166	39%
2015	1358*	416*	84**	208	-

Note: values in red missed the goal

*Linear progression from previous metrics

**Extrapolated out to include December numbers. The field checking has not been completed for all December tree weather events.

Table 19, VM Cost per Mile and All Vegetation Management Work Metric

Year	Actual Annual Miles Managed all work	Cost per Mile of VM
2009	N/A	$6,575
2010	N/A	$2,990
2011	3,455	$2,612
2012	3,364	$3,272
2013	4,014	$1,657
2014	4,721	$1,439
2015	5,565	$1,058

VM Model Performance

The AM model for Distribution VM was revised in 2010, but the recent changes to the work performed and errors experienced justify updating the model. We anticipate completing the update in 2016.

VM Summary

Depending on how the program is evaluated, not enough miles are completed each year to achieve the goal of a 5 year cycle. The costs per mile may be too high and/or the current funding levels are too low and the impacts of herbicide spraying and enhanced risk tree work modify the meaning of work per mile. Vegetation Management's performance does show continued improvement but further analysis will provide an opportunity to re-evaluate our current performance and update future expectations.

Distribution Grid Modernization Program

Avista initiated a Grid Modernization Program designed to reduce energy losses, improve operation, and increase the long-term reliability of its overhead and underground electric distribution system. The program includes replacing poles, transformers (Pad Mount, OH & Submersible), cross arms, arresters, air switches, grounds, cutouts, riser wire, insulators, conduit and conductors in order to address concerns related to age, capacity, high electrical resistance, strength, and mechanical ability. The program also includes the addition of wildlife guards, smart grid devices, switched capacitor banks, balancing feeders, removing unauthorized attachments, replacing open wire secondary, and reconfigurations.

When funded to a level that allows 5-6 feeders to be upgraded per year, the continuous program represents a 60 year interval to upgrade all the feeders in Avista's system and coordinates all of its activities with Avista's Wood Pole Management. The objectives of the Grid Modernization Program are listed in Table 20.

Table 20, Grid Modernization Program Objectives

Objective	Objective Description
Safety	Focus on public and employee safety through smart design and work practices
Reliability	Replace aging and failed infrastructure that has a high likelihood of creating a need for unplanned crew call-outs
Avoided Costs	Replace equipment that has high energy losses with new equipment that is more energy efficient and improve the overall feeder performance
Operational Ability	Replace conductor and equipment that hinders outage detection and install automation devices that enable isolation of outages
Capital Offset	Avoid future equipment O&M costs with programmatic rebuild of failing system

Selected Metrics

The metrics selected include miles of work completed, OMT sustained outages on feeders with Feeder Upgrade work completed, and energy savings provided by completed work.

Based on Avista's 2015 Integrated Resource Plan dated August 31st, 2015, Table 8.3, the realized and anticipated energy savings by identified feeders is shown in Table 21.

Table 21, 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**

The miles of work planned is ultimately driven by the approved budget and generally can only be projected for 5 years. In order to maintain a 60 year cycle, Avista would need to address an average of 137 miles per year of overhead circuit miles.

For tracking the impacts of the work on outages, we will monitor the following OMT sub-reasons shown in Table 22. While the Grid Modernization will affect all of the sub-reasons listed in Table 22**Error! eference source not found.**, the sub-reasons identified as potentially avoidable represent the most direct impact of the work. We assume that the number of OMT sustained outages will be reduced by 0.1 outages per mile of overhead work completed.

Table 22, OMT Sub-Reasons impacted by Grid Modernization

OMT Sub-Reason	GM Potentially Avoidable	Wood Pole Management
Arrester	x	
Bird		x
Capacitor	x	
Conductor - Pri	x	
Conductor - Sec	x	
Connector - Pri	x	
Connector - Sec	x	
Cross arm - rotten	x	x
Cutout/Fuse	x	x
Elbow	x	
Insulator	x	x
Insulator Pin	x	x
Lightning		
Pole Fire		
Pole - rotten	x	x
Recloser	x	
Regulator	x	
Snow/Ice		x
Squirrel		x
Switch/Disconnect	x	
Transformer - OH	x	x
Transformer UG	x	
Undetermined		
Weather		
Wildlife Guard	x	x
Wind		x

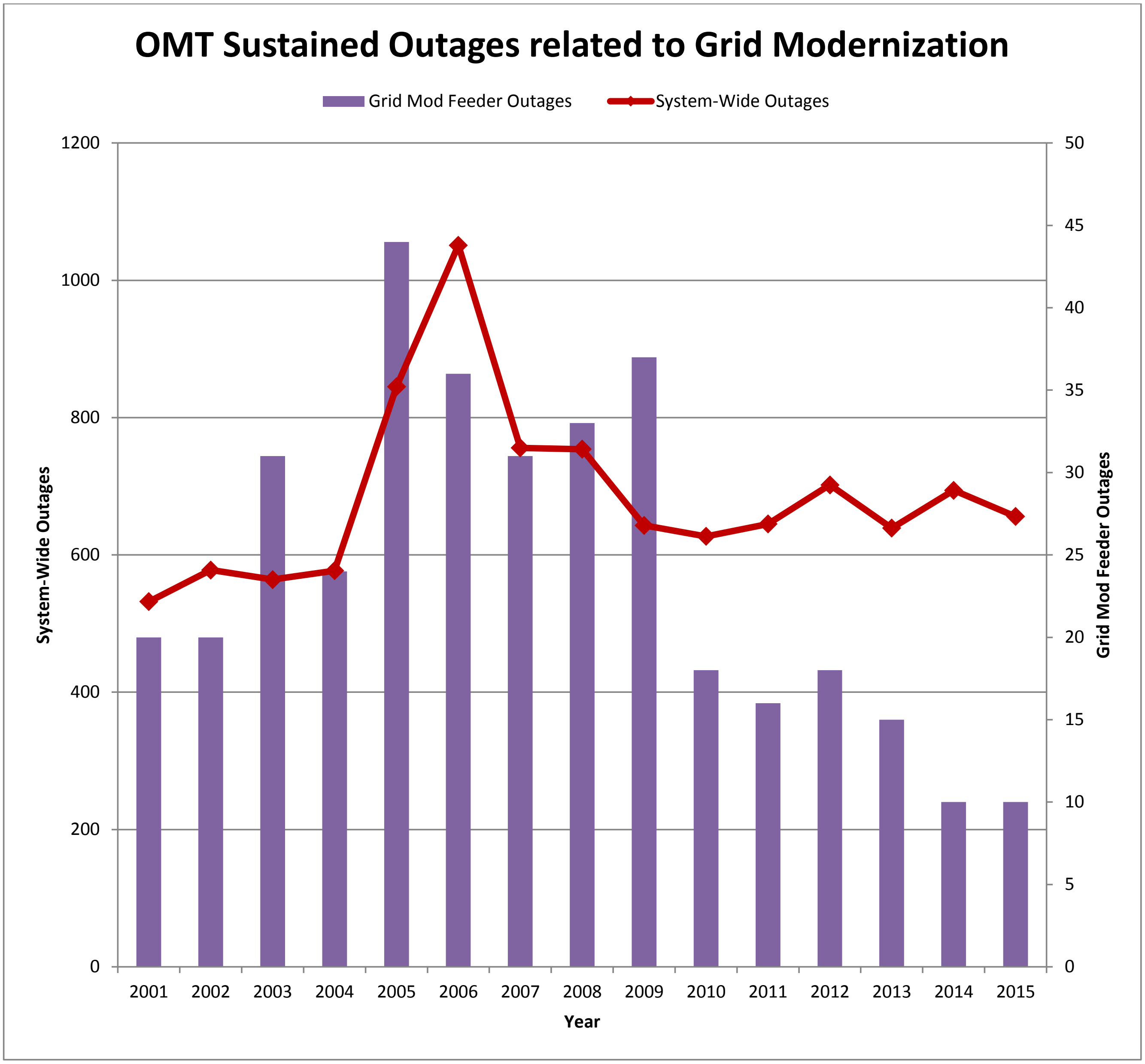


Figure 18, OMT Sustained Outages related to Grid Modernization

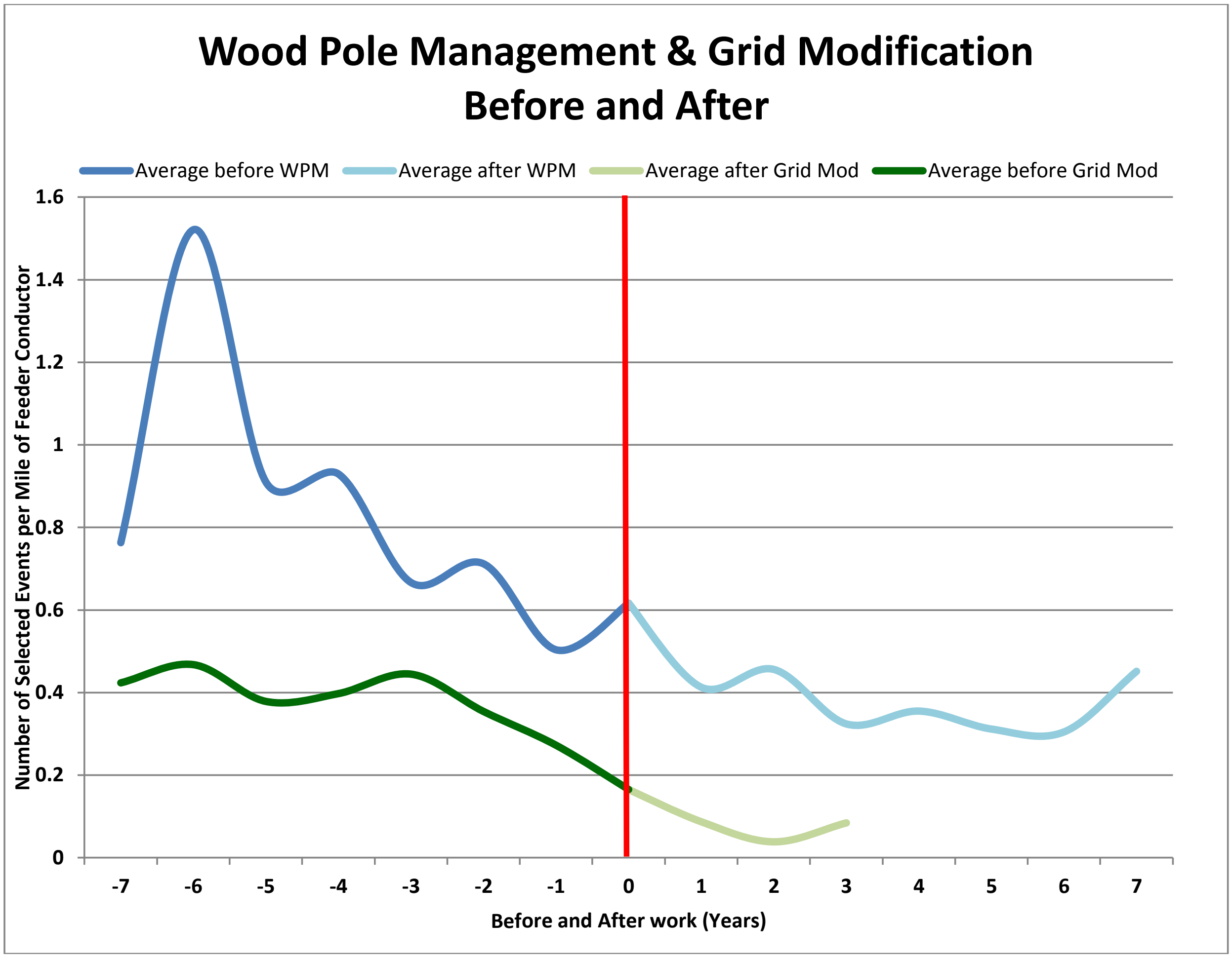


Figure 19, Wood Pole Management and Grid Modernization Before and After

Metric Performance

The results of the first four years work are shown in Table 23 the major event days from 2015 were removed to more accurately show program value). The year 2012 marks the beginning of the program. The number of miles actually completed missed the goal of 137 and the number of sustained outages just fell short of its goal. Figure 19 shows the prior and post trends for WPM and Grid Mod. These trends are broken down to be outage specific per program on a per mile of OH Conductor basis. The graph shows a steady trend downward for both programs after work is done on a feeder. Grid Mod work tends to trend down prior to the completion date due to the time it takes to complete the Grid Mod work and in some cases feeders being previously completed by WPM. A feeder may take multiple years to complete thus some portion of the benefits are gained in the couple years before completion. The before/after portion of the graph is set so that all the work done for these programs since 2008 is set to a zero year on the year it was completed. The program is reducing outages as seen in Figure 19 and Table 23 even though the planned miles have yet to be met. Missing this goal increases our program cycle, the current goal is a 60 year cycle. Continuing to miss this mileage can impact the sustained outages over time.

Table 23, Metric Performance for Grid Modernization Program

Year	Planned Miles for Modernization (Miles)*	Actual Miles Completed (Miles)**	Anticipated Number of Sustained Outages	Realized Number of Sustained Outages
2012	95	73.33	2340	2251
2013	137	53.83	2327	1840
2014	137	78.64	2313	1791
2015	137	85.2	2300	2342
2016	190***		2286	
2017	190***		2272	

*Note: The planned or anticipated values may be modified to match approved work plans for each year that more accurately align with the actual work planned. Overall outages are based on the Reliability Outage events considered

**Data from Grid Modernization Group

***Grid Mod works on both overhead and underground equipment. Future metrics and analysis will be based on total circuit miles

Summary

The Grid Modernization Program began in earnest in 2012 and represents feeder replacement work and upgrades founded on smart grid work. Overall the program is improving outages and improving the health of our system. The anticipated miles completed and cycle time may need to be modified in the future if the miles continue to miss the goal, however, the anticipated outage reduction appears to be on target and so the mileage is not an issue at this time.

Worst Feeders

Since 2009, Avista has invested $1-2M annually to improve the reliability of its most underperforming distribution circuits (aka – Worst Feeders). The Company operates over three hundred and fifty (350) individual circuits throughout Northern Idaho and Eastern Washington. Many of these circuits serve rural geographic regions and may extend for hundreds of miles. In most situations, rural circuits route through heavily timbered national forest areas and are subject to tree, wind, and storm related outages. Avista's SAIFI target in 2015 was 1.17. So, on average, an Avista customer could expect one sustained, contingency outage event in 2015. However, many rural customers experience three to five sustained outages per year with a few circuits topping the SAIFI chart at above six (see Table 24). Avista operating engineers are instructed to systematically review outage logs for these circuits and determine an appropriate level of treatment. Projects vary by individual circumstance but in many cases additional circuit reclosers are installed to reduce outage exposure and to automatically restore power to upstream customers. In other locations, circuits in outage prone areas are converted from overhead to underground. In other situations, circuits are effectively 'hardened' by shortening conductor span lengths or by increasing phase spacing. Of particular note is the Grangeville 1273 circuit. Though its SAIFI metric is the highest in the Company, the current average of 9.02 is a significant improvement over the previous three year average of 21.9. A program investment of $217,686 was made on this line and has help to improve its reliability performance. On another circuit, Roxboro 751, over 1 million dollars was invested to convert overhead line segments to underground cable and the SAIFI statistics improved from 5.35 to 2.67. In fact, Roxboro now ranks 35th in our feeder list and does not appear in the top twenty 'worst feeders' as depicted in the graphics. In 2016, Avista plans to invest $1.5 million dollars in ten (10) circuit projects. This includes the final phase of the Roxboro 751 project along with other multi-year projects including Gifford Feeders 34F1 and 34F2 together with Colville 34F1 projects. Other projects are first year efforts to improve the service reliability of rural distribution circuits. The 2016 capital plan for the worst feeder program is indicated in Table 25.

Table 24, Worst Feeder SAIFI 3 Year Average

FDR	2012-2014 SAIFI 3yr Avg
GRV1273	9.02
STM633	6.82
SPI12F1	6.40
ODN732	6.28
GIF34F1	5.21
GIF34F2	4.79
CHW12F4	4.48
VAL12F2	4.47
CLV34F1	4.44
RDN12F2	4.43
JPE1287	4.27
CHW12F3	4.25
CKF711	4.13
SAG741	4.11
SPR761	4.07
VAL12F1	3.54
SWT2403	3.47
CHW12F2	3.46
MIS431	3.45
RDN12F1	3.40

Table 25, Worst Feeder Projects and Costs

Project Code (SUB FDR SAIFI RANK- DESC)	$ in 000's
GIF 34F1 (5)	250
SPT4S21- Reroute heavily tree area	100
COT2404	50
RSA 431 - various locales	50
LAT 421- various	50
GIF 34F2 (6) - Twin Lake	250
JPE1787(11)-WEI1289(25)	100
CLV 34F1 (9)	250
ROX 751 OH/UG Conversion (35)	150
SPO- #6 Crapo Removal 8 miles	250

Feeder Tie Circuits

Urban distribution feeders can be connected to other feeders as a means of “back-up” to serve customer load. By closing a “tie” switch between the two feeders, it is possible to electrically “feed” a portion of the adjacent feeder.

Service reliability can be compromised by the contingency loss of substation equipment such as the substation transformer, and voltage regulator. Car-hit poles can cause lengthy outages. Critical issues with picking up an adjacent feeder include the reserve capacity of the host feeder and the end of line service voltage.

In rural areas, feeders with back-up capability are rare because the distance between adjacent circuits may be several miles. As with urban feeders, loss of substation equipment can cause feeder outages. Also, losing a portion of the main feeder trunk on a rural, radial feeder due to a tree through the line and/or via wind damage can also cause an outage that could be minimized with a “tie” feeder capability.

Feeder Tie projects increase the reliability of both of the circuits involved in the “tie”.

ARD12F2-ORN12F1 Tie Circuit

This feeder tie project will allow the Arden12F2 distribution feeder to be fed by Orin12F1. The “tie” is being built by installing new conductor between the “gap” in the two circuits (see Figure 20). The conductor has a cross sectional area allowing it to pick up the load of Arden12F2. In addition the voltage drop of the “tie” conductor is small. Also, a set of voltage regulators is being installed to increase the voltage on the Arden12F2 feeder to keep it within the required limits. If there is an outage on the Orin12F1 feeder, the Arden12F2 will be able to pick up a portion of Orin12F1, but not the entire feeder.

This is a two year project with a cost of $850,000 covering a distance of 2 miles between the two feeders.

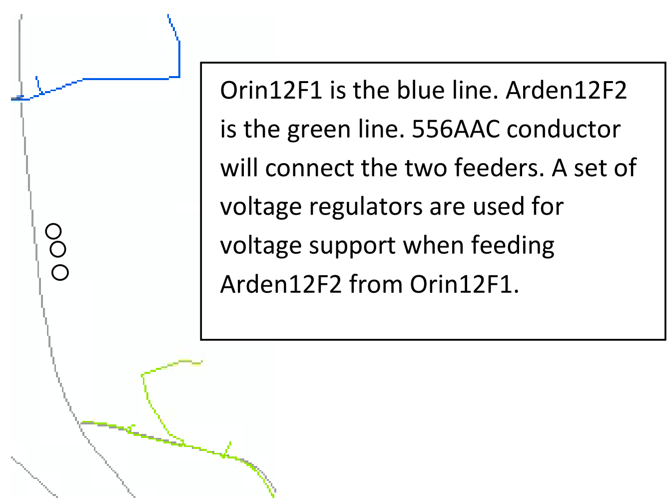
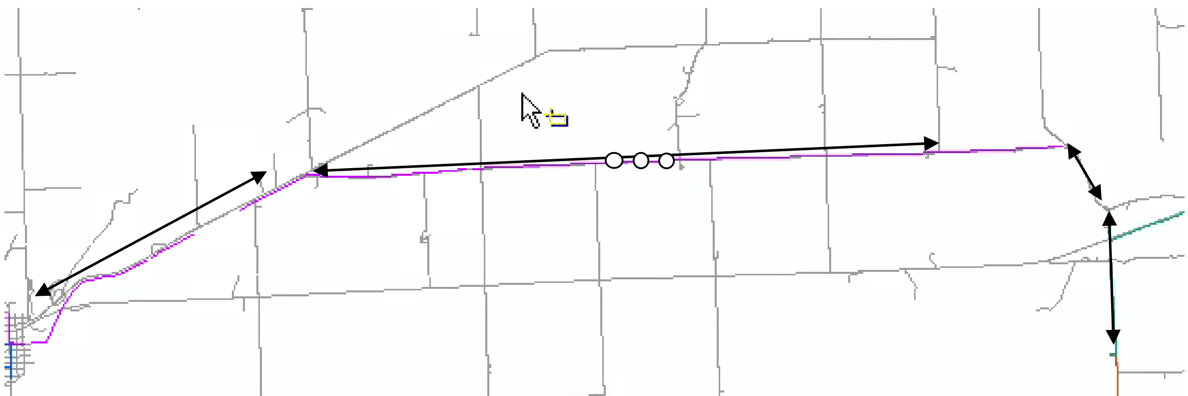


Figure 20, ARD12F2 to ORN12F1 Tie

DAV12F2-RDN12F1 Tie Circuit

This circuit tie will allow Rearden12F1 to be fed from Davenport12F2 and vice versa. The "tie" is being built by installing new conductor between the "gap" in the two circuits (see Figure 21). Also, a set of voltage regulators is being installed to increase the voltage on the host feeder to support customer service voltage.

This is a multiyear project with a cost of $1.8 million dollars, connecting a distance of 10 miles between the two feeders.



Davenpor
t

Ten miles of 556AAC conductor and a set of voltage regulators enables picking up either substation from the other direction.

Rearden Substation

Figure 21, DAV12F2 - RDN12F1 Tie

At this point in time, approximately 5 miles of the tie circuit has been upgraded to 556 AAC. This new conductor will allow either substation to carry 4 MVA in the Summer, and 6 MVA in the Winter.

When all the conductor is upgraded, the load carrying capability will be doubled and either substation can pick up the other any time of the year.

Summary

This program is a new program and metrics have yet to be established. Metrics will be worked on this year with the department running this program. We need to see the results from these future metrics before we draw any conclusions from the program.

Spokane Electric Network

Equipment Types and Aging

Major network equipment falls into four categories: network transformers, network protectors, cable (primary and secondary), and physical facilities – duct banks, vaults, manholes, and handholes.

Transformers and Protectors – some age, and maybe initial cost, data may be available via Maximo. A casual search indicates 27 transformers with purchase dates between 1930 and 1950 still in service in the network – these records are not verified. Another casual search of network protector records indicates units dating to 1947 still in service.

Cable – we do not have specific records regarding age of cables. A fair percentage is "OLD" – comments below.

Physical facilities – again, no specific records. Again, a fair percentage is "OLD".

KPI and Metrics

There are no established performance metrics for the downtown network. Given that the very nature of the network architecture is intended to prevent outages, and that OMT does not "see" network events, we have no specific outage data other than to state that the numbers would be small in comparison with the rest of the Avista system. Assuming the "network communications" project discussed in the "Non-routine Projects" section below actually comes to fruition, we would be better able to identify, track, and analyze outages should they actually occur.

Capital Budgets and Spending - Overview

CapX expenses in the downtown network fall into six general categories. Five are covered in "blanket" projects; the sixth category is funded by specific CPRs. Details:

1. New services: Commercial, residential, Street Lights
2. Replacement of old primary cable (Paper Insulated Lead Cable, "PILC")
3. Replacement of old secondary cable (PILC or Rubber Insulated Neutral Cable, "RINC")
4. Purchase and replacement of aging transformers and network protectors
5. Repair/refurbishment/replacement of vaults/manholes/handholes
6. The fifth category, covered by specific CPRs, may involve projects such as:
    a. Work required due to extensive city projects – e.g., the upcoming major rebuild of Lincoln and Monroe Sts where we have extensive existing facilities which will need major work or replacement
    b. Adding a "SCADA" and communications capability to the existing network – a trial project for Post West is budgeted.

New Services – Expenses

Generally self-explanatory. '15 budget $200K

Replacement of old PILC primary cable– Expenses

Our 2015 budget for PILC cable replacement was $340K. The PILC primary cable in our network is typically 30 years old or more; we do not have specific information on when much of it was installed.

Our network has about 96,700 feet of primary cable, about 47,900 feet is still PILC. We have targeted for replacing 7,500 feet of primary PILC each year. In 2015, due to personnel shortages and other more pressing work, we only replaced 6300 feet of primary cable.

The PILC cable has been very reliable through the years of service; however, as it ages, we have observed an increase in failures. Our goal of maximizing service in the downtown network drives the PILC replacement effort. Figure 22 and Figure 23 are illustrations of failures that occurred with older PILC cable.

Avista was fortunate in that we have only had one PILC cable failure in 2015 and one in 2013. This low failure rate is in large part due to the proactive replacement of the old cable. Owing to the redundant nature of our network, neither of these events resulted in customer outages.

Figure 22, A faulted PILC cable

Figure 23, A second faulted PILC cable

Replacement of old PILC and RINC secondary cable– Expenses

Factors driving replacement of PILC primary and PILC/RINC secondary are essentially the same. We replaced about 4,600 feet of secondary cable in 2015.

Purchase of new and replacement of aging transformers and network protectors– Expenses

Our 2015 budget for purchasing transformers and protectors was $920K; for replacement activities including associated cable, vault accessories, etc. was $1.1M.

We have 174 transformers in our network, each equipped with a network protector. Network transformers and network protectors are specialized devices specifically designed and built to ensure maximum operating reliability, and in the case of the protector, to improve and ensure safety for the crews working on the network.

We target replacing 12 transformers per year, and generally, the protector is replaced at the same time (there are exceptions). Replacement of a network transformer is a labor-intensive operation, and typically involves added expenses for hiring a crane to move the old and new transformers in and out of the vault, traffic control, and often crew overtime. We prioritize replacing very old transformers, transformers which are found to still have PCB oil, and transformers where routine oil sampling indicates contamination. In addition, transformers where oil sampling indicates high concentrations of combustible gasses (typically caused by internal arcing or similar events) are replaced immediately. In 2015 we replaced one transformer due to a high concentration of combustible gasses, one due to contaminated oil, and one ca. 1947 vintage transformer after a bulge was noted in the primary compartment case. We also replaced three aged transformers on a more “routine” basis.

A transformer failure can be a dramatic and dangerous event. Avista has been fortunate to not experience a violent transformer failure in recent years (a quick search indicates that the last one was in 2008.) Figure 24 illustrates the transformer which failed in 2008 due to some anomaly in the primary compartment.

Figure 24, A network transformer after a failure in the primary compartment

Repairs/refurbishment/replacement of vaults/manholes/handholes– Expenses

Our 2015 budget for this work was $500K.

Our system contains 140 vaults, 325 manholes, and 295 handholes. Many of these, particularly manholes and handholes, date from the early 1900s and are still in service. In particular, where these are located in a traveled street, they have often deteriorated due to stresses from traffic, weather, and related factors. Vaults which have grated covers for circulating air for transformer cooling are often subjected to chemicals used for deicing streets in winter, which collects in the vaults and deteriorates the concrete.

When these facilities become deteriorated to the extent we have found in some cases, they represent not only the possibility of interruptions to service, but becoming traffic hazards as well. In the case of facilities in sidewalk areas, we have seen cases where cracking or buckling concrete, or deformed lids, have the potential to be a trip hazard for pedestrians.

Mitigating the vault, manhole, and handhole deterioration has ranged from being as simple as installing a new lid to removal and replacement of the entire facility. Figure 25 through Figure 27 illustrate various underground facility deterioration we have recently found, and some of the remediation efforts undertaken.

In 2015, we repaired or replaced 6 of these facilities. We have 3 more in queue pending a break in winter weather, and we have not started our 2016 inspection cycle.

Figure 25, Interior of a badly deteriorated old manhole in a heavily traveled street

Figure 26, Duct bank damage entering an old deteriorated manhole

Figure 27, Complete replacement of a badly deteriorated manhole

Non-routine Projects Being Carried Out on Specific CARs– Expenses

We had two open CPRs for network projects in 2015.

Network Communications Stage 1– Expenses

This project was budgeted for $122.4K

The scope of this pilot project involves adding communications capabilities to network protectors in a subset of the Post St West sub-network. This communications capability will enable remote reading of protector status (closed, tripped, locked open, number of protector operations), and remote instantaneous load readings. This capability will not immediately improve system reliability, but will pave the way for additional capability such as remote protector switching and remote indication of vault conditions (temperature alarm, unauthorized entry, etc.) which is expected to benefit overall network operation and maintenance. For convenience – think "smart grid" for the downtown Spokane network. The CPR was first opened in 2014, but to date, lack of personnel resources has resulted in no charges. This CPR remains open for 2016.

Monroe and Lincoln St Repaving– Expenses

This project was budgeted for $495K ($475K construction, $20K removal/retirement)

The City of Spokane has informed Avista of plans to extensively renovate and repave both Lincoln and Monroe Streets from 3rd Ave north to Main St in the main downtown corridor. This project will result in Avista needing to extensively modify, rebuild, and possibly even move network facilities in those streets. The CPR was opened in 2015 in anticipation of ordering long-lead items, but planning delays resulted in no expenditures in '15. The CPR remains open for 2016.

Distribution Line Protection

Avista's Electric Distribution system is configured into a trunk and lateral system. Lateral circuits are protected via fuse-links and operate under fault conditions to isolate the lateral in order to minimize the number of affected customers in an outage. Engineering recommends installation of cut-outs on un-fused lateral circuits and the replacement of obsolete fuse equipment (e.g. Chance, Durabute/V-shaped, Open Fuse Link/Grasshopper, Q-Q, Load Break/Elephant Ear, and Porcelain Box Cutouts). As part of the program, sizing of fuses will be reviewed to assure protection of facilities, as well as coordination with upstream/downstream protective devices. This is a targeted program to ensure adequate protection of lateral circuits and to replace known defective equipment.

Assets Not Specifically Covered Under a Program

These assets do not have a planned AM program, so no specific metrics or KPIs have been identified. The general metrics discussed above for number of OMT Events (Table 1) and the associated action level; Risk Action Curve limits; and requests by responsible parties will determine in the future if a plan will be developed or if action is needed. In summary, Table 26 lists assets we continue to monitor to determine if and when planned actions are needed.

Table 26, Assets Not Specifically Covered Under a Program

Asset	Other information
Distribution Capacitors	Smart Grid added switch capacitors but our initial analysis did not indicate a strategy was justified
Distribution Cutotuts	Addressed through the WPM program and Distribution Line protection
Dead End Insulators	-
Distribution Mid- Line Reclosers	Substation Asset Management is analyzing strategies for this asset
Distribution Mid- Line Voltage Regulators	Substation Asset Management is analyzing strategies for this asset
Open Wire Secondary	Previous analysis indicated that this program was not financially justified. We believe Grid Mod will address many of these issues.
Primary Conductors	-
Primary Connections	-
Secondary Conductors	-
Primary Conductors	-
Riser Termination	--
URD Secondary Cable	Although we are monitoring this one closely we have yet to see a need to implement a strategy

Conclusion

In this report, we documented and examined the KPIs and metrics AM selected for the AM Distribution system programs and provided the results for 2015. Some of the metrics compared how an asset performed with a program and how it would have performed without a program. The difference in performance provide an estimate of the cost saving and value of an AM program. While the exact savings are impossible to calculate in most cases, it provides a relative comparison and supporting justification or motivation for change in AM decisions made in the past. Other KPIs and metrics provided indications of how well an asset performed and help determined if further work is required. Some AM models clearly need more work to better predict future conditions and will be scheduled in the future if it makes sense. This year other non-AM programs were included in this report and submitted by the group in charge of each program. These program write-ups did not follow the same template as the AM write-ups but were included within the document for project comparison.

Distribution Vegetation Management

2016 Washington
AIR12F1
AIR12F2
AIR12F3
CFD1210
CFD1211
CHE12F1
CHE12F2
CHE12F3
CHE12F4
CLA56
EWN241
FOR2.3
GIF34F2
INT12F1
INT12F2
L&R511
L&S12F1
L&S12F2
L&S12F3
L&S12F4
L&S12F5
LOO12F1
LOO12F2
MLN12F2
ROK451
ROX751
SE12F1
SE12F2
SE12F3
SE12F4
SE12F5
SOT522
SOT523

SPI12F1
TUR111
TUR112
TUR113
TUR115
TUR116
TUR117
TVW131
TVW132
VAL12F1
Idaho
CGC331
CKF711
DAL131
DAL132
DAL133
DAL134
GRV1271
GRV1272
GRV1273
GRV1274
KAM1291
KAM1292
KAM1293
KOO1298
KOO1299
RAT231
RAT233
SAG741
SPT4S21
SPT4S22
SPT4S23
SPT4S30
Montana
NRC352

2017 Washington
CHW12F1
CHW12F2
CHW12F3
CHW12F4
COB12F1
COB12F2
DVP12F1
DVP12F2
ECL221
ECL222
FWT12F1
FWT12F2
FWT12F3
FWT12F4
GLN12F1
GLN12F2
GRN12F1
GRN12F2
GRN12F3
L&R512
LEO611
LEO612
LF34F1
LIB12F1
LIB12F2
LIB12F3
LIB12F4
MEA12F1
MEA12F2
MLN12F1
OTH501
OTH502
OTH503
OTH505
ROS12F1
ROS12F2
ROS12F3
ROS12F4
ROS12F5
ROS12F6
Idaho
BUN422
BUN423
BUN424
BUN426
CRG1260
CRG1261
CRG1263
MIS431
NEZ1267
ODN731
ODN732
ORO1280
ORO1281
ORO1282
PIN441
PIN442
PIN443
POT321
POT322
PRA221
PRA222
PVW241
PVW243
WOR471
SWT2403
WIK1278
WIK1279

2018 Washington
3HT12F1
3HT12F2
3HT12F3
3HT12F4
3HT12F5
3HT12F6
3HT12F7
3HT12F8
9CE12F1
9CE12F2
9CE12F3
9CE12F4
ARD12F1
BKR12F1
BKR12F3
C&W12F1
C&W12F2
C&W12F3
C&W12F4
C&W12F5
C&W12F6
CLV12F1
CLV12F2
CLV12F3
CLV12F4
CLV34F1
DRY1208
DRY1209
GAR461
HAR4F1
HAR4F2
KET12F1
MIL12F1
MIL12F2
MIL12F3
MIL12F4
NW12F1
NW12F2
NW12F3
NW12F4
NW13T23
PAL311
PAL312
RDN12F1
RDN12F2
RIT731
RIT732
SPA442
SPU121
SPU122
SPU123
SPU124
SPU125
WAK12F1
WAK12F2
WAK12F3
WAK12F4
Idaho
BIG411
BIG412
BIG413
BLU321
COT2401
COT2402
HUE141
HUE142
LKV341
LKV342
LKV343
LKY551
M15511
M15512
M15513
M15514
M15515
M23621
NMO521
NMO522
OSB522
STM631
STM632
STM633

2019 Washington
ARD12F2
BKR12F2
DEP12F1
DEP12F2
DIA231
DIA232
EFM12F1
EFM12F2
H&W12F1
H&W12F2
KET12F2
LAT421
LAT422
LIN711
ORI12F1
ORI12F2
ORI12F3
SUN12F1
SUN12F2
SUN12F3
SUN12F4
SUN12F5
SUN12F6
WAS781
WIL12F1
WIL12F2
Idaho
BLA311
CDA121
CDA122
CDA123
CDA124
CDA125
JUL661
LOL1359
OGA611
OLD721
OLD722
OSB521
PF211
PF212
PRV4S40
SLW1316
SLW1348
SLW1358
SLW1368
SPL361
TEN1253
TEN1254
TEN1255
TEN1256
TEN1257

2020 Washington
BEA12F1
BEA12F2
BEA12F3
BEA12F4
BEA12F5
BEA12F6
BEA13T09
F&C12F1
F&C12F2
F&C12F3
F&C12F4
F&C12F5
F&C12F6
FOR12F1
GIF34F1
LL12F1
NE12F1
NE12F2
NE12F3
NE12F4
NE12F5
ODS12F1
OPT12F1
OPT12F2
PDL1201
PDL1202
PDL1203
PDL1204
PST12F1
RSA431
SIP12F1
SIP12F2
SIP12F3
SIP12F4
SIP12F5
SLK12F1
SLK12F2
SLK12F3
SOT521
SPI12F2
SPR761
TKO411
TKO412
VAL12F2
VAL12F3
Idaho
APW111
APW112
APW113
APW114
APW115
APW116
AVD151
AVD152
CKF712
DER651
DER652
HOL1205
HOL1206
HOL1207
IDR251
IDR252
IDR253
JPE1287
JUL662
LOL1266
N131222
N131321
PF213
SAG742
WAL542
WAL543
WAL544
WAL545
WEI1289

Distribution Wood Pole Management

2016	2017	2018	2019	2020
SOT522	BEA12F3	APW116	9CE12F1	LIN711
AIR12F3	BEA13T09	ARD12F1	9CE12F2	BLA311
APW114	COT2401 - ID	ARD12F2	9CE12F3	CHW12F1
APW115	COT2402 - ID	BEA12F4	BLU321	CHW12F2
CHE12F4	DVP12F2	BEA12F6	BLU322	CHW12F3
CLA56	F&C12F3	BIG411	FWT12F2	CHW12F4
L&S12F1	F&C12F4	CFD1210 - WA	GIF34F2	EWN241
L&S12F2	F&C12F5	CHE12F1	INT12F1	JUL661
L&S12F3	F&C12F6	CHE12F2	INT12F2	JUL662
L&S12F4	FOR12F1	CMP12F2	LAT421 - WA	KAM1291
L&S12F5	FOR2.3	FWT12F4	LAT422 - WA	KAM1292
LKV341	IDR253	JPE1287 - ID	LTF34F1	KAM1293
LKV342	OTH501	OPT12F1	NE12F5	LEO611
LKV343	PVW243	OPT12F2	PRV4S40	LOO12F2
LOL1359 - ID	SIP12F1	OSB521	RSA431	MIS431
MLN12F1	SIP12F3	PST12F1	SPI12F2	ORI12F1
MLN12F2	SOT523	PST12F2	WAK12F1	ORI12F2
NLW1222 - ID	SWT2403 - ID	SLW1348 - ID	WAK12F3	PIN441
SPT4S23		SPA442 - WA	WAK12F4	POT321
		SPT4S22		RDN12F1
				RIT731
				RIT732
				SPL361
				WEI1289

2021	2022	2023	2024	2025
CFD1210	ECL221	9CE12F4	BIG412	BKR12F1
CRG1260	ORO1282	BUN423	BKR12F3	CDA125
DVP12F1	PAL311	BUN426	CRG1261	CRG1263
FWT12F1	PAL312	CLV12F1	DER652	F&C12F2
FWT12F3	PIN443	GRV1274	H&W12F1	HAR4F2
HOL1205	POT322	M15512	H&W12F2	LEO612
HOL1206	RDN12F2	PDL1201	LIB12F3	LIB12F1
NE12F4	SPT4S21	PDL1202	ODS12F1	LIB12F4
PF213	STM631	SE12F1	ORI12F3	M15511
ROS12F3	VAL12F2	SLW1316	ORO1281	MIL12F1
SE12F3	VAL12F3	SOT521	SLK12F3	NEZ1267
SIP12F2		SUN12F1	WAL542	NLW1321
SLW1348		SUN12F3		NMO522
SLW1358				SIP12F5
WOR471				SUN12F6
				TUR116

2026	2027	2028	2029	2030
AIR12F1	DAL131	CLV12F2	3HT12F4	BIG413
CFD1211	DAL132	CLV34F1	BEA12F5	BKR12F2
DRY1208	DAL134	ECL222	C&W12F1	BUN422
GRV1271	MEA12F2	GRN12F1	CDA121	BUN424
HUE141	MIL12F2	ROK451	CDA122	DRY1209
KOO1298	MIL12F4	TKO411	CDA124	GRN12F2
KOO1299	PF212	TKO412	CLV12F3	GRV1272
OGA611	PRA221		CLV12F4	GRV1273
PDL1203	PRA222		HOL1207	HUE142
PF211	TEN1253		LKY551	KET12F1
WAL543	TUR117		MEA12F1	L&R511
WIK1278			NE12F3	L&R512
WIK1279			SE12F5	LKY552
WIL12F1			TEN1257	NMO521
				OSB522
				PIN442
				PVW241
				WAL544
				WAL545

2031	2032	2033	2034	2035
3HT12F1	CKF711	NW12F4	AIR12F2	BEA12F1
3HT12F2	CKF712	3HT12F5	CHE12F3	ODN731
3HT12F3	DIA231	3HT12F6	COB12F1	ODN732
CGC331	DIA232	3HT12F7	COB12F2	SPU121
M15514	EFM12F2	APW111	EFM12F1	SPU122
NRC351	HAR4F1	APW112	M15515	SPU123
ROX751	KET12F2	C&W12F2	MIL12F3	SPU124
SLW1368	LL12F1	C&W12F3	STM633	SPU125
SUN12F2	LOO12F1	C&W12F4	SUN12F4	TEN1254
TUR113	PDL1204	C&W12F5	SUN12F5	TUR111
	STM632	C&W12F6		TUR115
		NE12F2		VAL12F1
		NW12F1		
		NW12F3		
		SPT4S30		
		WAK12F2		

Grid Modernization

2016 Grid Modernization Plan Feeder	Design	Constr	State	Region	Area
BEA12F1		x	WA	West	Spokane
M23621		x	ID	South	Pullman/Mosc
MIL12F2	x	x	WA	West	Spokane
MIS431	x		WA	East	Kellogg
ORO1280	x		ID	South	Grangeville
PDL1201	x		WA	South	Lewiston/Clark
RAT231		x	ID	East	Coeur d'Alene
RAT233	x	x	ID	East	Coeur d'Alene
SPI12F1	x	x	WA	West	Colville
SPR761	x		WA	West	Othello
TUR112	x		WA	South	Pullman/Mosc
WAK12F2		x	WA	West	Spokane

2017 Grid Modernization Plan Feeder	Design	Constr	State	Region	Area
2016 Carryover	x	x			
F&C12F1	x		WA	West	Spokane
M15514	x		ID	South	Pullman/Mosc
MIL12F2		x	WA	West	Spokane
MIS431	x		WA	East	Kellogg
ORO1280		x			
PDL1201		x	WA	South	Lewiston/Clark
RAT233	x	x	ID	East	Coeur d'Alene
SPI12F1		x	WA	West	Colville
SPR761	x	x	WA	West	Othello
TUR112	x	x	WA	South	Pullman/Mosc

2018 Grid Modernization Plan Feeder	Design	Constr	State	Region	Area
2017 Carryover	x	x			
BEA12F2	x		WA	West	Spokane
DEP12F2	x		WA	West	Deer Park
F&C12F1	x	x	WA	West	Spokane
HOL1205	x		WA	South	Lewiston/Clark
M15514		x	ID	South	Pullman/Mosc
MIL12F2		x	ID	West	Spokane
MIS431	x	x	WA	East	Kellogg
TEN1255	x		ID	South	Lewiston/Clark
RAT233		x	ID	East	Coeur d'Alene
SPI12F1		x	ID	West	Colville
SPR761		x	WA	West	Othello

2019 Grid Modernization Plan Feeder	Design	Constr	State	Region	Area
2018 Carryover					
BEA12F2	x	x	WA	West	Spokane
F&C12F1		x	WA	West	Spokane
HOL1205		x	ID	South	Lewiston/Clark
M15514		x	ID	South	Pullman/Mosc
MIL12F2		x	WA	West	Spokane
MIS431	x	x	ID	East	Spokane
MLN12F1	x	x	WA	West	Deer Park
RAT233	x	x	ID	East	Kellogg
SPR761		x	WA	West	Othello
TEN1255	x	x	ID	South	Lewiston/Clark
TEN1256	x		WA	South	Lewiston/Clark
TUR112		x	WA	South	Pullman/Mosc

Transformer Change-Out Program

TCOP Work Plan Year	Program Working	Count
2016	GMP	305
2016	TCOP	1027
2016	WPM	180
2017	GMP	459
2017	TCOP	480
2017	WPM	64
2017 Predicted Non Detect	TCOP	204
2018	GMP	252
2018	TCOP	14
2018	WPM	138
2018 Predicted Non Detect	GMP	5
2018 Predicted Non Detect	TCOP	1031

Business Cases

Distribution Wood Pole Management

Investment Name:	**Distribution Wood Pole Management**		
Requested Amount	**Estimated Total Capital Expenditure**	**Assessments:**	
Duration/Timeframe	Indefinite Year Program	Financial:	7.42%
Dept., Area:	Asset Maintenance	Strategic:	Life-cycle asset management
Owner:	Glenn Madden (Manager)	Business Risk:	Business Risk Reduction >5 and <= 10
Sponsor:	Cox/H. Rosentrater	Program Risk:	High certainty around cost, schedule and resources
Category:	Program		
Mandate/Reg. Reference:	NESC - See WPM Compliance Plan for details	Assessment Score:	93

Recommend Program Description:	Performance	Capital Cost	O&M Cost	Other Costs	Business Risk Score
		Annual Cost Summary - Increase/(Decrease)			
Distribution Wood Pole Management Program inspects all Electric Distribution Feeders on a 20 year cycle and repairs or replaces wood poles, crossarms, missing lightning arresters, missing grounds, bad cutouts, bad insulating pins, bad insulators, leaking transformers, replaces guy wires not meeting current code requirements on poles replaced by WPM, and replaces pre-1981 transformers	Customer IRR = 7.42% and avoids an average of 1,700 additional events per year	$ 11,172,022	$ 530,943	$ 5,996,350	15

Alternatives:		Performance	Capital Cost	O&M Cost	Other Costs	Business Risk Score
			Annual Cost Summary - Increase/(Decrease)			
Status Quo : No Wood Pole Management	Run wood poles and associated equipment to failure	Increase OMT events by 1,700 events	$ 8,186,361	$ -	$ 6,834,467	25
Alternative 1: Distribution Wood Pole Management - 20 Year Inspection Cycle	Distribution Wood Pole Management Program inspects all Electric Distribution Feeders on a 20 year cycle and repairs or replaces wood poles, crossarms, missing lightning arresters, missing grounds, bad cutouts, bad insulating pins, bad insulators, leaking transformers, and replaces pre-1981 transformers. Note: does not cover the additional costs associated with the backlog that is related to new requirements such as additional grounding and anchor rod replacements.	describe any incremental changes in operations	$ 10,712,022	$ 530,943	$ 5,996,350	15
Alternative 2: Distribution Wood Pole Management - 20 Year Inspection Cycle with Guy Wire	Distribution Wood Pole Management Program inspects all Electric Distribution Feeders on a 20 year cycle and repairs or replaces wood poles, crossarms, missing lightning arresters, missing grounds, bad cutouts, bad insulating pins, bad insulators, leaking transformers, replaces guy wires not meeting current code requirements on poles replaced by WPM, and replaces pre-1981 transformers	describe any incremental changes in operations	$ 11,172,022	$ 530,943	$ 5,996,350	0
Alternative 3 Name : Distribution Wood Pole Management - 10 Year Inspection Cycle with Guy	Distribution Wood Pole Management Program inspects all Electric Distribution Feeders on a 10 year cycle and repairs or replaces wood poles, crossarms, missing lightning arresters, missing grounds, bad cutouts, bad insulating pins, bad insulators, leaking transformers, replaces guy wires not meeting current code requirements, and replaces pre-1981 transformers	describe any incremental changes in operations	$ 17,296,437	$ 961,699	$ 4,920,632	0

Program Cash Flows

	Capital Cost	O&M Cost	Other Costs	Approved
Previous	$ 21,393,700		$ -	$ 18,767,986
2015	$ 11,500,000			$ 10,600,000
2016	$ 11,200,000	$ 543,155	$ 4,564,898	$ 7,840,000
2017	$ 14,700,000	$ 555,648	$ 4,574,638	$ 12,000,000
2018	$ 14,700,000	$ 570,094	$ 4,588,630	$ 15,700,000
2019	$ 14,700,000	$ 584,916	$ 4,611,573	$ 16,060,000
2020	$ 14,700,000	$ 600,124	$ 4,634,631	$ 14,700,000
2021+	$ 15,700,000	$ 615,728	$ 4,657,804	$ -
Total	$ 118,593,700	$ 3,469,665	$ 27,632,174	$ 95,667,986

Associated Ers (list all applicable):

2060

ER	2016	2017	2018	2019	2020	Total
2060	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -	$ -

Mandate Excerpt (if applicable):

The current WPM program complies with the following part of the National Electric Safety Code: 013, 121, 212 A, 212 B, and 261 A.2

Additional Justifications:

Any supplementary information that may be useful in describing in more detail the nature of the Project, the urgency, etc.

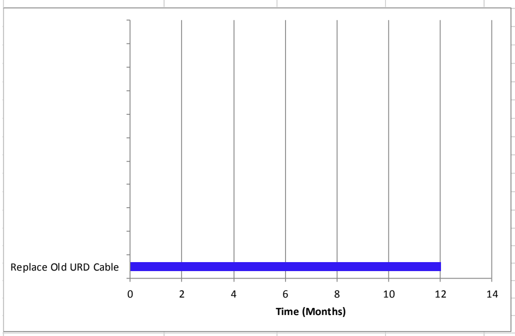
URD Primary Cable

Investment Name:	**Primary URD Cable Replacement 2013**		
Requested Amount	**$1,800,000**	**Assessments:**	
Duration/Timeframe	2 Year Project	Financial:	MH - >= 9% & <12% CIRR
Dept.., Area:	Asset Management & Process Improvement	Strategic:	Life Cycle Programs
Owner:	Kevin Christie	Operational:	Operations improved beyond current levels
Sponsor:	Jason Thackson	Business Risk:	ERM Reduction >5 and <= 10
Category:	Project	Project/Program Risk:	High certainty around cost, schedule and resources
Mandate/Reg. Reference:	n/a	Assessment Score:	110

Recommend Project Description:	**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**ERM Risk Score**
		Cost Summary - Increase/(Decrease)			
Complete the replacement of the un-jacketed first generation of Primary URD cable	Customer IRR = 10% and avoids an average of 600 outages per year	$ 1,800,000	$ -	$ -	4

Alternatives:		**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**ERM Risk Score**
			Cost Summary - Increase/(Decrease)			
Status Quo :	Number of Primary URD Cable faults would increase and the cost to repair the cable would also increase. Without this work and the past 4 years of work, the increased O&M costs would sum up to $8.8 million over the next 5 years.	Increase number of Outage towards 700 per year	$ -	$ -	$ 1,300,000	10
Alternative 1: Primary URD Cable Replacement	Complete the replacement of the un-jacketed first generation of Primary URD cable	Customer IRR = 10% and avoids an average of 600 outages per year	$ 1,800,000	$ -	$ -	4
Alternative 2: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0
Alternative 3 Name : Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0

Timeline



Construction Cash Flows (CWIP)

	Capital Cost	**O&M Cost**	**Other Costs**	**Approved**
Previous	$ 19,852,679	$ -	$ -	$ 19,852,679
2012	$ 1,800,000	$ -	$ -	$ 1,982,000
2013	$ 1,000,000	$ -	$ -	$ 1,000,000
2014	$ 1,000,000	$ -	$ -	$ 750,000
2015	$ 1,000,000	$ -	$ -	$ 1,000,000
2016	$ 1,000,000	$ -	$ -	$ 200,000
2017	$ 1,000,000	$ -	$ -	$ 500,000
2018	$ 1,000,000	$ -	$ -	$ 1,000,000
2019	$ -	$ -	$ -	$ -
2020	$ -	$ -	$ -	$ 800,000
Total	$ 27,652,679	$ -	$ -	$ 27,084,679

Milestones (high level targets)

November-11	Project Started	December-12	Plant In Service	mm/dd/yy	open
March-12	Project Plan	December-12	Project Complete	mm/dd/yy	open
June-12	Project Design	mm/dd/yy	open	mm/dd/yy	open
March-12	Major Procurement	mm/dd/yy	open		
September-12	Construction Start	mm/dd/yy	open		

Milestones should be general. In some cases it may be as simple as project start, project complete. Use your judgement on project progress so that progress can be measured.

Associated Ers (list all applicable):	Current ER	2054

Mandate Excerpt (if applicable):

Additional Justifications:

Transformer Change Out Program

Investment Name:	**Distibution Transformer Change-Out Program**					
Requested Amount	**$ 7,000,000**	**Assessments:**				
Duration/Timeframe	25 Year Program	Financial:	Medium - >= 5% & <9% CIRR			
Dept.., Area:	Asset Management & Process Improvement	Strategic:	Life Cycle Programs			
Owner:	Glenn Madden (Manager) & Al Fisher (Dir)	Operational:	Operations require execution to perform at current levels			
Sponsor:	Don Kopczynski	Business Risk:	ERM Reduction >5 and <= 10			
Category:	Program	Program Risk:	High certainty around cost, schedule and resources			
Mandate/Reg. Reference:	n/a	Assessment Score:	89	**Annual Cost Summary - Increase/(Decrease)**		
Recommend Program Description:		**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
The Distribution Transformer Change-Out Program has three main drivers. First, the pre-1981 distribution transformers that are targeted for replacement average 42 years of age and are a minimum of 30 years old. 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 pcb containing oil. 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.		When completed save an average of 5.6 MW per hour and eliminate PCB environmental risks	$ 5,800,000	$ 105,000	$ -	3

			Annual Cost Summary - Increase/(Decrease)			
Alternatives:		**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
Unfunded Program:	No planned replacement program for distribution transformers. Substancially higher risk of a pcb containing oil spill occuring.	n/a	$ 4,500,000	$ 200,000	$ 900,000	12
Alternative 1: Transformer Change-Out Program	The Distribution Transformer Change-Out Program has three main drivers. First, the pre-1981 distribution transformers that are targeted for replacement average 42 years of age and are a minimum of 30 years old. Their replacement will increase the reliability and availability of the system.	When completed save an average of 5.6 MW per	$ 5,800,000	$ 105,000	$ -	3
Alternative 2:	Distribution Engineering has proposed that any pole that the TCOP does work on needs to have the guy replaced with the new standard guy insulator (fiber cable).		$ 200,000	$ -	$ -	0
Alternative 3 Name :			$ -	$ -	$ -	0

Program Cash Flows

5 years of costs

	Capital Cost	O&M Cost	Other Costs	Approved
2012	$ 7,000,000	$ 100,000	$ -	$ 6,000,000
2013	$ 7,200,000	$ 102,000	$ -	$ 2,924,015
2014	$ 5,800,000	$ 105,000	$ -	$ 3,944,000
2015	$ 5,800,000	$ 107,000	$ -	$ 3,750,000
2016	$ 5,800,000	$ 110,000	$ -	$ 2,200,000
2017	$ 1,100,000			$ 1,900,000
2018				$ 1,700,000
Total	$ 32,700,000	$ 524,000	$ -	$ 22,418,015

Associated Ers (list all applicable):

Current ER	1003
	2060
	2535

Mandate Excerpt (if applicable):

Additional Justifications:

Area and Street Light

Investment Name:	**Street Light Management**		
Requested Amount	**$475,000**	**Assessments:**	
Duration/Timeframe	Indefinite 2014	Financial:	7.92%
Dept.., Area:	Operations	Strategic:	Life-cycle asset management
Owner:	Al Fisher	Business Risk:	Business Risk Reduction >5 and <= 10
Sponsor:	Don Kopczynski	Program Risk:	Moderate certainty around cost, schedule and resources
Category:	Program		
Mandate/Reg. Reference:	n/a	Assessment Score:	89

Recommend Program Description:	**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
		Annual Cost Summary - Increase/(Decrease)			
Street Light Maintenance Program. This program is a 5 year planned replacement of bulbs and 10 year planned replacement of photocells. This alternative has the starterboards running to failure.	7.92%	$ 475,000	$ (250,000)	$ (750,000)	8

Alternatives:		**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
			Annual Cost Summary - Increase/(Decrease)			
Unfunded Program: Continue maintaining the street lights as failures occur	The lights are currently maintained based on customer feedback and/or due to being noticed by an Avista employee. Many street lights are out for long periods of time which can put us at risk. We also spend a large amount of time driving from issue to issue.	6.29% 2 - S3 event in 10 years	$ -	$ 1,500,000	$ 1,800,000	16
Alternative 1:	Street Light Maintenance Program. This program is a 5 year planned replacement of bulbs and 10 year planned replacement of photocells. This alternative has the starterboards running to failure.	7.92% 1.5 - S3 event in 10 years	$ 475,000	$ (250,000)	$ (750,000)	8
Alternative 2:	Street Light Maintenance Program. This program is a 5 year planned replacement of bulbs and starterboards and a 10 year planned replacement of photocells.	7.28% 1 - S3 event in 10 years	$ 890,000	$ (250,000)	$ (1,175,000)	12
Alternative 3:	Street Light Maintenance Program. This program is a 5 year planned replacement of bulbs and a 10 year planned replacement of photocells and starterboards.	7.82% 1 - S3 event in 10 years	$ 895,000	$ (250,000)	$ (1,165,000)	12

Program Cash Flows

	Capital Cost	O&M Cost	Other Costs	Approved
Previous	$ -	$ -	$ -	$ -
2013	$ -	$ -	$ -	$ -
2014	$ 475,000	$ (250,000)	$ -	$ -
2015	$ 484,500	$ (500,000)	$ -	$ 2,400,000
2016	$ 494,190	$ (750,000)	$ -	$ 1,500,000
2017	$ 504,074	$ (1,000,000)	$ -	$ 1,500,000
2018	$ -	$ -	$ -	$ 1,500,000
2019	$ -	$ -	$ -	$ 1,500,000
2020				
Total	$ 1,957,764	$ (2,500,000)	$ -	$ 8,400,000

Associated Ers (list all applicable):

New ER

ER	2013	2014	2015	2016	2017	Total
New ER	$ -	$ 475,000	$ 484,500	$ 494,190	$ 504,074	$ 1,957,764
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ -	$ 475,000	$ 484,500	$ 494,190	$ 504,074	$ 1,957,764

Mandate Excerpt (if applicable):

Additional Justifications:

Grid Modernization

Investment Name:	**Distribution Grid Modernization**		
Requested Amount	**See Plan Below**	**Assessments:**	
Duration/Timeframe	Indefinite Year Program	Financial:	6.4% Customer IRR
Dept.., Area:	Distribution Engineering	Strategic:	Life-cycle asset management
Owner:	Troy A. Dehnel	Business Risk:	Business Risk Reduction >15
Sponsor:	Don Kopczynski	Program Risk:	High certainty around cost, schedule and resources
Category:	Program		
Mandate/Reg. Reference:	Federal & State Clear Zone Mitigation Directives	Assessment Score:	133

Recommend Program Description:	Performance	Capital Cost	O&M Cost	Other Costs	Business Risk Score
		Annual Cost Summary - Increase/(Decrease)			
The Distribution Grid Modernization Program provides value to customers and shareholders by improving Grid Reliability, Energy Savings and Operational Ability through a systematic and managed upgrade of our aging distribution system. This program seeks cost effective opportunities to increase service quality performance and system availability through the identification of locations that would benefit from the addition of switched capacitor banks, regulators and smart grid devices. The long-term plan represented by the IRR of 6.4% aims to upgrade 6 feeders per year to cover the whole distribution system in a 60 year cycle. This coordinates well with Wood Pole Management's 20 year cycle. The average cost to rebuild each feeder is estimated to be $3.5M.	When completed save an average of 1,970 MWh* annually & Reduce Outages	$ 21,000,000	$ -	$ 198,000	4

Alternatives:		Performance	Capital Cost	O&M Cost	Other Costs	Business Risk Score
			Annual Cost Summary - Increase/(Decrease)			
Unfunded Program:	No systematic plan for wholistic address of conductors, reconfiguring services for better access, or adding devices that benefit the performance of the feeder.	n/a	$ 120,000	$ -	$ 1,980,000	25
Alternative 1: Brief name of alternative (if applicable)	The Dist Grid Modernization Program provides benefits to customers, employees, and shareholders by replacing problematic poles, cross-arms, cut-outs, transformers, conductor, etc. In addition, adding switched capacitor banks and smart grid devices is of benefit due to increased energy efficiency and system reliability.	When completed save an average of 1,970 MWh* annually & Reduce Outages	$ 21,000,000	$ -	$ 198,000	4
Alternative 2: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0
Alternative 3 Name : Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0

Program Cash Flows

	Capital Cost	O&M Cost	Other Costs	Approved
Previous	$ 7,308,357	$ -	$ -	$ 7,308,357
2014	$ 8,686,019	$ -	$ -	$ 9,586,000
2015	$ 11,000,000	$ -	$ -	$ 12,310,000
2016	$ 12,000,000	$ -	$ -	$ 7,000,000
2017	$ 13,000,000	$ -	$ -	$ 13,000,000
2018	$ 15,000,000	$ -	$ -	$ 15,000,000
2019	$ 18,000,000	$ -	$ -	$ 21,000,000
2020	$ 21,000,000	$ -	$ -	$ 20,800,000
Total	$ 105,994,376	$ -	$ -	$ 106,004,357

Associated Ers (list all applicable):	
Dist Grid Moderniz	2470
Sandpoint SG	2570
Grid Mod Automati	2599

ER	2015	2016	2017	2018	2019	Total
Dist Grid Modernization	$ -	$ -	$ -	$ -	$ -	$ -
2470	$ 11,000,000	$ 11,000,000	$ 13,000,000	$ 15,000,000	$ 15,000,000	$ 65,000,000
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
Sandpoint SG	$ -	$ -	$ -	$ -	$ -	$ -
2570	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
Grid Mod Automation	$ -	$ -	$ -	$ -	$ -	$ -
2599	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 11,000,000	$ 11,000,000	$ 13,000,000	$ 15,000,000	$ 15,000,000	$ 65,000,000

Mandate Excerpt (if applicable):

WSDOT Target Zero, an FHWA mandated initiative in MAP-21, requires that utilities move all non-breakaway structures out of the clear zone as defined in the 10/2005 AASHTO "A Guide for Accommodating Utilities Within Highway Right-of-Way. WA State law requires that we complete this task by year 2030.

Additional Justifications:

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.

Worst Feeder

Investment Name:	**Underperforming Elec Ckts (Worst FDRs)**		
Requested Amount	**$2,000,000**	**Assessments:**	
Duration/Timeframe	on-going Year Program	Financial:	Medium - >= 5% & <9% CIRR
Dept.., Area:	Engineering/Operations	Strategic:	Life Cycle Programs
Owner:	Dave James	Operational:	Operations require execution to perform at current levels
Sponsor:	Howell/H Rosentrater	Business Risk:	ERM Reduction >5 and <= 10
Category:	Program	Program Risk:	Moderate certainty around cost, schedule and resources
Mandate/Reg. Reference:	n/a	Assessment Score:	84

Recommend Program Description:	**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
Initiating in 2009, ER 2414- "Worst Feeders" was proposed by Asset Management to improve the service reliability of the Company's worst-performing electric distribution circuits. Many rural feeders significantly exceed the Company SAIFI target of 2.1. This program is coordinated through divisional Area Engineers to identify treatment of these feeders. Work plans may include, reconstruction, hardening, vegetation management, conversion from OH to UG, enhanced protection, and relocation.	Improve the overall system performance of the Company's "top ten" worst feeders.	$ 2,000,000	$ -	$ -	12

Annual Cost Summary - Increase/(Decrease)

Alternatives:		**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
Unfunded Program:	Rural area reliability indices expected to worsen as infrastructure ages and deteriotes. Expect customer contacts to local media and state government and regulatory bodies.	Ten to twenty rural FDRs whose SAIFI exceeds 10	$ -	$ -	$ -	20
50% funding	Funding at $1,000,000 would restrict current treatment to top five worst feeders.	annual spend restricted to top five worst feeders	$ 1,000,000	$ -	$ -	12
25% funding	Funding at 500,000 would restrict treatment to enhanced protection only (adding midline reclosers, additional fusing)	work plan restricted to enhanced protection	$ 500,000	$ -	$ -	0
		describe any incremental changes in operations	$ -	$ -	$ -	0

Program Cash Flows

5 years of costs

	Capital Cost	O&M Cost	Other Costs	Approved
Previous	$ 6,000,000			$ 5,050,550
2015	$ 2,000,000	$ -	$ -	$ 1,035,041
2016	$ 2,000,000			$ 1,500,000
2017	$ 2,000,000			$ 2,500,000
2018	$ 2,000,000	$ -	$ -	$ 2,000,000
2019	$ 2,000,000	$ -	$ -	$ 2,000,000
Total	$ 10,000,000	$ -	$ -	$ 9,035,041

Associated Ers (list all applicable):

Current ER	2414

Mandate Excerpt (if applicable):

Additional Justifications:

Any supplementary information that may be useful in describing in more detail the nature of the Program, the urgency, etc.

Feeder Tie Circuits

Investment Name:	**Segment Reconductor & FDR Tie Program**		
Requested Amount	**$4,000,000/year**	**Assessments:**	
Duration/Timeframe	on-going Year Program	Financial:	0.00%
Dept.., Area:	Distribution Engineering	Strategic:	Life-cycle asset management
Owner:	David Howell	Business Risk:	Business Risk Reduction - None
Sponsor:	Heather Rosentrater	Program Risk:	Low certainty around cost, schedule and resources
Category:	Program		
Mandate/Reg. Reference:	n/a	Assessment Score:	33

Recommend Program Description:	Annual Cost Summary - Increase/(Decrease)				
	Performance	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
The Company's Distribution Grid system includes 18,000 circuit miles of overhead and underground primary conductors. As load and generation patterns shift, certain areas (segments) of the system become thermally overloaded. These constrained portions of the system are identified through systematic planning studies or from operational studyworks conducted by Area Engineers. In addition, FDR 'Tie' switches are installed to allow load shifts between FDR circuits to balance loads and in response to either maintenance or forced outages.	Electric Delivery Capacity	$ 4,000,000	$ -	$ -	4

Alternatives:		Annual Cost Summary - Increase/(Decrease)				
		Performance	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
Unfunded Program:	Avista's Distribution System Planning criteria (e.g. 500 A Plan) mandates performance levels for distribution circuits including capacity and voltage requirements. This program is aimed at maintaining compliance with planning criteria.	n/a	$ -	$ -	$ -	16
Alternative 1: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	4
Alternative 2: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0
Alternative 3 Name : Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0

Program Cash Flows

	Capital Cost	O&M Cost	Other Costs	Approved
2015	$ 3,735,000	$ -	$ -	$ 3,573,505
2016	$ 3,810,000	$ -	$ -	$ 3,810,000
2017	$ 4,175,000	$ -	$ -	$ 4,175,000
2018	$ 3,900,000	$ -	$ -	$ 3,900,000
2019	$ 4,000,000	$ -	$ -	$ 4,000,000
2020	$ 4,000,000	$ -	$ -	$ 4,000,000
2021+	$ 4,000,000	$ -	$ -	$ -
Total	$ 27,620,000	$ -	$ -	$ 23,458,505

Associated Ers (list all applicable):			
2514	2515	2516	

ER	2016	2017	2018	2019	2020	Total
2514	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 10,000,000
2515	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 5,000,000
2516	$ 810,000	$ 1,175,000	$ 900,000	$ 1,000,000	$ 1,000,000	$ 4,885,000
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
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0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 3,810,000	$ 4,175,000	$ 3,900,000	$ 4,000,000	$ 4,000,000	$ 19,885,000

Mandate Excerpt (if applicable):

Avista Distribution Planning Criteria (500 Amp)

Additional Justifications:

This program is a foundational element of the Company's overall effort to maintain the electric delivery system. While many of the asset managmeent program such as WPM, TCOP, Worst Feeders, and Grid Mod are targeted efforts to maintain reliability, this program specifically identifies thermal, voltage, and capacity 'tie' constraints. The program represents the collective effort of distibution planners and area engineers to manager our ability to serve customer load, efficiently, and securely.

Network

Investment Name:	**Spokane Elec. Network**		
Requested Amount	**$2,300,000 annually**	**Assessments:**	
Duration/Timeframe	n/a Year Program	Financial:	MH - >= 9% & <12% CIRR
Dept.., Area:	Engineering	Strategic:	Life Cycle Programs
Owner:	John McClain	Operational:	Operations require execution to perform at current levels
Sponsor:	Cox/H Rosentrater	Business Risk:	ERM Reduction >5 and <= 10
Category:	Program	Program Risk:	High certainty around cost, schedule and resources
Mandate/Reg. Reference:	n/a	Assessment Score:	97

Recommend Program Description:	**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
		Annual Cost Summary - Increase/(Decrease)			
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 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 dedicated cable crew resources specifically trained to operate, construct, inspect and maintain these systems. All equipment and cables are located beneath city streets and adjacent properties. Topology in the Network is unique to Avista electric distribution and requires specialized material, equipment, tooling and training to perform maintenance repair, planned replacement and capacity growth projects. The scope of annual capital replacements and additions includes: 7500 feet of secondary cable, 7500 feet of primary cable, 10 refurbished manholes & vaults, 10 tranformer replacements, and 20 street light replacements.	Investments necessary to maintain current operations and to extend the life of current assets.	$ 2,300,000	$ 348,251	$ 215,000	6

Alternatives:		**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
			Annual Cost Summary - Increase/(Decrease)			
Unfunded Program:	Unfunding Network operations assumes zero PM activities and an eventual loss system functionality.	n/a	$ -	$ -	$ -	25
Alternative 1: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	6
Alternative 2: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0
Alternative 3 Name : Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0

Program Cash Flows

5 years of costs

	Capital Cost	O&M Cost	Other Costs	Approved
Previous	$ 6,750,000			$ 6,338,007
2015	$ 2,300,000	$ 348,250	$ 215,000	$ 2,100,000
2016	$ 2,300,000	$ 348,250	$ 215,000	$ 2,300,000
2017	$ 2,300,000	$ 348,250	$ 215,000	$ 2,300,000
2018	$ 2,300,000	$ 348,250	$ 215,000	$ 2,300,000
2019	$ 2,300,000	$ 348,250	$ 215,000	$ 2,300,000
2020				$ 2,300,000
Total	$ 11,500,000	$ 1,741,250	$ 1,075,000	$ 13,600,000
	CapX Specific	O&M	O&B	

Associated Ers (list all applicable):

Current ER		2058	2237	2251
		CapX Repl.	Metro PILC	Post St PILC

Mandate Excerpt (if applicable):

Various WUTC tariff schedules are associated with customer classifications in downtown Spokane. NESC/WAC govern public and worker safety.

Additional Justifications:

Service to the core business district in Spokane is afforded a much higher level of service reliability than other urban or rural areas. This reflects the importance of continuous service to hospitals, law enforcement, city government, banking, legal, commerce, and retail sectors of the local economy.

Line Protection

Investment Name:	Distribution Line Protection		
Requested Amount	875,000 5-years	Assessments:	
Duration/Timeframe	On-going Year Program	Financial:	MH - >= 9% & <12% CIRR
Dept.., Area:	Engineering	Strategic:	Life Cycle Programs
Owner:	Dave James	Operational:	Operations require execution to perform at current levels
Sponsor:	Cox/H. Rosentrater	Business Risk:	ERM Reduction >5 and <= 10
Category:	Program	Program Risk:	Moderate certainty around cost, schedule and resources
Mandate/Reg. Reference:	n/a	Assessment Score:	93

Recommend Program Description:	Performance	Capital Cost	O&M Cost	Other Costs	ERM Risk Score
Avista's Electric Distribution system is configured into a trunk and lateral system. Lateral circuits are protected via fuse-links and operate under fault conditions to isolate the lateral minimize the number of affected customers. Engineering recommends treatment of the following: 1. Removal and replacement of Chance Cutouts 2. Removal and replacement of Durabute cutouts 3. Installation of cut-outs on unfused lateral circuits. This is a targeted program to ensure adequate protection of lateral circuits and to replace known defective equipment. The Chance fuse cutout devices are porcelain cutouts prone to mechanical failure at a much higher failure rate than peer group devices when manually operated by line craft personnel during various line switching scenarios. This presents a significant hazard to line personnel as	Investments necessary to maintain current operations and to extend the life of current assets.	$ 250,000	$ 10,000		8

Annual Cost Summary - Increase/(Decrease)

Alternatives:		Performance	Capital Cost	O&M Cost	Other Costs	ERM Risk Score
Unfunded Program:		n/a	$ -	$ -	$ -	15
Alternative 1: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	8
Alternative 2: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0
Alternative 3 Name : Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0

Program Cash Flows

5 years of costs

	Capital Cost	O&M Cost	Other Costs	Approved
2013	$ 250,000	$ 5,000	$ -	$ 250,000
2014	$ 250,000	$ 10,000	$ -	$ 250,000
2015	$ 125,000	$ 10,000	$ -	$ 125,000
2016	$ 125,000	$ 10,000	$ -	$ 125,000
2017	$ 125,000	$ 5,000	$ -	$ 125,000
2018	$ -	$ -	$ -	$ 125,000
2019	$ -	$ -	$ -	$ 125,000
2020				$ 125,000
Total	$ 875,000	$ 40,000	$ -	$ 1,250,000

Associated Ers (list all applicable):

Current ER	
2416	System Wide

Mandate Excerpt (if applicable):

Additional Justifications:

This program was funded for a 2-year period in the 2009-2010 timeframe. This request allows for completion of the Chance cutout replacements but also includes the installation of devices on unfused laterals.

2016

Substation System Review Asset Management

David Thompson
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February 12, 2016

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Substation System Review, 2016

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Purpose

This report provides summary information relating to the annual review of Avista's electric substations operating in its Washington and Idaho service territory. The intent is to present a comprehensive overview of the substation capital assets, performance, risks, ongoing asset management programs, current and planned projects, and summary recommendations. Asset Management Plans are intended to serve a general audience from the perspective of long-term, balanced optimization of lifecycle costs, system performance, and risk management. A consistent sequence of asset management plans will provide the continuity required for continuous improvement of capital asset management, as well as historical information useful for rate case submissions.

With Avista's implementation of IBM's Maximo as its Asset Information System in 2014, a distinct reference point for asset data has been established. The Maximo implementation provides a comprehensive informational and historical repository for all asset data, applications, locations, inspection history, maintenance activity, and life cycle status. As such, the reportable data included in this report centers around activities in 2014 and 2015 in order to leverage the reference data within Maximo and to provide consistent and repeatable data from a single source for this and future reports.

Avista Utilities currently operates 162 substations consisting of:

- 21 transmission substations
- 30 transmission substations with distribution
- 109 distribution substations
- 2 foreign-owned substations.

In addition, there are 14 locations associated with generation.

Equipment Portfolio

From a perspective of key equipment as reference, the average age of the 162 substations is just over 31 years. Figure 1 shows the age distribution of the substation population.

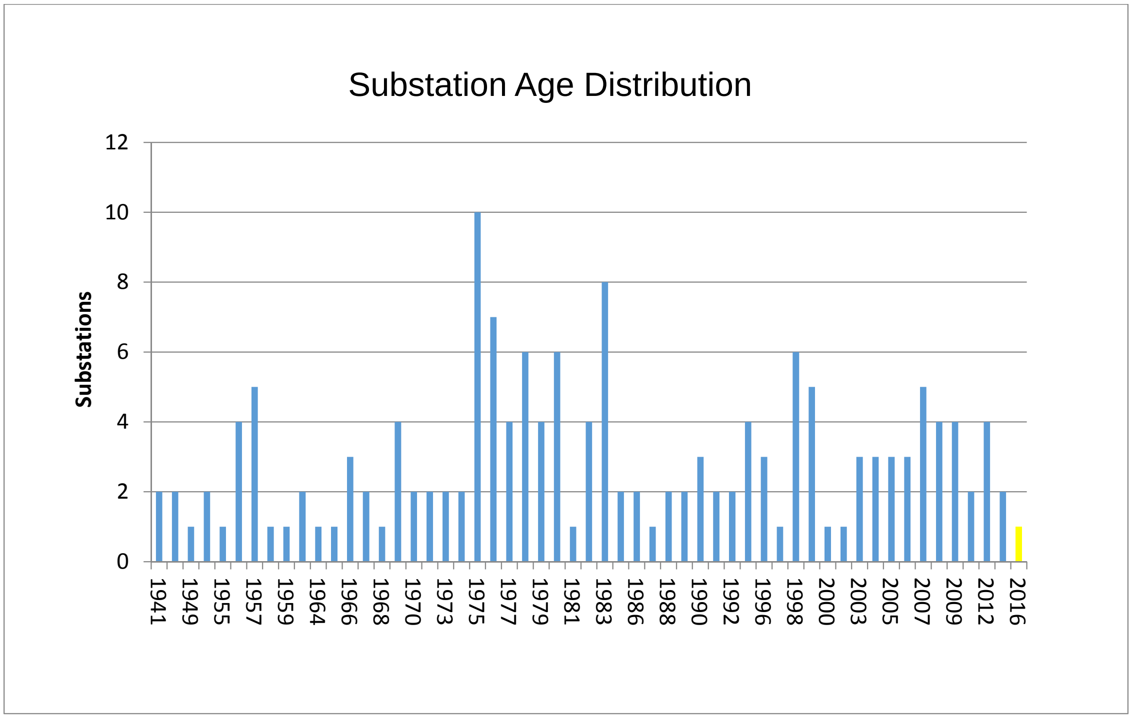


Figure 1: Substation Age Distribution

Substations are typically classified by voltage and function. The number of sites in each of these categories is included in Figure 2. In addition to the standard population of 230kV and 115kV substations, Avista continues to operate six substations at lower system voltages. These include the Kooskia substation at 34kV, the St. John substation at 24kV, and four substations at 13kV including Coeur d'Alene Shaft Mine, Sunshine Mine, and two at the Washington State University campus in Pullman.

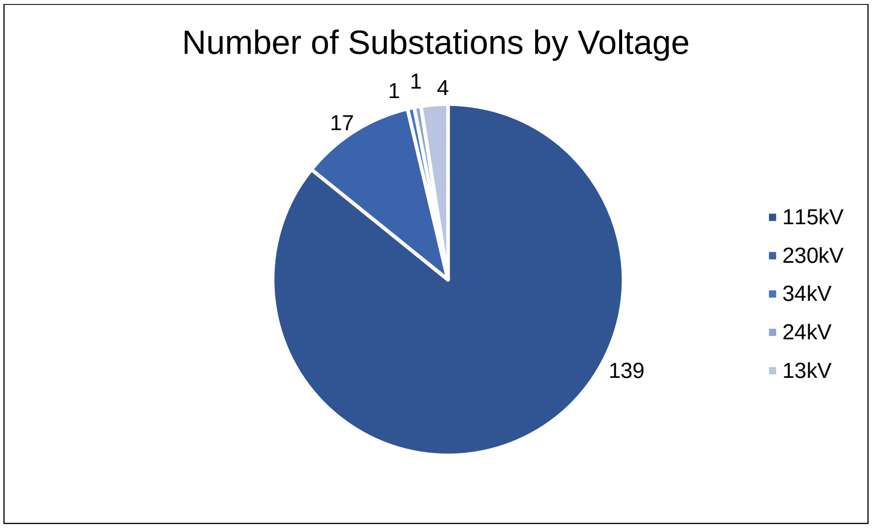


Figure 2: Substations by classification

Included in the totals above are 13 switching stations, 11 in the 115kV group and two at 230kV, that do not incorporate voltage transformers or regulation. Standard interconnect and protection services are provided at these locations, supporting their inclusion in the general substation reporting.

Each substation is comprised of major assets that coordinate to serve the principal regulation, switching, and protection activities of each site. Each asset class has unique maintenance, lifecycle, and operational considerations. Within the greater population of substations, the quantity of each asset is shown in Table 1.

Capital Asset	Quantity
Air Switch	1,175
Disconnect Switch	1,171
Bushings	1,890
Circuit Switcher	120
High Voltage Circuit Breakers	318
Low Voltage Circuit Breakers	353
Reclosers	309
Switchgear	95
Autotransformers	17
Power Transformers	211
Voltage Regulators	1,341

Table 1: Substation asset quantities

Within the current implementation of the Maximo asset database, fields that provide the manufactured date, in-service date, and last-installed date continue to be updated and populated with the data available from the database integration. As such, succinct reports providing age profiles for these substation asset families are not included at this time.

Capital Replacement and Maintenance

Projects with current approved Business Case proposals are included in this Capital Replacement and Maintenance section, including a brief description of the project's scope and purpose. In summary, specific project evaluation metrics are included in Table 2.

	Internal Rate of Return	Benefit/Cost Ratio	Risk Reduction Factor
Asset Management Capital	5% to 9%	N/A	0.027302
Capital Spares	5% to 9%	N/A	0.015362
Distribution Station Rebuilds	9% to 12%	N/A	0.010633
Garden Springs	5% to 9%	N/A	0.004268
New Distribution Stations	5% to 9%	N/A	0.009185
Noxon Switchyard	5% to 9%	N/A	0.004268
South Region Voltage Control	7%	N/A	0.000798
Westside Rebuild	7%	N/A	0.017570

Table 2: Capital Project Metrics

Substation Asset Management Capital Maintenance

The Substation Asset Management Capital Maintenance program installs, replaces, or upgrades substation apparatus based on Asset Management planning or emergency replacement determinations. All obsolete, end-of-life, or failed apparatus, based on the Asset Management analysis, are included under this program. Apparatus includes panel houses, high voltage breakers, relays, metering, surge arresters, insulating rock, fence work, low voltage breakers and reclosers, circuit switchers, SCADA systems, batteries and chargers, power transformers, high voltage fuses, air switches, capacitor banks, autotransformer diagnostic equipment, step voltage regulators, and instrument transformers.

Substation Capital Spares

The Substation Capital Spares program maintains Avista's inventory of power transformers and high voltage circuit breakers in order to manage the long lead time of the procurement cycle for these system-critical items. These components are capitalized at receipt and placed in service in response to both planned and emergency installations. The program expenditures may vary significantly year to year due to the specific equipment purchased and deployed in any given year.

Distribution Substation Rebuilds

The Distribution Substation Rebuild program supports either the complete replacement or rebuild of existing substation infrastructure as the site nears the end of its useful life, a need to support increased capacity requirements, or to implement modifications necessary to accommodate equipment upgrades. Included in the program are Wood Substation rebuilds as well as upgrades to substations to comply with current design and construction standards. Some substation rebuilds are necessitated by external requirements, including obligation to serve, customer or load growth, or technology improvement projects such as Smart Grid. Substation rebuilds currently planned to be completed under this program in the next five years include Big Creek, Kamiah, and South Lewiston (Wood Substations), 9th & Central, Ford, Sprague, Davenport, and Northwest (Lifecycle), Deer Park, Gifford, Lee & Reynolds, Huetter, Dalton, and Southeast (Equipment Additions), and Hallett & White (Growth).

Garden Springs Substation Integration

The Garden Spring Substation Integration project will construct a new 230kV/115kV substation at the existing Garden Springs property that will terminate the existing Airway Heights-Sunset, Sunset-Westside, and South Fairchild Tap 115kV transmission lines. Options being considered to energize the 230kV bus include the possibility of a new interconnection with the BPA Bell-Coulee #5 230kV transmission line and a new 230kV feed from the Westside Substation following the completion of the Westside Substation Rebuild Project. Both of the newly designated Garden Springs-Sunset 115kV transmission lines will require upgrades to 150MVA capacity conductors.

New Distribution Substations

The New Distribution Substation program provides for new distribution substations in the system in order to serve new and growing load, increased system reliability, and operational flexibility. New substations under this program will require planning and operational studies, justification, and approved Project Diagrams prior to funding. Current plans for new substation projects include Tamarack in northeast Moscow, Greenacres in the Spokane Valley, and Hillyard and Downtown West in Spokane. Design and construction phases will be coordinated to achieve one new substation per year depending on need and justification.

Noxon Switchyard Rebuild

The existing Noxon Rapids 230kV Switchyard requires reconstruction due to the age and condition of the equipment within the station. The existing bus, constructed as a strain bus with a number of recent failures, is configured as a single bus with a tie breaker separating the East and West bus segments. This station is the interconnection point of the Noxon Rapids Hydroelectric generation as well as a principal interconnect point between Avista and BPA. As such, this is a crucial asset for the reliable operation of the Western Montana Hydro Complex. Equipment outages within the station, either planned or unplanned, can cause significant curtailments of the local generation output. Due to the key role of the station, a complete rebuild will require coordination with Avista's Energy Resources Department and affected utilities, including BPA. The Noxon Switchyard Rebuild Project is a greenfield design incorporating a double bus-double breaker 230kV switching station as a complete replacement of the existing Noxon Switchyard.

South Region Voltage Control

Avista's 230kV transmission system in the southern area of its service territory, generally located around the cities of Lewiston and Clarkston, experiences excessive high voltage during periods of low power loading. Voltage levels exceed equipment ratings over approximately 35% of the time. Continued operation of equipment outside its specifications and ratings exposes Avista to potentially significant legal and regulatory risks. This is in addition to increasing the probability of large-scale outages due to equipment failure. The installation of 230kV Reactors at North Lewiston substation will eliminate existing overvoltage conditions in Avista's southern region, which includes the 230kV buses at Dry Creek, Lolo, North Lewiston, Moscow, and Shawnee substations.

Westside Substation Rebuild-Phase One

Phase One of the Westside Substation Rebuild will extend the existing Westside Substation and the 115kV and 230kV buses and will support design and installation options in consideration of a new 250MVA autotransformer and other substation equipment. This installation will eliminate overload potentials for certain bus outages and tie breaker failure contingencies in the Spokane area. Following the completion of Phase One, the second phase will replace a second autotransformer with a new 250MVA unit. The final phase would extend the 230kV yard to a double breaker-double bus configuration. In addition, alternatives for the 115kV configuration would be considered to achieve either a breaker-and-and-half or a full double breaker-double bus implementation.

Capital Spending

For 2015, the major capital expenditures associated with substation construction or equipment activities are included in Table 3. As most capital projects extend over multiple calendar years, the summary expenditures listed may represent only a portion of the overall project's expenses. In total, these projects represent $24.4 million in capital spending during 2015.

ER	Project	Capital Expenditure	Status
2532	Noxon 230kV Substation Rebuild	$10,162,871	Partial in 2016
2000	Substation - Capital Spares	$3,267,594	Ongoing
2589	Mobile Substation - Purchase New Mobile Substations	$2,539,571	2015
2443	Greenacres 115kV/13kV Substation New Construction	$1,661,927	2016
2215	Substation Asset Management Capital Maintenance	$915,677	Ongoing
2001	System - High Voltage Circuit Breaker Replacements	$580,324	Ongoing
2278	Replace Obsolete Reclosers	$530,128	Ongoing
2484	Moscow 230kV Substation Rebuild Switchyard	$527,614	Complete
2275	Rock and Fence Restoration	$450,226	Ongoing
2449	System - Substation Air Switches Replacements	$447,733	Ongoing
1006	System - Distribution Power Transformers	$394,856	Ongoing
1107	Lewiston Mill Road - 115kV substation construction	$369,980	2015
2493	Replace/Upgrade Voltage Regulators	$343,358	Ongoing
2446	Irvin Substation- New Construction	$296,734	Ongoing
2590	Deer Park 115kV Substation - Minor Rebuild	$247,956	2016
1108	Hallett & White Substation Expansion	$142,621	Ongoing
2294	System - Batteries	$140,538	Ongoing
2546	Blue Creek 115kV Rebuild	$104,669	Complete
2592	Sprague 115kV Substation Minor Rebuild	$96,304	2016
2204	Wood Substation Rebuilds	$89,274	Ongoing
2571	Clearwater 115kV Substation Upgrades	$85,695	Complete
2573	Little Falls 115kV Substation Rebuild	$66,485	Ongoing
2341	Ninth & Central Substation - Increase Capacity and Rebuild	$54,960	In progress
2569	Gifford 115kV - Rebuild Substation	$28,251	Ongoing
2538	College & Walnut Substation Yard Expansion	$27,473	2016
2425	System - High Voltage Fuse Upgrades	$25,135	Ongoing
2112	Beacon 230kV Substation Bus Conversion	$14,286	Ongoing
2505	System-Replace Current and Potential Devices	$13,262	Ongoing
2531	Westside 230kV Substation Rebuild	$12,598	In progress
2274	New Substations	$11,088	Ongoing
2561	Lewiston Mill Road 115kV Substation	$8,912	2016
2343	System - Replace/Install Substation Structures	$8,702	Ongoing
2336	System - Replace Distribution Power Transformers	$7,939	Ongoing
2572	Noxon Construction Substation - Minor Rebuild	$2,471	Complete
2591	Davenport 115kV Substation - Minor Rebuild	$2,275	Ongoing

Table 3: Substation Capital Expenditures – 2015

Maintenance and Operations (M&O) Spending

During 2015, a total of nearly $4.7 million supported Maintenance and Operations activities relating to existing substations. As shown in Figure 3, approximately 85.1% of the maintenance and operation expenses were associated with planned services, while the remaining 14.9% was in response to unplanned or reactive activities. Figure 4 shows the total substation maintenance and operations spending by calendar month throughout 2015.

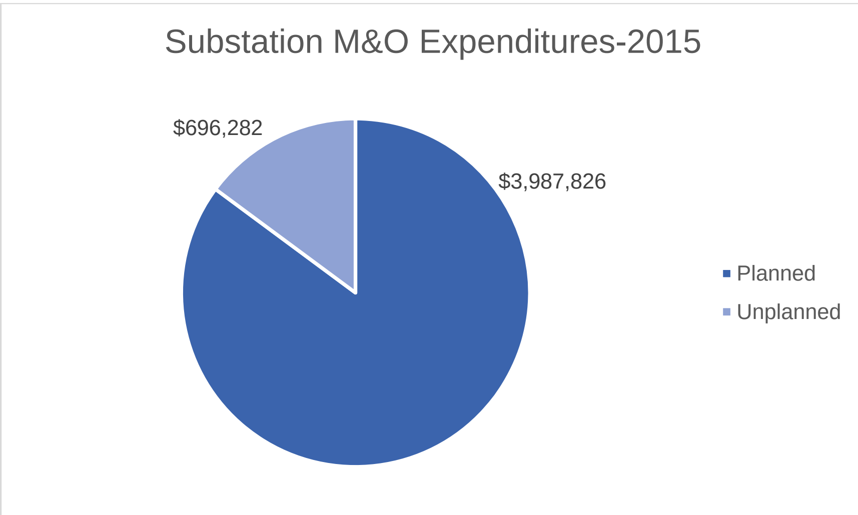


Figure 3: Substation M&O Expenditures

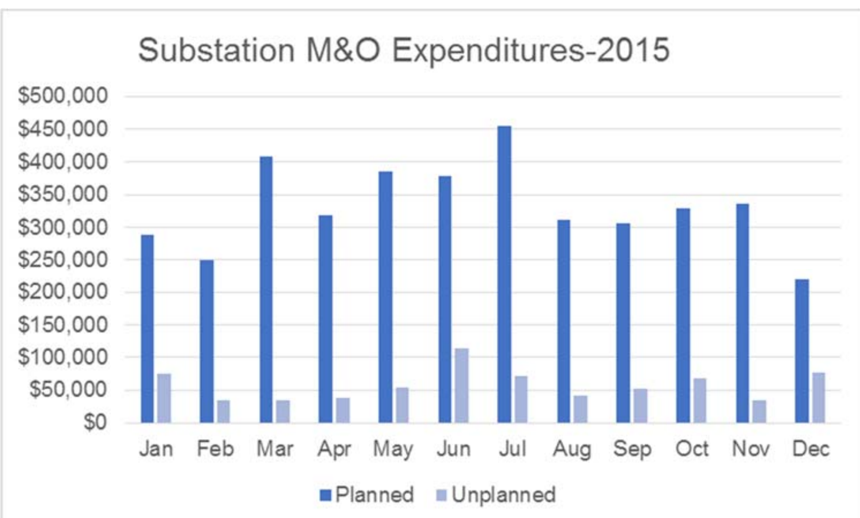


Figure 4: Substation M&O Expenditures by Month

Substation maintenance activities are tracked by both distribution and transmission tasks. As noted earlier, many of the substation locations provide both distribution and transmission services. For 2015, the allocation between transmission and distribution expenses, both maintenance and operations, along with unplanned expenditures, are shown in Figure 5.

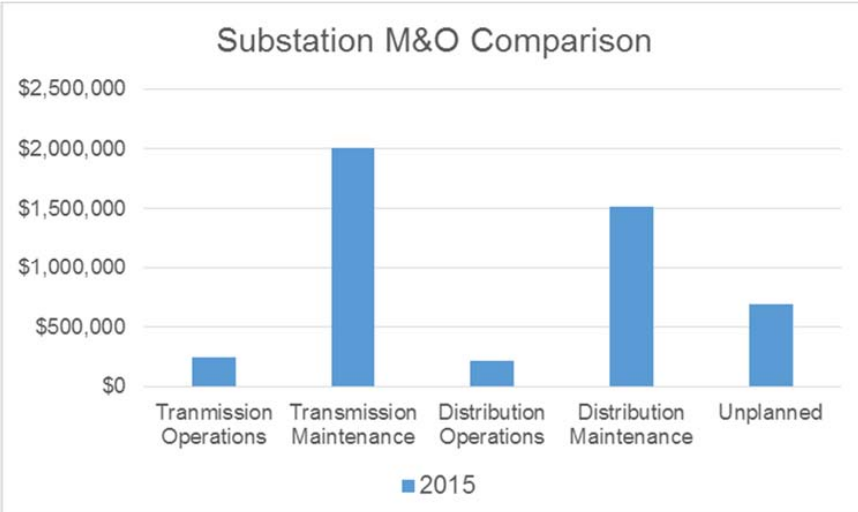


Figure 5: Substation M&O Comparison

Key Performance Indicators

Key Performance Indicators (KPIs) have been identified for tracking and review of key activities. These KPIs continue to be refined relative to the metrics monitored. The metrics are published on a monthly basis, providing a perspective about the implementation and use of Maximo, system reliability, and progress towards particular key project goals as linked to substation performance. A combination of lagging and leading indicators are tracked in order to provide both retrospective and prospective views. It is generally expected that the proper focus on the correct leading indicators will guide satisfactory results after a defined lag period. When this does not occur, deeper investigation and root-cause analysis may help to identify other factors affecting the expected causal relationship.

One of the primary goals of Asset Management is to optimally manage risk and performance relative to capital investment and maintenance expenditures. The nexus of planned maintenance and capital replacement activity compared to emergency repair costs, outages, lost profits and other possible outcomes over time should be clearly identified. Additional reviews of predicted activity versus actual outcomes for a variety of scenarios should also serve to help determine the continuation of or adjustment to ongoing programs and projects. The availability of sufficient reliable data to support these analytic opportunities continues to be a challenge, but is expected to be mollified as the Maximo implementation and structured use becomes integrated into the formal work processes. For example, safety incidents, emergency repair and replacement work, and other similar activities continue to be transacted in Operations under blanket accounts, precluding the ability to extract detailed transactional data associated with specific project and related work activities at a substation. The Asset Management group continues to suggest opportunities and support improvements to achieve the goal of a complete corporate implementation of Maximo.

The KPIs in Figure 6 and Figure 7 show projected and actual metrics relating to Work Orders within Maximo. Reactive Work Orders are associated with required Corrective Maintenance tasks that were in response to operational malfunction issues or items requiring attention following a planned inspection. Throughout 2015, the projected target has been achieved. The Average Age metric tracks the rolling number of days existing Work Orders have been active. This metric continues to not meet the expected performance level, though this topic continues to be addressed with the Operations teams.

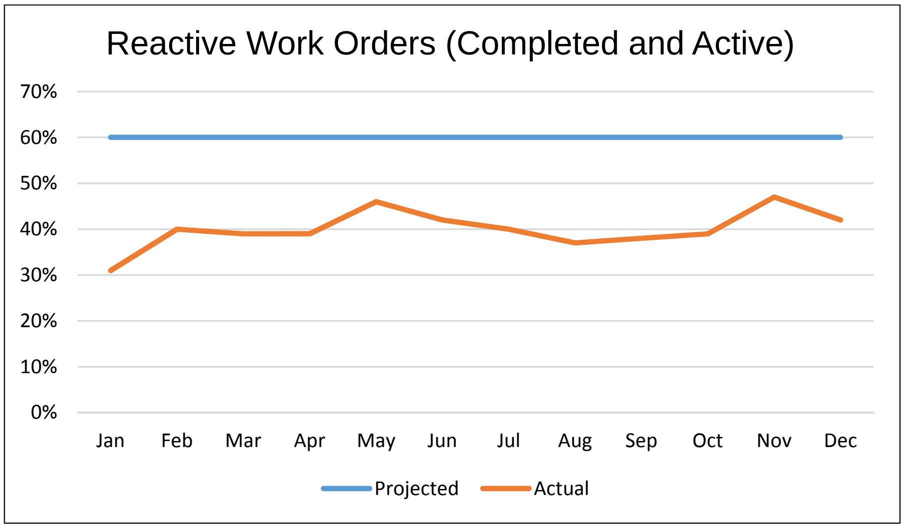


Figure 6: KPI-Reactive Work Orders

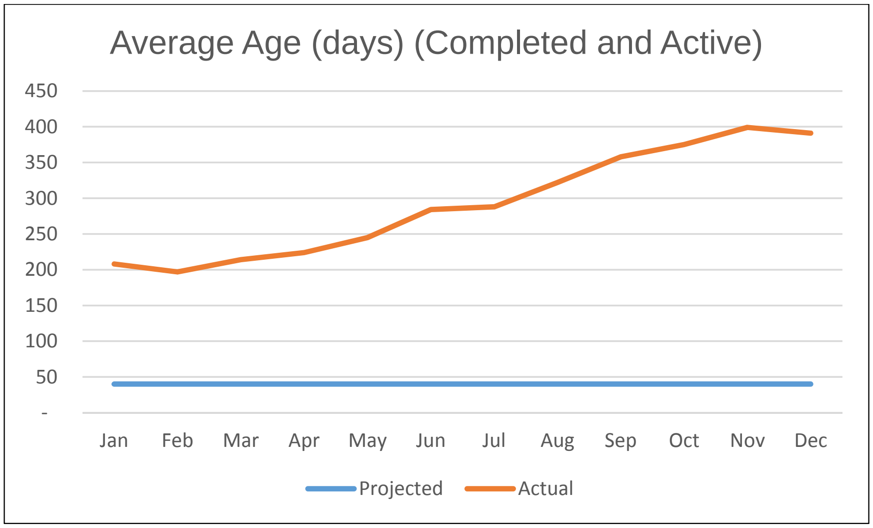


Figure 7: KPI-Work Order Average Age

Metrics associated with customer outages due to substation activity are shown in Figure 8 through Figure 11. In 2015, the projected outage metrics, whether time or quantity, have typically been satisfied, demonstrating the expected reliability of service for the end customer.

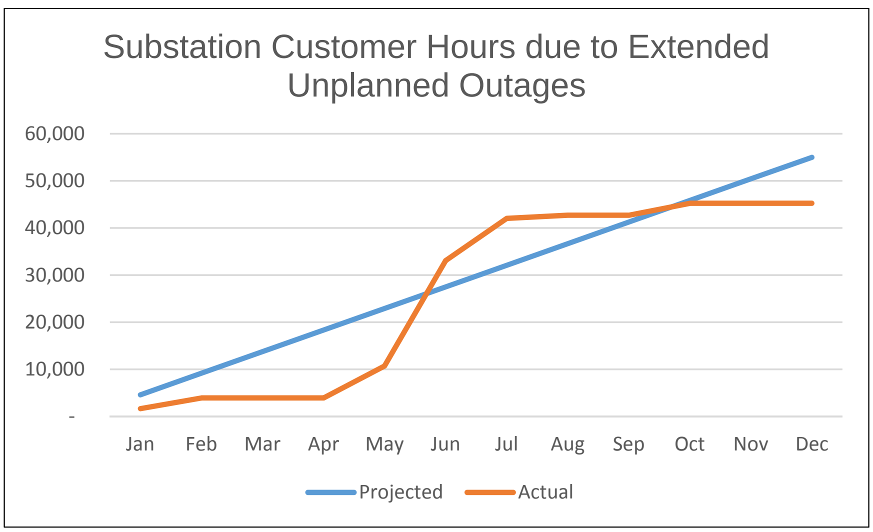


Figure 8: Hours of Unplanned Outages

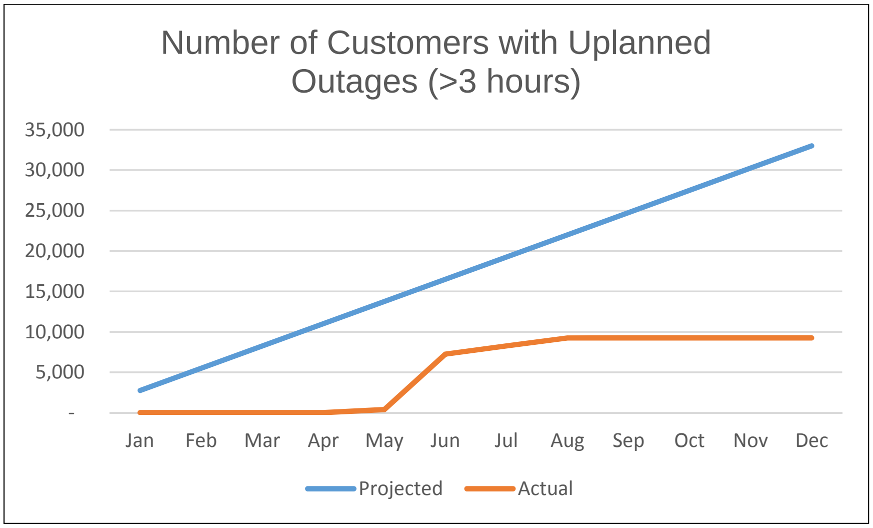


Figure 9: Customers Affected by Unplanned Outages

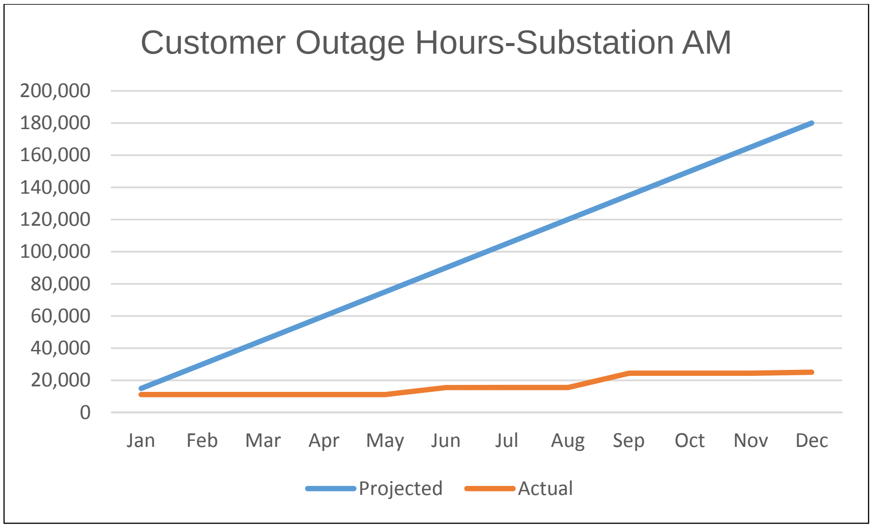


Figure 10: Customer Outage Hours

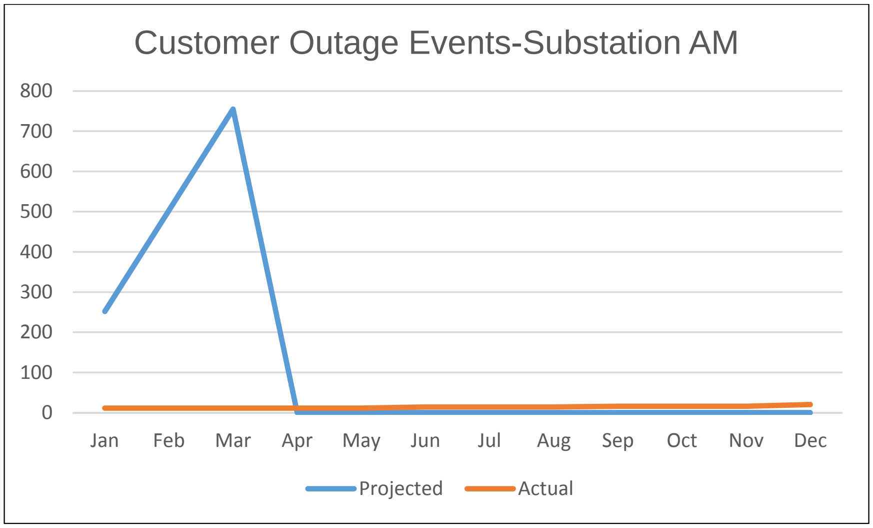


Figure 11: Customer Outage Events

The metrics shown in Figure 12 through Figure 15 relate to specific substation equipment-related programs. Figure 12 identifies the equipment replacement activities associated with the PCB Removal program, including qualifying equipment removed from substations. Equipment identified as a PCB-containing device continues to be prioritized for removal or replacement in conjunction with other related activities. The remaining three graphs represent power transformer, voltage regulator, and air switch assets.

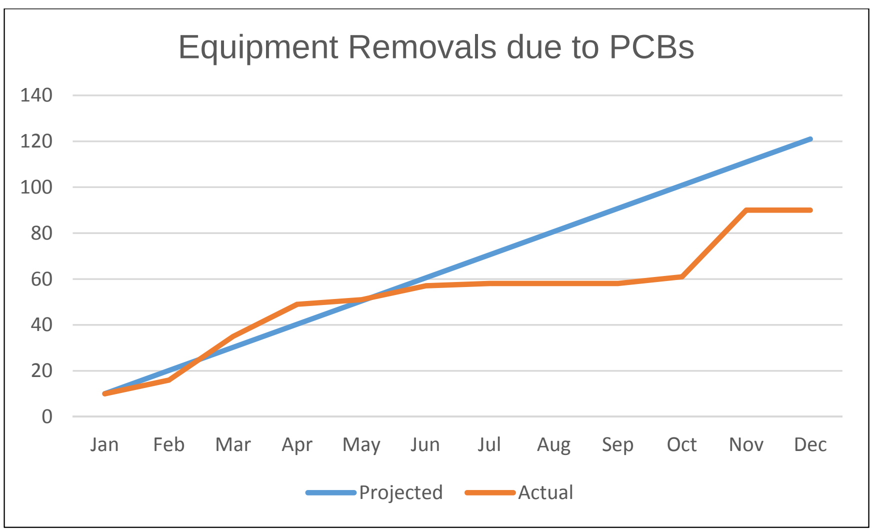


Figure 12: Equipment Removals due to PCB content

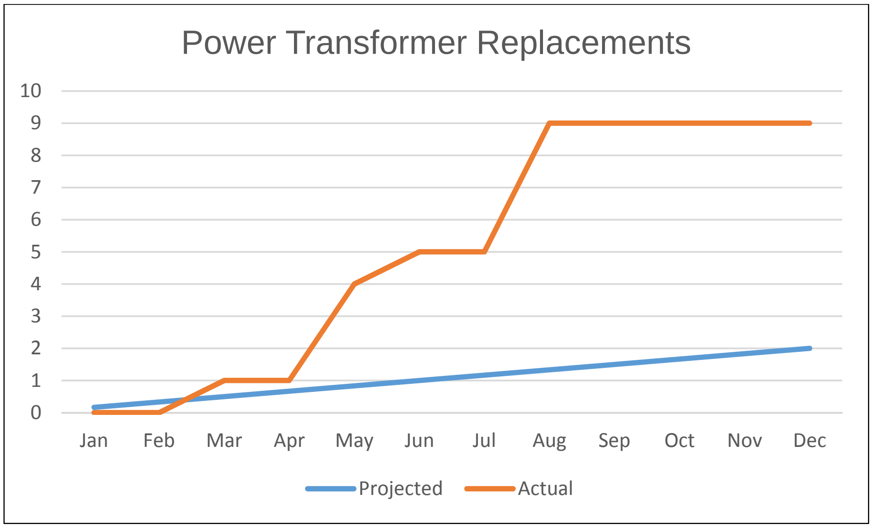


Figure 13: Power Transformer Replacements

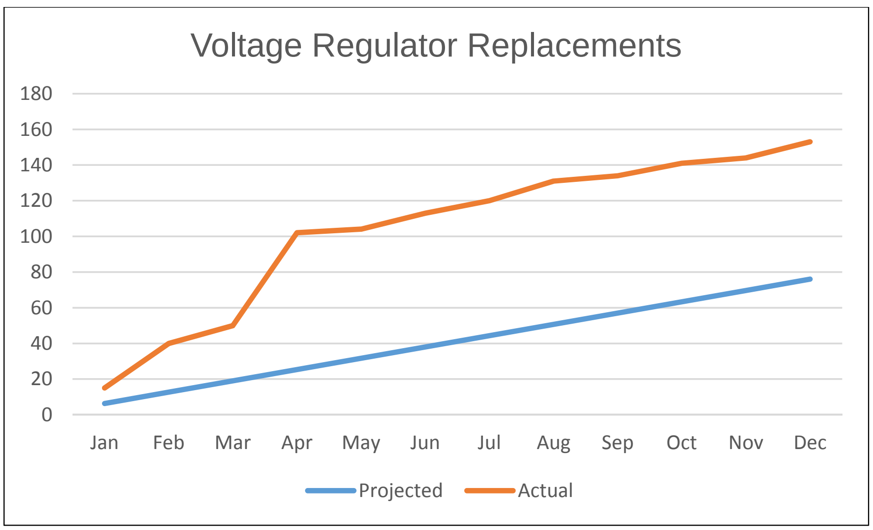


Figure 14: Voltage Regulator Replacements

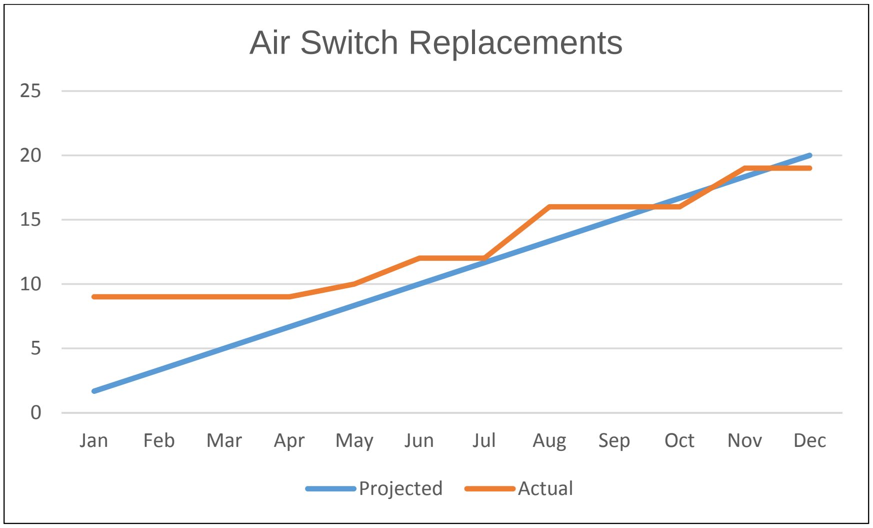


Figure 15: Air Switch Replacements

The Wood Substation Replacement program did not achieve a completed substation replacement during 2015 as noted in the graph shown in Figure 16.

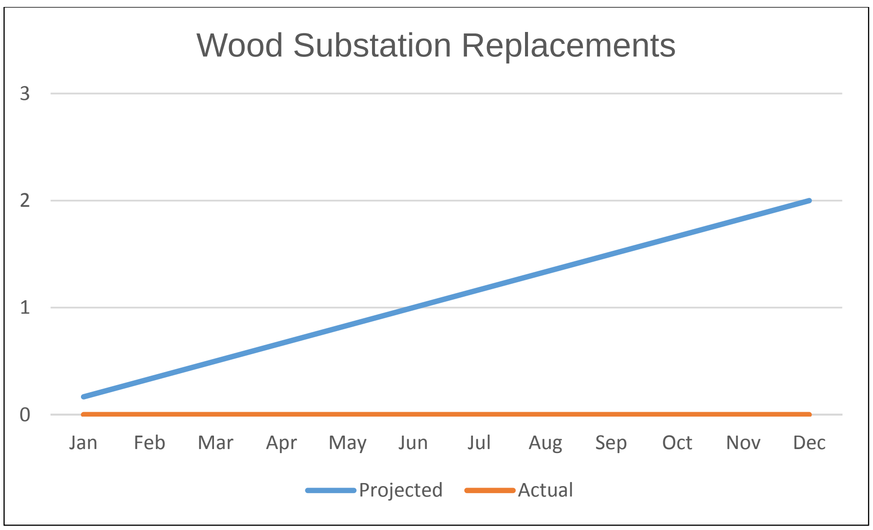


Figure 16: Wood Substation Replacements

These final two KPIs evaluate system awareness criteria regarding level of service. The Risk Action Curve metric in Figure 17 tracks outage event parameters, including frequency and severity, to signal additional action if the accumulated outage activity requires further review and analysis. The OMT High Limit in Figure 18 tracks to an acceptable limits of service statistical metric for outage events.

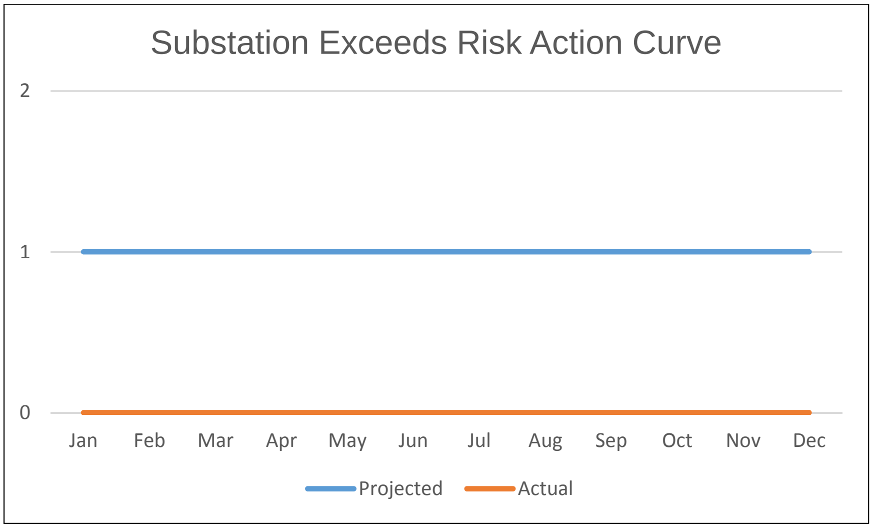


Figure 17: Substation Risk Action Curve

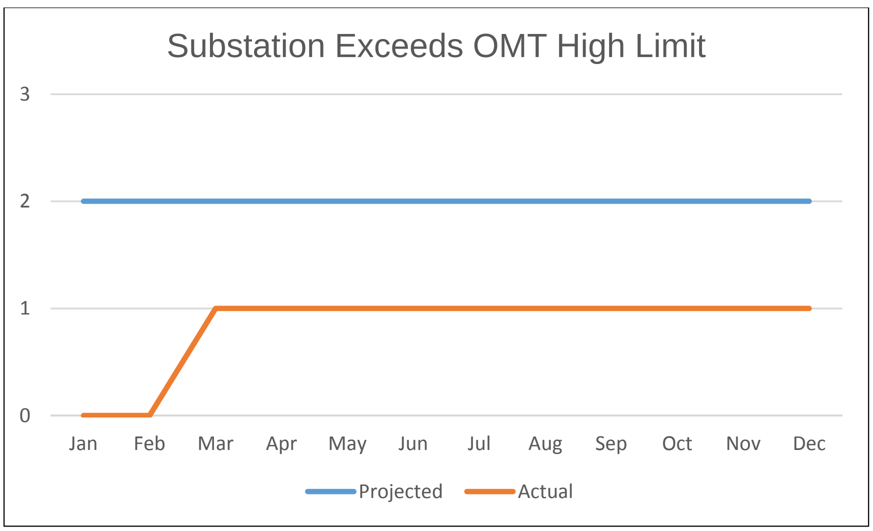
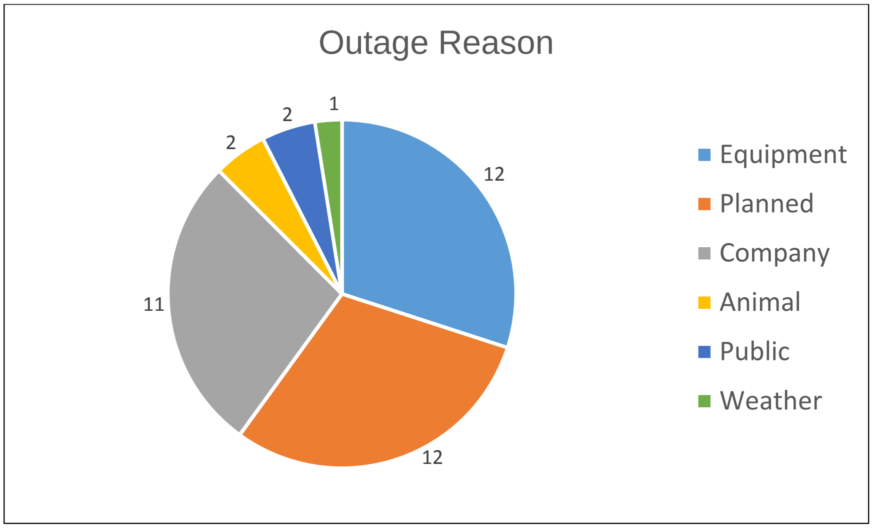


Figure 18: Substation OMT Limit

Outages

During 2015, 40 outage events occurred attributable to either planned or unplanned substation activity. For these outage events, the average duration was 2 hours 51 minutes and affected approximately 990 customers. Durations ranged from 5 minutes to 8 hours 48 minutes and impacted customers ranged from 1 to just over 4000. The data is derived from the annual reliability reports provided by Operations Management.



Programs

Substation PCB Removal

In 2010, an assessment was completed of equipment containing Polychlorinated Biphenyls (PCBs) within the Avista substation. PCBs are typically a minor constituent of oil within substation equipment including

- Power transformers
- Oil circuit breakers
- Voltage regulators
- Potential transformers
- Current transformers
- Station service transformers
- Capacitors
- Electromechanical relays.

Under the current process, the substation power transformers have been tested for PCBs and units with PCB concentrations of greater than 50 ppm are slated for removal. Voltage regulators, as brought in for repair, are tested and replaced if PCB concentrations of 50 ppm or greater are identified. Other substation equipment that is found to contain oil with the 50 ppm concentration of PCBs is evaluated on a case by case basis. The equipment may be decommissioned or reconditioned with clean oil and returned to service.

Additional regulation at both Federal and State levels continue to be monitored for refinement of this program.

Power Transformer Replacement

Avista's aging population of power transformers continues to be evaluated and included as key factors in substation upgrade projects or rebuilds. Transformer upgrades can provide significant energy savings based on the operational efficiency of the units, as well as additional configuration flexibility.

During 2014 and 2015, power transformer replacement projects have been completed at:

- Moscow 230 Spare (2013)
- Blue Creek #1 (2014)
- North Lewiston #1 (2014)

Voltage Regulator Replacement

Voltage regulators have been identified as significant contributors to substation reliability, and ongoing evaluation and modeling is in progress. The age profile is shown below Figure 19. In the conjunction with substation upgrades, older vintage voltage regulators are being replaced. The success of this ongoing program is shown by the shift in the age profile. Presently, the average age of installed base of voltage regulators is 15.5 years, though approximately 20% of the units have been installed for more than 30 years.

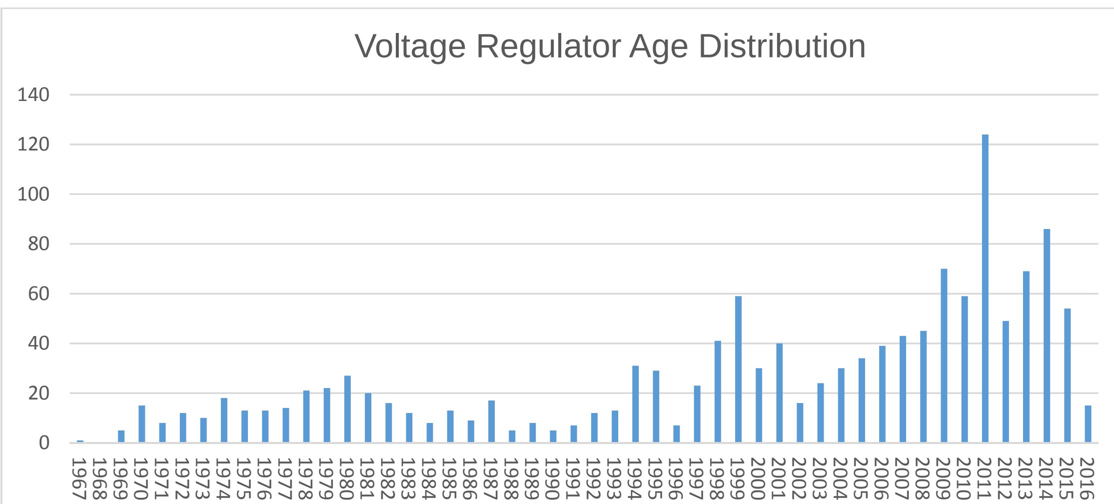


Figure 19: Voltage Regulator Age Distribution

Substation Air Switch Replacement

The Substation Air Switch Replacement program deals with both planned and unplanned replacements.

In the case where air switches do not operate properly, flashover and possible tripping of bus protection devices may occur. This can be the result of a component failure at the whips or vacrupter switch or other adjustment issues with the air switch itself. While most air switch missed operations could be prevented with regular inspection and maintenance, the limited scope of current maintenance procedures doesn't extend to the level of blade adjustments or the replacement of live parts, such as contacts and whips, or the repair of ground mats.

Many air switches are operated remotely. In these instances, Avista personnel may not be present to observe the opening of the switch, limiting the identification of potential issues. Minor functional issues could indicate the increasing probability of a major or catastrophic failure. Small quantities of emergency repair materials are maintained for the legacy population, but many of the air switches are out of production and replacement parts are difficult to procure.

Completed Substation Design and Construction Projects

The Substation Engineering group performs the scope, design, and project management functions for all facets of substation construction, including designated equipment replacement, rebuilds, and new site construction. The following tables describe the current status of projects within the engineering group's queue.

Substation Rebuilds completed in 2014 and 2015
Blue Creek – 115kV/13kV new construction
Clearwater 115kV/34kV substation upgrade
Lewiston Mill Road new construction
Moscow 230kV/115kV/24kV new construction
North Lewiston 115kV/13kV removal of equipment
Noxon Construction 230kV/13kV substation rebuild
Noxon Rapids 230kV west bus rebuild
Odessa 115kV/13kV substation upgrade
Irvin 115kV/13kV substation
Bruce Road 115kV/13kV substation

Table 4: Substation Rebuilds completed in 2014 and 2015

Completed Projects	BI Reference
Sunset - Replace MOAS A-184 (Four Lakes Tap)	AMS85
Grangeville - Replace A-337 Relay and Battery Cabinet	AMS09
Ross Park - 115kV Relay Upgrade	SS802
Third & Hatch - 115kV Relay Upgrade	SS802
Beacon - Upgrade A-605 Line Relays	SS802
Ninth & Central – Minor Upgrades	SS802
Noxon - Add Line Position for Noxon Reactor Station	AS202
Opportunity--Install 115kV Breakers	SS204

Table 5: Completed Projects

Projects in Design or Construction

The Substation Engineering group performs the scope, design, and project management functions for all facets of substation construction, including designated equipment replacement, rebuilds, and new site construction. The following three tables describe the current status of projects within the engineering group's queue.

Construction and Field Work in Progress	BI Reference
Bronx - HVP Upgrade	42P09
Oden - HVP Upgrade	42P09
Bunker Hill - HVP Upgrade	42P09
Nine Mile Substation - Install GSU 1	GG811
Noxon 230kV Reactor Station--New Construction	AS202
Greenacres--New 115kV/13kV Substation	SS644
Pine Creek - Replace Auto Transformer #1	AMS28

Table 6: Work in Progress

Engineering active and pending construction	BI Reference
Benton-Othello Transfer A-131 MOAS	AMS85
Beacon - Grid Modernization - Feeder 12F1	SS406
Beacon - Replace 13kV Breaker - 12F6	AMS83
Harrington - Rebuild to 115kV/13kV Substation	BS303
Mobile Battery - Add SCADA	XS951
Noxon - Hot Springs #1 and #2 Line Relay Upgrades	AMS07
Beacon--Replace Fence	AMS82
Beacon--115kV Line Relay Upgrade A-610, A-613	SS802
Noxon - Refurbish Existing East Bus	AS202
College & Walnut – Yard Expansion	AMS82
Sprague - Minor Rebuild	FS402
Deer Park--Metering/SCADA/Panel house	SS405
Othello - Replace Feeder 501 and 502 Breakers	AMS83
Othello - Replace Air Switch A-41	AMS83
Lolo - Communications DC Plant Refresh	
St. John - Replace 24kV Switches	AMS85
Shawnee - Communications DC Plant Refresh	
St. Maries - Upgrade AC/DC Station Service	AMS10

Table 7: Active and Pending Construction

Waiting prioritization or delayed	BI Reference
Replace SMP - Dry Creek	XS951
Replace SMPs - Post Street	XS951
Ramsey--Line Relay Upgrade A-669	CS802
Cabinet - Remove Relays and Change CT Ratios	AG103

Table 8: Delayed Projects

Future Projects	BI Reference
North Lewiston 230kV--Install Reactors	LS306
Kamiah - Rebuild	LS208
Gifford - Add 115/13kV Station to Substations	WS201
Westside - Increase Capacity; New Autotransformer	SS201
Priest River – Temporary Breaker Install	AMS83
Ford - Replace Transformer	AMS28
Ford - Install New 12F2 Feeder Position	BS202
Waikiki - Grid Modernization - Feeder 12F2	SS542
Priest River - Minor Rebuild - Distribution	AMS83
Irvin--New 115kV Switching Station	SS904
Hallett & White - Add Capacity	SS523
Rathdrum - Grid Modernization - Feeder 231	CS502
Rathdrum - Grid Modernization - Feeder 233	CS502
Juliaetta - Replace MOAS units A-120 and A-173	AMS85
Jaype - Remove and Salvage	
Colville - Replace Battery	AMS10
Chester - Replace Battery	AMS10
Rockford - Replace Battery	AMS10
Fort Wright - Replace Battery	AMS10
Beacon--Install Serveron DGA on both autotransformers	XS903
Ritzville - Replace A-94 MOAS Control Box	AMS85
Northwest - Add Fiber Redundancy/Upgrade	XS951
Millwood - Add Radios in Yard - 2 Poles	
Othello Switching Station - HVP Upgrade	42P09
Clearwater - Upgrade Metering	XS801
Clearwater - Replace Battery	AMS09
Oden - Replace 115kV Switches	AMS85
Bronx - Replace small conductor	AMS32
Garfield - Replace HV Fuses	AMS80
Clearwater--Microwave Refresh	

Future Projects	BI Reference
Beacon - Add Thermal Relays - A-603/A-607	XS002
St. Maries--Install SCADA	XS951
Ninth & Central - Rebuild Distribution Sub	SS514
S. Lewiston 115--Rebuild station, replace transformers	LS207
Ninth & Central - Move lateral line into substation	SS514
Moscow City—Upgrade SCADA/Integrate System	XS951
Indian Trail - Add Fiber; Upgrade Communications	XS951
Northwest - Rebuild	SS206
College & Walnut - Replace Breakers A-431 and A-432	AMS32
Davenport - Minor Rebuild	BS400
Colville - HVP Upgrade	42P09
Kooskia 115kV--Replace Transformer	AMS28
Milan - Replace A-599 MOAS	AMS85
N. Moscow - Install A-369 MOAS	AMS85
Warden - Replace Breakers	AMS32
Warden - Install SSVT for Station Service	XS905
Otis Orchards – Install SSVT for Station Service	XS905
Beacon--Upgrade SCADA/Integration System	XS951
Clearwater--Upgrade Relaying	AMS07
St. Maries - Install 115kV Arresters	AMS81
O'Gara - Install 115kV Arresters	AMS81
Lee & Reynolds--Add Transformer #2	AMS28
Upriver--Replace/Upgrade Metering	XS801
Dry Gulch--Replace/Upgrade Metering	XS801
Cabinet - Install substation fuses/Lighting circuits	AMS80
Clearwater - Replace/Upgrade SCADA	XS951
Little Falls – Rebuild	BS304
Tenth & Stewart--Station Upgrades/Rebuild	LS202
Valley - Rebuild Substation	WS402
Sunset - Rebuild Substation	SS890

Future Projects	BI Reference
Metro - Rebuild Substation	SS208
Big Creek - Rebuild Substation	KS201
Coeur Shaft - Minor Rebuild	TBD
Pound Lane - Rebuild Substation	TBD
Chester - Rebuild Substation	SS207
Othello - Rebuild Substation	TBD
Silver Lake - Rebuild Substation	TBD
Dalton - Rebuild Substation	TBD
Huetter - Rebuild 115kV Yard	CS503
Bronx - Rebuild Substation	AS203
Noxon Rapids - New Substation	AS202
Saddle Mt. - New Substation	TBD
Tamarack - New Substation	PS203
McFarlane - New Substation	SS516
Bovill - New Substation	TBD
Ross Park--Install Security Wall	06P98
Post Street Transformer Cooling Discharge	TBD
ORO - Grid Modernization - Feeder 1280	TBD

Table 9: Future Projects

System Planning Projects

There is considerable opportunity for more collaboration between Asset Management and System Planning on capital asset risk assessments, analyses and development of long-term asset management plans, where overlaps and synergistic opportunities present themselves. Risk is equivalent to the product of the probability and the consequence of a given event.

Currently, there are no substation System Planning projects that are covered by Asset Management.

Reference and Data Sources

Various information and data sources were used to compile the information for this report. As referenced in the Purpose introduction, the emphasis was placed on Avista's Maximo implementation for all inventory and date-specific asset details. This process will provide a tracking database for repeatable historical references, trending, and accurate data snapshots as the system continues to be deployed and data capture processes refined.

Other sources include Availability Workbench simulations, the legacy Major Equipment Tracking System (METS), Outage Management Tool (OMT) data, substation engineering files, substation engineering SharePoint site, and the substation Projects and Capital Budget spreadsheets.

2016

Electric Transmission System
2016 Asset Management Plan

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Avista Corp.

02-01-2016

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Approved by:

Scott Waples, Director of Planning and Asset Management

Front cover:

Steel Structures on the Benewah – Boulder 230kV Line (November, 2015)
1959 Original Construction
2015 Phase 1 Structure Replacement Project

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Purpose

System asset management plans are meant to serve a general audience from the perspective of long-term, balanced optimization of lifecycle costs, performance, and risk management. The intent is to help the reader become rapidly familiar with the system's physical assets, performance, risks, operational plans, and primary replacement and maintenance programs. Consistent annual updates of this plan provide the continuity required for useful historical information and continuous improvement of asset management practices.

For easy reference, a "Quick Facts" sheet is used to highlight key information and recommendations of this system-level asset management plan. At the individual program and project level, additional "Quick Facts" sheets may also be available. For more details, please visit the Asset Management Sharepoint site at Asset Management Plans. This update reflects the best available information as of December 31, 2015.

Executive Summary

Consistent with last year's assessment, the primary message of this asset management plan is that the company must commit itself to sustainably replace the bulk of the aging transmission system over the next three decades. This is essential to achieve the company's strategic objectives of maintaining reliability levels while minimizing total lifecycle costs, requiring over $624 million in capital replacement investment. As this represents a significant increase in capital investment as well as internal and external workloads from recent years, success demands strong company support and management. In order to be most effective and beneficial to customers and the company, it also requires fact-based prioritization and targeting of available funds to the riskiest elements of the system.

Key performance indicators (Table 5) for the transmission system showed results lower than targeted for 2015. Completed ground inspections were lower than planned and aerial inspections were on-track. Aging 115kV pole replacements were 80% below target, while aging 230kV pole replacements were 37% above target. Customer outages were 97% higher than targeted, while emergency spending was 50% higher than targeted. Finally, the follow-up repair backlog increased, ending the year with five category 4 items overdue and the oldest item in the backlog at 35 months. Much of this may be due to improved identification and tracking methods that were recently implemented.

Replacement budget recommendations remain relatively unchanged at $12 million for 115kV and $9 million for 230kV. Planned budgets for 2016 and 2017 are relatively close to this recommendation. Additional mandated, growth and reimbursable capital projects, as well as O&M work puts the total planned budget for

Transmission Engineering at approximately $25 million for 2016, and is expected to remain at this level or increase for many years. This output level is nearly triple that of just a few years ago, while dedicated staff have only increased from five to six in the transmission engineering group. In order to reduce operational risks, it is strongly recommended that management consider assigning additional dedicated staff members, as well as proper equipment for safe and effective fieldwork.

Outages and unplanned spending was $2 million in 2015 , mostly as the result of a severe winter wind storm that raised overall unplanned spending on the 230 kV and 115kV systems by $700k.

Notable achievements in 2015 include:

1. Design and project management of an expanded number of mandated and system planning projects including LiDAR mitigation, at $16.4 million in 2015 compared to $7.5 million in 2014.
2. Completion of minor rebuild and LiDAR mitigation on Moscow - Orofino 230kV, Devil's Gap – Stratford 115 kV, and Noxon – Hot Springs 230 kV
3. Total rebuild on Bronx – Cabinet 230 kV, tie line to the new Noxon reactor, and structure replacement projects on Benewah-Moscow 230 kV and Devils Gap-Lind 115 kV.
4. Approved 2015 budget closely matching the recommended replacement budget of $12 million for 115kV and $9 million for 230kV.
5. Effective transition of administrative maintenance work from departing staff, as well as hiring and productive output of new engineering staff.
6. Published a comprehensive set of construction standards for transmission engineering and effectively integrated the use of PLS-CADD software. Consistently using both as a baseline for continuous improvement, as a collaborative team effort.
7. Confirmation of system pole data including material and location, allowing for detailed expected service life information on each transmission line.
8. Began simulation studies for Lolo – Oxbow 230kV and Noxon – Pine Creek 230kV circuits.
9. In cooperation with other utilities, continued a major project to determine best design, construction, inspection and maintenance of self-weathering steel structures.

Beyond execution of approved construction, below is a list of recommended initiatives to further improve the long-term performance and stewardship of transmission assets.

1. Provide additional dedicated staff as appropriate, to handle long-term increased workloads in the Transmission Engineering group and support processes.

2. Engage asset stakeholders within each major region of the transmission system in order to develop a comprehensive, prioritized capital project plan for the next 20 years.

3. Continue improving the transmission construction standards to reflect best practices in design and construction work. Engage line crews and regional staff.

4. Monitor the lead time for as-built construction updates to AFM, Plan and Profile (P&P) drawings, and the engineering vault files, with a target of six months. Carry out periodic quality audits of construction in the field and recorded data.

5. Develop a comprehensive inspection and planned maintenance program for steel transmission structures.

6. Develop a systematic air switch risk ranking method, replacement schedule, and inspection and maintenance program.

7. Complete rebuild simulation studies and business cases for Lolo – Oxbow 230kV and Noxon – Pine Creek 230kV circuits.

8. Determine the risks and appropriate mitigation work resulting from structural loads of distribution underbuild.

9. Complete a system-wide simulation study to support optimal Transmission asset inspection intervals as well as planned and unplanned replacement budget targets, including annual minor vs. major rebuild budgets.

10. Implement transmission outage software which will allow for accurate and efficient analysis of outages and causes on each transmission line and aerial patrol inspection software for follow up tracking.

Assets

The tables and charts below provide a high-level summary of physical assets in the transmission system, replacement values, and expected service lives. Replacement values represent the cost to replace existing assets with equivalent new equipment in 2015 dollars, not including right-of-way purchases, capacity or ratings upgrades, mandated projects, and other work associated with growth-related installations.

Circuit Type	Installation Cost/Mile	Removal Cost/Mile	Miles	Total Replacement Cost
69kV Circuit	$250,000	$20,000	0.4	$113,400
115 Single Circuit	$400,000	$20,000	1457.1	$611,986,200
115 Underground Circuit	$3,600,000	$180,000	2.8	$10,584,000
115 Double Circuit	$525,000	$20,000	23.9	$13,014,600
230 Single Circuit	$700,000	$20,000	604.3	$435,081,600
115-230 Double Circuit	$850,000	$20,000	55.3	$48,145,800
230 Double Circuit	$900,000	$20,000	25.8	$23,736,000
			2169.6	**$1,142,661,600**
		Average Asset Lifecycle (Years)		70
	Annual Levelized Replacement Spending over Lifecycle			**$16,323,737**

Table 1: Primary Assets of the Electric Transmission System – Circuits

Asset Category	Quantity 230kV	Quantity 115kV	Quantity Total	Expected Service Life (years)
Structures	4990	16483	21473	65
Poles	9021	27401	36422	70
Air switches	2	188	190	40
Conductor (miles)	2055	4602	6657	100
Compression sleeves	1370	3068	4438	50
Insulators	22978	60202	83180	70

Table 2: Component Assets and Quantities

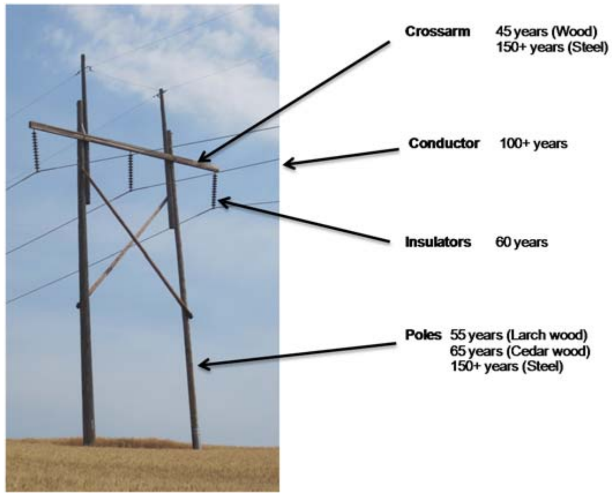
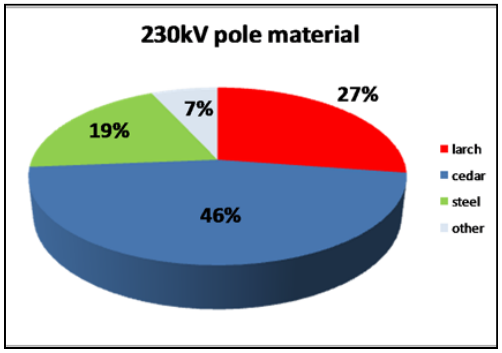
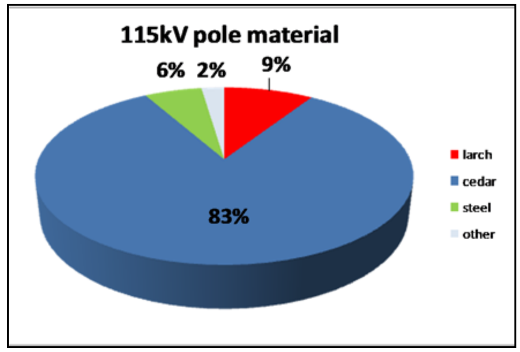


Figure 1: Example Transmission Asset Components and Expected Service Life

100	Steel Towers (galvanized steel)
50	Steel Pole/Tubular structures (galvanized or painted)
2585	Self-Weathering Steel Structures
18817	Wood Pole Structures
4	Hybrid Concrete/Steel structures
0	Concrete Structures
0	Aluminum Structures
40	Laminated Wood Structures
21596	Total Transmission Structures
9.7	average # structures/mile
3277	# self-weathering (cor-ten) steel poles
50	# tubular galvanized steel poles
8	# hybrid concrete/steel poles
7602	# larch poles
366	# fir poles
25079	# cedar poles
40	# laminated wood poles
36422	Total # Poles
5660	# beyond expected service life
16%	% beyond expected service life
80	# of structures with buried galvanized steel foundations
1014	# of structures with coated buried steel foundations
unknown	# of structures with caisson concrete foundations
2700	# of structures with anchors

Table 3: Transmission Structures and Poles





pole material	larch	cedar	steel	other	total
service life	55	65	150	70	69
# 115 poles	2347	21198	1506	597	25648
# 230 poles	2545	4312	1813	635	9305
total # poles	4892	25510	3319	1232	34953

Table 4: 115kV vs 230kV Pole Materials

Key Performance Indicators (KPIs)

The table below shows overall KPI results for 2015, which are monitored and recorded on a monthly basis throughout the year. The first four are leading indicators over which we have direct operational control. The final two KPIs are lagging indicators of system performance, which should have a causal link to the leading indicators. In other words, if we consistently execute well as demonstrated by the leading indicators, over time we should see satisfactory outcomes as manifested by the lagging indicators, and vice versa. When this does not occur, deeper investigation and root-cause analysis is justified, as something other than the expected causal relationship is potentially at play.

By these measures, performance was lower than targeted for structural ground inspections. Aerial patrol inspections remained on-track overall. System-wide follow-up repairs from ground and aerial patrol inspections were higher than planned for category 4 and 5 items. This may be primarily due to improved tracking methods. Aging infrastructure replacement was less than the levelized investment required to maintain system reliability over the long term for 115kV, as roughly indicated by the number of older poles replaced. Reliability performance and emergency spending were higher than targeted.

Completed Structural Ground Inspections	Projected	Actual	Normalized
# wood poles ground inspected	2400	2145	0.89
Completed Structural Aerial Inspections	**Projected**	**Actual**	**Normalized**
% of 230kV system inspected	100	100	1.00
% of 115kV system inspected	70	70	1.00
Followup Repair Backlog	**Projected**	**Actual**	**Normalized**
# worksites overdue (> 1 year after inspection year)	10	8	0.80
# Category 4 or 5 items overdue (> 6 months since inspection, ground + aerial)	1	5	5.00
oldest item in backlog (# months since inspection)	18	35	1.94
Aging Infrastructure Replacement	**Projected**	**Actual**	**Normalized**
# 115kV wood poles older than 60 years replaced with steel	500	98	0.20
# 230kV wood poles older than 50 years replaced with steel	175	240	1.37
# air switches > 40 yrs old replaced	4	1	0.25
Reliability Performance	**Projected**	**Actual**	**Normalized**
Extended Unplanned Outages due to Transmission (Customer-Hrs)	133,142	262,949	1.97
# of Customers with Unplanned Transmission Outages > 3 Hrs	10,182	24,927	2.45
Emergency Spending	**Projected**	**Actual**	**Normalized**
230kV Emergency Spending	$204,022	$ 388,272	1.83
115kV Emergency Spending	$ 1,116,997	$ 1,792,649	1.44
total Emergency Spending	$ 1,321,019	$ 2,180,921	1.50

Unity Box Metrics - Monthly	Weighting	2015 Result
Completed Structural Ground Inspections	20.00%	0.89
Completed Structural Aerial Inspections	20.00%	1.00
Followup Repair Backlog	15.00%	3.19
Aging Infrastructure Replacement	15.00%	0.73
Reliability Performance	15.00%	2.31
Emergency Spending	15.00%	1.50
Sum of Weight * Value	100.00%	1.54

Results
1 = Planned/On-Track
<1 = Better than Planned
>1 = Worse than Planned

Table 5: Transmission KPIs and Unity Box Metrics

It is strongly recommended that $21 million per year over a 30-year timeframe is allocated for worn-out infrastructure replacements – $12 million for 115kV, and $9 million for 230kV. As we ramp up replacement construction in the years ahead, we expect to meet or exceed these goals. We will continue to replace equipment primarily on the basis of recent inspection and condition assessments, however the age and respective service life of the system at a high-level provides a strong leading indicator of long-term system reliability.

Additional performance measures are tabulated below since 2010:

Performance Measure	Goal	2010	2011	2012	2013	2014	2015	Remarks
Customer-Hours unplanned, extended outage due to transmission issues	113,142	255,426	64,453	82,908	238,861	200,977	262,949	
# of customers of Tx related unplanned outages greater than 3 hrs	10,182	16,478	6,644	5,409	17,135	17,609	24,927	
Tx emergency repair costs	$1,321,019	$1,442,969	$1,029,597	$1,409,972	$1,630,943	$3,040,313	$2,180,921	
Avista crew safety: # recordable injuries from Transmission work	0	not avail	not avail	not avail	not avail	not avail	not avail	Unable to isolate to Transmission
Top 10 worst performing components - by failures	NA	not avail	not avail	not avail	not avail	not avail	not avail	Not available from OMT data
Top 10 worst performing circuits by # of component failures	NA	not avail	not avail	not avail	not avail	not avail	not avail	Not available from OMT data

Table 6: Additional Performance Measures, 2010-2015

Note that important performance measures currently cannot be evaluated due to inadequate data availability. This includes safety incidents from transmission work, the total number of annual failures and respective failure modes for various transmission lines and system-wide asset components such as poles, air switches, crossarms, insulators, splice connections, and so forth. An ongoing, long-term effort is necessary to make this information available and assimilate into our set of KPIs and circuit risk rankings. It is also essential to taking the next steps in evaluating the benefit and value of asset management programs and projects for continuous improvement.

Capital Replacement and Maintenance Investment

Levelized replacement spending is the annual spending required to replace the asset category in a perfectly level form over the asset's service life in 2015 dollars, not including inflation. Prior to adjusting for uneven service life profiles, this provides a simple, rough-cut measure to compare against actual replacement spending each year, i.e. the minimum needed to keep up with aging infrastructure that places reliability at risk. This currently stands at $16.3 million per year for the transmission system.

Relative to other major areas of the transmission and distribution (T&D) system, transmission assets have a longer service life, and the total replacement value of $1.1 billion is on par with substation's $0.9 billion and about half of distribution's $2.0 billion. All together, levelized replacement spending is roughly $84 million per year in perpetuity for Avista's T&D system (2014 dollars). However, as shorter lived wood materials are replaced with steel in the decades ahead, we expect overall service life to increase from 70 years to over 100 years for the transmission system. Assuming all other factors being equal, this in turn would reduce the minimum levelized spending to under $12 million/year, roughly 50 years from now.

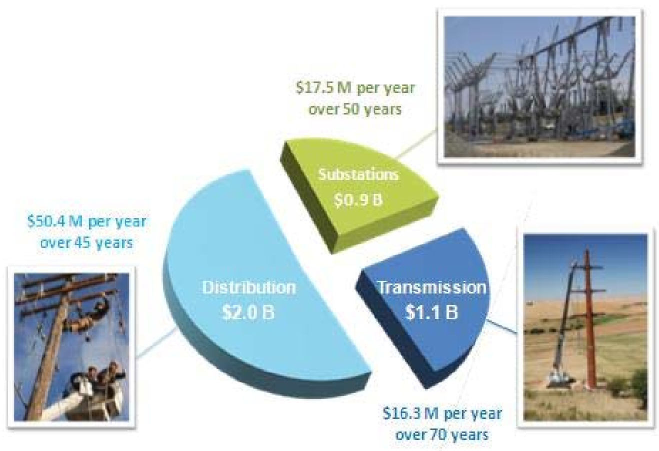


Figure 2: Transmission and Distribution System Replacement Values, Average Service Life, and Levelized Replacement Spending

The next step is to look more closely at the replacement cost of actual installed assets compared to remaining service life. This provides the basis for levelized replacement budgets given actual remaining service life profiles, as summarized in the following chart.

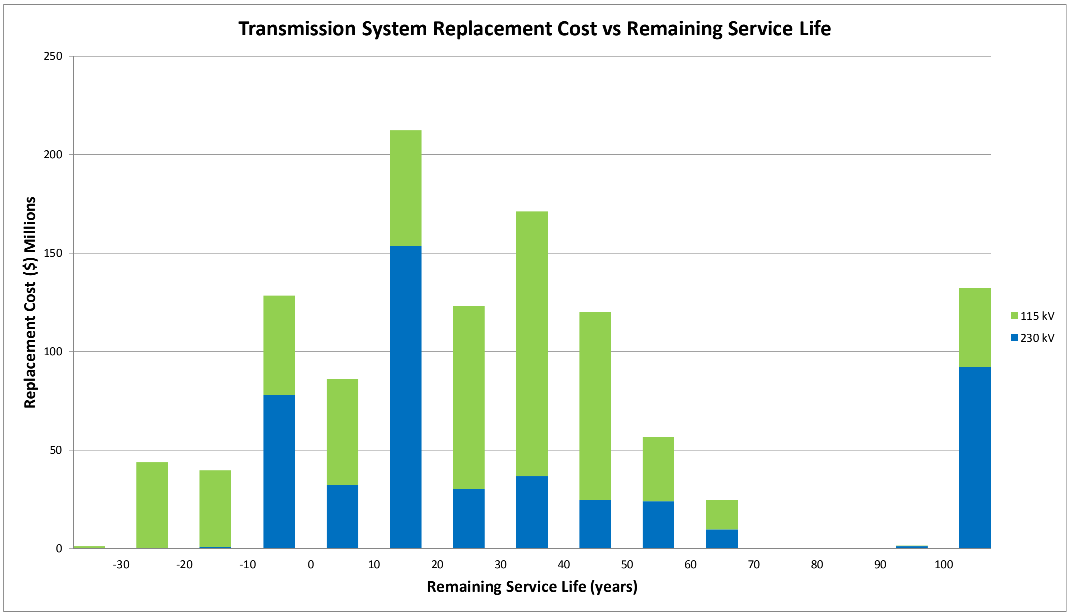


Figure 3: Replacement Cost vs. Remaining Service Life

Note that field assets costing $234 million to replace are currently beyond expected service life, based on their age and statistical predictions of mean time to failure (everything to the left of 0 years in Figure 3 above). The oldest and greatest quantities of these assets are 115kV transmission lines. This represents a significant risk to the continued reliability of the transmission system, particularly for those 115kV circuits with more than 10 years past normal service life.

To address this issue, several alternatives present themselves in terms of long-term replacement policies, as shown in the table below. 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.

The table below presents a simple levelization that reduces the volatility and operational business risk of ramping up and down construction work from year-to-year, while responsibly maintaining system performance. Again, it should be emphasized that in order to be most effective, this level of replacement spending must be targeted at those assets that pose the greatest overall risk, as discussed in the Risk Prioritization section of this report.

		Cumulative Replacement Costs ($)			
Tx Capital Assets Service Life (yrs)	Levelized Replacement Period (yrs)	115kV	230kV	Total	Annual Levelized Replacement Spending ($)
-10 or less					
0 or less	10	$134,307,405	$78,477,092	$212,784,497	$21,278,450
10 or less	10	$188,044,730	$110,751,445	$298,796,176	$29,879,618
20 or less	20	$246,950,622	$264,119,590	$511,070,211	$25,553,511
30 or less	30	$339,538,157	$294,522,966	$634,061,123	$21,135,371
40 or less	40	$473,944,191	$331,318,848	$805,263,038	$20,131,576
50 or less	50	$569,441,268	$356,005,350	$925,446,618	$18,508,932
60 or less	60	$602,081,970	$379,756,364	$981,838,334	$16,363,972
70 or less	70	$617,172,136	$389,475,050	$1,006,647,186	$14,380,674

Table 7: Levelized Replacement Spending Options

A variety of data uncertainties result in +/- 5% confidence in the stated figures. In terms of replacement costs, the most significant uncertainty from year to year involves the volatility of contract labor. Extensive work was recently completed to confirm 115kV and 230kV pole data, most importantly the identification of pole material and respective expected service life, which has greatly improved confidence levels.

The recommended $21.1 million per year in levelized replacement spending over the next 30 years is higher than the $19.1 million actual replacement spending in 2015. Significant effort is underway to ramp up replacement construction in 2016 and sustain it over ensuing years. Other project categories include growth, mandated, and reimbursable capital projects, operations and maintenance (O&M) programs, and unplanned/emergency work. These figures are tabulated below for 2015. Spending associated with liability claims and the underground network are not included, due to data uncertainty. Please note that many construction projects involve a combination of replacement, growth, and mandated work, therefore these figures are rough approximations. Historically, upwards of 90% of transmission construction is through contractors.

$	19,074,307	Replacement
$	6,301,988	Growth/Upgrade
$	2,180,921	Unplanned/Emergency
$	936,843	O&M - Veg Management
$	327,319	O&M - Other
$	25,000	Reimburseable work completed
$	28,846,378	Total
$	26,640,457	Total Planned non-reimburseable
$	26,665,457	Total Planned Capital (including reimburseable)
$	1,264,162	Total Planned O&M
$	2,180,921	Total Unplanned/Emergency Capital
unknown		Total Unplanned O&M

Table 8: 2015 Transmission Spending

2015 Tx Project Spend		Program/Project Description	ER	BI	Type
$	5,344,333	Devils Gap-Lind 115kV Transmission Rebuild Proj	2564	ST302	Replacement
$	5,316,486	Benewah-Moscow 230kV - Structure Replacement	2577	PT305	Replacement
$	3,426,340	LiDAR Mitigation Projects, Med Priority	2560	CT203, various	Mandated Replacement
$	3,419,420	Xsmn Asset Management	2423	AMT81	Growth/Replacement
$	2,475,619	Benton-Othello 115 Recond	2457	FT130	Growth/Replacement
$	2,053,414	Asset Mgmt Trans Minor Rebuilds WA	2057	AMT12	Replacement
$	692,288	Noxon 230 kV Stn Rebuild:Transmission Integration	2532	AT300	Growth/Mandated
$	627,195	Asset Mgmt Trans Minor Rebuilds ID	2057	AMT13	Replacement
$	529,411	Transmission Line Road Move	2056	56L08	Replacement
$	443,619	Asset Mgmt Transmission Switch Upgrade	2254	AMT10	Replacement
$	411,600	Chelan-Stratford 115kV - Rbld Columbia River Xing	2574	BT304	Growth/Mandated
$	249,540	Lewiston Mill Rd. 115 kV Substation Integration	1107	LT403	Growth/Mandated
$	198,319	9CE-Sunset 115kV Transmission Line Rebuild	2557	ST503	Growth/Replacement
$	85,599	Opportunity Sub 115kV Breaker Add - Tx Integration	2552	ST307	Growth/Mandated
$	84,903	Irvin 115kV Switching Stn: Transmission Integration	2446	ST102	Growth/Mandated
$	18,209	Greenacres 115 Sub New Cons:Transmission Integrate	2443	ST203	Growth/Mandated
$	-	Burke-Thompson A&B 115kV Transmission Rebuld Proj	2550	CT101	Replacement
$	-	LiDAR Mitigation Projects, Low Priority	2579	CT304, various	Growth/Mandated
$	-	Asset Mgmt Transmission Wood Sub Rebuild	2204	AMT08	Replacement

Table 9: 2015 Planned Capital Projects (Non-Reimburseable)

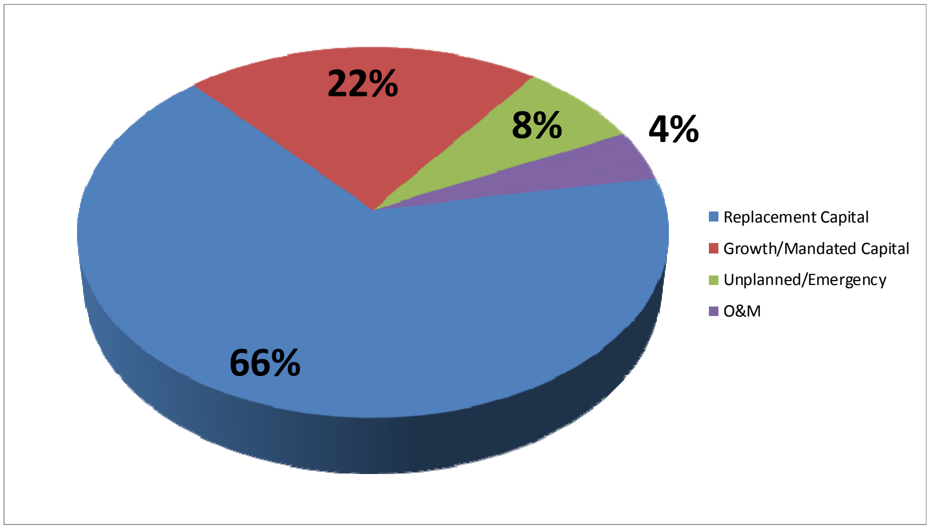


Figure 4: 2014 Planned Capital, O&M, and Emergency Spending

This shows that approximately 92% of spending was planned, vs. 8% unplanned in 2015. The percent of planned work should increase as planned replacements ramp up and unplanned/emergency spending is held constant or reduced. Growth and mandated projects (e.g. LiDAR projects) of $6.3 million resulted in 22% of total Transmission spending in 2015. Although the spending in this category is highly variable from year to year, a constant value of $3 million is assumed for the future. A small increase of 2% per year is assumed for reimbursable projects such as road moves. O&M dollars may be reduced over the long-term, due to expected lower inspection costs of steel poles as they are used to replace existing wood poles; however, this was not accounted for as it is somewhat uncertain and represents a relatively insignificant sum. Other figures represent recommendations for planned replacement and maintenance programs as specified in the Programs section of this report. Optimal planned spending may vary considerably after making adjustments for actual condition assessments as inspections are completed, capturing economies of scale opportunities when rebuilding larger sections of line, and taking into account cost of capital considerations from year to year. Notwithstanding these variables, the numbers below represent the minimum recommended investment for consistent, planned transmission work in the years ahead.

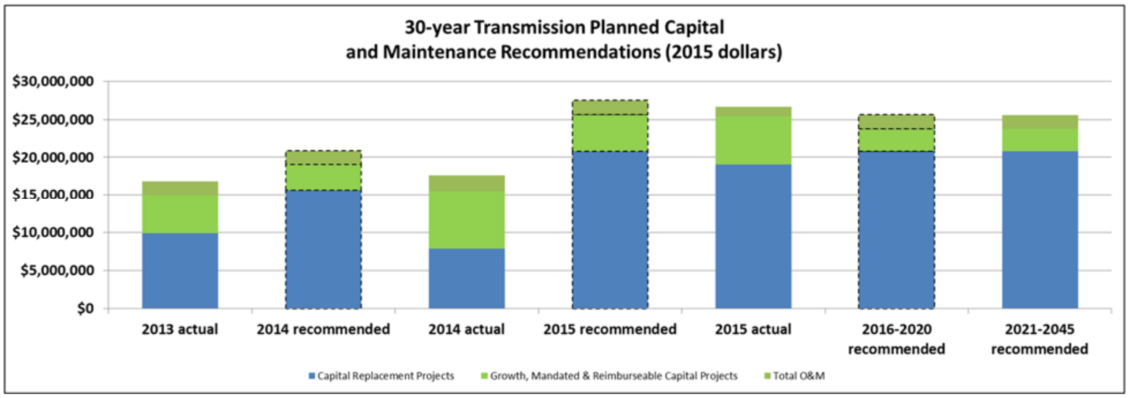


Figure 5: 30-year Transmission Planned Capital and Maintenance Recommendations

	Major Capital Replacement Projects	Growth/Mandated Capital Projects	Reimburseable Capital Projects	Air Switch Replacements	Minor Rebuilds & Repairs	Structural Ground Inspection	Structural Aerial Patrols	Vegetation Management	Fire Retardant Program	230kV Foundation Grouting	Capital Replacement Projects	Growth, Mandated & Reimburseable Capital Projects	Total O&M	Total Planned
O&M %	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%				
Capital %	100%	100%	100%	100%	100%	0%	0%	0%	0%	0%				
2013 actual	$8,785,633	$3,965,832	$1,136,787	$150,556	$970,036	$294,000	$94,595	$1,100,000	$200,000	$100,000	$9,906,225	$5,102,619	$1,788,595	$16,797,439
2014 recommended	$14,110,816	$2,210,000	$1,159,523	$264,000	$1,300,000	$192,000	$100,000	$1,200,000	$242,000	$100,000	$15,674,816	$3,369,523	$1,834,000	$20,878,339
2014 actual	$3,638,255	$7,499,457	$150,000	$135,493	$4,103,971	$317,790	$103,154	$1,300,000	$188,111	$181,405	$7,877,719	$7,649,457	$2,090,460	$17,617,636
2015 recommended	$18,667,888	$3,000,000	$1,870,600	$392,507	$1,700,000	$216,000	$100,000	$1,200,000	$242,000	$100,000	$20,760,395	$4,870,600	$1,858,000	$27,488,995
2015 actual	$15,420,668	$6,301,988	$25,000	$443,619	$3,210,020	$68,142	$135,318	$936,843	$19,322	$104,537	$19,074,307	$6,326,988	$1,264,162	$26,665,457
2016-2020 recommended	$18,496,395	$3,000,000	$25,500	$264,000	$2,000,000	$216,000	$103,154	$1,200,000	$242,000	$100,000	$20,760,395	$3,025,500	$1,861,154	$25,647,049
2021-2045 recommended	$18,496,395	$3,000,000	$26,010	$264,000	$2,000,000	$216,000	$103,154	$1,200,000	$242,000	$0	$20,760,395	$3,026,010	$1,761,154	$25,547,559

Table 10: 30-year Planned Capital and O&M Recommendations

In short, in order to minimize lifecycle costs and maintain system performance, the bulk of the transmission system needs to be rebuilt over the next three decades, if not sooner. This is no small endeavor, entailing significant financial and operational risk. Although construction and even design work may be contracted out, internal workloads will in all cases rise substantially in the years ahead for the Transmission Engineering group and supporting departments. A successful transition and sustained production of high quality design work and construction in the field – that will last well into the 22nd century – requires careful management and strong support across the company.

Process Capability

As of 2010, total planned design, project management, and construction capital and O&M work for the Transmission system originating from the Transmission Engineering group was less than $10 million per year. At that time, Transmission Engineering had a dedicated staff of five members – one manager, three engineers, and one technician – equivalent to roughly $2.0 million per staff member. In 2015, total planned work amounts to $26,665,457 with a dedicated staff of six members – one manager and five engineers – equivalent to $4.4 million per staff member. This represents an output productivity increase of 120% in only a few years time. Hidden workloads such as mandated reporting and analysis from regulatory bodies such as NERC are also on the rise. In order to remedy operational risks and achieve management objectives, the need for additional staff, equipment, and improved support processes should be considered a very high priority, seriously investigated, and remedied as appropriate.

Other opportunities for improved process capability include reducing overall project lead times, particularly from the time of internal project initiation to the beginning of construction, which has increased substantially. Construction timelines and total costs may also be reduced, for example by completing line projects in one or two years instead of three to five.

Continued engagement and integration with internal and contracted line crews to communicate and improve construction standards is also recommended as a way to improve overall process capability.

Risk Prioritization

According to Wikipedia, risk is defined as " . . . 1. The probability of something happening multiplied by the resulting cost or benefit if it does. (This concept is more properly known as the 'Expectation Value' and is used to compare levels of risk)"

- from http://en.wikipedia.org/wiki/Risk

In mathematical form, this is expressed as:

$$\text{Risk/Benefit} = \sum_{i=1}^{n} (\text{Event Probability})\, i \;*\; (\text{Event Consequence})\, i$$

The transmission system's major circuits were ranked by this formulation. The rankings will be used as a starting point for further deliberation among internal stakeholders, with the goal of allocating resources where they will have the most significant risk reduction. The rankings may also be used to justify inspection and follow-up work earlier than normally scheduled (currently a 15-year inspection cycle on each line). At minimum, the rankings will be used to prioritize the commissioning of detailed studies, simulations and development of business cases for major line rebuild projects.

The first component of risk for our transmission lines is the probability of a failure event, which we will refer to as the asset's "**Probability Index**". This is a normalized relative score from 1 (low unplanned event probability) to 100 (high unplanned event probability). The factors and respective weighting for the Probability Index are as follows, derived from a combination of the line's condition, track record, and severity of operating environment. Each factor is scored from 1 (low) to 5 (high), based on a set of objective measures collaboratively developed by representatives in Asset Management, Transmission Design, System Planning, and System Operations groups. In the future, improved data and analysis may allow for actual probability estimates rather than relative scoring methods.

% Weight	Criteria
25	Unplanned outages/spending
20	Remaining service life
20	Time since last minor rebuild, # items identified for replacement
20	# of miles
15	Severity of terrain & operating environment (soil conditions, weather intensity, vegetation, relative probability of vehicle/equip. impacts, etc)

Table 11: Probability Index Criteria and Weightings

The second component of risk (event consequence), we will refer to as the asset's "**Consequence Index**". It is a measure of the severity of consequences should an unplanned failure event occur. This is also a normalized relative score from 1 (low severity = low event consequence) to 5 (high severity = high event consequence). The factors and respective weighting for the Consequence Index are as follows, derived from the relative importance of the line in terms of power flow, its effect on the system should it become unavailable, the relative time and cost to effect repairs, and potential secondary damage based on safety, environmental issues and its proximity to other company and private property. In the future, improved data and analysis may allow consequences to be financially quantified, rather than relative scoring methods.

% weight	criteria
40	power delivery
20	potential damages (company/private/environmental)
15	access
15	system stability, voltage control and thermal problems
10	voltage & configuration

Table 12: Consequence Index Criteria

With these indices in hand, we have the ability to prioritize lines based on comparable risk levels, which we refer to as the line's "**Reliability Risk Index**", where

Reliability Risk Index = (Probability Index) * (Consequence Index)

This is also normalized from a score of 1 (low risk) to 100 (high risk). In order to be worthwhile, it is essential that the risk index is useful to making practical business decisions. It must produce credible results to a wide variety of experts and decision makers, and it must be reliably reproduced each year without a great burden of effort. Over time, improvement in our ability to collect and use data may allow us to evaluate shorter segments of lines with greater ease, providing a refined view of system risk at the line segment or even structure level. This would facilitate a more detailed view of system risks and optimized mitigation efforts. The development and use of aids that help visualize results (e.g. color-coded system maps), may also be worthwhile.

The top 20 highest risk transmission lines are shown in the table below, and the complete list is included as Appendix A. This iteration only includes transmission lines and taps that are longer than one mile. An additional 37 short lines and taps not included in the risk index account for 14.3 additional miles, representing less than 0.7% of total Transmission system mileage.

Transmission Line Name	Voltage (kV)	Length (miles)	Replacement Value	Probability Index	Consequence Index	Risk Index
Lolo - Oxbow	230	63.41	$45,655,200	85.4	100.0	100.0
Noxon - Pine Creek	230	43.51	$31,327,200	80.5	87.8	82.8
Benewah - Pine Creek	230	42.77	$30,794,400	68.3	87.8	70.3
Walla Walla - Wanapum	230	77.78	$56,001,600	68.4	83.7	67.1
Benewah - Boulder	230	26.15	$18,828,000	67.1	72.9	57.3
Hot Springs - Noxon #2	230	70.05	$50,436,000	66.0	68.8	53.2
Dry Creek - Talbot	230	28.27	$20,354,400	51.4	78.3	47.1
Latah - Moscow	115	51.41	$21,592,200	96.0	41.7	47.0
Devils Gap - Stratford	115	86.19	$36,199,800	100.0	39.0	45.6
Post Street - 3rd & Hatch	115	1.76	$3,696,000	70	100	43
Benewah - Moscow	230	44.28	$31,881,600	61.1	59.3	42.5
Cabinet - Rathdrum	230	52.3	$37,656,000	41.7	86.4	42.3
Bronx - Cabinet	115	32.38	$13,599,600	59.4	55.2	38.4
Metro - Post Street	115	0.5	$1,890,000	60	100	38
Ninth & Central - Sunset	115	8.63	$3,624,600	39.0	75.6	34.7
Burke - Pine Creek #3	115	23.79	$9,991,800	67.0	44.4	34.6
Shawnee - Sunset	115	61.51	$25,834,200	79.0	36.3	33.4
Sunset - Westside	115	10.03	$4,212,600	53.0	53.9	33.2
Hatwai - Lolo	230	8.27	$5,954,400	28.9	93.2	31.6

Table 13: Top 20 Most at Risk Circuits according to the Reliability Risk Index

Note that the two underground 115kV circuits, Post Street – 3rd & Hatch, and Metro – Post Street both have a 100 consequence rating and probability ratings of 70 and 60, respectively. The consequence of unplanned outages on these lines is arguably much larger than those of any other line on the system as they serve the high density core of downtown Spokane. In other words, the risks listed above may be understated for these two lines. A strong recommendation for full replacement of both lines is advised in the near future – realistically within 5 to 10 years.

It is important to recognize that the risk index does not yet provide an absolute priority order for replacement and maintenance decisions – option costs to reduce risks must first be factored in. Specifically, cost option analyses must be performed to determine which project options result in the highest reduction of risk per dollar spent. According to best practice asset management principles, this analyses results in a system "**Criticality Index"** for each line in priority order, where each line would be ranked according to:

Criticality Index = (Original Risk – Residual Risk) / (Option Cost)

Finally, other opportunities and benefits are factored in, also known as "bundling" in asset management parlance, to arrive at a final priority order for replacement and maintenance projects. These opportunities and benefits may come from various areas such as system planning for capacity and growth requirements, system operations, regulatory compliance, protection engineering and communications, operations, and power supply. After factoring in these priorities, a comprehensive replacement and maintenance plan for 20 years may be developed, sequenced according to system operations restrictions and with higher levels of detail for projects within the 10 year timeframe. A good start in this direction may be accomplished through the concept of area mitigation plans which involve and integrate stakeholders within each major transmission area of the system (e.g. Big Bend, Spokane, Lewis-Clark, etc).

Ultimately, objective rankings must be useful and effective, helping the organization to arrive at the right business decisions with less effort. Asset management staff will continue to facilitate and support this collaborative undertaking, striving for improvement and strong results.

Unplanned Spending

Unplanned spending represents capital replacement of those transmission assets that have unexpectedly failed and require prompt attention, typically by Avista crews (e.g. storm response events). Despite the variability that is correlated with fluctuations in weather intensity, unplanned spending is an especially important lagging indicator of system performance, trends, and the effectiveness of asset management programs. In addition to cost premiums incurred from overtime labor, unplanned work typically presents greater safety risks to the public and on-site Avista employees, as well as other risks including property damage, environmental, general liability, planned work delays, and additional rework costs following the event. We have set annual goals at the average of unplanned spending from 2009 through 2012, reflecting a desire to maintain system reliability. This results in "targets" of $1.1 million for 115kV and $210k for 230kV, for a total of $1.3 million per year. Note that in past years we have consistently spent a much greater amount of total unplanned dollars on the 115kV system, at roughly four times the proportional value of capital assets when compared to the 230kV system. This is consistent with the fact that 230kV assets are felt to pose a higher potential consequence should they fail, and therefore we maintain them accordingly – deliberately effecting a lower frequency of unplanned events on the 230kV system, relative to 115kV. While this may be the case, it remains that the optimal target of unplanned spending has not been quantitatively determined for either system. This is a desired output from a future system model and analysis, involving the quantification and simulation of all significant risks and costs associated with unplanned events, maintenance and replacement work. Note that zero emergency spending is actually sub-optimal unless there is zero tolerance for any risk – otherwise, it represents over-investment in the design configuration and actual condition of physical assets.

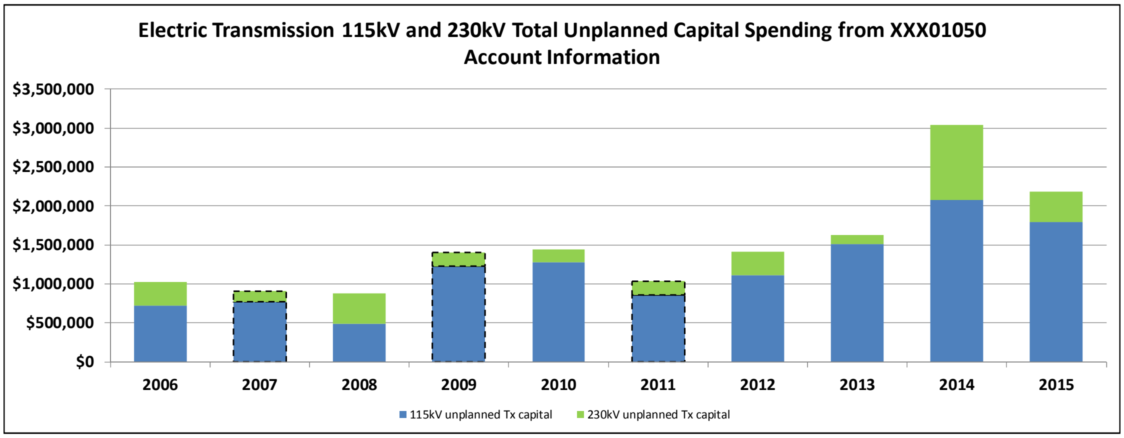


Figure 6: 115kV and 230kV Total Unplanned Capital Spending

		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
115kV - WA	115kV - WA	$312,958	$609,438	$265,221	$874,996	$649,760	$585,250	$499,341	$1,123,122	$1,640,237	$1,087,223
115kV - ID	115kV - ID	$406,111	$161,470	$221,343	$349,459	$626,503	$274,517	$608,163	$389,492	$437,978	$705,426
115kV - all	115kV - all	$719,070	$770,908	$486,564	$1,224,455	$1,276,263	$859,767	$1,107,505	$1,512,614	$2,078,216	**$1,792,649**
230kV - WA	230kV - WA	$215,228	$97,946	$215,416	$57,721	$73,482	$156,491	$58,976	$89,984	$13,286	$116,311
230kV - ID	230kV - ID	$74,783	$32,856	$120,056	$89,364	$79,950	$12,979	$228,681	-$134,091	$945,631	$259,884
230kV - MT w/ Colstrip	230kV - MT w/ Colstrip	$0	$286,338	$257,879	$249,429	$368,855	$574,428	$298,059	$436,991	$249,307	$402,324
230kV - MT w/o Colstrip	230kV - MT w/o Colstrip	$0	$1,590	$59,590	$27,525	$13,275	$0	$72	$18,910	$0	$12,077
230kV - OR	230kV - OR	$12,273	$0	$0	$2,475	$0	$360	$14,738	$9,435	$3,181	$0
230kV - all	230kV - all w/o Colstrip	$302,285	$132,392	$395,062	$177,085	$166,706	$169,830	$302,467	$118,329	$962,097	**$388,272**
115kV and 230kV (all)	115kV and 230kV (all)	$1,021,354	$903,300	$881,625	$1,401,539	$1,442,969	$1,029,597	$1,409,972	$1,630,943	$3,040,313	**$2,180,921**

Table 14: Transmission Unplanned and Emergency Spending, 2006 - 2015

Total unplanned spending in 2015 was $2.18 million, significantly higher than any year recorded since 2006 except for 2014, and well above the target of $1.3 million per year. This was due to a major wind storm in November 2015, totaling $700k.

Unfortunately, the use of 115kV blanket accounts does not allow for ready analysis of unplanned spending on individual 115kV circuits. This is necessary to get a better understanding of risk and asset prioritization on a line-by-line basis. New software is in the process of implementation by System Operations. This should be complete by 2016 with annual data available for analysis starting in 2017.

The figures above do not include spending on the 11% Avista ownership of the roughly 500 miles of 500kV Colstrip transmission and substation assets.

Outages

Outages are a strong lagging indicator of system reliability and are highly correlated with unplanned and emergency spending. It is also the principle source of emerging trends and problem root cause analysis that is critical to maintaining system reliability over the long term. A full list of outage information for 2015 on a line-by-line basis is provided in Appendix B. Below are highlights of this information.

Primary data was obtained from both the annual Reliability Reports created by Operations Management and the Transmission Outage Reports (TOR) created by System Operations. The Reliability Report includes data on sustained outages (longer than five minutes) for Transmission related events that affect customers – it does not include any outages that do not affect customers. The TOR on the other hand, includes any transmission event (sustained or momentary), but it does not contain information about customer outages. Utilizing the TOR, System Operations compiles the Transmission Adequacy Database System (TADS), and associated mandated NERC reports for 230kV lines, but not for 115kV lines. It is important to analyze both the Reliability and TOR reports because they each contain different but important information regarding outages on the transmission system. This is currently a laborious process, as neither the Reliability nor TOR reports consistently list transmission lines that apply to each event. The Reliability Reports indicate substations and feeders associated with customer outages related to a transmission line outage, but not which transmission line that applies. Breaker identification is provided on the TOR and must be used to cross reference other information, in some cases multiple sources, to identify the applicable transmission line. New software is being implemented that will help identify outage events on each transmission line, greatly improving analysis capability. This data is expected to be available for analysis by 2017.

Based on the TOR data, there were 477 transmission line outages recorded in 2015, 182 of which were planned, 165 that were trip and recloses that lasted less than a minute, and 130 unplanned outages over one minute. Of these outages, only 35 caused an actual customer outage. The Transmission lines with the most sustained, unplanned outage occurrences are as follows (regardless if a line outage caused a customer outage):

Ranking	Transmission Line Name2	#Unplanned Outages
1	Lind - Shawnee 115 kV	19
2	Moscow 230 - Orofino 115 kV	17
3	Bronx - Cabinet 115 kV	16
4	Benewah - Pine Creek 115 kV	15
5	Devils Gap - Stratford 115 kV	13
6	Hot Springs - Noxon #1 2230 kV	9
7	CdA 15th St - Pine Creek 115 kV	8
8	Cabinet - Rathdrum 230 kV	8
9	Walla Walla - Wanapum 230 kV	8
10	Boulder - Rathdrum 115 kV	8

Table 15: Transmission lines with the most unplanned outages in 2014

Based on the Reliability Report, over 281,000 hours of unplanned customer outages were recorded in 2015. The transmission lines with the most unplanned customer-hours outage are as follows:

Ranking	Transmission Line Name2	Customer Hours
1	Devil's Gap - Lind 115 kV	74696:25
2	Addy - Kettle Falls 115 kV	51848:52
3	Beacon - Ross Park 115 kV	30852:35
4	Devils Gap - Stratford 115 kV	15388:45
5	Ninth & Central - Otis Orchards 115 kV	13257:14
6	Moscow 230 - Orofino 115 kV	8838:57
7	JAYPE-OROFINO 115 kV	6351:55
8	Clearwater - Lolo #2 115 kV	6093:56
9	Lolo - Nez Perce 115 kV	6002:19
10	Ninth & Central - Otis Orchards 115 kV	5971:43

Table 16: Transmission lines that caused the most customer hours lost in 2015

Over 27,000 customers experienced an outage that lasted longer than three hours, representing a slight increase from last year. The Transmission lines with the highest number of customers experiencing outages greater than 3 hours are as follows:

Ranking	Transmission Line Name2	# Customers experiencing Outages >3 hrs
1	Addy - Kettle Falls 115 kV	**13210**
2	Devils Gap - Stratford 115 kV	**2944**
3	Ninth & Central - Otis Orchards 115 kV	**2077**
4	Grangeville - Nez Perce #2 115 kV	**1271**
5	JAYPE-OROFINO 115 kV	**1122**
6	Moscow 230 - Orofino 115 kV	**797**
7	Clearwater - Lolo #2 115 kV	**652**
8	Devil's Gap - Lind 115 kV	**563**
9	Jaype - Orofino 115 kV	**288**
10	Lind - Washtucna 115 kV	**244**

Table 17: Transmission Lines causing the most customer outages greater than 3 hours in 2015

Overall, the data shows that the 115 kV system is significantly less reliable than the 230 kV system in terms of total outages and customers directly affected.

The causes for customer outages lasting longer than three hours increased for rotten crossarms, insulators, switch/disconnect, pole fires, cars hitting poles, and snow/ice events. These types of outages should be monitored closely as surveys indicate that outages lasting longer than three hours are the most important reliability factor driving customer satisfaction. Appropriate steps should be taken to prevent these outages in the future and to reduce repair time should an outage occur. Weather related outages caused the most customer-hours lost per occurrence.

It should be noted that two lines appear on all three of the 'worst transmission line' lists described above:

1. Moscow 230 - Orofino 115 kV
2. Devils Gap-Stratford 115 kV

Extending the above lists to include the worst 20 lines, four other lines would appear on all three indices:

3. Ninth & Central – Otis Orchards 115 kV
4. Devil's Gap - Lind 115 kV

Based on this information, closer monitoring for these lines is warranted. Moscow 230 – Orofino 115kV is scheduled for a minor rebuild in 2016. Devils Gap-Stratford 115kV is scheduled for a LiDAR/minor rebuild in 2016 and is being considered for full rebuild. In 2015, breakers were installed at Opportunity to help sectionalize Ninth & Central – Otis Orchards 115kV and by 2017 the Irvin Switching Station should be in service which will add an emergency tie to Opportunity to improve performance. Devils's Gap – Lind 115kV is scheduled for a major rebuild in 2017 – 2018.

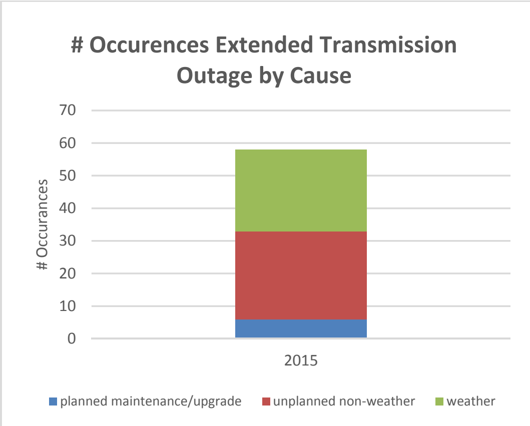
In 2015 there were 162 feeder outages, but only 58 unique transmission events that caused those outages. The 2015 data was analyzed to indicate only the number of unique transmission outages for each subreason.

Reason	**Sub Reason**	**# Outage Occurances**
ANIMAL	Squirrel	2
EQUIPMENT OH	Capacitor	5
EQUIPMENT OH	Crossarm-rotten	1
EQUIPMENT OH	Regulator	1
EQUIPMENT OH	Switch/Disconnect	1
PLANNED	Maint/Upgrade	6
POLE FIRE	Pole Fire	15
PUBLIC	Car Hit Pole	1
PUBLIC	Fire	13
TREE	Weather	1
UNDETERMINED	Undetermined	1
WEATHER	Wind	11
		58

Table 18: Transmission Outage Causes, 2009-2015

Pole fire related outages continue to dominate both in terms of number of occurrences and customer-hour outages. At over 50,000 hours, pole fires had the highest number of customer-hour outages. This number is higher than last year (29,000 customer-hours) and highlights the need to continue the fire retardant program and to replace wood poles with steel poles.

As can be seen from Figure 5 below, unplanned, non-weather and weather events dominate both the number of occurances and customer-hours outages for the transmission lines.



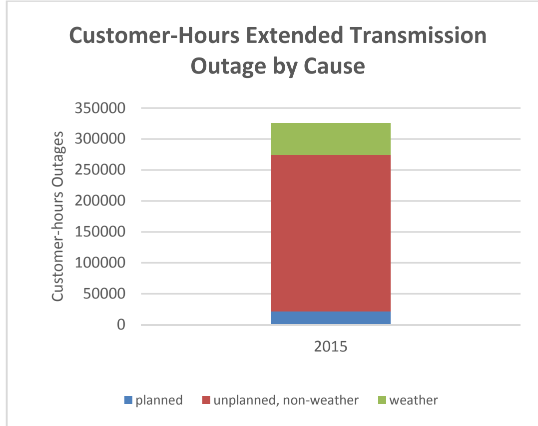


Figure 7: Transmission outage causes affecting customers in 2015

Programs

1. Major Rebuilds

Out of the $26,640,457 million in planned capital replacement projects in 2015, $15,420,668 was spent on major rebuilds, $3,210,020 on minor rebuilds and $443,619 on switch replacements, for a total of $19,074,307. The recommended level is a minimum of $18.5 million for major rebuilds, $2.0 million for minor rebuilds and $264k for switch replacements, for a total of $21 million replacement spending per year for 30 years. As stated previously, replacement projects do not include additional capital projects that are mandated, growth related, reimbursable, or otherwise do not address aging infrastructure. Furthermore, the recommended spending is the minimum levelized spending over the entire 30 year period, which in the shorter term may need to be increased to minimize lifecycle costs – given inspection results, risk analysis, cost of capital, and economies of scale opportunities.

The most significant major rebuild and reconductor projects currently planned through 2020 are listed below, with rough estimates of budget dollars allocated for each year. Please note that these plans are subject to change and projects for 2019 and 2020 in particular are only partially complete.

Description	BI	Description2	2016	2017	2018	2019	2020
West Plains Trans Reinforcement	ST305	Garden Springs - Sunset	$ 450,000	$ 600,000	$ -	$ -	$ -
Pine Creek - Burke - Thompson Falls	CT101	Rebuild Transmission	$ 25,000	$ 3,500,000	$ -	$ -	$ -
9CE-Sunset 115kV Transmission	ST503	Reconductor/Rebuild	$ 2,250,000	$ -	$ -	$ -	$ -
High Resistance Conductor Replacement	xTxxx	Reconductor/Rebuild	$ -	$ -	$ -	$ -	$ -
Cabinet-Noxon 230kV Rebuild	AT700	CAB-NOX Rebuild w/Reconductor	$ -	$ -	$ 7,500,000	$ 7,500,000	$ -
Noxon-Pine Creek 230kV Rebuild	KT901	NOX-PCR Rebuild w/Reconductor	$ -	$ -	$ -	$ -	$ 7,500,000
Lolo-Oxbow 230kV Rebuild	LT900	LOL_OXB Rebuild w/Reconductor	$ -	$ -	$ -	$ -	$ 7,500,000
Benewah-Pine Creek 230 kV Rebuild	CT908	BEN-PIN Rebuild w/Reconductor	$ -	$ -	$ -	$ -	$ -
Sys-Rebuild Trans-Condition	AMT81	BRX-CAB & BRX-SCR Rebuild	$ 3,600,000	$ 1,500,000	$ 4,500,000	$ 2,500,000	$ 2,500,000
Ben-Oth SS 115 - ReCond/Rebld	FT130	Ben-Oth SS 115 - ReCond/Rebld	$ 3,000,000	$ 1,500,000	$ -	$ -	$ -
CDA-Pine Creek 115kV Rebuild	CT300	Rebuild Transmission	$ 25,000	$ 4,000,000	$ 6,000,000	$ 5,000,000	$ -
Devils Gap-Lind 115kV Rebuild	ST302	Rebuild Transmission	$ 1,002,134	$ 2,900,000	$ -	$ -	$ -
Chelan-Stratford 115kV Rebuild	BT304	Rebuild Columbia River Crossing	$ -	$ -	$ -	$ -	$ -
Addy-Devils Gap 115kV Reconductor	ST306	Recon/Rebld near Ford Substation	$ -	$ 25,000	$ 2,000,000	$ -	$ -
Recon/Rebld GDN-SLK 115kV Line	ST304	Recon/Rebld South Fairchild Tap	$ -	$ -	$ -	$ -	$ -
Beacon-Bell-F&C-Waikiki Reconfiguration	ST318	Reconfiguration into Bell and Waikiki	$ -	$ 25,000	$ 2,000,000	$ -	$ -
BEN-MOS Rebuild w/o Reconductor	PT305	BEN-MOS Rebuild w/o Reconductor	$ 8,684,000	$ 6,802,393	$ -	$ -	$ -

Table 19: Major Rebuild Projects, 2016 – 2020

Effort will continue to be applied to prioritize replacement spending according to risk and criticality rankings, using detailed analysis where appropriate and engaging various stakeholders to arrive at optimized business decisions. In the last several years, detailed simulation studies have repeatedly shown major rebuilds as the optimal rebuild option for those lines with older assets and relatively higher risk rankings, rather than sectional or partial rebuilds, or minor rebuild options. Due to the infrequency of conductor failures, unless system planning determines a need or benefit for increased capacity, these studies indicate rebuilding structures and re-using the existing conductor as optimal. Calculated Customer Internal Rate of Return (CIRR) are typically at 8% or higher, with strong business risk reduction and final assessment scores of 90 or more, placing them in the top 25% of competing capital project business cases across the company. Accordingly, similar simulation studies in the future are expected to generate comparable results, i.e. analysis of old, high risk lines will continue to show major rebuilds as the optimal rebuild decision from the standpoint of lowest lifecycle costs, including reduced business risk and lowest consequence costs for the customer.

2. Minor Rebuilds

The information collected by aerial patrols is used in conjunction with inspection reports to prioritize and budget minor rebuild capital projects, where a major rebuild is not justified. Our goal is to complete repairs and replacements for high-risk issues from 0 to 6 months after identification by aerial or ground inspection, and for all other moderate risk issues by the end of the year following the inspection year.

Planned inspections and follow-up work in the form of minor rebuilds is effective in maintaining service levels while minimizing near-term capital and O&M costs. Where warranted and on a line-by-line basis, detailed simulation modeling helps ascertain the optimal rebuild approach and support a business case to compete with others in the company's capital projects selection and budgeting process. A system-wide simulation model or other method is needed to help validate and/or provide adjustment recommendations to our inspection intervals, minor rebuild target budgets, and fact-based policies on minor vs. sectional vs. full rebuild thresholds. Current policy is to conduct detailed ground inspections every 15 years, following up with minor or major rebuilds as condition assessments justify. Current budget plans for minor rebuilds and air switch replacements are listed below, subject to changes. Given the large number of old lines due for inspection, the age profile of air switches and an expected life of 40 years for each air switch, it is recommended to increase the minor rebuild budget to $2.0 million per year and air switch replacements at $264,000 per year.

Description	BI	Description2	2016	2017	2018	2019	2020
Tx Minor Rebuilds	AMT12	Tx Minor Rebuild - WA	$775,000	$775,000	$800,000	$825,000	$850,000
Tx Minor Rebuilds	AMT13	Tx Minor Rebuild - ID	$772,262	$780,249	$813,420	$848,117	$885,022
Sys-Trans Air Sw Upgrade	AMT10	Asset Man Trans Sw Upgrade	$225,000	$225,000	$230,000	$230,000	$235,000

Table 20: Minor Rebuild and Switch Upgrade Budget, 2016 – 2020

See the Area Work Plans section at the end of this report for a detailed list of minor rebuild projects in 2015.

3. Air Switch Replacements

Transmission Air Switches (TAS) are used to sectionalize transmission lines during outages or when performing maintenance. The frequency of operation varies greatly depending on location. Some TAS may not be operated for years.

TAS may not operate properly when opened and flashover, possibly tripping the line out. This can be the result of a component failure (whips and vac-rupters) or the TAS may be out of adjustment. Most TAS mis-operations could be avoided with regular inspection and maintenance, however we currently have no planned inspection or maintenance program. Inspections could range from systematic visual inspection to infrared scanning and inspections for corona discharge. Maintenance could consist of exercising switches, lubrication, blade adjustment, replacement of live parts such as contacts and whips, and repair of ground mats and platforms.

Ground grids and platforms are installed at the base of each switch to provide equal potential between an operator's hands and feet in the event of a flashover of the air switch. The typical ground grid is buried copper wire attached to ground rods covered with fine gravel. Over time the ground grids may be damaged by machinery, cattle and erosion, or even theft. In 2008, 80 TAS were fitted with grounding platforms for worker safety. During this process a new worm gear handle was installed and disconnecting whips were adjusted. Operating pivot joints of the switch mechanisms are not affected by this work. Thus, the 2008 work was safety related, not switch mechanism related. Remaining switches in the system requiring new platforms need to be confirmed and upgraded. It is estimated that close to 100 switches require new platforms.

With radial switching of the 115kV transmission system, many TAS are operated remotely. In these instances, company personnel are not present to observe the opening of the switch and some problems therefore remain hidden. A small problem could progress to the point where a major failure occurs. A small amount of material is maintained in the warehouse and Beacon yard for emergency repairs, but many of the switches are old and parts are often difficult to locate.

Typically three to four TAS are replaced each year. A detailed inventory of 115kV TAS outside substations was completed in 2013, including determination of age where formerly 20% of the assets were unknown. TAS inventory includes 180 switches of various types and configurations, as shown below according to remaining service life. Based on this profile, levelized replacement should increase to five replacements per year, requiring an increase to $264,000 from the current $225,000 annual budget. Annual budgets should be prioritized according to a rational condition assessment and quantitative risk assessment, rather than ad-hoc requests from field personnel and anecdotal observation which is the current method.

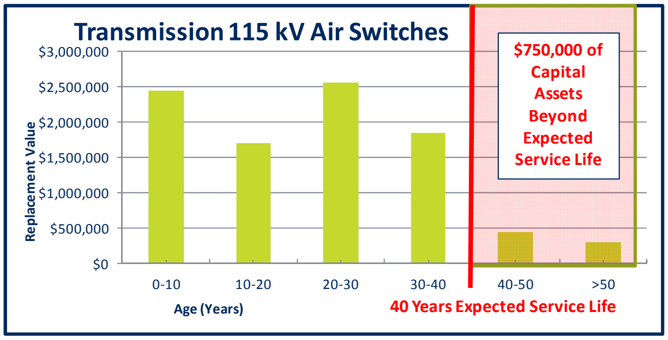


Figure 8: Air Switch Replacement Value vs. Remaining Service Life

Thorough investigation of industry best-practices regarding inspection and planned maintenance of air switches, with follow-up recommendations is recommended. At minimum, a reasonable condition assessment program is envisioned, such as visual inspection at least every two years, possibly annual inspection for those more critical switches, and annual performance evaluation based on System Operations input. Below is a prioritized list of switches due for repairs or replacement in the next few years, with those switches exhibiting operational problems listed first.

SW #	Problems	Age (yrs)	LINE/SUBSTATION
A-70	Problem Switch; Scheduled 2016	84	Chelan-Stratford
A-336	Old KPF, Needs Replaced; Scheduled 2016	49	Grangeville-Nez Perce #1: Cottonwood Tap
A-355	Old KPF on a broken pole; Scheduled 2016	48	Jaype-Orofino
A-346	Wood in Switching Mech. Is bowed; Scheduled 2016	47	Grangeville-Nez Perce #2
A-376	Old KPF, Needs Replaced; Scheduled 2016	43	Grangeville-Nez Perce #2
A-298	Needs whips; Center 0 and North 0 gone, South Bent	38	115kv Boulder-Rathdrum
A-158	Doesn't work properly, drop load on both sides then use switch, mat ground straps need repair	31	Beacon-Francis & Cedar
A-345	Pole Needs Structure # Tag	30	Grangeville-Nez Perce #2
A-442	Repaired in 2015	26	Dworshak-Orofino
A-377	Scott paper tap; Engerized to Switch; Scheduled 2016	21	Grangeville-Nez Perce #2 : Scott Paper Tap
A-176	Mat ground straps need repair	18	Bell-Northeast
A-679	Difficult to Close	15	Othello-Warden #2
A-680	Replaced in 2015	15	Othello-Warden #2
A-358	Old KPF, Needs Replaced	10	Jaype-Orofino
A-407	Broken Crossarms	4	Grangeville-Nez Perce #1
A-421	Ground Cables and Strands cut, NEEDS REPAIR	4	Ramsey-Rathdrum #1
A-184	Replaced in 2015	61	Shawnee-Sunset
A-19		59	Pine Street-Rathdrum: Oldtown Tap
A-26		59	Burke-Pine Creek # 3
A-220		57	Lolo-Nez Perce
A-221		57	Lolo-Nez Perce
A-173	Replaced in 2015	47	Moscow 230-Orofino
A-58	Replaced in 2015	46	Chelan-Stratford
A-295	Replaced in 2015	46	Benewah-Pine Creek : St Maries Tap
A-49		44	Devils Gap-Stratford
A-126		40	8th & Fancher-Latah 115 kV
A-127		40	8th & Fancher-Latah 115 kV

Table 21: Air Switch Priority List for Repairs and Replacements

Finally, transmission outage cause tracking needs to be improved in order to ascertain failure trends for the air switch population and to justify long-term replacement policy, e.g. improved data for line outage durations and affected customers that result from failed air switch operations. In reading through notes on the TOR, Asset Management was able to determine that there were 122 outages from 1975 through 2007, resulting in an average of 3.7 outages per year caused by switches. The durations and quantified consequences of these outages however are unknown and difficult to model.

4. Structural Ground Inspections (Wood Pole Management)

Avista wood transmission structures are predominately butt-treated Western Red Cedar poles. Most of the service territory is in a semi-arid climate. The most common failure mode for wood poles is internal and external decay at or near the ground line. Transmission Wood Pole Management (WPM) measures this decay and determines which poles must be reinforced or replaced. Details describing inspection techniques are in the company's "Specification for Inspection and Treatment of Wood Poles, S-622".

The testing program is valuable in identification of poles needing replacement or reinforcement, as well as identifying other structure components requiring repair or replacement. Compared to the pre-1987 method of solely visual inspections for pole integrity, the testing program replaces about 15% as many poles.

Wood transmission poles are on a 15-year inspection cycle. We are currently targeting inspection of 2,400 wood transmission poles annually out of 36,422 wood poles installed. At this pace, by 2019 we will reach the 15-year cycle for all transmission lines. See the Area Work Plans section of this report for a list of future planned inspections.

In recent years, prioritization and scheduling of ground inspections has been based on the time since the last ground inspection. Results of these inspections provide the basis for case-by-case analysis and the scope of subsequent minor and major rebuild projects on each line. While it is important that we maintain a maximum 15-year ground inspection cycle, it is recommended that future inspection scheduling includes consideration of the risk index, which may justify earlier inspection. As a general rule, critical assets that exhibit age-related failures should be inspected to verify condition and justify service extension or removal near the end of their expected service lives. We currently have many 115kV lines (non-Western Electricity Coordinating Council pathways) with assets 10 or more years past expected service life, that have not been inspected for nearly 20 years. This poses a significant unknown risk.

If actual condition assessment warrants service extension, shorter inspection intervals are prudent when the time to failure characteristics worsen with age – as is the case with much of our transmission wood infrastructure. Approximately 17% of the system is beyond its expected life, with a large portion of those assets over 15 years since the last ground inspection. The scattered age profile on many lines that results over many decades from periodic minor rebuilds and one-off replacements, makes this situation difficult to remedy – one must choose between the pros and cons of spotty replacements when failure occurs on one end of the spectrum, to larger line section replacements and full rebuilds on the other. Regardless, for those lines that have significant sections or quantities of older assets that demonstrate higher relative risks, out-of-cycle inspection and a shorter inspection interval may be warranted (e.g. 10 years instead of 15).

5. Structural Aerial Patrols

The Avista transmission system covers a large geographical area that has all types of terrain. Transmission Aerial Patrols (TAP) have been utilized to provide a quick above-ground inspection to identify significant problems that require immediate attention, such as lightning damage, cracked or sagging crossarms, fire damage, bird nests and danger trees.

In addition, aerial patrols can identify improper uses of the transmission Right-of-Way (R/W), such as dwellings, grain bins, and other types of clearance problems that must be addressed. Typically, the patrol will be performed in the spring. Identified repairs, depending on severity, are scheduled to be performed within 6 months.

TAP inspects 100% of 230kV lines and 70% of 115kV lines annually. The remaining 30% of 115kV lines are located in urban areas that are frequently viewed by line personnel for potential problems. The Transmission Design group schedules patrols for each service territory. The TAP areas are: Spokane (includes Othello, Davenport and Colville), Coeur d'Alene (includes Kellogg and St. Maries), Pullman, and Lewiston/Clarkston (includes Grangeville and Orofino).

Aerial patrols are performed by qualified personnel from Transmission Design, often accompanied by local office personnel. Inspection forms have been developed that contain a weighting system to identify the severity of defects. This information can then be utilized to make recommendations for necessary repairs.

6. Vegetation Aerial Patrols and Follow-up Work

The Transmission Vegetation Management (TVM) program maintains the transmission system clear of trees and other vegetation, in order to provide safe clearance from trees and reduce outages caused by trees, weather, snow, ice and wind.

The entire 230kV system is annually inspected with a combination of aerial and ground patrols by the System Forester, who solely manages the overall program. Select 115kV lines are also patrolled according to criticality. In addition, vegetation issues noted during structural aerial patrols on the 115kV system, as well as fielding of transmission line projects by Transmission Engineering are relayed to the System Forester. Based on this information, follow-up work plans are adjusted and executed with contract crews over the course of the year.

Over the next ten years, annual budgets of $1.2 million are recommended to allow for optimal completion of major re-clearing work and a transition to Integrated Vegetation Management. It is expected that annual budgets will be evaluated and fine tuned to fit workloads as appropriate.

See the Transmission Vegetation Management Program reference (Avista Utilities, 2012) for more details on the program.

7. Fire Retardant Coatings

After several fires and a 2008 study to initiate systematic remediation, fire retardant coating has been applied to the base of wood transmission poles system-wide. At this point the entire 230kV system has been deemed adequately protected and the 115kV system is approximately 37% complete. Given the fire event of last year, the Lolo-Oxbow 230kV line is planned for early recoating in 2016 to reduce risk (coatings are expected to remain effective for 12 years, Lolo-Oxbow was coated in 2007). Targeted areas include those subject to grassland fires and in close proximity to railroads. Protective coating is not applied to heavily forested areas as it is deemed inadequate in these areas to merit the cost of application.

It is estimated that approximately 4,210 poles remain to be coated in the 115kV system. Following the current plan to coat 179 poles in 2015 (179 115 kV poles and 535 230 kV poles repainting the Lolo – Oxbow line was cut from the 2015 scope of work due to budget), it is recommended to coat 1000 poles per year for the following five years to complete the work by 2020. At a total labor and materials cost of $242/pole, this equates to $242,000/year. Beyond this, regular maintenance and upkeep will only be required, at an unknown amount depending on the longevity of the coatings. Until better information is obtained, $50k/year for ongoing coating maintenance is estimated. Performance metrics could be considered to monitor performance of this program, possibly in terms of % of the system protected, maintenance spending and actual fire damage costs. As noted in the Outages section, pole fire incidents have increased, reinforcing the necessity of monitoring and adjustment of this program.

See Whicker (2013) for more details and history of this program, which is now administered by the Transmission Design group.

8. 230kV Foundation Grouting

The Noxon-Pine Creek and Cabinet – Rathdrum 230kV circuits have unique steel structures where the interface between the steel sleeve in the foundation and above-ground structure requires re-grouting after approximately 30 years, to avoid destructive corrosion. This work has been completed on the Noxon-Pine Creek 230kV line. Approximately $350k out of $500k of foundation grouting work on Cabinet – Rathdrum 230kV was completed through 2015. Another $100k/year is planned through project completion in 2017.

9. Polymer Insulators

Transmission Line Polymer Insulators (TPI) provide insulation at the connection points for transmission lines to the supporting structure. Other types of insulators include toughened glass and older porcelain types. Although no significant problems have been noted on 115kV lines, there were numerous faults on 230kV lines from 1998 to 2008 attributable to poly insulators causing line outages, and five mechanical failures that caused the line to fall.

In 2008 a plan was initiated to replace TPIs and install corona rings on dead-end TPI insulators on various 230kV lines (without corona rings, TPIs are expected to fail in the 10 – 15 year timeframe, with corona rings the expected service life is extended to an unknown age).

Work was completed primarily in 2009 on N. Lewiston - Shawnee 230kV and Dry Creek – N. Lewiston 230kV, and in 2011 all suspension and dead-end TPIs on the Hatwai - N. Lewiston 230kV were replaced with toughened glass insulators.

This work appears to have been effective. From 2009 to 2012, only 2 sustained outage occurrences involving insulators are recorded. However, the degree to which TPIs exist on the remainder of the system and the prediction of current and future risk is unknown.

For this reason, it is recommended that at least on 230kV lines, future ground inspections include information gathering on the insulator type, so that an analysis of risk and optimal mitigation actions may be made in a short time period should that become necessary.

Current transmission engineering standards use toughened glass insulators for 230kV, and either toughened glass or poly insulators for 115kV. Due to the lighter weight of polymer insulators, they are generally preferred by Avista crews. However, given the problems experienced on 230kV lines and anecdotal evidence of high scrap rates for TPIs on 115kV projects, their use on 115kV lines poses some unknown risks and a systematic monitoring program may be advisable.

10. Conductor & Compression Sleeves

Credible condition and failure characteristics of conductor and compression sleeves (dead ends), and the location and age of thousands of compression dead ends in the system are currently unknown. Provided proper installation, protection, and service conditions, most conductor will last over 100 years, if not indefinitely. The compression dead ends, however, are expected to last between 40 and 50 years, posing a more immediate reliability risk.

Between 2008 and 2010, an effective risk mitigation program was carried out for in-line compression dead ends on 230kV AAC lines, following several years of one to two failures per year. Since then, no known in-line compression dead end failures have occurred. See Whicker (2009) for more details on the 230kV in-line sleeve mitigation project.

In 2015, Noxon-Pine Creek 230 kV was inspected and all failed compression dead ends were replaced. Compression dead ends that could fail in the future were identified. This data was gathered and sent back to the compression dead end manufacturer, AFL. The manufacturer ran a failure analysis on all the compression dead ends that failed and determined that the ones that failed didn't have the joint compound (oxide inhibitor) in the compression dead end. Avista's transmission department looked into this and determined that the specifications didn't call for the inhibitor. More than likely the inhibitor was not applied by the crew/contractor and that is why the compression dead ends failed. The transmission design department has now added the inhibitor to the specifications and they will make sure the crew/contractor puts the inhibitor inside the compression dead end.

Program Ranking Criteria

Programs implemented in the Transmission Department are chosen based on ranking criteria which consist of the customer internal rate of return, risk reduction ratio, revised risk score, and health index. The health index currently is not identified for each transmission program; however, each program is based upon the customer internal rate of return (CIRR) and revised risk score. The lower the revised risk score, the higher the rank for that program. The revised risk score is based upon the financial impact risks (consequential costs/revenues); legal, regulatory, and external business affairs risks; customer service and reliability risks; and the likelihood of each risk occurring per year. Table 22 details current Transmission Department programs and their ranking criteria.

Program	Customer Internal Rate of Return	Risk Reduction Factor	Revised Risk Score	Health Index
Transmission - NERC High Priority Mitigation	5% ≤ CIRR < 9%	0.011	1	N/A
Transmission - NERC Medium Priority Mitigation	Cirr = 9%	0.003	1	N/A
Transmission - NERC Low Priority Mitigation	Cirr = 9%	0.003	1	N/A
Transmission - New Construction	Cirr = 8%	0.003	1	N/A
Transmission - Reconductors and Rebuilds	Cirr = 10%	0.011	1	N/A
Transmission - Asset Management	Cirr = 10%	0.042	12	N/A

Table 22: Program Ranking Criteria

The NERC High, Medium, and Low Mitigation programs reconfigure insulator attachments, and/or rebuilds existing transmission line structures, or removes 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*". Mitigation brings lines in compliance with the National Electric Safety Code (NESC) minimum clearances values. These code minimums have been adopted into the State of Washington's Administrative Code (WAC).

The NERC High Priority Mitigation Capital Program (ER2560) covers mitigation work on Avista's "High Priority" 230kV transmission lines, including: Benewah-Pine Creek (BI CT203), Cabinet-Noxon (BI AT203), Cabinet-Rathdrum (BI CT202), Hatwai-North Lewiston (BI LT205), Lolo-Oxbow (BI LT202), and Noxon-Pine Creek (BI AT202).

The NERC Medium Priority Mitigation Capital Program (ER25xx) covers mitigation work on Avista's "Medium Priority" 230kV and 115kV transmission lines, including North Lewiston-Shawnee 230kV, Beacon-Bell #4 230kV, Beacon-Bell #5 230kV, Noxon-Hot Springs #2 230kV, Beacon-Boulder #2 115kV, Beacon-Francis & Cedar 115kV, 9th & Central-Otis 115kV, Northwest-Westside 115kV, Dry Creek-Talbot 230kV, Walla Walla-Wanapum 230kV, Benewah-Moscow 230kV, Devils Gap-Stratford 115kV.

The NERC Low Priority Mitigation Capital Program (ER25xx) covers mitigation work on Avista's "Low Priority" 230kV and 115kV transmission lines.

The Transmission New Construction Program supports addition of new switching stations and substations to the system in order to serve new and growing load as well as for increased system reliability and operational flexibility. Projects include ER2578: HAT-LOL #2 230kV and 25xx: Westside-Garden Springs 230kV.

The Transmission Reconductors and Rebuilds Program reconductors and/or rebuilds existing transmission lines as they reach the end of their useful lives, require increased capacity, or present a risk management issue. Projects include: ER 2310 - West Plains Transmission Reinforcement, ER 2550 - Pine Creek-Burke-Thompson, ER 2557 9CE-Sunset Rebuild, ER 2423 - System Condition Rebuild, ER 2457 Benton-Othello Rebuild, ER2556 CDA-Pine Creek Rebuild, ER 2564 Devils Gap-Lind Major Rebuild, ER 2574 - Chelan-Stratford River Crossing Rebuild, ER 2576a Addy-Devils Gap Reconductor, ER 2575 Garden Springs-Silver Lake Rebuild, ER 2582 BEA-BEL-F&C-WAI Reconfiguration, ER 2577 BEN-M23 Rebuild, ER 25xa - Out-Year Transmission Rebuild. The Transmission Asset Management Program covers the follow-up work to the Wood Pole Inspection in ER 2057 and Air Switch Replacements in ER 2254.

Benchmarking

Asset replacement spending relative to other utilities is one area of particular interest. A 2008 study performed by First Quartile Consulting gathered data from 17 utilities of various sizes and geographic service territories in the U.S. and Canada, providing the 3-year average transmission line replacement capital spending per asset as shown in the figure below.

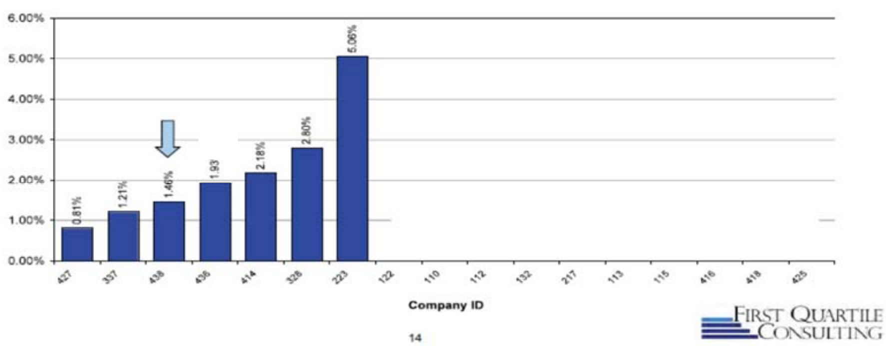


Figure 9: 3-year Transmission Lines Replacement Capital Spending per Asset (First Quartile Consulting, 2008)

This shows that out of seven companies providing data, the median was 1.93% and the mean was 2.41% over a three year period. Avista's comparable replacement spending over the last two years and the recommended annual replacement spending over a 30-year period are shown in the table below.

$ 7,877,719	2014 planned replacement spending
$ 3,040,313	2014 unplanned/emergency replacement spending
$ 10,918,032	2014 total replacement capital spending
$ 1,140,319,249	Transmission asset replacement value
0.96%	2014 replacement spending capital per asset
$ 19,074,307	2015 planned replacement spending
$ 2,180,921	2015 unplanned/emergency replacement spending
$ 21,255,228	2015 total replacement capital spening
$ 1,140,319,249	Transmission asset replacement value
1.86%	2015 replacement spending capital per asset
$ 21,135,371	Recommended planned annual replacement spending (30 year plan)
$ 1,321,019	Targeted unplanned/emergency replacement spending
$ 22,456,390	Targeted total replacement capital spending (30 year plan)
$ 1,140,319,249	Transmission asset replacement value
1.97%	Recommended replacement spending capital per asset

Table 23: Avista Transmission Lines Replacement Capital Spending per Asset

This shows that Avista's capital replacement spending over the last two years is lower than the study's average, close to the lowest of the seven reported utilities. Comparably, the recommended capital replacement spending as part of a levelized 30-year plan of $21.1 million (planned work) plus an assumed $1.3 million unplanned emergency work results in 1.97%, very near the study's median and less than the average.

Idaho Power is a very good benchmark utility for Avista in terms of size, operating environment and electric transmission component and system similarities. In discussions with their staff, thorough transmission structure ground inspections are conducted every 10 years, with quick visual inspections (drive-bys) every 2 years. It is also clear that in general, Idaho Power spends considerably more time and effort on O&M maintenance activities relative to Avista, at least in areas of transmission and substation systems.

Idaho Power is also projecting a significant rise in capital replacement of aging infrastructure in the next several decades, as shown below. Over just the next 10 years, this indicates a total capital spend for Idaho Power of $211 million for replacement of wood poles alone, or $21 million per year levelized. This is similar in magnitude to the recommended replacement of aging wood infrastructure at Avista over the next several decades.

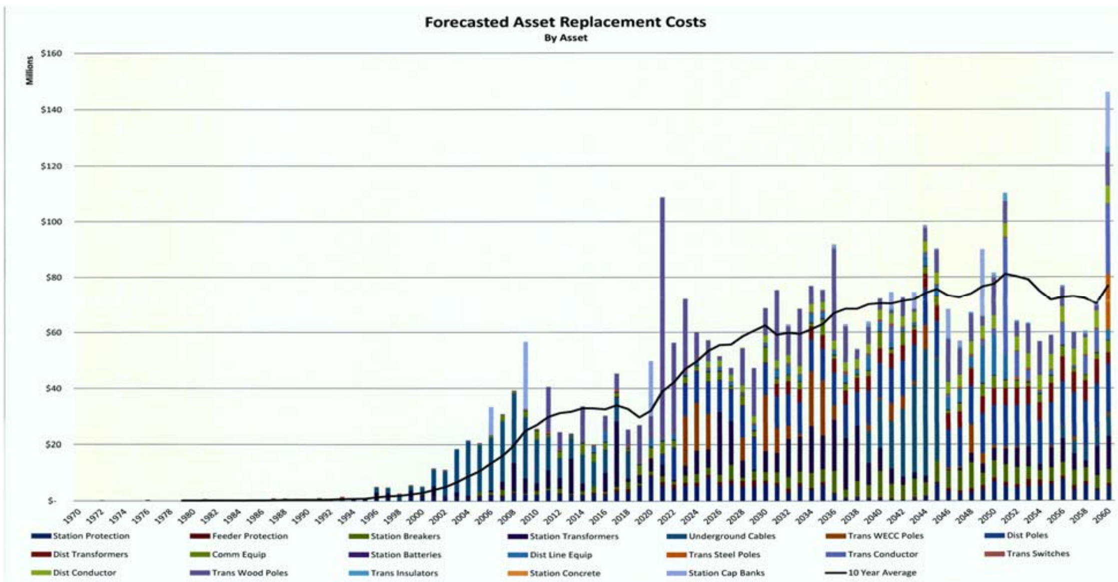
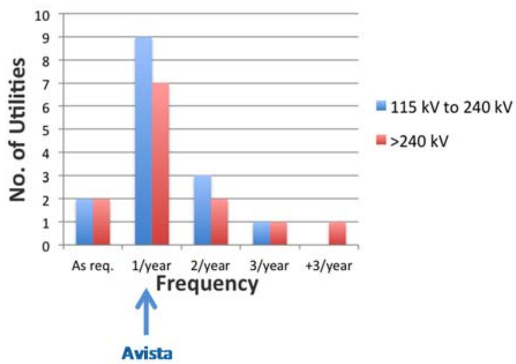


Figure 10: Idaho Power Long-term Replacement Costs

As stated previously, investigation of air switch maintenance practices of various utilities indicates that most utilities perform a much greater degree of maintenance than Avista.

In terms of broader maintenance benchmarking, a study through a CEATI report (excerpts below) show that Avista is among the majority of peers conducting aerial patrols once per year, but that of all 15 utilities responding, we have the longest ground inspection interval at 15 years, as compared to the most common interval of 10 years.

This does not necessarily mean that our inspection interval needs to be shortened. However, it does at least indicate where we stand relative to other utilities participating in the survey, and at minimum would tend to discourage extending our inspection interval any further.



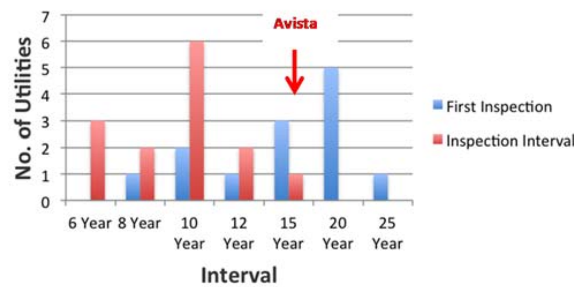


Figure 11: Maintenance Benchmarking: Aerial Patrols (left) and Pole Inspections (right)

Data Integrity

The following table lists the various sources of information used for Asset Management purposes. Data gathering from non-electronic sources, as well as mining and cleaning of available information makes up a disproportionately large amount of current work for Asset Management staff, on the order of 80% of total work. Long term, in order to provide the most value to Avista this needs to be reversed with 80% applied to analyzing data and 20% to gathering and cleaning data.

Data Integrity - Electric Transmission System

Status	Data Source	Notes/Comments
	AFM	Wood species info missing for 115kV; potentially large # of stubs entered as pole installs, major job backlog updates pending from 1992
	Line History Binder	Great historical info but hasn't been updated for 15 years
	Safety information	Unable to isolate to Transmission work
	Plan & Profile (P&P drawings)	Major job backlog updates pending from 1992 to present; long term migration to digital (PLS-CADD) format
	WPM database	Pole information is not updated to reflect followup work or other projects, just at time of inspection; handnotes need to be consolidated and alphebetized, line naming conventions need to be synced up; wood species in hand notes and electronic files needs to be uploaded to AFM
	Maximo	Does not always capture component failure mode data as designed
	Transmission Engineering Guidelines	Partially complete, need more participation to complete
	Engineering files vault	Engineers need to submit as-built updates more promptly, "archived" files need to be refiled in their proper line section
	Discoverer	Unwieldly to summarize costing across different Tx projects, difficult to isolate costs/activities to Tx
	AWB simulations	Building on progress/standards/methods
	PLS-CADD and design/construction standards	Progress continues, published new standards in 2014
	Air Switch Master Inventory Spreadsheet	Updated inventory and detailed info complete
	OMT data	Mostly reliable info but some categories are mixed with substations, for example PMs that really are transmission related are placed in subs

Table 24: Transmission Asset Data Integrity

We are 100% complete processing updates to a backlog of 459 transmission jobs dated from 1992 to the present in our GIS/AFM database and on plan and profile (P&P) drawings. WPM inspection records in handnote form have been entered electronically. Pole material type, location and installation dates have been synchronized with updated AFM information. However, this clean dataset now exists in spreadsheet form and needs to be uploaded to AFM. Line history binders are in the process of being updated and converted to electronic files. Engineers are following the construction as-built recording process, however prompt updates continue to be problematic. A realistic goal of 6-months from the completion of construction to records updating complete and project close-out has been established. Maximo implementation is in progress. It appears that many years will be needed to obtain quality data that may be effectively used for asset management purposes. The new transmission construction standards are a major accomplishment and are being used as a baseline for improvement on a regular basis.

Material Usage

According to Supply Chain staff, a definitive list of parts, quantities and funds spent on transmission work is currently unavailable. The following list of materials was tabulated from a query of the Oracle database for those projects listed as Transmission from October 2010 to October 2012. This should not be taken as complete costing information, but may be reasonably considered accurate for the relative use of material categories.

Category	Total Amount	%
steel poles	$1,770,582	44%
other	$466,378	12%
fire retardant coating	$445,514	11%
crossarms	$349,709	9%
air switches	$293,131	7%
conductor	$259,622	6%
insulators	$228,702	6%
crossbraces	$96,212	2%
vibration dampers	$78,916	2%
wood poles	$52,927	1%
total	$4,050,929	100%

Table 25: Relative Material Purchases, 10/2010 – 10/2012

Root Cause Analysis (RCA)

Following the Othello storm in September 2013, a team was formed to study the causes of the event and develop effective solutions to prevent recurrence, as appropriate. Representatives from Transmission Design, Asset Management, Distribution Engineering, Construction Services, and Spokane Electric participated. In addition to technical forensics, a rigorous methodology was followed known as the "Apollo Root Cause Analysis method™ ", requiring evidence and team consensus to develop effective solutions. Not only the root causes, but also the significance of the event and the more severe consequences that were narrowly avoided were unexpectedly discovered through the team's deliberations. A summary report was generated and a number of significant action items initiated to prevent or mitigate similar events in the future.

Unexpected events such as the Othello storm, while undesirable, in many cases offer rare opportunities to learn and improve. No single formula or approach is generically applicable to all problems. However, the Apollo RCA method or close variant is applicable to many, and it is hoped that it may be used to greater effect in the future. Lessons learned from this effort will inform the next RCA effort if/when it arises.

System Planning Projects

The tables below list substation and transmission projects at various stages from study through construction. This list is a snapshot of current plans and is subject to frequent change. For more details, see the System Planning Assessment (Avista, 2015). The first two tables below list projects classified as corrective action plans in order to mitigate performance issues. The last two tables contain projects that are not categorized as corrective action plans.

Overall, customer and load growth is low at about 1%, and is expected to remain stagnant for many years. Customer loads may even decrease over the next few years, due to continued conservation and efficiency trends such as the conversion to LED lighting. One exception to this is in the West Plains area, which is forecasted to grow at a higher rate in both the residential and business sectors for several years. Major system planning needs include adding transformer capacity, and improved redundancy around the Spokane area. This will most likely be best accomplished by the addition of new, looped 230kV transmission lines around Spokane.

Clear, objective ranking and decision criteria and its consistent use in the company's capital project selection and budgeting process is recommended, in order to reduce the time and effort required to develop, review, approve, prioritize, and execute construction projects.

	Starts	Start	End	y	Estimate
Big Bend	**2033**	**2017**	**2018**	**77.25**	**$82,125,000**
1-Completed					
Chelan - Stratford 115 kV Transmission Line River Crossing				0.01	
Stratford 115 kV Station Rebuild				0.01	
2-Planned					
Addy - Devils Gap 115 kV Transmission Line Reconductor	Present	2017	2018	4.16	$2,025,000
Benton - Othello SS 115 kV Transmission Line Rebuild	Present	2015	2016	77.25	$7,100,000
3-Needs Further Analysis					
Addy - Kettle Falls Protection Scheme	Present			45.00	$1,000,000
Chelan - Stratford 115 kV Transmission Line Rebuild	Present			2.48	$13,000,000
Lind – Warden 115 kV Transmission Line Rebuild	2033			0.14	$9,000,000
Saddle Mountain Integration	Present			23.18	$16,400,000
4-Conceptual					
Devils Gap - Stratford 115 kV Transmission Line Rebuild	2019			1.40	$30,100,000
Devils Gap Station Reconfiguration	Present			16.00	$3,000,000
Kettle Falls Capacitor Bank	2024			0.02	$500,000
Coeur d'Alene	**2034**	**2016**	**2018**	**90.30**	**$46,300,000**
1-Completed					
Lancaster Interconnection				0.01	
2-Planned					
Cabinet – Bronx – Sand Creek 115 kV Transmission Line Rebuild	Present	2015	2017	76.88	$7,500,000
Coeur d'Alene – Pine Creek 115 kV Transmission Line Rebuild	Present	2016	2018	90.30	$12,750,000
Pine Creek Transformer Replacement	2034			0.01	$500,000
3-Needs Further Analysis					
St. Maries Cap Bank	Present			3.13	$500,000
4-Conceptual					
Cabinet 230/115 kV Transformer Automatic LTC	2019			0.21	$50,000
Rathdrum 115 kV Bus Reconfiguration	2034			1.29	$5,000,000
Sandpoint Reinforcement	Present			16.31	$20,000,000
Lewiston/Clarkston	**2030**	**2017**	**2019**	**150.00**	**$15,325,000**
2-Planned					
Lolo Transformer Replacement	Present			0.13	$1,000,000
North Lewiston Reactors	Present	2015	2016	150.00	$4,900,000
4-Conceptual					
Hatwai - Lolo #2 230 KV Transmission Line	Present	2017	2019	7.97	$8,025,000
South Lewiston Station Rebuild	2030	2015	2016	0.06	$1,400,000

Table 26: Corrective System Planning Projects (Big Bend, CDA & Lewiston/Clarkston)

	Year Issue Starts	Construction Start	Construction End	Priority	Cost Estimate
Palouse	**Present**			**107.25**	**$2,500,000**
1-Completed					
Moscow 230 Station Rebuild				0.01	
4-Conceptual					
Shawnee #2 230/115 kV Transformer	Present			107.25	$2,500,000
Spokane	**2034**	**2017**	**2019**	**157.50**	**$147,715,000**
2-Planned					
Garden Springs 115 kV Station Integration	Present	2017	2019	12.50	$8,200,000
Ninth & Central - Sunset 115 kV Transmission Line Rebuild	2023	2015	2016	0.05	$925,000
Spokane Valley Transmission Reinforcement	Present	2015	2016	157.50	$8,890,000
Westside Transformer Replacement	Present	2015	2016	1.38	$2,500,000
3-Needs Further Analysis					
Bell - Beacon Protection Scheme	Present			128.25	$0
Garden Springs 230 kV Station Integration	2032			0.14	$15,000,000
Nine Mile - Westside Protection Upgrade	Present			26.00	$200,000
4-Conceptual					
Beacon - Francis & Cedar 115 kV Transmission Line Reconductor	2032			0.01	$1,500,000
Beacon 230 kV Capacitor	Present			25.00	$1,500,000
Garden Springs - Ninth & Central 230 kV Transmission Line	2034			1.25	$30,000,000
Garden Springs - Thornton 230 kV Transmission Line	Present			5.63	$30,000,000
Ninth & Central 230 kV Integration	Present			56.25	$15,000,000
Rathdrum - Westside 230 kV Transmission Line	2034			0.09	$30,000,000
Silver Lake Switching Station	2032			0.01	$4,000,000
System	**Present**			**600.00**	**$220,000**
3-Needs Further Analysis					
230 kV Capacitor Automatic Switching	Present			25.00	$20,000
RAS Update	Present			600.00	$200,000
Grand Total					**$294,185,000**

Table 27: Corrective System Planning Projects (Palouse, Spokane and System)

	Construction Start	Construction End	Cost Estimate
Big Bend	**2019**	**2019**	**$18,747,700**
1-Completed			
Odessa Cap Bank			
2-Planned			
Devils Gap - Lind 115 kV Transmission Line Rebuild	2015	2016	$7,997,700
Ford Station Rebuild	2018	2019	$1,275,000
Gifford Station Rebuild	2015	2015	$1,200,000
Harrington Station Rebuild	2015	2016	$3,000,000
Little Falls Station Rebuild	2015	2017	$4,275,000
Valley Station Rebuild	2019	2019	$1,000,000
3-Needs Further Analysis			
49 Degrees Station			
Bruce Siding Station			
Lee and Reynolds Transformation			
Coeur d'Alene	**2019**	**2019**	**$44,625,000**
1-Completed			
Blue Creek Station Rebuild			
Julia Street			
Noxon Construction Station			
2-Planned			
Beck Road Station	2015	2014	
Benewah - Pine Creek 230 kV Transmission Line Rebuild	2018	2019	$15,000,000
Big Creek Station Rebuild	2016	2017	$1,300,000
Burke - Pine Creek #3 & #4 115 kV Transmission Line Rebuild	2015	2015	$3,500,000
Cabinet - Noxon 230 kV Transmission Line Rebuild	2017	2018	$1,500,000
Noxon Rapids 230 kV Switchyard Rebuild	2015	2019	$21,075,000
Priest River Station			
Sandpoint, Sagle, and Oden Grid Modernization			
St. Maries SCADA Upgrade/Add Feeder	2018	2018	$750,000
3-Needs Further Analysis			
Bronx Station	2019	2019	$1,500,000
Cabinet Gorge Switching Station			
Carlin Bay Station			
Noxon - Pine Creek #2 230 kV Transmission Line			
Lewiston/Clarkston	**2018**	**2019**	**$5,625,000**
1-Completed			
10th & Stewart Station Rebuild			
Lewiston Mill Road Station			
North Lewiston Distribution Station Relocation			
2-Planned			
Clearwater Station Upgrade	2015	2016	$1,000,000
Grangeville Station Rebuild	2018	2019	$2,025,000
Kamiah Wood Station Rebuild	2017	2018	$1,300,000
Kooskia Transformer Replacement			
Pound Land Station Rebuild	2017	2018	$1,300,000
3-Needs Further Analysis			
Wheatland Station			$0

Table 28: Non-Corrective System Planning Projects (Big Bend, CDA & Lewiston/Clarkston)

Palouse	**2018**	**2019**	**$29,053,800**
2-Planned			
Benewah - Moscow 230 kV Transmission Line Rebuild	2015	2017	$24,178,800
Diamond Station Minor Rebuild			
Moscow City 115 SCADA/Minor Rebuild			
North Moscow Transformation	2018	2019	$1,800,000
Potlatch Transformer Replacement			
Tekoa SCADA Upgrade/Minor Rebuild			
3-Needs Further Analysis			
Deary - Potlatch 115 kV Transmission Line			
Tamarack Station	2018	2019	$3,075,000
Spokane	**2017**	**2019**	**$39,785,000**
2-Planned			
Chester Station Rebuild	2017	2018	$1,460,000
Deer Park Partial Rebuild	2015	2015	$750,000
Downtown West Station	2016	2018	$2,275,000
Greenacres/Otis Orchards Stations	2015	2015	$1,375,000
Hallett & White - Silver Lake 115 kV Transmission Line Rebuild	2017	2018	$2,025,000
Irvin Distribution	2016	2017	$1,875,000
Metro Station Rebuild	2016	2019	$13,150,000
Ninth & Central Station Upgrade	2015	2017	$2,950,000
Northwest Station Rebuild	2016	2017	$1,675,000
Ross Park Station Rebuild	2015	2017	$6,000,000
Southeast Capacity Increase	2016	2016	$450,000
Sunset Station Rebuild	2017	2019	$3,775,000
3-Needs Further Analysis			
Beacon - Bell - Francis & Cedar - Waikiki Reconfiguration	2016	2017	$2,025,000
Beacon Station Rebuild			
College and Walnut Consolidation/Rebuild			
Downtown East Station			
Hallett & White Capacitor Bank			
Hawthorne Station			
Hillyard Station			
Westside Station Rebuild			
System	**2015**	**2017**	**$9,794,000**
2-Planned			
Line Ratings Mitigation	2015	2017	$8,794,000
Spokane - Coeur d'Alene 115 kV Relay Upgrades	2015	2015	$1,000,000
Grand Total			**$147,630,500**

Table 29: Non-Corrective System Planning Projects (Palouse, Spokane and System)

Area Work Plans

The following transmission projects are scheduled for work based on a variety of factors including changing system and operational requirements, remaining service life, asset condition, and performance. This list is provided for planning and reference purposes only. It represents current plans and is subject to frequent change. See the Transmission Engineering Manager for the latest revision. Those items with no marks for any year represent tentative projects under consideration.

See the end of the list for the current minor rebuild and ground inspection schedule, which typically drives follow-up repairs and minor rebuilds the following year (when a major rebuild is not justified based on condition assessment).

TRR = Transmission Rebuild/Reconductor Program Business Case
NT = New Transmission Program Business Case
PS = Project Specific Business Case
TAM = Transmission Asset Management Program Business Case
SDSR = Substation - Distribution Station Rebuild Program Business Case
SNDS = Substation - New Distribution Stations Program Business Case
SVTR = Spokane Valley Transmission Reinforcement Program Business Case
HPRM = High Priority Line Ratings Mitigation Program Business Case
MPRM = Medium Priority Line Ratings Mitigation Program Business Case
LPRM = Low Priority Line Ratings Mitigation Program Business Case
NG = New Growth

Table 30: Project Type Key

Business Case	Area	ER Description	2016	2017	2018	2019
TRR	All	Sys - Rebuild Trans - Condition			X	X
	All	Trans Air Switch Platform Grd Mat	X			
LPRM	All	LP Line Ratings Mitigation Project		X		
LPRM	All	LP Line Ratings Mitigation Project	X			
PS	Big Bend	Harrington 115-4kV	X			
SNDS	Big Bend	Bruce Siding 115 Sub - New			X	X
TRR	Big Bend	Ben-Oth SS 115 - ReCond/ReBld			X	X
TR	Big Bend	Devils Gap-Lind 115kV Rebuild	X	X	X	X
SDSR	Big Bend	Ford 115-13kV Sub		X	X	X
SDSR	Big Bend	Little Falls 115kV Sub	X	X	X	X
TR	Big Bend	Chelan-Stratford 115kV	X			
SDSR	CDA	Bronx 115-21 Sub - Construct	X	X		
TR	CDA	CDA-Pine Creek 115kV Rebuild	X	X		
TR	CDA	Cabinet-Noxon 230kV	X			
TR	CDA	Benewah-Pine Creek 230kV	X			
PS	CDA	Cabinet Gorge 230kV Switchyard	X			
SNDS	Lewis-Clark	Wheatland 115 Sub - Construct		X	X	
NT	Lewis-Clark	Hatwai-Lolo #2 230kV		X	X	X
TR	Lewis-Clark	Lolo-Oxbow 230kV	X			
SNDS	Palouse	Bovill 115kV Substation - New	X	X		
TR	Palouse	Benewah-Moscow 230kV	X	X		
SDSR	Spokane	Sunset 115kV Sub - Rebuild		X	X	
TR	Spokane	West Plains Trans Reinforcement			X	X
SNDS	Spokane	Downtown East 115 Sub- New				X
SDSR	Spokane	9CE 115 Sub - Rebuild/Expand		X	X	
SNDS	Spokane	Greenacres 115 Sub - Construct		X	X	
SVTR	Spokane	Irvin SS 115 - Construct	X	X	X	X
PS	Spokane	Westside 230kV Sub - Rebuild	X	X		
PS	Spokane	Garden Springs 230-115-13 Sub	X	X	X	X
SVTR	Spokane	Opportunity Sub 115-13kV	X			
SDSR	Spokane	Northwest 115-13kV Sub	X	X		
TR	Spokane	Garden Springs - Silver Lake 115kV	X	X		
TR	Spokane	BEA-BEL-F&C-WAI 115kV	X			
PS	Spokane	9CE Sub - New 230kV Transformation	X			
NT	Spokane	Westside/Garden Springs 230/115	X			

Table 31: Area Work Plans – Major Projects

2016 Minor Rebuilds (following previous ground inspections)		
Area	**Transmission Line**	**kV**
Spokane	Beacon - Boulder #2	115kV
CDA	Benewah - Boulder	230kV
CDA	Benewah - Pine Creek - 115kV	115kV
CDA	Benewah - Pine Creek - 115kV: St Maries Tap	115kV
Lewis-Clark	Dry Creek - N. Lewiston - 230kV	230kV
Lewis-Clark	Dry Creek - Pound Lane	115kV
CDA	Hot Springs - Noxon #2	230kV
Lewis-Clark	Moscow 230 - Orofino	115kV
Lewis-Clark	Nez Perce - Orofino	115kV
Spokane	Ninth & Central - Sunset	115kV
Big Bend	Othello Sw. Sta - Warden #1	115kV
CDA	Benewah - Pine Creek - 115kV: St Maries Tap	115kV

Table 32: Minor Rebuilds

Area	Transmission Line	kV	#Wood Poles	
OTHELLO	LIND - WARDEN	115KV	491	
CLARKSTON	JAYPE - OROFINO	115KV	395	
CLARKSTON	GRANGEVILLE - NEZ PERCE (GRANGEVILLE TAP)	115KV	9	
CLARKSTON	GRANGEVILLE - NEZ PERCE #2	115KV	487	
DAVENPORT	CHELAN - STRATFORD	115KV	1197	
SPOKANE	BEACON - BOULDER #5	230KV	6	
			2585	Year 2016 Total

Table 33: Ground Inspection Plan

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Appendix A –Transmission Probability, Consequence & Risk Index

Transmission Line Name	Voltage (kV)	Length (miles)	Replacement Value	Probability Index	Consequence Index	Risk Index
Lolo - Oxbow	230	63.41	$45,655,200	85.4	100.0	100.0
Noxon - Pine Creek	230	43.51	$31,327,200	80.5	87.8	82.8
Benewah - Pine Creek	230	42.77	$30,794,400	68.3	87.8	70.3
Walla Walla - Wanapum	230	77.78	$56,001,600	68.4	83.7	67.1
Benewah - Boulder	230	26.15	$18,828,000	67.1	72.9	57.3
Hot Springs - Noxon #2	230	70.05	$50,436,000	66.0	68.8	53.2
Dry Creek - Talbot	230	28.27	$20,354,400	51.4	78.3	47.1
Latah - Moscow	115	51.41	$21,592,200	96.0	41.7	47.0
Devils Gap - Stratford	115	86.19	$36,199,800	100.0	39.0	45.6
Post Street - 3rd & Hatch	115	1.76	$3,696,000	70	100	43
Benewah - Moscow	230	44.28	$31,881,600	61.1	59.3	42.5
Cabinet - Rathdrum	230	52.3	$37,656,000	41.7	86.4	42.3
Bronx - Cabinet	115	32.38	$13,599,600	59.4	55.2	38.4
Metro - Post Street	115	0.5	$1,890,000	60	100	38
Ninth & Central - Sunset	115	8.63	$3,624,600	39.0	75.6	34.7
Burke - Pine Creek #3	115	23.79	$9,991,800	67.0	44.4	34.6
Shawnee - Sunset	115	61.51	$25,834,200	79.0	36.3	33.4
Sunset - Westside	115	10.03	$4,212,600	53.0	53.9	33.2
Hatwai - Lolo	230	8.27	$5,954,400	28.9	93.2	31.6
Burke - Pine Creek #4	115	23.13	$9,714,600	69.0	37.6	30.4
Beacon - Boulder #2	115	13.73	$5,766,600	38.7	66.1	29.9
Addy - Devil's Gap	115	43.31	$18,190,200	58.0	43.0	29.3
Othello Sw. Sta - Warden #2	115	16.56	$6,955,200	53.7	45.8	28.8
Pine Street - Rathdrum	115	33.24	$13,960,800	47.0	51.2	28.3
Benton - Othello Switch Station	115	26.07	$10,949,400	64.0	37.6	28.3
CdA 15th St - Pine Creek	115	29.75	$12,495,000	83.0	28.1	27.3
Cabinet - Noxon	230	18.51	$13,327,200	31.3	71.5	26.3
Chelan - Stratford	115	49.44	$20,764,800	66.6	32.2	25.1
Moscow 230 - Orofino	115	41.59	$17,467,800	84.0	25.4	25.0
Boulder - Rathdrum	115	19.07	$8,009,400	58.6	36.3	24.9
Benewah - Pine Creek	115	45.02	$18,908,400	67.0	29.5	23.2
Jaype - Orofino	115	34.64	$14,548,800	66.6	29.5	23.0
Clearwater - N. Lewiston	115	3.21	$1,348,200	30.7	63.4	22.8
Ninth & Central - Otis Orchards	115	16.31	$6,850,200	28.9	66.1	22.4
N. Lewiston - Shawnee	230	34.28	$24,681,600	33.2	56.6	22.0
Burke - Thompson Falls A	115	3.96	$1,663,200	34.4	53.9	21.7
College & Walnut - Post Street	115	0.54	$2,041,200	2.8	100	21
Beacon - Bell #4	230	6.3	$4,536,000	22.8	78.3	20.9

Transmission Line Name	Voltage (kV)	Length (miles)	Replacement Value	Probability Index	Consequence Index	Risk Index
Devil's Gap - Lind	115	73.74	$30,970,800	95.1	18.6	20.8
Dry Creek - Lolo	230	11.23	$8,085,600	29.5	59.3	20.5
Eighth & Fancher - Latah	115	26.27	$11,033,400	55.6	30.8	20.1
Coulee - Westside	230	1.99	$1,432,800	27.1	62.0	19.7
Benewah - Thornton	230	32.2	$23,184,000	27.1	60.7	19.3
Shawnee - Thornton	230	27.83	$20,037,600	27.1	60.7	19.3
Hatwai - Moscow	230	18.05	$12,996,000	27.7	59.3	19.2
Grangeville - Nez Perce #2	115	37.17	$15,611,400	53.0	29.5	18.4
Bell - Northeast	115	1.53	$642,600	42.2	48.5	18.1
Addy - Kettle Falls	115	27.11	$11,386,200	27.7	55.2	17.9
Burke - Thompson Falls B	115	3.97	$1,667,400	28.3	53.9	17.9
Bell - Northeast	115	2.83	$1,188,600	31.9	34.9	17.3
Francis & Cedar - Northwest	115	2.12	$890,400	30.7	47.1	16.9
Grangeville - Nez Perce #1	115	26.9	$11,298,000	48.0	29.5	16.7
Lolo - Nez Perce	115	41.2	$17,304,000	55.7	25.4	16.6
Lolo - Pound Lane	115	10.25	$4,305,000	40.0	34.9	16.5
Beacon - Bell #5	230	6.04	$4,348,800	18.0	78.3	16.5
Dworshak - Orofino	115	3.62	$1,520,400	21.6	64.7	16.4
Airway Heights - Devils Gap	115	20.6	$8,652,000	22.8	60.7	16.2
Beacon - Ross Park	115	2.06	$865,200	20.4	67.5	16.1
Lind - Warden	115	21.71	$9,118,200	44.5	30.8	16.1
Hatwai - N. Lewiston	230	6.99	$5,032,800	18.0	75.6	15.9
Metro - Sunset	115	2.87	$1,205,400	24.6	52.5	15.1
Devils Gap - Ninemile	115	18.78	$7,887,600	28.9	44.4	15.0
Beacon - Boulder #1	115	13.07	$5,489,400	38.7	32.2	14.6
Moscow 230- Terre View	115	11.94	$5,014,800	40.4	30.8	14.6
Bronx - Sand Creek	115	6.62	$2,780,400	30.7	40.3	14.5
Beacon - Ninth & Central #2	115	3.5	$1,470,000	22.8	53.9	14.4
Beacon - Bell #1	115	6.86	$2,881,200	29.5	41.7	14.4
Lind - Shawnee	115	75.81	$31,840,200	83.6	14.6	14.3
Moscow 230 - Orofino	115	21.33	$8,958,600	50.0	24.1	14.1
College & Walnut - Westside	115	8.79	$3,691,800	24.0	49.8	14.0
Northwest - Westside	115	1.95	$819,000	24.0	49.8	14.0
Ross Park - Third & Hatch	115	2.19	$919,800	19.2	60.7	13.6
Beacon - Northeast	115	5.25	$2,205,000	30.7	41.7	13.5
Ninemile - Westside	115	6.8	$2,856,000	22.8	49.8	13.3
Nez Perce - Orofino	115	17.28	$7,257,600	27.7	40.3	13.1
Post Falls - Ramsey	115	9.01	$3,784,200	28.9	36.3	12.3
Addy - Gifford	115	20.68	$8,685,600	51.9	20.0	12.2
Ramsey - Rathdrum #1	115	8.42	$3,536,400	24.0	41.7	11.7
Beacon - Boulder	230	11.95	$8,604,000	17.4	56.6	11.5

Transmission Line Name	Voltage (kV)	Length (miles)	Replacement Value	Probability Index	Consequence Index	Risk Index
Beacon - Ninth & Central #1	115	3.73	$1,566,600	18.0	53.9	11.3
Stratford - Summer Falls	115	6.3	$2,646,000	18.0	53.9	11.3
Beacon - Francis & Cedar	115	11.56	$4,855,200	34.3	28.1	11.3
Appleway - Rathdrum	115	11.77	$4,943,400	20.4	47.1	11.2
Shawnee - Terre View	115	10.05	$4,221,000	30.1	30.8	10.9
Dry Creek - N. Lewiston	230	8.06	$5,803,200	13.1	70.2	10.7
CdA 15th St - Rathdrum	115	12.67	$5,321,400	19.2	47.1	10.6
Milan Tap	115	8.22	$3,452,400	30.1	29.5	10.4
Shawnee - South Pullman	115	12.7	$5,334,000	35.0	25.4	10.4
Beacon - Rathdrum	230	25.36	$18,259,200	16.2	53.9	10.2
Airway Heights - Silver Lake	115	10.77	$4,523,400	24.0	36.3	10.2
Boulder - Lancaster	230	13.29	$9,568,800	11.3	76.9	10.2
Libby - Noxon	230	0.79	$568,800	12.5	68.8	10.1
Moscow 230 - South Pullman	115	12.07	$5,069,400	23.0	36.3	9.7
Colbert Tap	115	3.19	$1,339,800	34.3	24.1	9.7
Clearwater - Lolo #2	115	8.56	$3,595,200	24.0	33.5	9.4
Otis Orchards - Post Falls	115	7.62	$3,200,400	24.0	30.8	8.7
Ninth & Central - Third & Hatch	115	4.34	$1,822,800	24.0	29.5	8.3
Lind - Washtucna	115	28.78	$12,087,600	30.1	22.7	8.0
Benewah - Pine Creek	115	7.06	$2,965,200	27.0	24.1	7.6
Burke - Pine Creek #3	115	4.58	$1,923,600	23.0	28.1	7.5
Shawnee - Sunset	115	7.12	$2,990,400	37.0	15.9	6.8
Devils Gap - Long Lake #2	115	1.03	$432,600	13.1	41.7	6.4
Albeni Falls - Pine Street	115	2.27	$953,400	13.1	40.3	6.2
Francis & Cedar - Ross Park	115	5.16	$2,167,200	14.3	36.3	6.1
Clearwater - Lolo #1	115	8.63	$3,624,600	24.0	20.0	5.6
Dry Creek - Pound Lane	115	3.89	$1,633,800	12.5	36.3	5.3
Airway Heights - Sunset	115	9.52	$3,998,400	18.0	25.4	5.3
Sunset - Westside	115	11.97	$5,027,400	22.0	21.3	5.2
Latah - Moscow	115	10.37	$4,355,400	17.0	25.4	5.0
Dry Creek - N. Lewiston	115	8.17	$3,431,400	13.1	30.8	4.7
Devils Gap - Little Falls #2	115	3.9	$1,638,000	24.0	15.9	4.5
Othello Sw. Sta - Warden #1	115	8.28	$3,477,600	36.1	10.5	4.4
CdA 15th St - Ramsey	115	3.17	$1,331,400	9.4	36.3	4.0
Moscow City - N. Lewiston	115	22.19	$9,319,800	16.2	21.3	4.0
Devils Gap - Little Falls #1	115	3.42	$1,436,400	19.2	14.6	3.3
Critchfield - Dry Creek	115	1.58	$663,600	13.1	20.0	3.1
Benewah - Latah	115	6.68	$2,805,600	5.9	40.3	3.0
Lolo - Pound Lane	115	2.94	$1,234,800	12.0	20.0	2.8
Bell - Westside	230	1.99	$1,432,800	2.8	72.9	2.4

Transmission Line Name	Voltage (kV)	Length (miles)	Replacement Value	Probability Index	Consequence Index	Risk Index
Lancaster - Rathdrum	230	2.93	$2,109,600	2.8	63.4	2.1
Wilbur Tap	115	5.35	$2,247,000	14.3	11.8	2.0
Benton - Othello Switch Station	115	3.79	$1,591,800	8.0	20.0	1.9
Dower - Post Falls	115	2.16	$907,200	9.4	17.3	1.9
Boulder - Otis Orchards #1	115	3.45	$1,449,000	2.8	39.0	1.3
Boulder - Otis Orchards #2	115	2.73	$1,146,600	2.8	34.9	1.1
Grangeville - Nez Perce #1	115	6.34	$2,662,800	8.0	11.8	1.1

Appendix B – Transmission System Outage Data

Transmission Line Name	Voltage (kV)	# Line Outages	#Planned Outages	#Unplanned Outages	Transmission Line Name	Voltage (kV)	# Line Outages	#Planned Outages	#Unplanned Outages	Transmission Line Name	Voltage (kV)	# Line Outages	#Planned Outages	#Unplanned Outages
AVISTA DOES NOT OWN		22	3	19	Shawnee - Terre View	115	3	0	3	Otis Orchards - Post Falls	115	1	1	0
Lind - Shawnee	115	21	2	19	Lolo - Pound Lane	115	3	0	3	Beacon-Bell #4	230	1	1	0
Moscow 230 - Orofino	115	17	0	17	College & Walnut - Westside	115	3	0	3	Noxon Construction Tap	230	0	0	0
Bronx - Cabinet	115	16	0	16	Cabinet - Noxon	230	3	0	3	Airway Heights - Sunset	115	2	2	0
Benewah - Pine Creek	115	18	3	15	Benewah - Pine Creek	230	5	3	2	Albeni Falls - Pine Street	115	0	0	0
Devils Gap - Stratford	115	13	0	13	Libby - Noxon	230	3	1	2	Beacon - Ninth & Central #1	115	0	0	0
Hot Springs - Noxon #1	230	9	0	9	Beacon - Boulder #2	115	2	0	2	Beacon - Ninth & Central #2	115	0	0	0
CdA 15th St - Pine Creek	115	11	3	8	Moscow 230- Terre View	115	2	0	2	Boulder - Boulder Park	115	0	0	0
Cabinet - Rathdrum	230	10	2	8	Othello Sw. Sta - Warden #2	115	5	3	2	Boulder - Otis Orchards #1	115	0	0	0
Walla Walla - Wanapum	230	11	3	8	Hatwai - Moscow	230	3	1	2	Boulder - Otis Orchards #2	115	0	0	0
Boulder - Rathdrum	115	9	1	8	Addy - Kettle Falls	115	2	0	2	Bronx Tap	115	0	0	0
Ninth & Central - Otis Orchards	115	10	2	8	Airway Heights - Devils Gap	115	4	2	2	CdA 15th St - Ramsey	115	0	0	0
Ross Park - Third & Hatch	115	8	0	8	Beacon - Francis & Cedar	115	3	1	2	College & Walnut - Post Street	115	1	1	0
Shawnee - Sunset	115	10	3	7	Benewah - Latah	115	2	0	2	Critchfield - Dry Creek	115	0	0	0
Noxon - Pine Creek	230	9	2	7	Lind - Warden	115	2	0	2	Devils Gap - Long Lake #1	115	0	0	0
Chelan - Stratford	115	7	0	7	Post Street - 3rd & Hatch	115	2	0	2	Devils Gap - Long Lake #2	115	0	0	0
Benton - Othello Switch Station	115	8	2	6	Latah - Moscow	115	3	2	1	Dower - Post Falls	115	0	0	0
Lolo - Nez Perce	115	10	4	6	Sunset - Westside	115	6	5	1	Dry Creek - N. Lewiston	115	0	0	0
Hot Springs - Noxon #2	230	6	0	6	Burke - Thompson Falls B	115	5	4	1	LOON LAKE TAP	115	0	0	0
Ramsey - Rathdrum #1	115	7	1	6	Beacon - Boulder	230	1	0	1	Metro - Sunset	115	0	0	0
Devil's Gap - Lind	115	6	1	5	Hatwai - Lolo	230	2	1	1	NE-NE Turbine Generator	115	0	0	0
Shawnee - South Pullman	115	6	1	5	Airway Heights - Silver Lake	115	2	1	1	Nez Perce - Orofino	115	0	0	0
Benewah - Moscow	230	5	0	5	Lind - Washtucna	115	2	1	1	Rathdrum C.T. - Rathdrum #2	115	0	0	0
Burke - Pine Creek #4	115	6	1	5	Post Falls - Ramsey	115	2	1	1	Sagle Tap	115	0	0	0
Appleway - Rathdrum	115	6	1	5	Clearwater - Lolo #1	115	4	3	1	Stratford - Summer Falls	115	0	0	0
Benewah - Boulder	230	5	0	5	Devils Gap - Little Falls #1	115	2	1	1	Wilbur Tap	115	0	0	0
Clearwater - Lolo #2	115	7	2	5	Ninth & Central - Sunset	115	6	5	1	Milan Tap	115	0	0	0
CdA 15th St - Rathdrum	115	5	0	5	Beacon-Bell #5	230	2	1	1	Millwood - Paper Mill	60	0	0	0
Burke - Thompson Falls A	115	12	8	4	Bell - Westside	230	1	0	1	Colbert Tap	115	0	0	0
Dry Creek - Talbot	230	4	0	4	Dry Creek - Lolo	230	4	3	1	Francis & Cedar - Northwest	115	0	0	0
Lolo - Oxbow	230	5	1	4	Appleway - Ramsey	115	1	0	1	Kettle Falls Tap	115	0	0	0
Burke - Pine Creek #3	115	4	0	4	Dworshak - Orofino	115	1	0	1	Boulder - Lancaster	230	0	0	0
Ninth & Central - Third & Hatch	115	6	2	4	Mead Tap	115	1	0	1	Hatwai - N. Lewiston	230	0	0	0
Beacon - Ross Park	115	5	1	4	Metro - Post Street	115	1	0	1	Eighth & Fancher - Latah	115	0	0	0
Dry Creek - Pound Lane	115	4	0	4	Addy - Devil's Gap	115	5	5	0	Shawnee - Thornton	230	0	0	0
Northwest - Westside	115	4	0	4	Jaype - Orofino	115	0	0	0	Devils Gap - Little Falls #2	115	0	0	0
Beacon - Bell #1	115	4	0	4	N. Lewiston - Shawnee	230	3	3	0	Pine Street - Rathdrum	115	0	0	0
Francis & Cedar - Ross Park	115	4	0	4	Devils Gap - Ninemile	115	3	3	0	Addy - Gifford	115	0	0	0
Moscow 230 - South Pullman	115	4	0	4	Beacon - Boulder #1	115	0	0	0	Lancaster - Rathdrum	230	0	0	0
Ninemile - Westside	115	4	0	4	Beacon - Northeast	115	2	2	0	Kettle Falls - KF Generator	115	0	0	0
Coulee - Westside	230	4	1	3	Grangeville - Nez Perce #1	115	1	1	0	Priest River Tap	115	0	0	0
Grangeville - Nez Perce #2	115	5	2	3	North Lewiston - Walla Walla	115	2	2	0	Bell - Northeast	115	0	0	0

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* For discussion of this project, please see Ms. Rosentrater's testimony (Exhibit No. 8, page)

** 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.

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:

- Grid Reliability - 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).

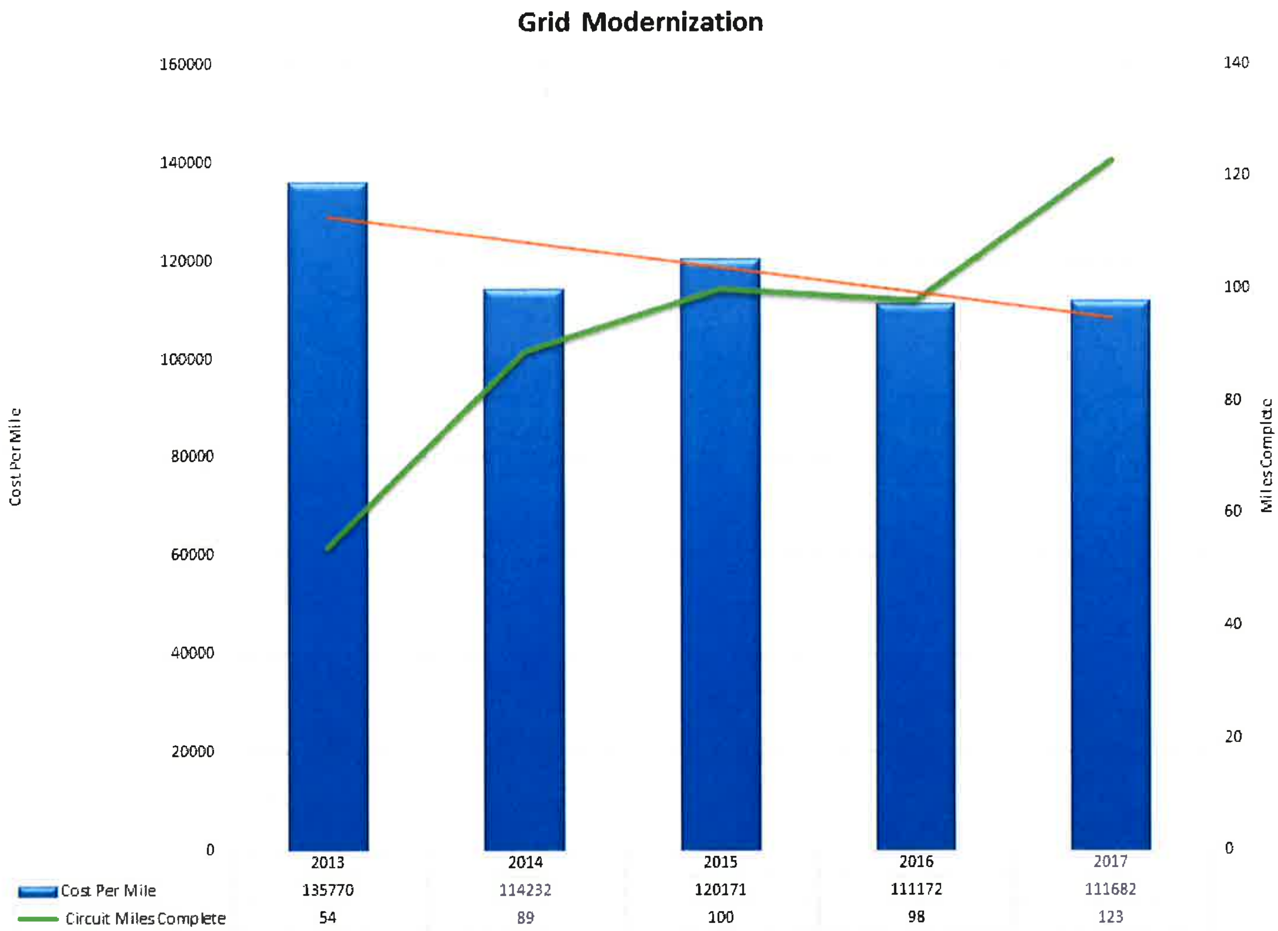
Based on Avista's 2015 Integrated Resource Plan dated August 31st, 2015, the realized and anticipated energy savings by identified feeders is shown in Table 1.

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**

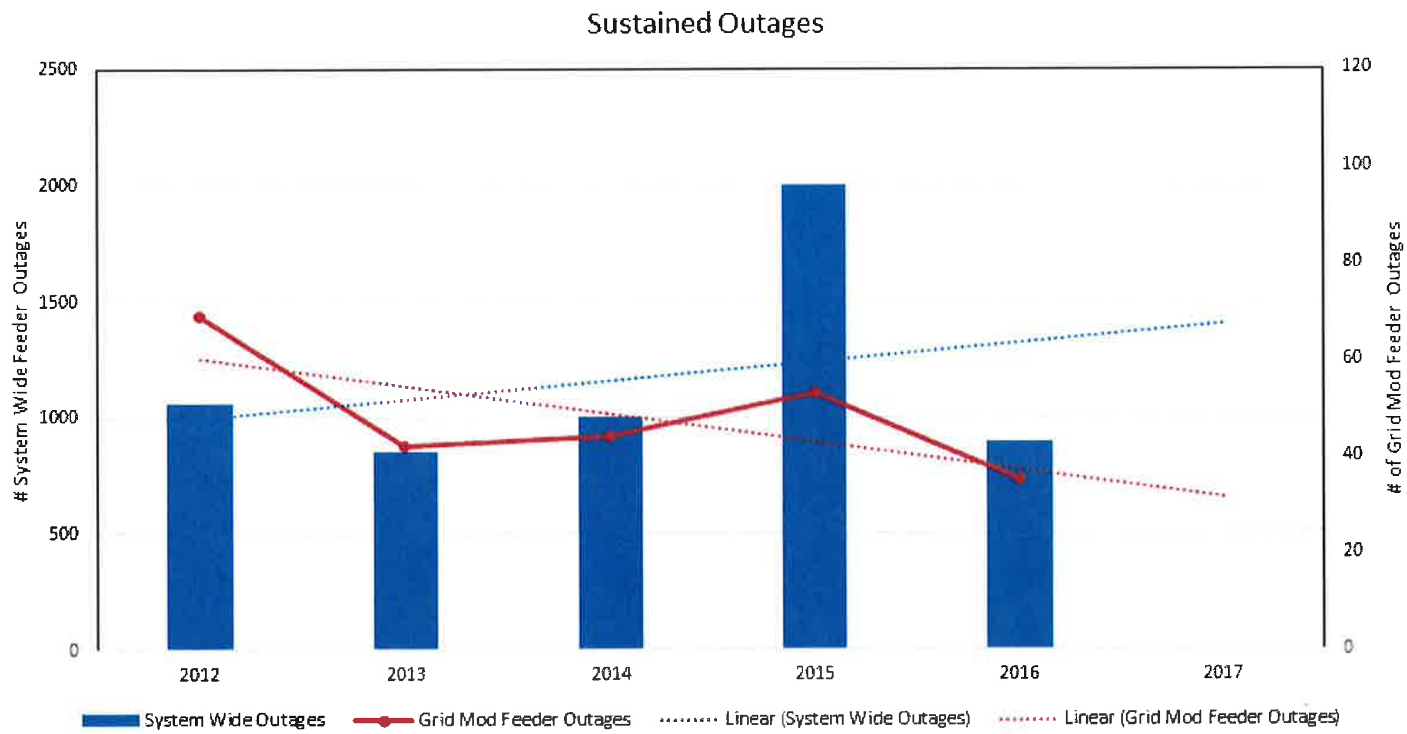
In order to address Avista's entire system and every customer in a 60 year cycle, the program would need to address an average of 190 miles per year of Avista's 11,300 total overhead and underground circuit miles. The miles of work planned is ultimately driven by the approved budget and generally can 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



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: Date: 4/17/17

Print Name: Laine Lambarth

Title: Grid Modernization Project Mgr

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	Laine Lambarth	4/14/2017	Bryan Cox	4/14/2017	Initial version

Template Version: 02/13/2017

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.

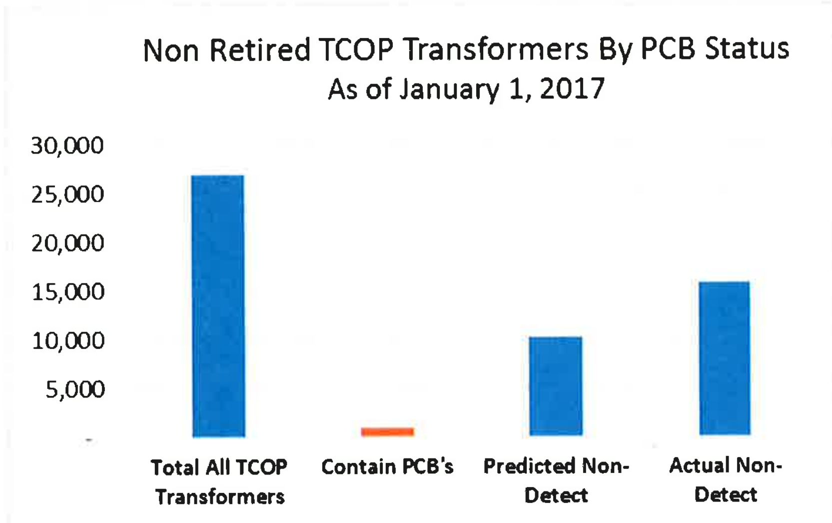
PCBs and PCB wastes are regulated by both the Washington Department of Ecology (Ecology), through the Dangerous Waste Regulations, Chapter 173-303 WAC, and by the U.S. Environmental Protection Agency (EPA) under 40 CFR Part 761, the Toxic Substances Control Act (TSCA). The transformers to be removed 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.

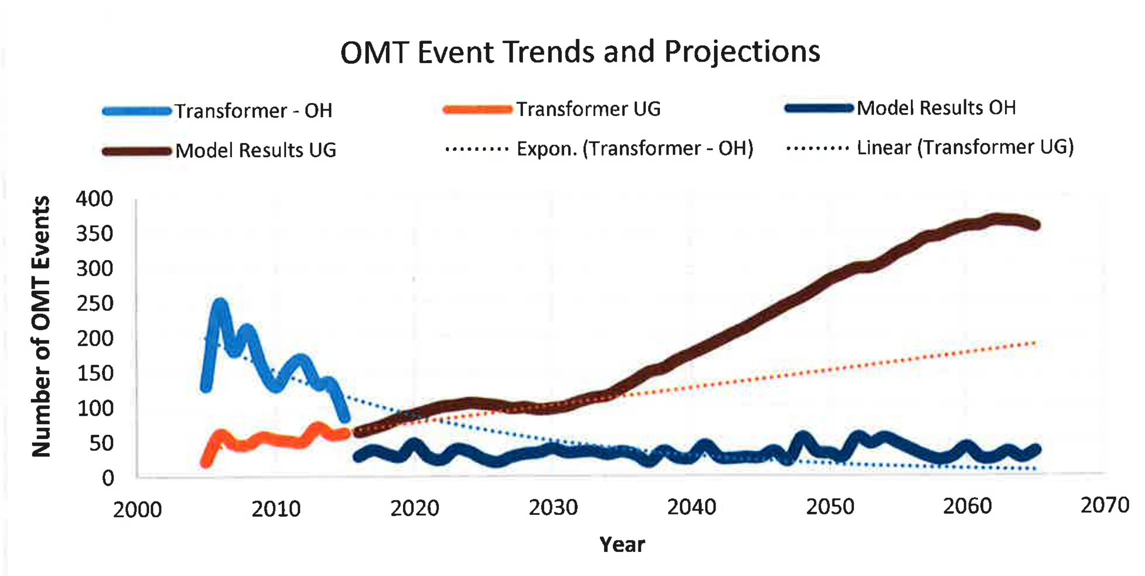
Currently, there are 906 transformers remaining in our system that are known or predicted to contain a PCB level greater than 1 part per million. In addition, there are 1,098 underground transformers that have been predicted to not contain PCBs (predicted non-detect) however, no actual tests have been 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.



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.



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.

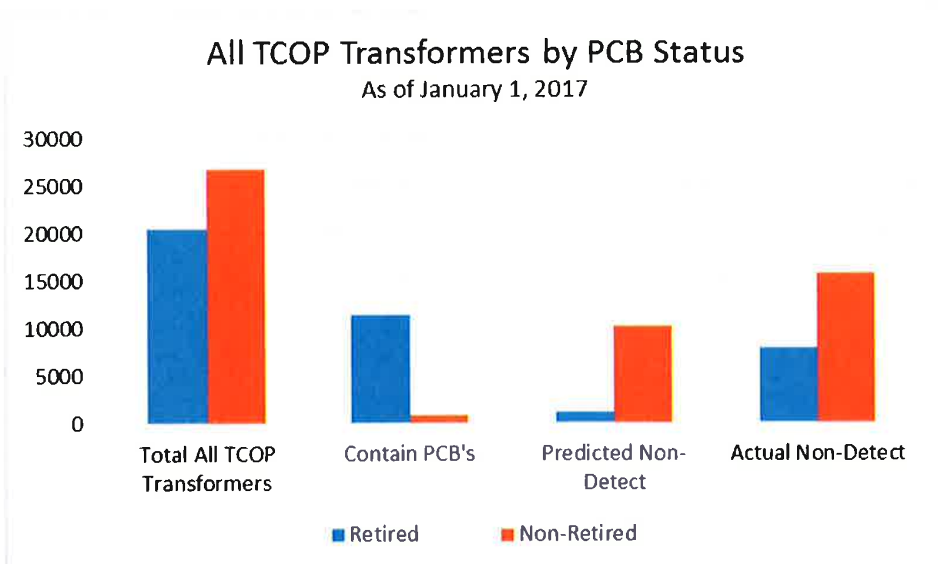
Another alternative discussed was to replace the targeted transformers "as we get there". In other words, if work is occurring at a site where a targeted transformer is located, the transformer would be replaced at that time. This method could be considered efficient by the same reasons as using the 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.

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.

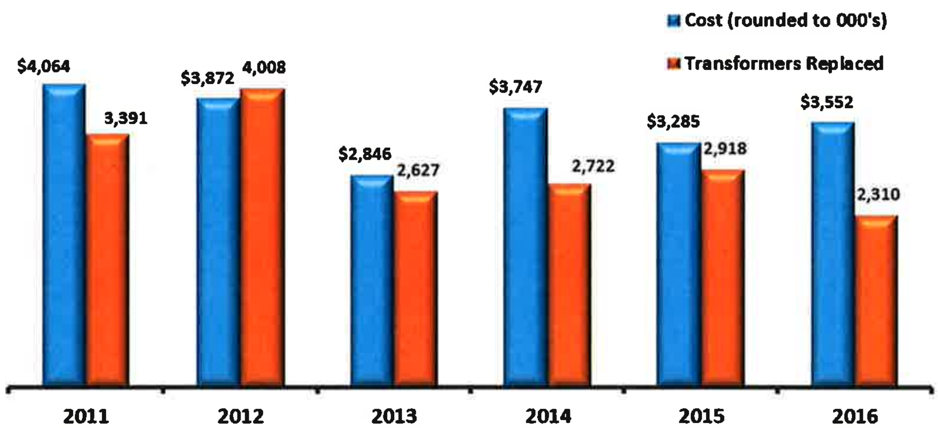
Public Safety and Health: Risks include: a potential for serious injury for crews or the public, significant damage to equipment, property or business, public health infrastructure impact up to 48 hours. If the program is unfunded, the potential occurrence is less than 1 per 10 years. If funded the potential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

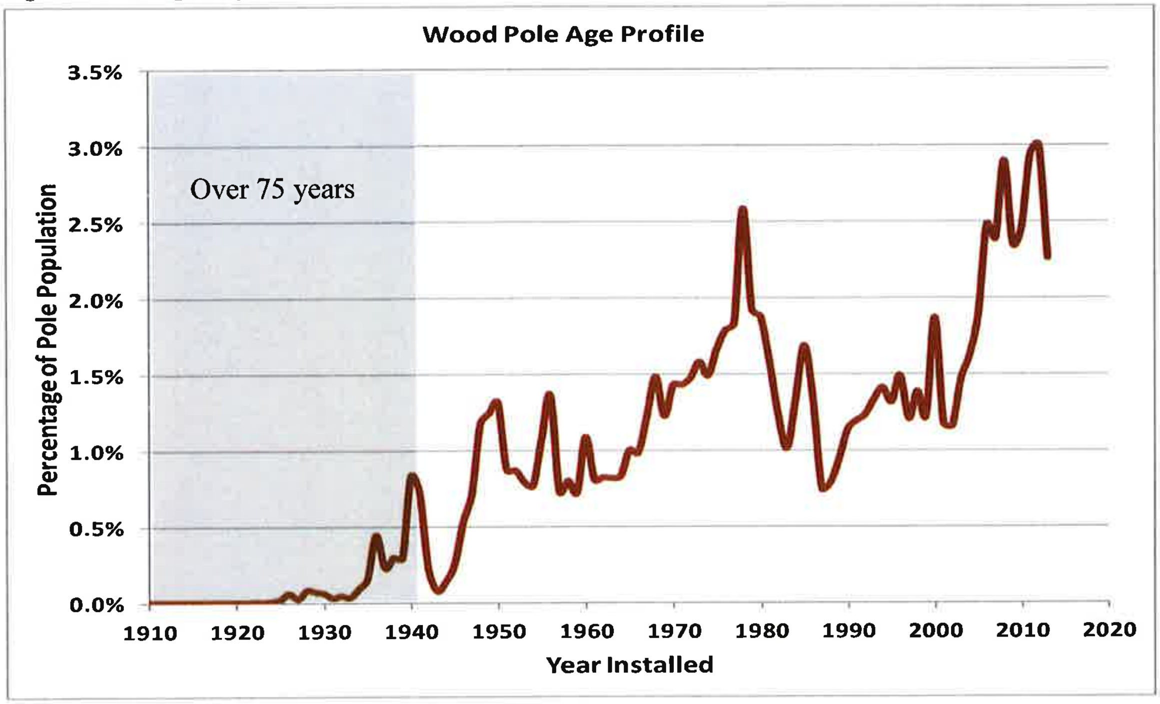
The work is required now to keep pace with the aging assets and expected failure rate. Figure 1 below shows the increased rate at which the poles are reaching the seventy-five year end of life. If this work is not maintained the aging infrastructure will cause an increasing rate of failures leading to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

Figure 1- Pole Age Profile



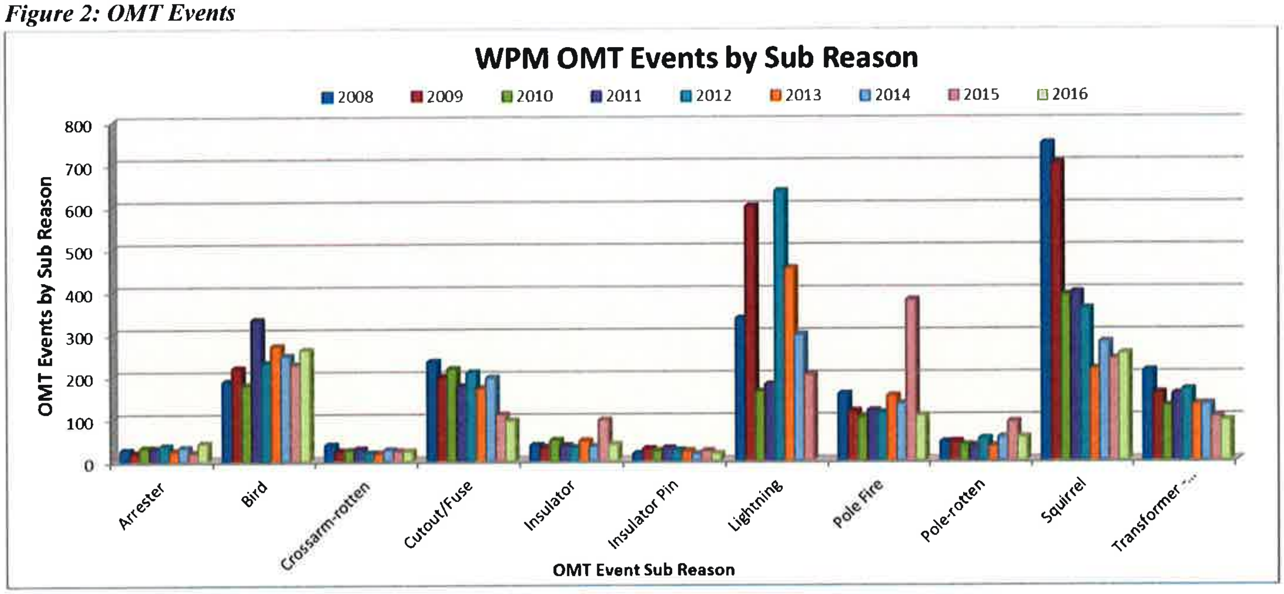
The Outage Management Tool (OMT) is used by Asset Management to track asset conditions and show trends of failures of specific equipment that should be targeted for replacement. This information is also used to track key Program performance as shown in Table 1 below. The number of outage type events 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

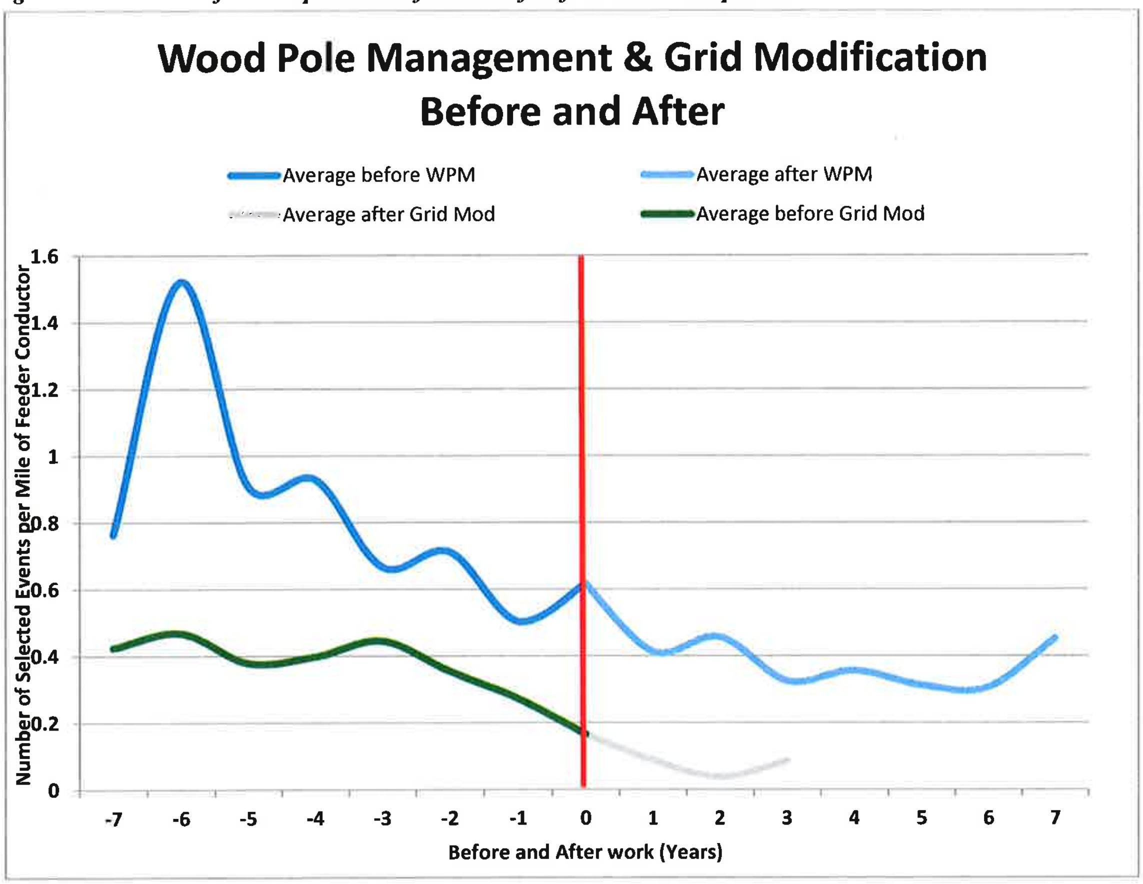
Option	Capital Cost	Start	Complete	Risk Mitigation
Do nothing	$0	Increases OMT events by 1700 events		
Distribution Wood Pole Management Program inspects all feeders on a 20 year cycle and repairs and replaces wood poles, crossarms, missing lightning arresters, missing/stolen grounds, bad cutouts, bad 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.

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:	[signature]	Date:	4-14-2017
Print Name:	Cody Krogh		
Title:	Mgr Asset Maintenance		
Role:	Business Case Owner		

Signature:	[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

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: HR 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]	[illegible]	[illegible]	[illegible]
Preferred Stock	0.00%	0.00%	0.00%	0.00%
Common Equity	[illegible]	[illegible]	[illegible]	[illegible]
			7.29%	6.35%

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 => 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

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)	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	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	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	[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	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	(1) General Structures, (2) Generation, Transmission, and Distribution, (3) Other Equipment, (4) Transportation Equipment
Book Life (Years)	45	Update
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	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) Period	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 =>	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%		Debt		[illegible]
Federal Income Tax Rate	35.00%		Preferred Stock		[illegible]
Discount Factor	6.35%		Common Equity		[illegible]
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	[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)	
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

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).

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.

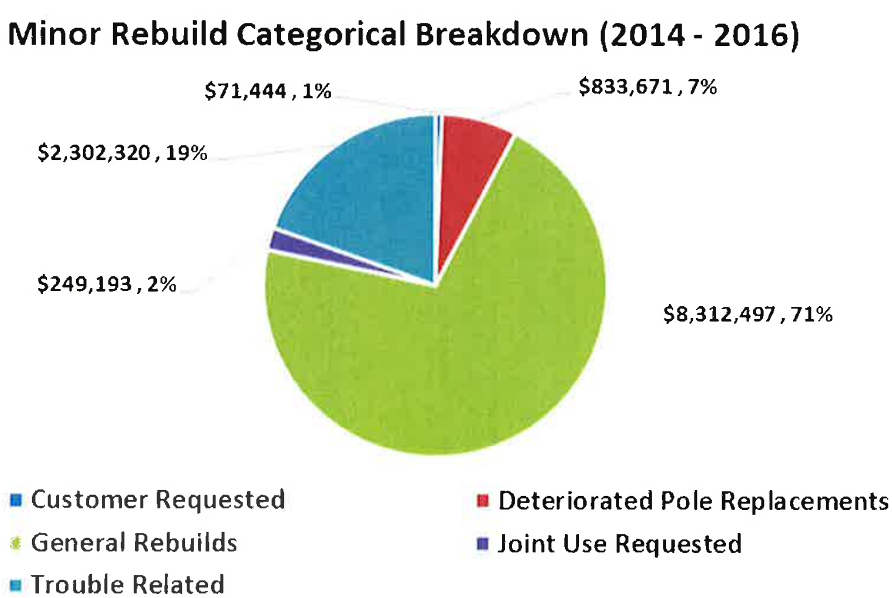


Figure 1: Distribution Minor Rebuild Categorical Breakdown

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.

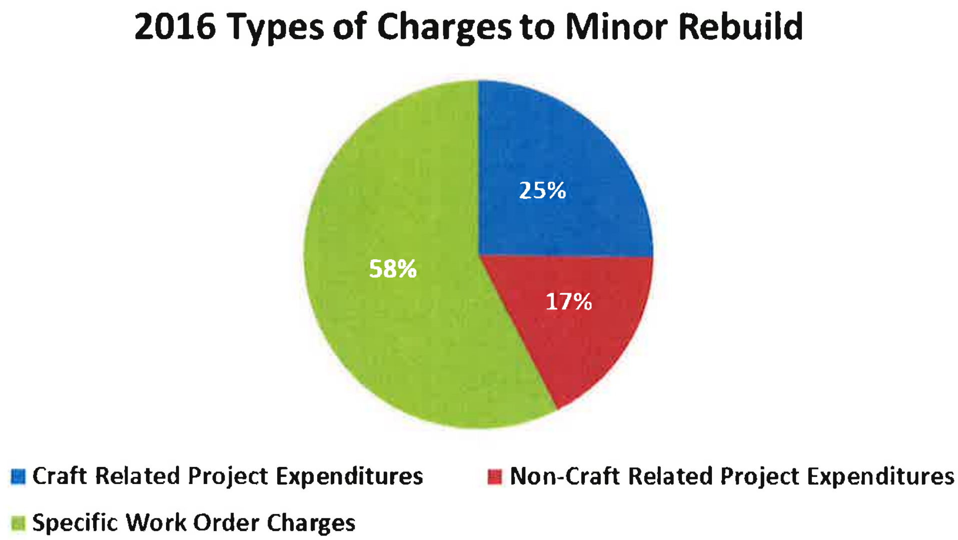


Figure 2: Types of Charges to Minor Rebuild (2016)

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

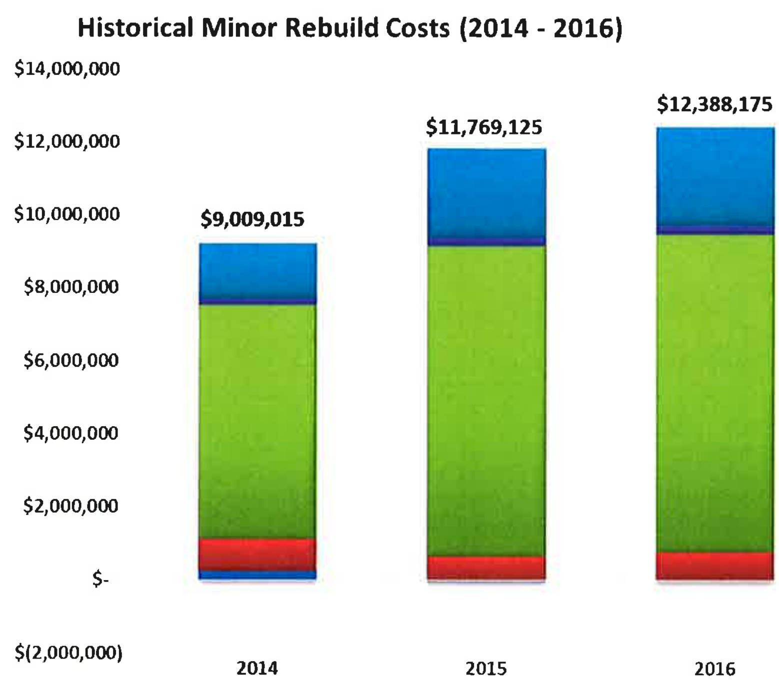
- **Craft Related Project Expenditures**: Craft labor (servicemen, general foremen, local rep), associated vehicle usage, trouble related work charges
- **Non-Craft Related Project Expenditures**: Non-craft labor, associated vehicle usage, contribution reimbursables (credits), and material issues/returns
- **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

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

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.

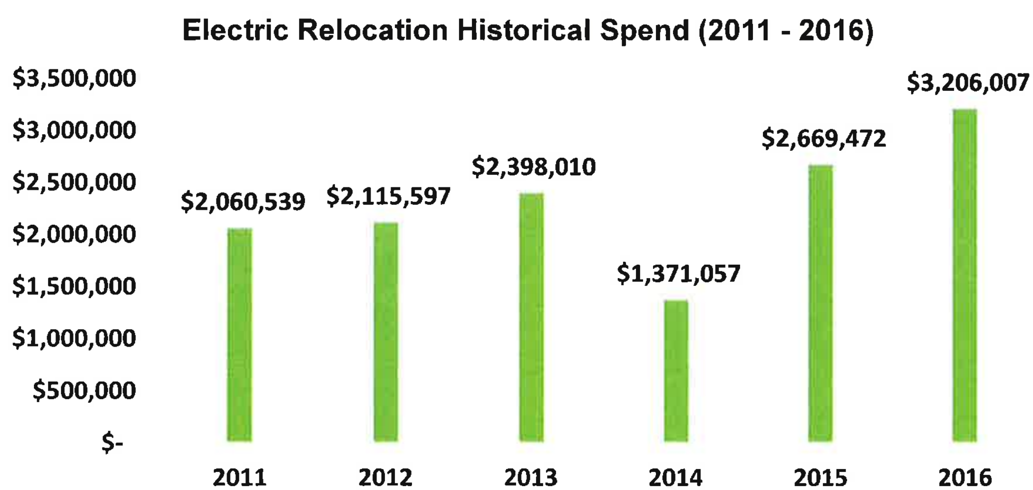
Under a Franchise Agreement or Permit, Avista is allowed to occupy space within a ROW owned by the respective jurisdiction in order to serve its customers. Electric relocations occur every year during the construction season, but are unplanned, so historical trends are used to estimate the annual cost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

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

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

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.

- 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**.

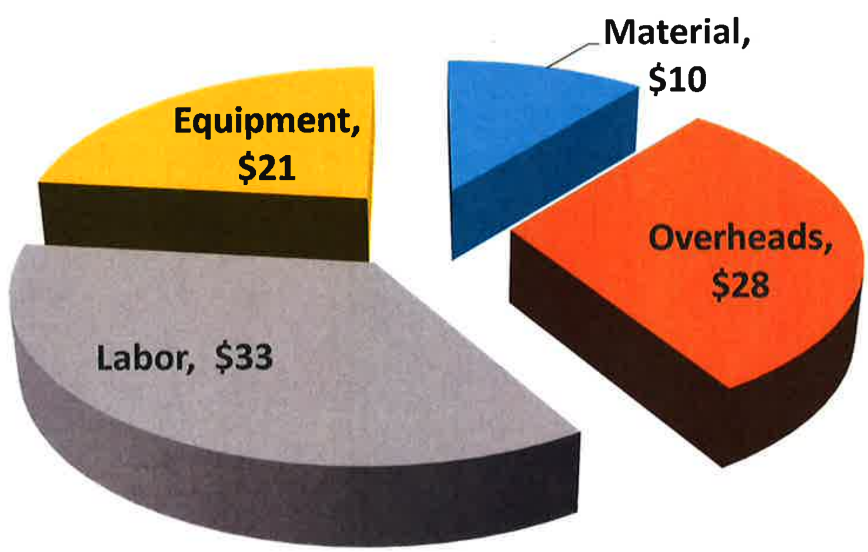


Figure 1: 2011 Cost Breakdown of a HPS Light Fixture

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.

Exhibit No. 8
Case Nos. AVU-E-17-01 and AVU-G-17-01
H. Rosentrater, Avista
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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.

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

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: Landen Grant 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.

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.

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).

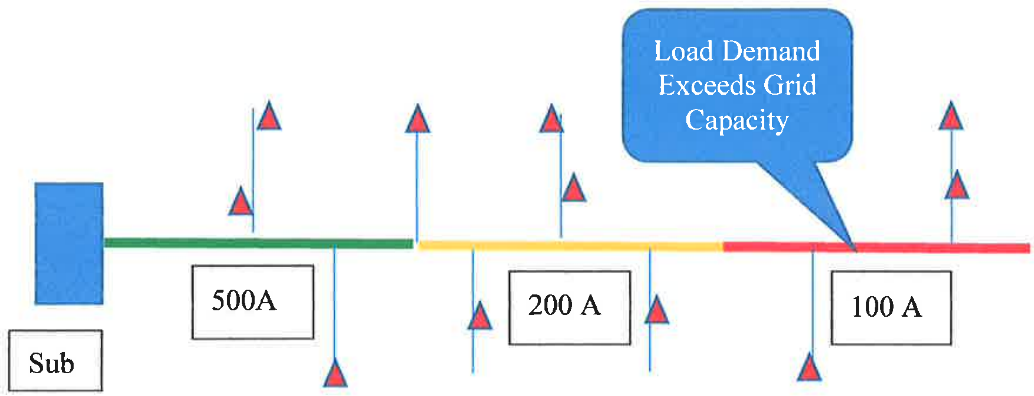


Illustration of Distribution Grid Capacity Constraint
Avista's Distribution System contains over 75 different wires and cables

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)

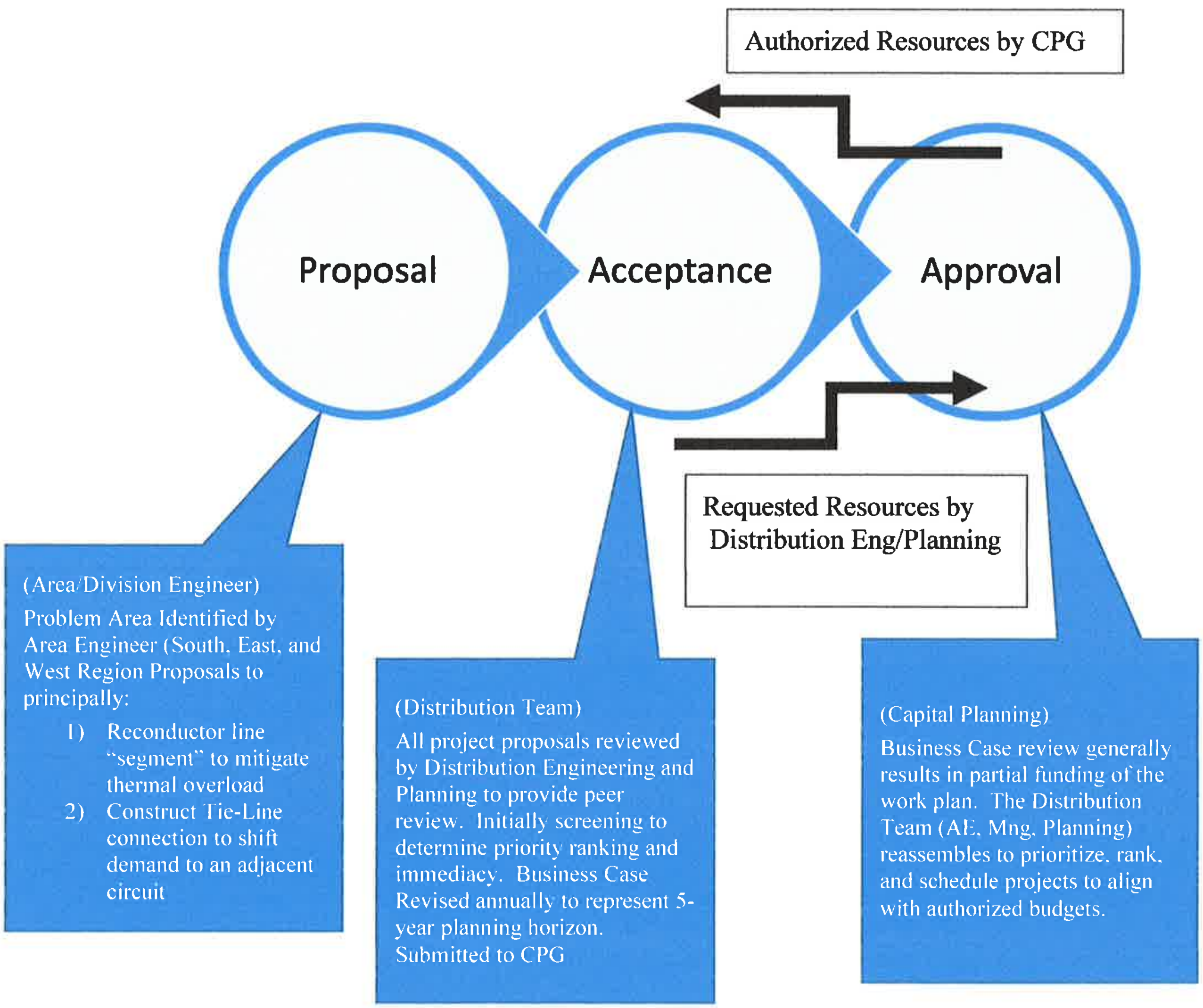
Legacy Conductors
2/0-3/0 Copper – 291-336 Amps (main trunk)
#2 Copper – 185 Amps (main trunk)
#6 Copper - 65 Amps (lateral circuit)

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

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.



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)

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.

APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Segment Reconductor and FDR Tie business case* and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 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

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
# Customers	642
Conn. KVA	29173
Peak KVA	11411
Utilization factor	0.391
Scada Status	3-Phase
Pri. Meter Customer	

Per Phase KVA

A: 9956

B: 9219

C: 9998

Notes

2015	AΦmax	BΦmax	CΦmax	BΦavg	Imbal. (%)	Peak Reactive (KVAR)	Station Regs (Buck Boost) AΦ		BΦ		CΦ	
	Feeder Demand (A)											
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

Historical Demand (A)

Year	Summer	Winter
13	336	272
14	372	302
15	380	298

Capacitor Information

Cap ID	KVAR Rating	Status	Smart ID	Location
71378	600	ON	Z906F	(126 - 149) S Scott
82239	600	ON	Z907F	(1 - 99) E Main

Reliability

Year	SAIFI	CAIDI
10	0.18	1:10:09
11	1.23	1:22:32
12	2.11	1:34:54
13	0.06	6:12:04
14	0.09	3:31:01
15	0.43	6:47:31

(Reliability data disregards major event days)

Feeder Health Check

	Value	Cond.	Section ID
Max Loading (%)	62.02	556AAC	369-445931-0
Location:	Pacific-2nd and Scott		
Min. Volts (V)	123.08	1CU15	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	593:50:08	53	11:12	Car Hit Pole	523 E 3RD AVE
868558	15-Dec	222:48:45	25	8:54	Maint/Upgrade	902 E BOONE AVE
790350	8-May	54:22:14	22	2:28	Maint/Upgrade	(1000 - 1098) E Sharp-Sinto
786456	19-Mar	24:11:30	5	4:53	Maint/Upgrade	(800 - 929) E Sprague

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)

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	422.8	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

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 Knutson	
3	Spokane	Spokane	Deer Park	Mos/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	

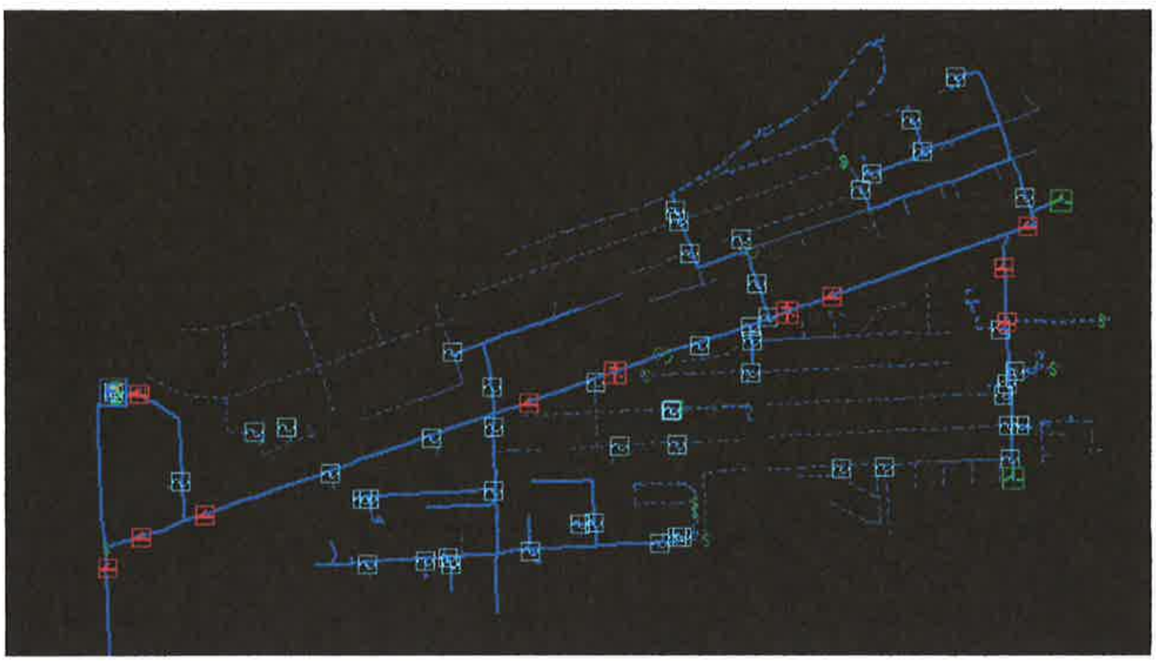
REV NOTES

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

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



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: [signature] 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

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*

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

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

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 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.

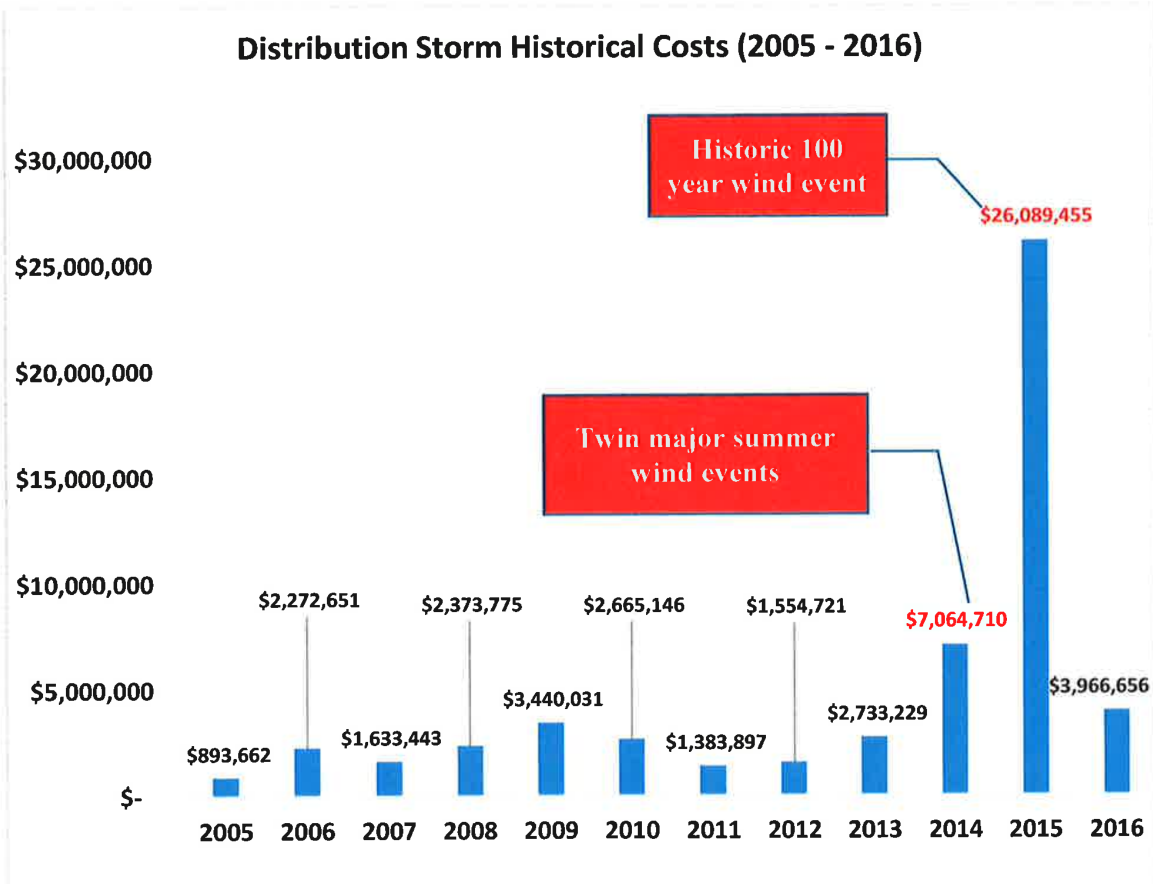


Figure 1: Dx Storm Historical Costs

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

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

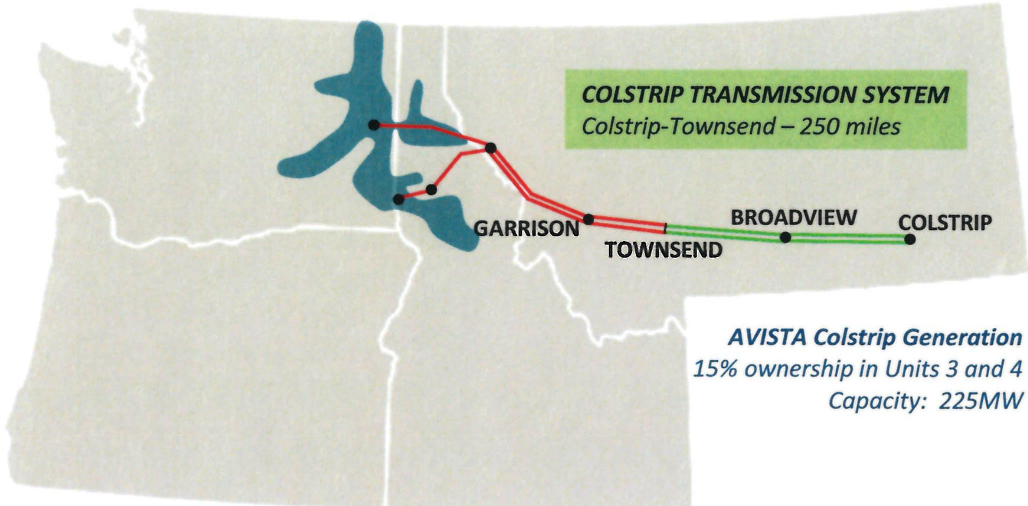
The Colstrip Transmission Committee, consisting of representatives of each of the parties to the Colstrip Project Transmission Agreement ("Agreement"), reviews and approves, on an annual basis, the capital and O&M expense program proposed by NorthWestern Energy (the designated Transmission Operator under 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.



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.

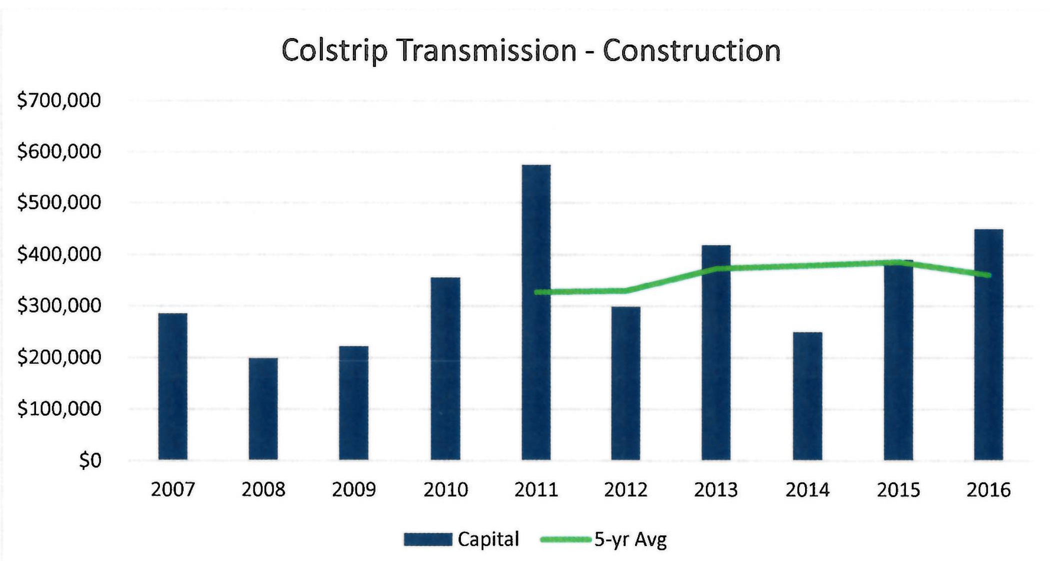
3 PROPOSAL AND RECOMMENDED SOLUTION

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

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: [signature] Date: 4/14/17
Print Name: Darrell Soyars
Title: Environmental Mgr.
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	03/29/17	Darrell Soyars	04/10/17	Initial version

Template Version: 02/24/2017

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.

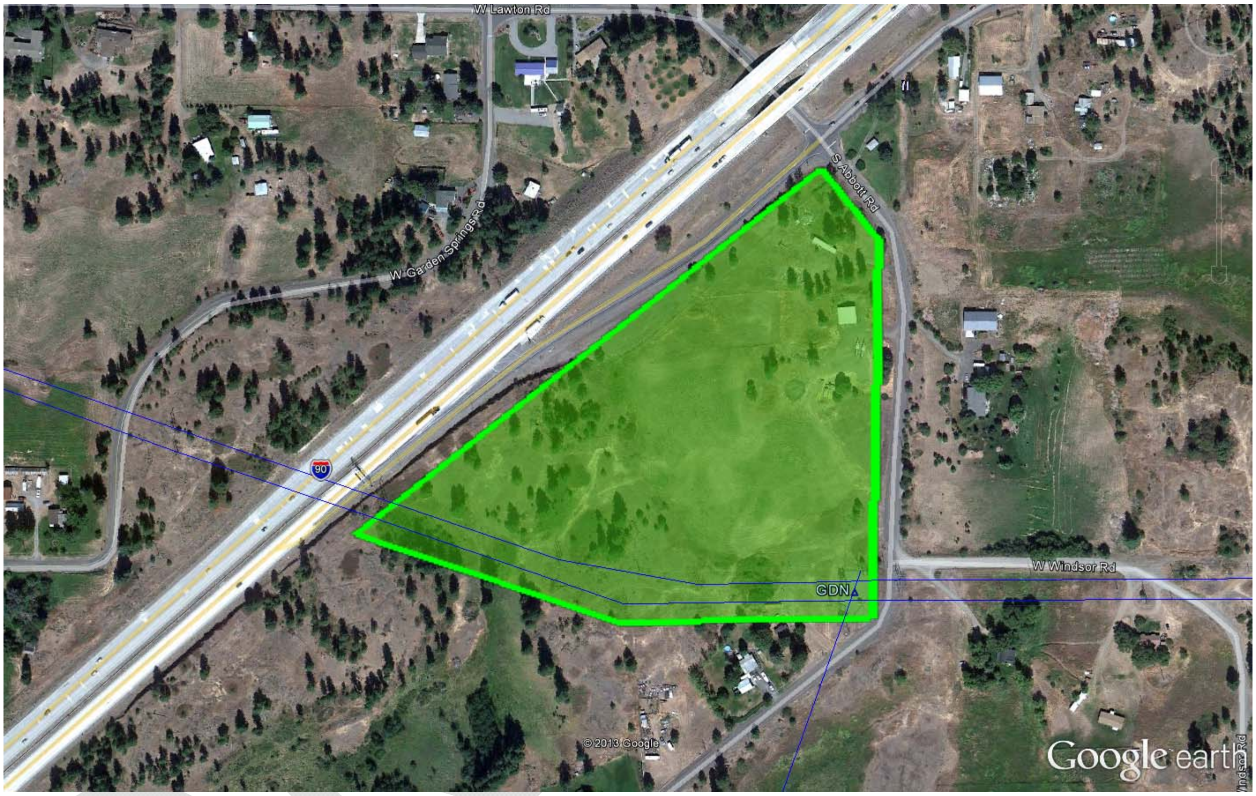
2 BUSINESS PROBLEM

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:

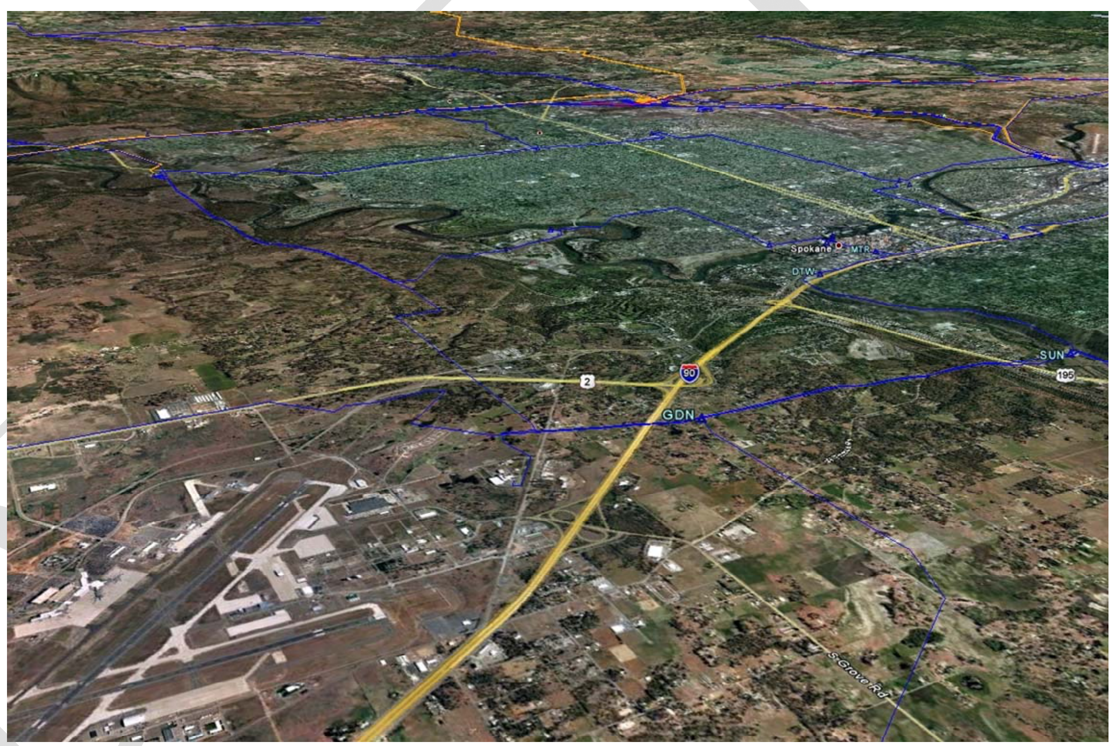
Constructing a 7.9-mile 230 kV transmission line from Westside to the new Garden Springs station was considered instead of the proposed Bluebird-Garden Springs 230 kV Transmission Line interconnection with BPA. Performance issues are not fully mitigated with this alternative. Specifically, the P7 outage 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

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*

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.

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*

<u>Alternative 1:</u>

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: [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: 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	*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: 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: 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

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: D. 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

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: S 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

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

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

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.

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

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.

<u>Solution:</u>

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: 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: [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

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.

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

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: [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	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.

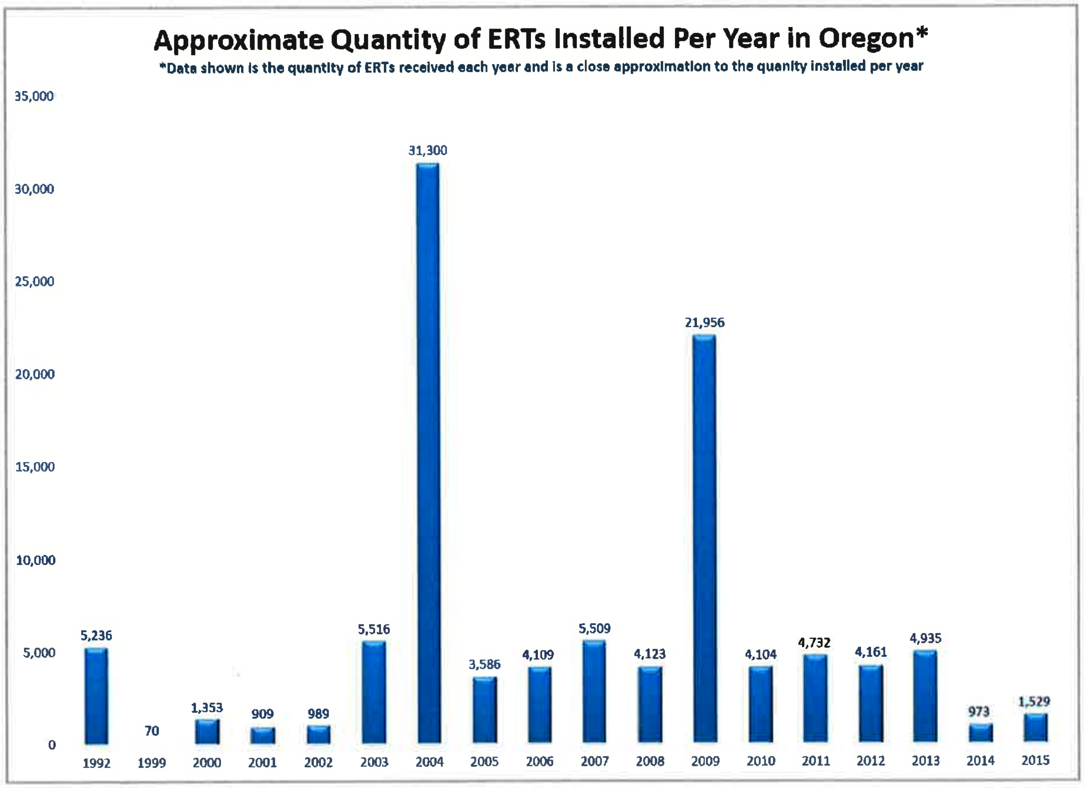


Figure 1 – Approximate Quantity of ERTs Installed per year in Oregon

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.

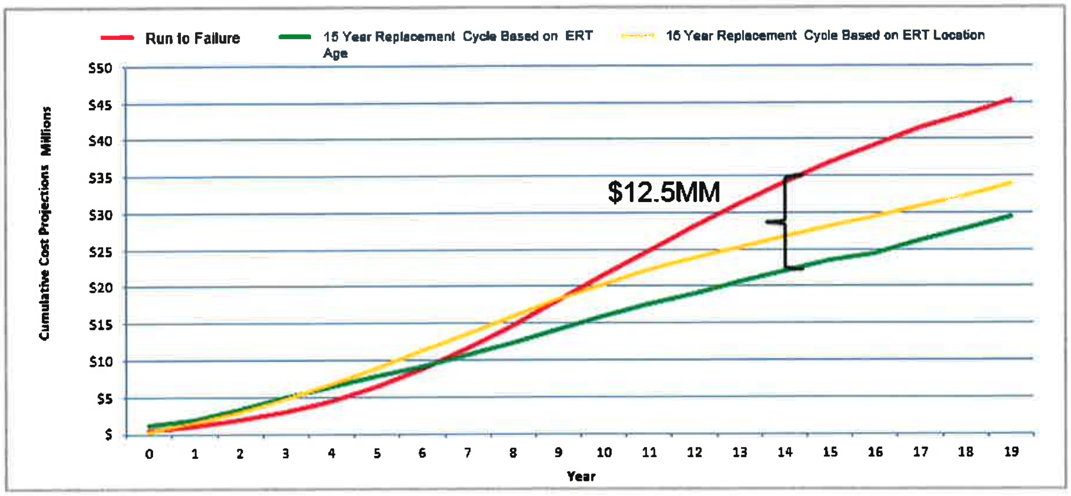


Figure 3 – Cost Comparison for Options: 1 (red), 2 (green), and 3 (yellow).

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

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: HR 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]	[illegible]	[illegible]	[illegible]
Preferred Stock	0.00%	0.00%	0.00%	0.00%
Common Equity	[illegible]	[illegible]	[illegible]	[illegible]
			7.29%	[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)	Savings or margin by year
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		
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)	Savings or margin by year
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		
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	1	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	[illegible]	[illegible]	[illegible]	[illegible]
Preferred Stock	[illegible]	[illegible]	[illegible]	[illegible]
Common Equity	[illegible]	[illegible]	[illegible]	[illegible]

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

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

Lev ROE 106
NPV equity 1,563

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

ID Gas - 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	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%		Debt	[illegible]	[illegible]
Federal Income Tax Rate	35.00%		Preferred Stock	0.00%	0.00%
Discount Factor	6.35%		Common Equity	[illegible]	[illegible]
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	

Green block (further columns): [illegible] [illegible]; 0.00% 0.00%; [illegible] [illegible]; [illegible] [illegible]

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

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

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:		Date:	4-17-17
Print Name:	Jeff Webb		
Title:	Manager of 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: 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: 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	04/13/2017	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.

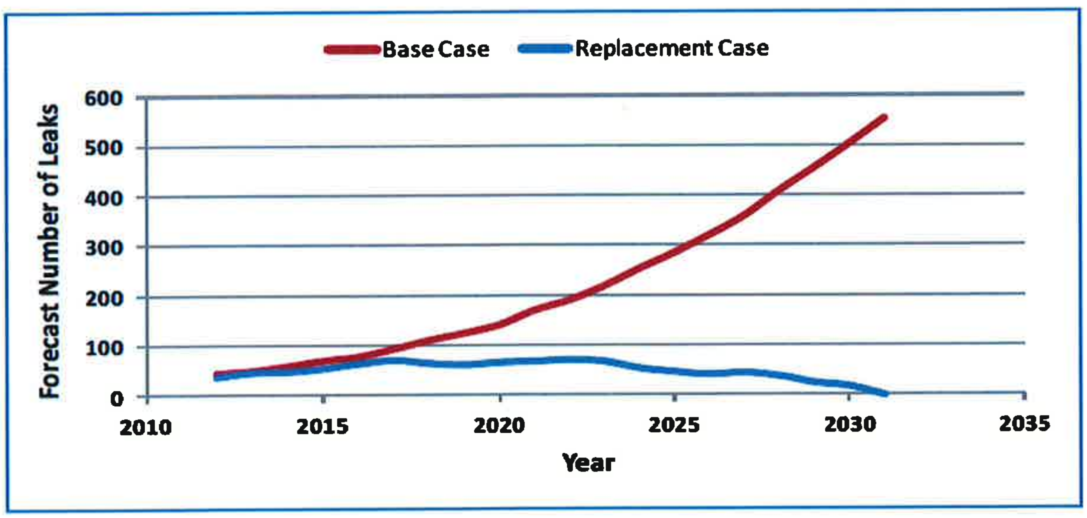
On December 31, 2012 the Washington Utilities and Transportation Commission (WUTC) issued its' policy statement on Accelerated Replacement of Pipeline Facilities with Elevated Risks which requires gas utility companies to file a plan every two year for replacing pipe that represents an elevated risk 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:

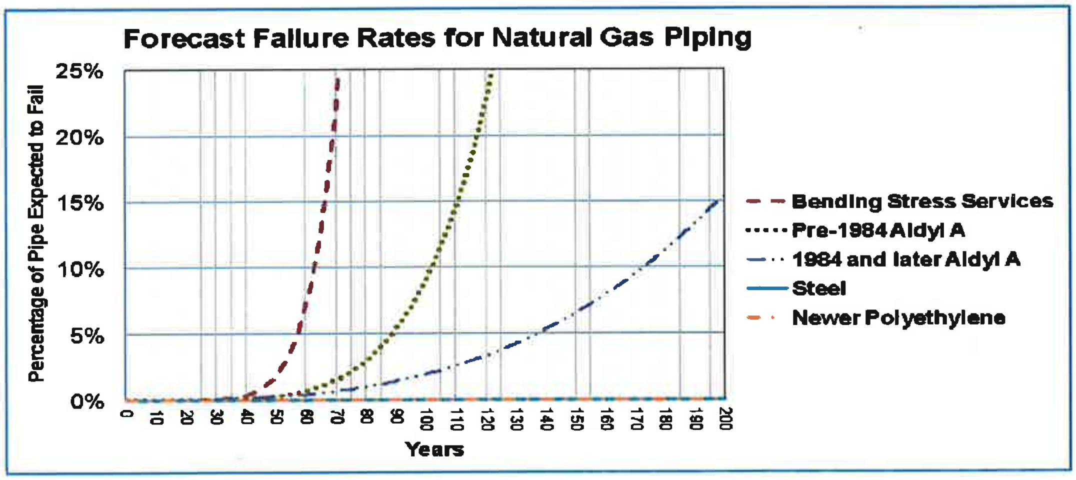
The need to conduct this program has been identified in "Avista's Proposed Protocol for Managing Select Aldyl A Pipe in Avista Utility's Natural Gas System" report. Further, and more specifically, due to the tendency for this material to suffer brittle-like cracking leak failures, Aldyl A will eventually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

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: Date: 4/07/17

Print Name: Michael B. Whitby

Title: Program/Project Manager

Role: Business Case Owner

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.

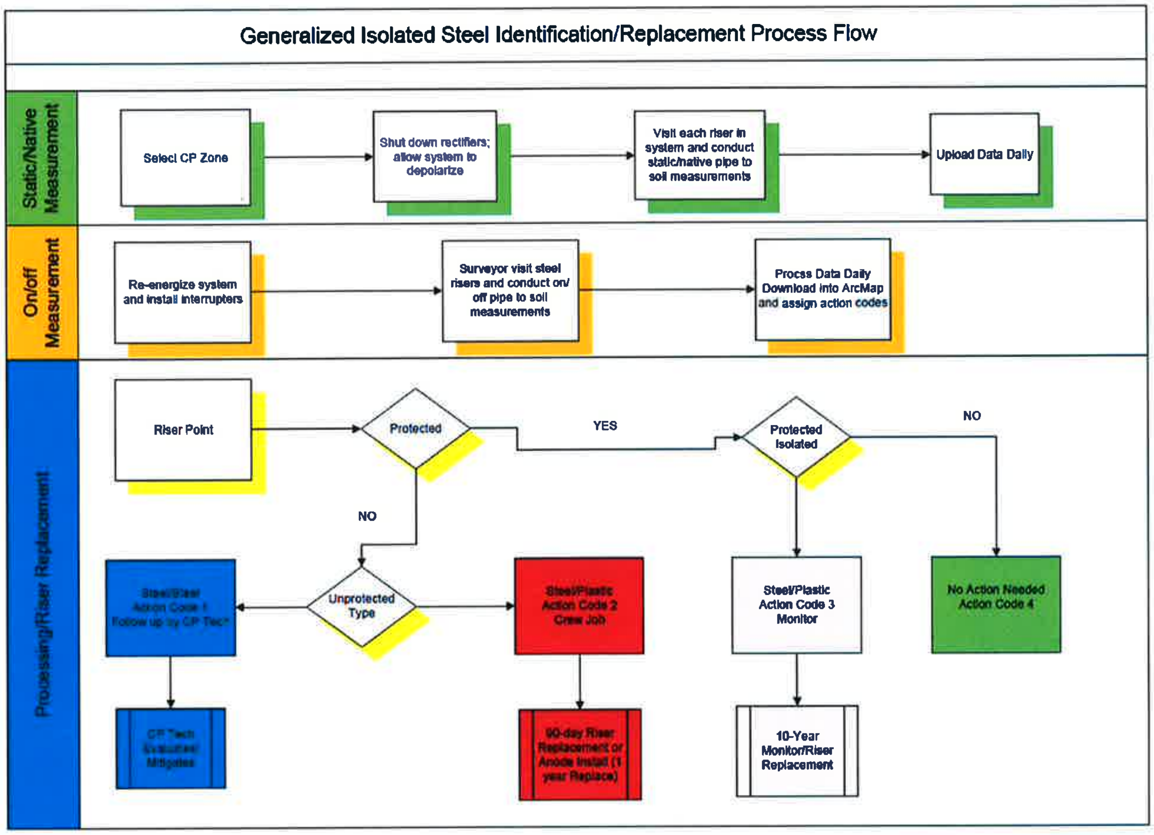


Image 1 – Generalized Work Flow

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:		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: 02/24/2017

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.

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

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

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.

	last updated		Rank	Feet		Description	
OBJECTID	SIZENUMBER	MATEI	NOTE!	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

Exhibit No. 8
Case Nos. AVU-E-17-01 and AVU-G-17-01
H. Rosentrater, Avista
Schedule 5, Page 209 of 325

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: 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 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:		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: 02/24/2017

Gas Schweitzer Mtn Rd HP Reinforcement, ER 3310

1 GENERAL INFORMATION

Requested Spend Amount	$1,500,000 (2018)
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner	Jeff Webb
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 – Gas Engineering
Category	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 Gas Planning, load growth in the Sandpoint Idaho area has exceeded the capacity of the existing gas distribution system. Adequate capacity is defined as system pressures at or above 15 pounds per square inch (psig) in the distribution system and 90 psig in the high pressure supply lines on a design day analysis. Without a reinforcement project, Avista will not have sufficient capacity to serve firm customer load in the Sandpoint area on a design day scenario.

It is proposed to install approximately 1.3 miles of 6" steel gas main on Schweitzer Mtn Rd to reinforce the distribution system of Sandpoint, ID.

Need for the Project: Currently, the NE part of Sandpoint is predicted to have capacity constraints on a design day. As part of our obligation to serve firm customers, this reinforcement is necessary to ensure the system capacity and resultant pressures are adequate. This project will also add an additional regulator station to the area to increase reliability.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing, Cold Wx Action Plan	$0		
Proceed as described above	$1,500,000	01 2018	12 2018
[TBD	$??	01 2018	12 2018

Space heating is the most predominate use of gas for Avista's firm customers. Should a gas outage occur during a cold weather event due to insufficient capacity of a distribution system, there would be a high level of risk associated with the health and safety of the individuals, and the potential damage to the buildings due to freezing water pipes. Completion of this reinforcement project greatly reduces this risk.

Since this area has insufficient capacity to serve firm customers on a design day, a cold weather action plan has been developed. This plan outlines particular activities that could be implemented such as the manual on-sight monitoring of system pressures, a media blast to request a temporary thermostat turndown, taking extraordinary measures to manually improve the capacity of the system by bypassing regulator stations or manually shedding load (shutting off customers completely), and/or preparing relight lists (to restore service to customers who have lost gas service).

Avista has determined it is not appropriate to rely upon a cold weather action plan for the safe and reliable operation of the natural gas distribution system. These are stop gap measures put in place because of a known capacity deficiency until a permanent reinforcement project can be completed. Operating in this mode requires Avista employees to work outdoors in extremely cold situations, which results in increased operations and maintenance expense (O&M expense) due to overtime pay and increased safety risks to our employees performing the manual intervention (i.e., working outdoors and driving vehicles in cold, snowy, and icy conditions). Additionally, these activities are last-ditch efforts to maintain service, and they do not represent a guarantee that service will be able to be maintained to customers paying a firm gas rate.

Additional efforts will be spent in 2017 to determine alternate piping solutions and determine the best option for construction in 2018.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Schweitzer Mtn Rd 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:	*[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: 03/07/2017

1 GENERAL INFORMATION

Requested Spend Amount	$10,000,000
Requesting Organization/Department	Gas Engineering
Business Case Owner	Jeff Webb, David Smith
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 - Gas Engineering
Category	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, load growth on the Williams Northwest Pipeline (NWP) Coeur d'Alene Lateral pipeline has exceeded both Avista's contractual delivery amounts as well as the physical capacity of the NWP Coeur d'Alene Lateral pipeline. In addition, the distribution system in the Hayden Lake, Idaho area will experience insufficient pressure during periods of peak demand 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. Without a reinforcement project, Avista will not have sufficient capacity to serve Firm customer load in the Coeur d'Alene, ID to Kellogg, ID corridor on a design day scenario.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 - Do nothing	$0		
Option 2 – Preferred Solution, Avista to construct approximately six miles of high pressure distribution pipeline in two phases to reinforce the distribution system in the greater Post Falls and Coeur d'Alene area.	$10,000,000	11/2015	12/2018
Option 3 – Alternative Solution, Compensate Williams Northwest Pipeline (NWP) for a mainline expansion of their Coeur d'Alene Lateral pipeline.	$10,000,000	11/2015	12/2019

Option 1 – Do nothing

Without a reinforcement project Avista does not have sufficient capacity to serve existing Firm customer load in the Coeur d'Alene, ID to Kellogg, ID corridor on a design day scenario, and cannot support any future customer growth. See Image 1 below for a load study analysis showing the Hayden Lake area distribution system with insufficient capacity. Approximately 3900 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, Avista to construct approximately six miles of high pressure distribution pipeline in two phases to reinforce the distribution system in the greater Post Falls and Coeur d'Alene area.

This option capitalizes on the capacity available from the recently constructed Chase Road Gate Station (supply point into Avista's system) located on the GTN-TransCanada (GTN) pipeline. This option consists of a multi-year project comprised of a two phase high pressure distribution pipeline reinforcement that will shift gas usage from NWP to GTN, and will also allow Avista to choose a portion of gas nominations from either NWP or GTN to take advantage of price differentials. This additional capacity will be used to support customer growth in the Post Falls, ID and Coeur d'Alene, ID area currently served from NWP. This option also inherently increases system reliability by having two independent interstate pipeline gas sources, which will reduce the risk of customer outages in the event of an abnormal operating condition. Another benefit of this option is that it will be completed approximately one year before Option 3, which will accommodate the existing needs and support additional customer growth sooner. Phase one and phase two both consist of installing approximately three miles of 6" high pressure distribution pipeline and two Regulator Stations (pressure reductions stations) within Avista's system, with phase one scheduled to be constructed in 2017 and phase two constructed in 2018. See Image 2 below for a load study analysis showing how the proposed reinforcement provides sufficient capacity to the Hayden Lake, ID area distribution system.

Option 3 – Alternative Solution, Compensate Williams Northwest Pipeline (NWP) for a mainline expansion of their Coeur d'Alene Lateral pipeline.

The NWP expansion would include the installation of up to 6 miles of 10" pipe beginning at or near the WA/ID border (west of Post Falls, ID), which involves investing significant money into the Williams NWP system instead of Avista's infrastructure. Additionally, Avista would be required to refurbish and expand at least four Gate Stations (NWP supply point into Avista's system) along the NWP Coeur d'Alene Lateral to accommodate the projected load growth. This option is estimated to take 4 years to complete, which does not provide a timely reinforcement to the deficient Hayden Lake area, nor does it offer timely support of continued customer growth. Another disadvantage of this option is that Avista would not gain the ability to have two independent interstate pipeline gas sources into one of the largest load centers in our system, which would reduce system reliability in the event of an abnormal operating condition.

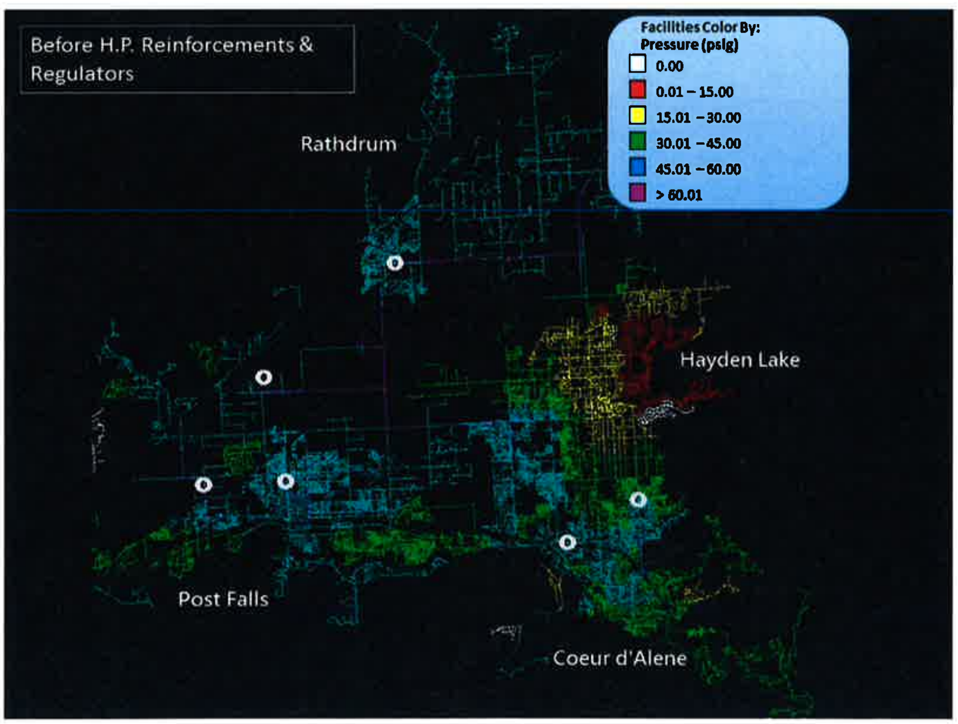


Image 1 – Distribution System Pressures before Proposed Reinforcement

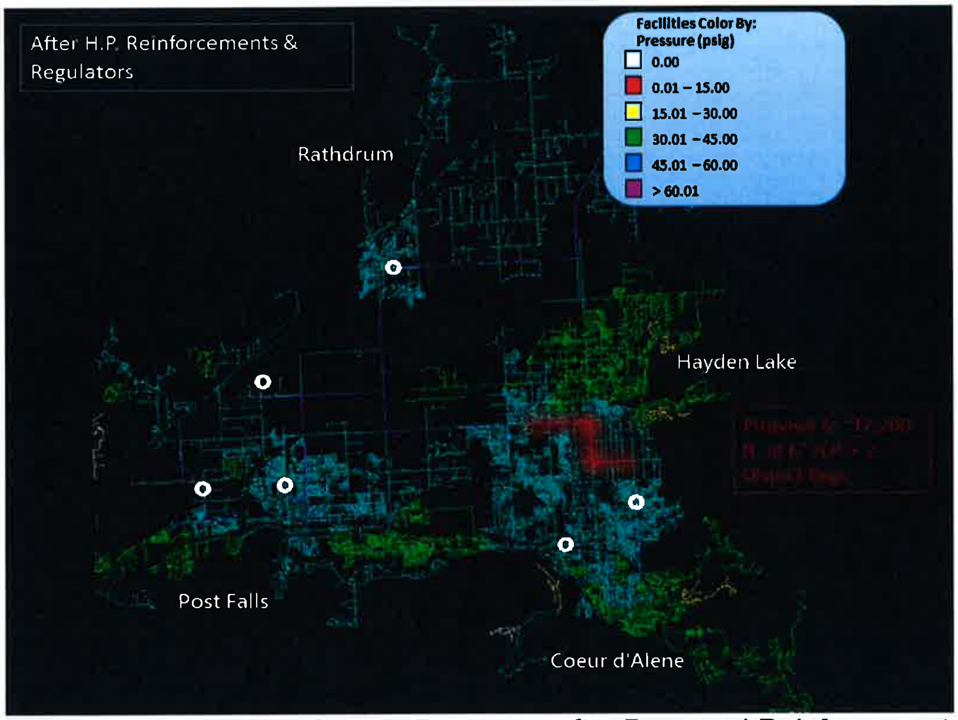


Image 2 – Distribution System Pressures after Proposed Reinforcement

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Rathdrum Prairie 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:	[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	4/17/2017			Initial version

Template Version: 02/24/2017

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

<u>OPTION 1 – PERFORM THE FOLLOWING NINE MAJOR PROJECTS:</u>

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:

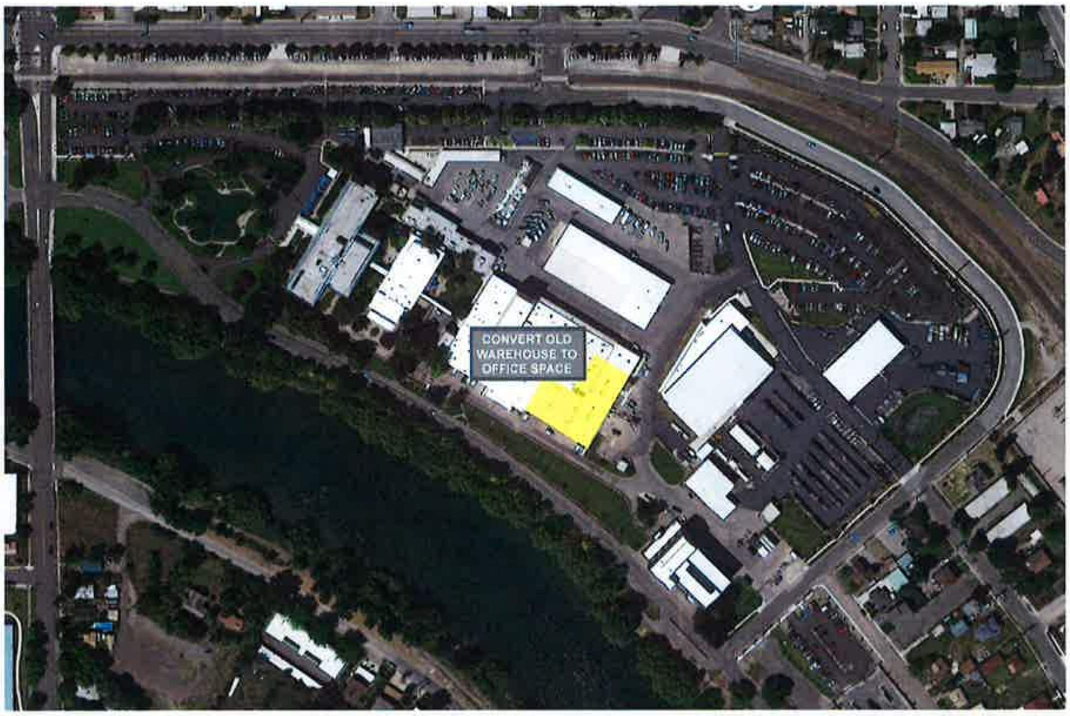
- Modernize the aged warehouse space within the service building.
- Expand and locate campus parking to align the available number of parking spaces with the number of employees working onsite, improving employee and public safety by reducing parking sprawl.
- Separate operations traffic from pedestrian 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.

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.

Project 2: Service Building Renovation into Office Space

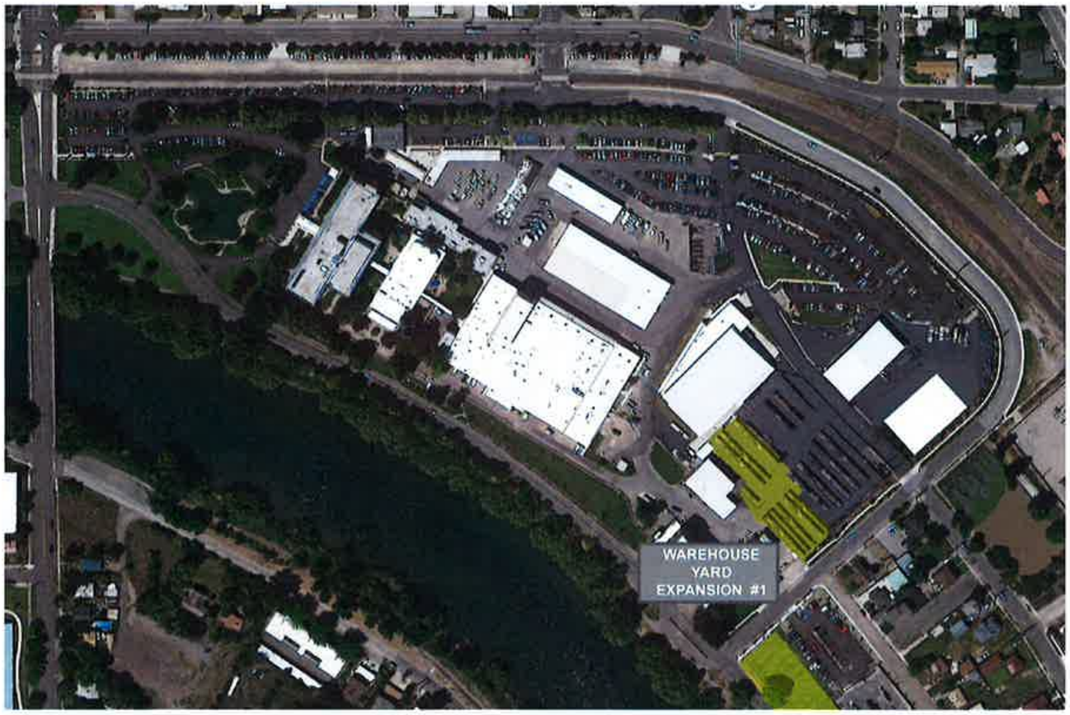


The Service Building Renovation was completed in 2014. It remodeled what was formerly the Warehouse space into administrative office space, with the ability to seat approximately 100 employees. It also created new restrooms, a new mailroom/graphics space, several conference rooms, and a break area. The 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.

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.

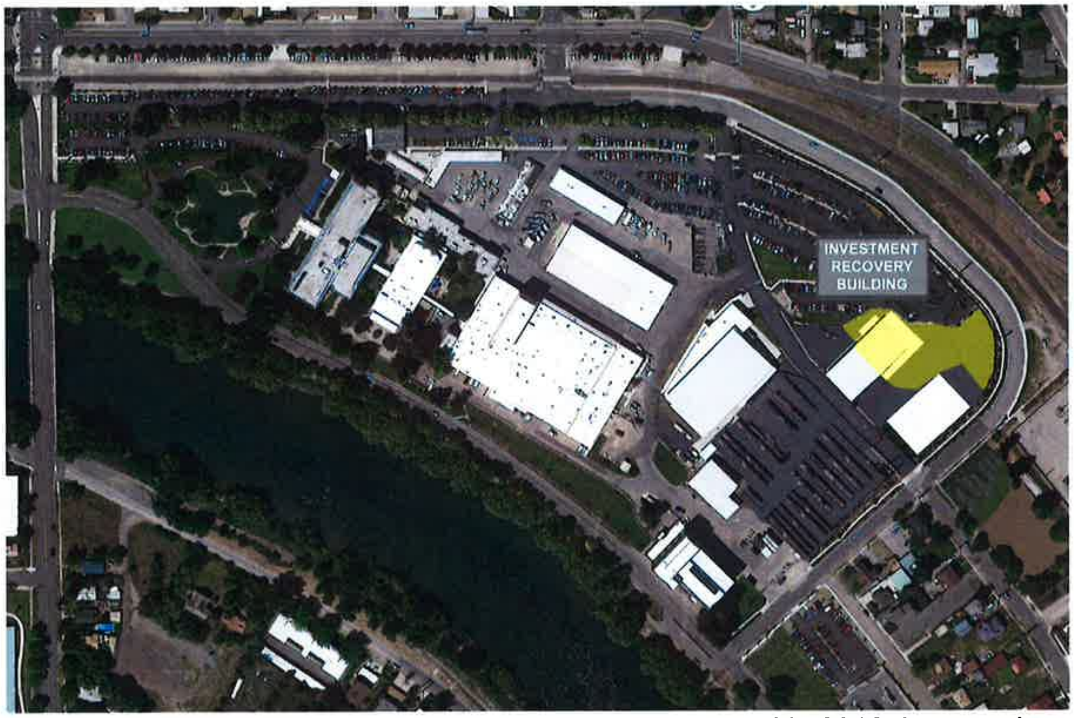
Projects 4 and 5: GPSS Storage Building and Warehouse Storage Yard Expansion #1



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



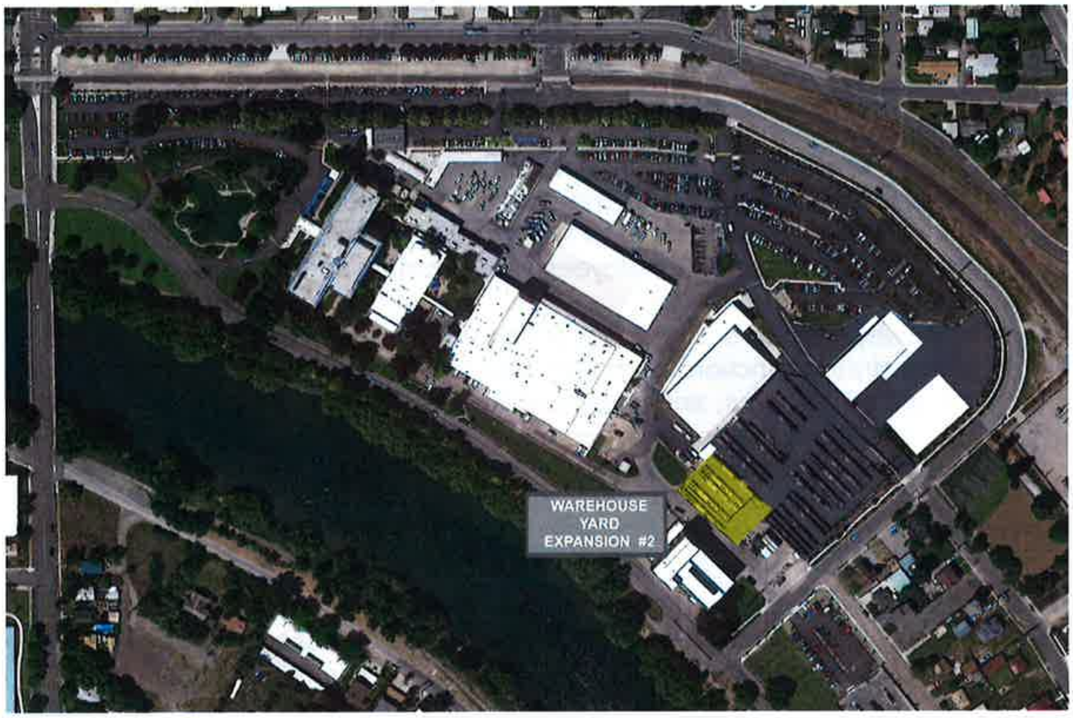
The new Investment Recovery (IR) building was completed in 2016. It created a new home for our recycling crews that deconstruct, sort, and catalog all applicable Avista components that field crews bring back from their daily work orders. This includes Avista crews not only local to Spokane, but also 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.

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.

- 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.

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

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

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

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.

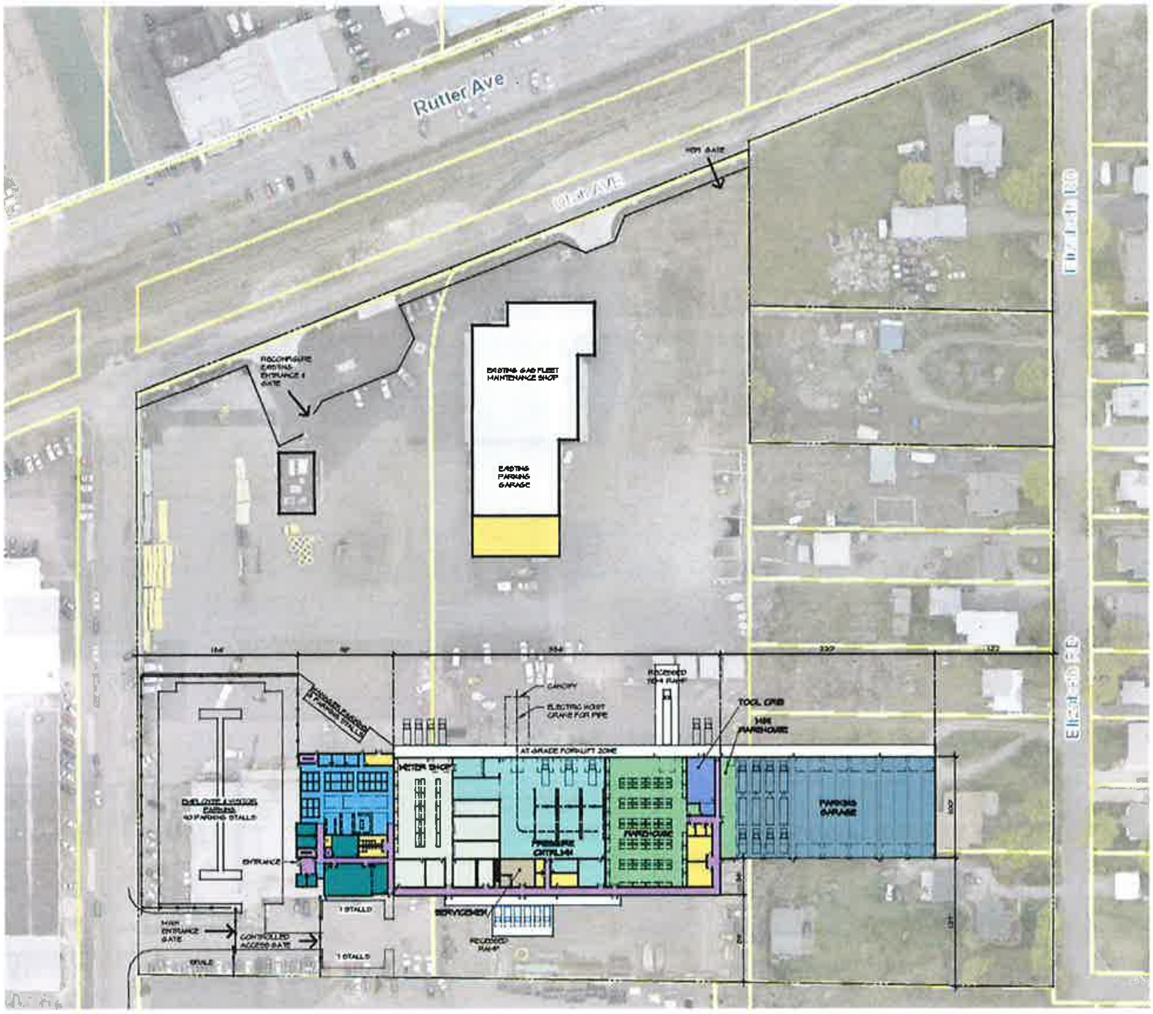
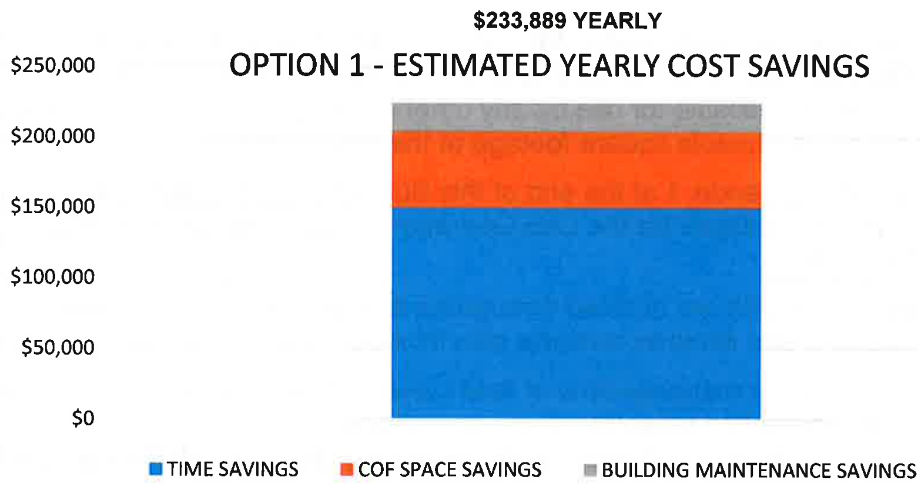


Exhibit No. 8
Case Nos. AVU-E-17-01 and AVU-G-17-01
H. Rosentrater, Avista
Schedule 5, Page 239 of 325

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

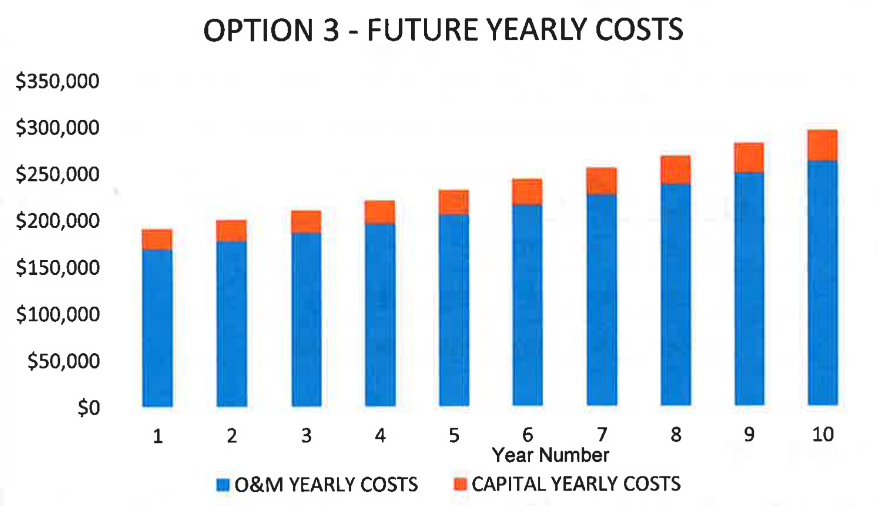
Facilities explored relocating the gas operations to an alternate sites, with the intent to build a facility similar to Option 1 above. In addition, the new site would have to build a new Fleet Maintenance Building and Vehicle Storage Building to replace their uses currently on the existing site. The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

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

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.

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.

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.

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: ______________________ 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











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

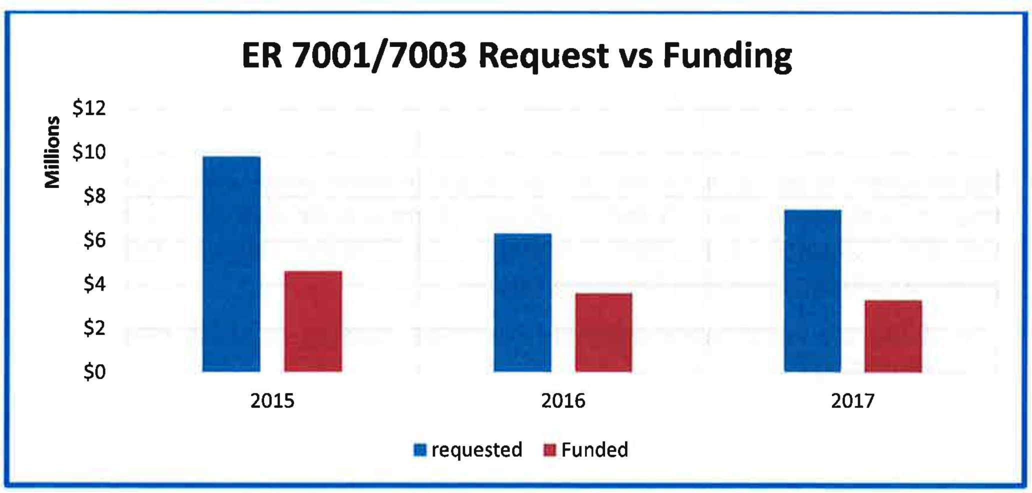
1.1 Steering Committee or Advisory Group Information

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.



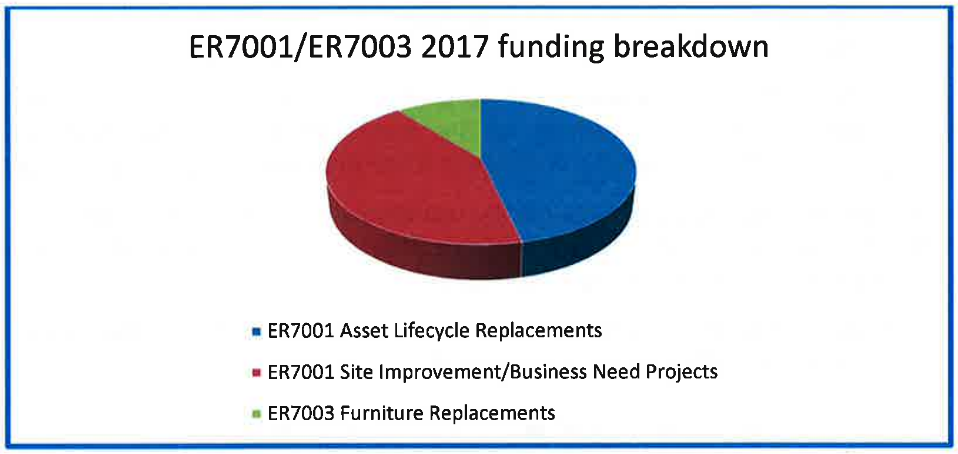
Funding backlog

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.)

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.

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

The undersigned acknowledge they have reviewed the ~~Airport Hangar~~ Facilities Structures & Improvement 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

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.

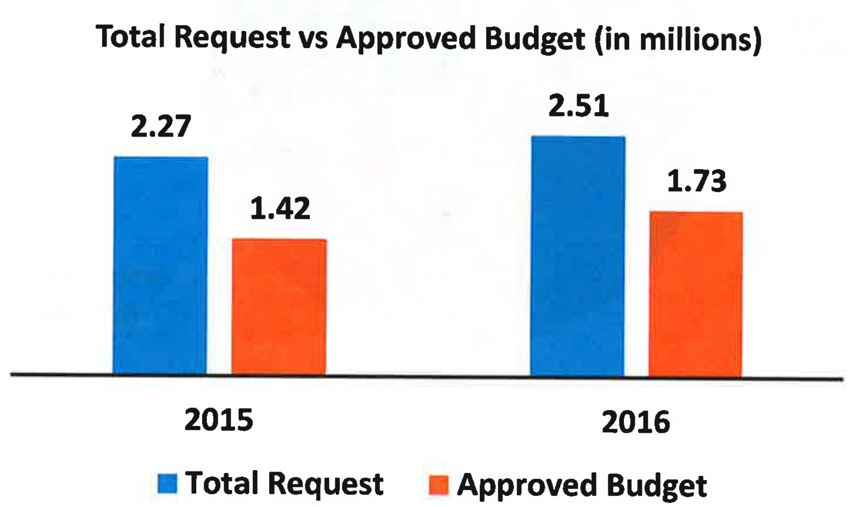


Figure 1

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)

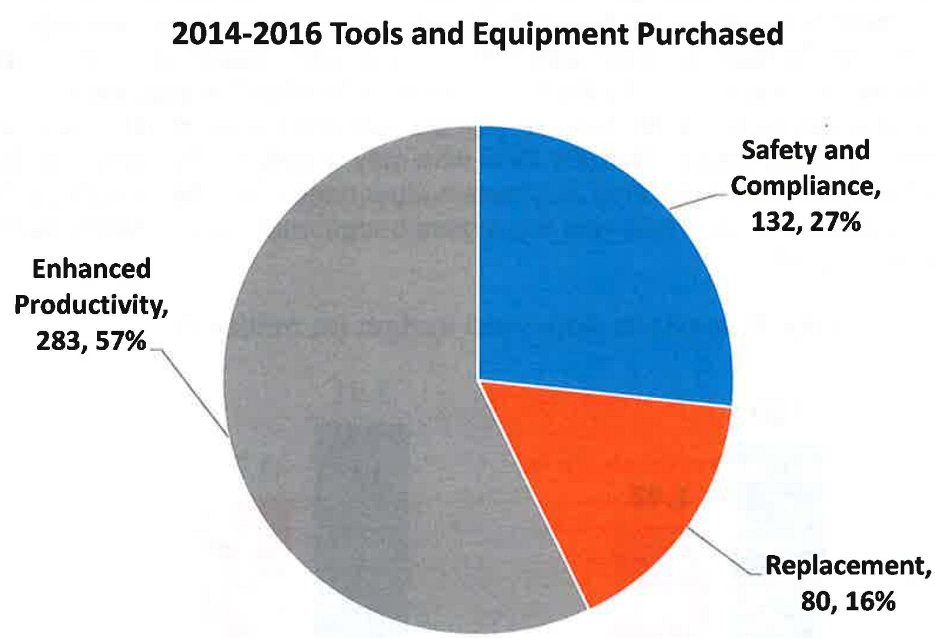


Figure 2

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.

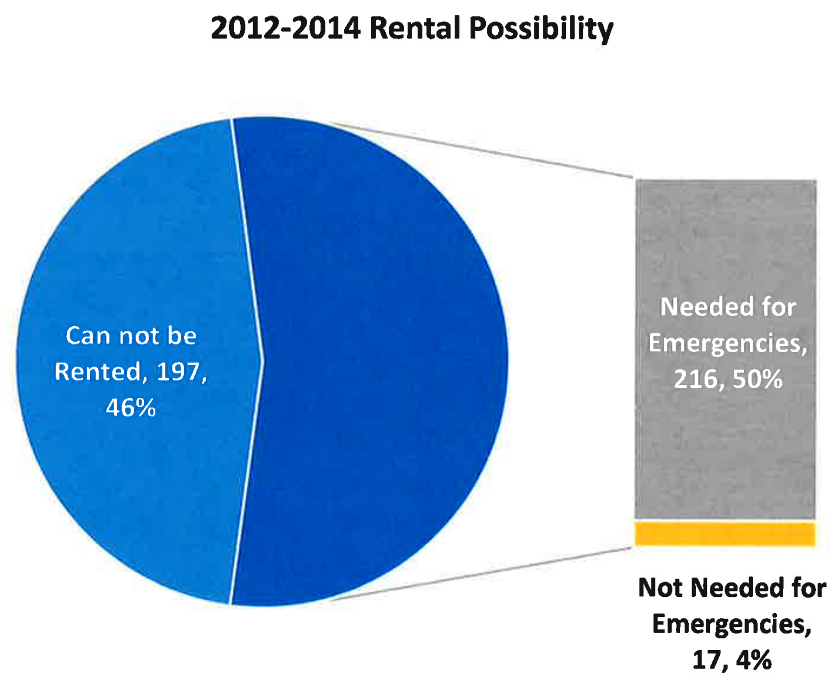


Figure 3

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.

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: [signature] Date: 5/2/17
Print Name: Glenn Madden
Title: Manager, Supply Chain
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

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

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:		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

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

- 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.

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.

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.

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	

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.

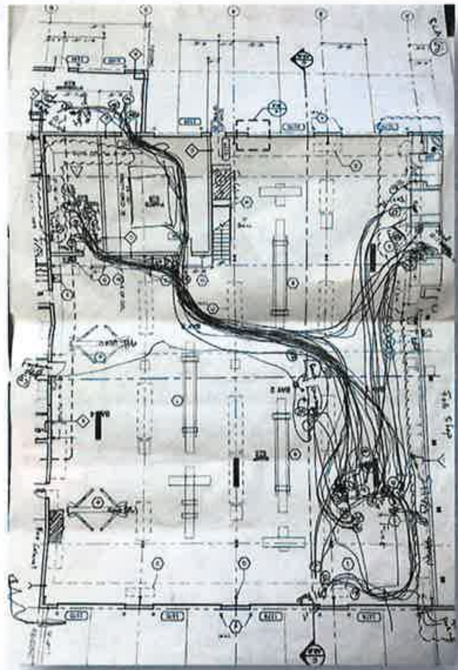
Operations traffic to the North end of the Campus.				
Option 2: Address the major issues in the existing building separately. • Replace Hydraulic systems, replace the constantly leaking roof, and install a CNG compliant exhausting system. • Increase the building in the future if needed.	$4,000,000	2017	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.		

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

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.

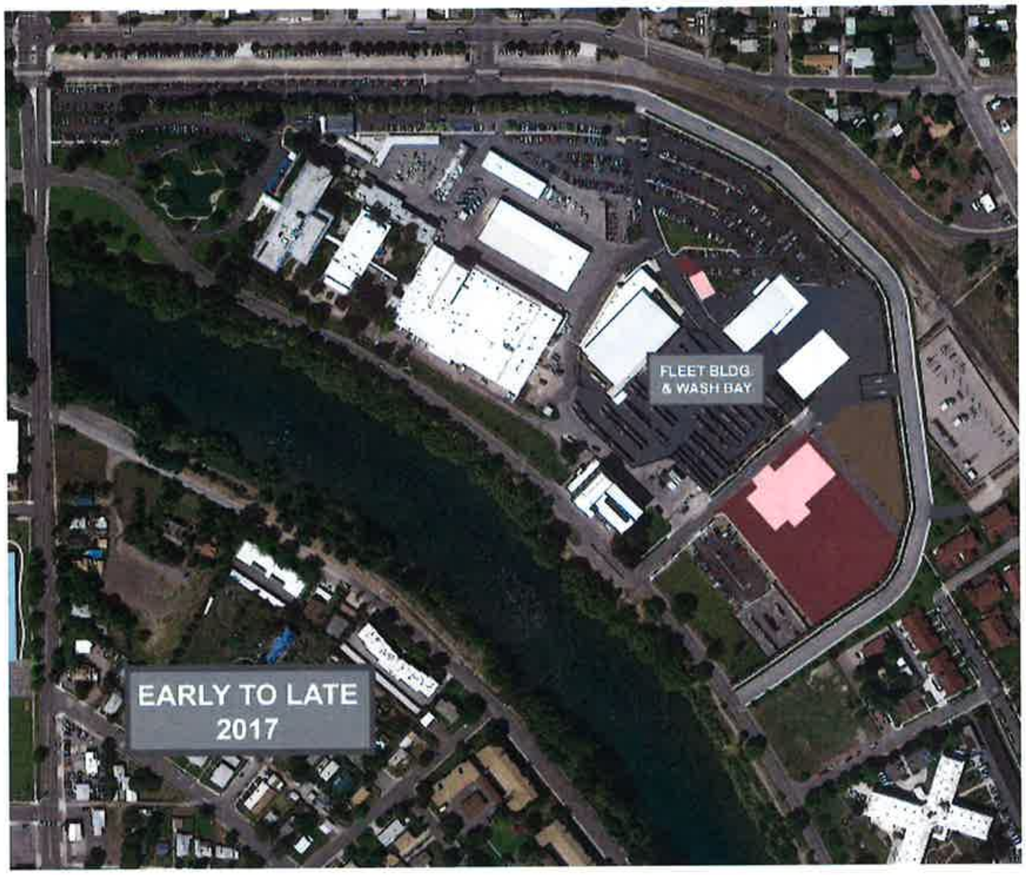


BPI Spaghetti workflow diagram

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:

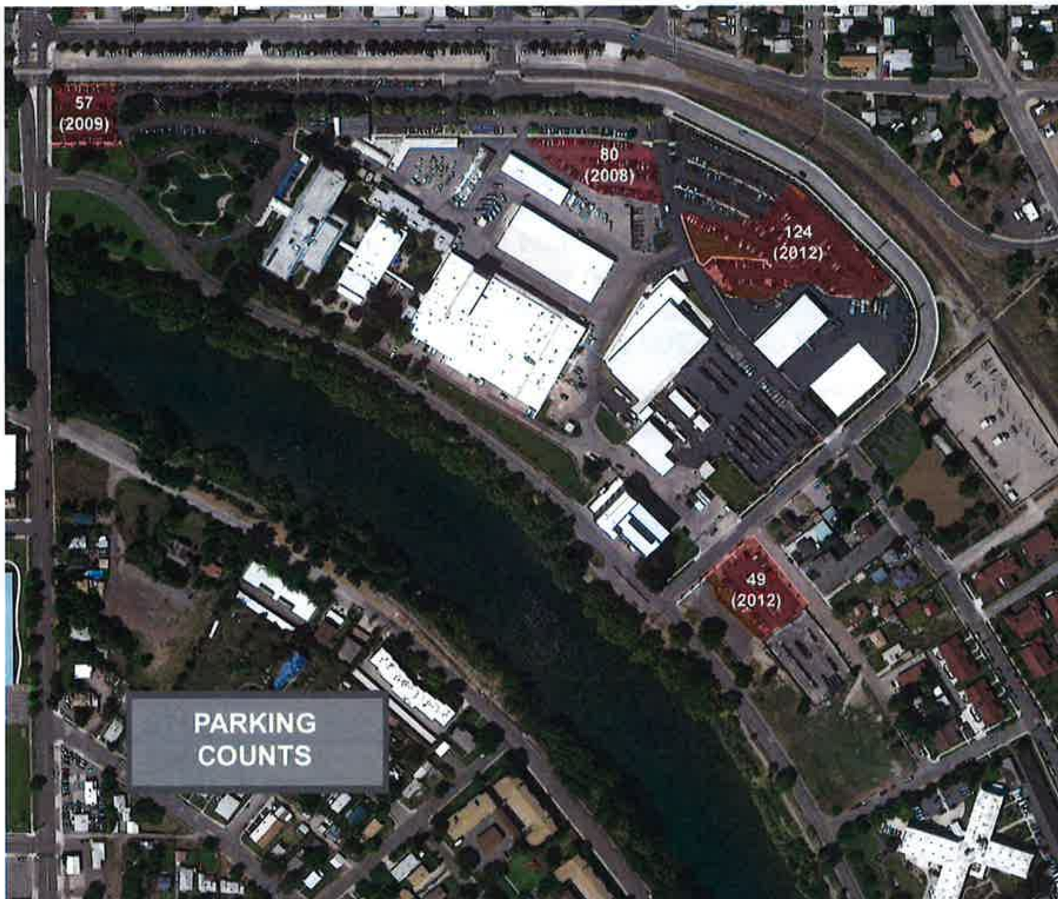
Doing nothing is not a viable option. New hydraulic lifts would be required soon, and basic space, environmental and compliance issues would still need to be addressed. We would need to reevaluate how to continue servicing CNG vehicles.

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****



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:

- 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:

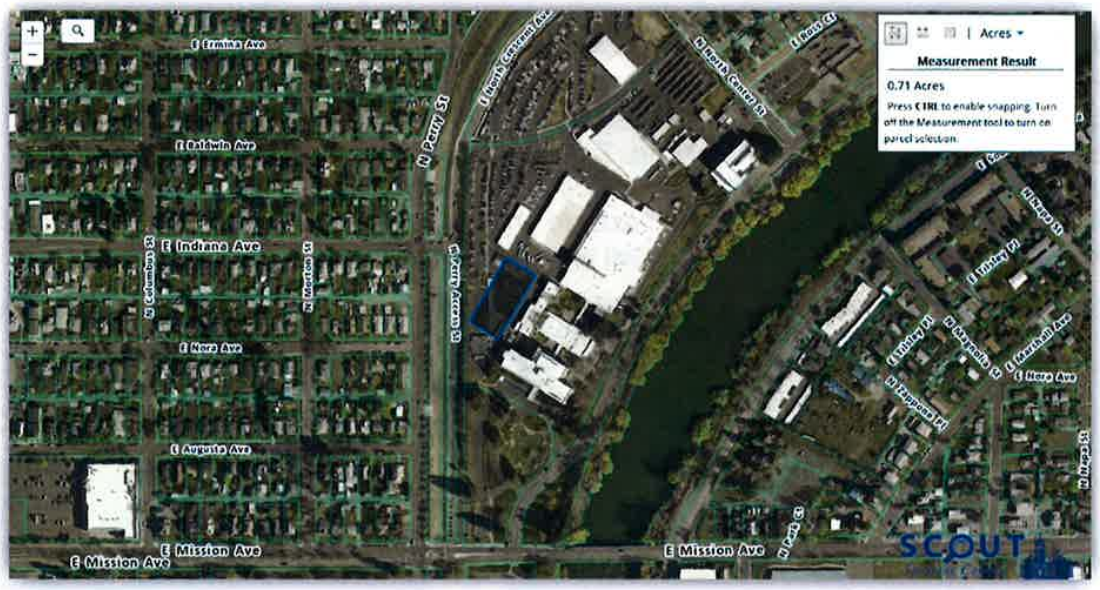
- **Option 1 (recommended)** – Construct a parking garage in the location of the original fleet building. The garage would be a four-story structure with five levels of parking.

- **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.



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.	

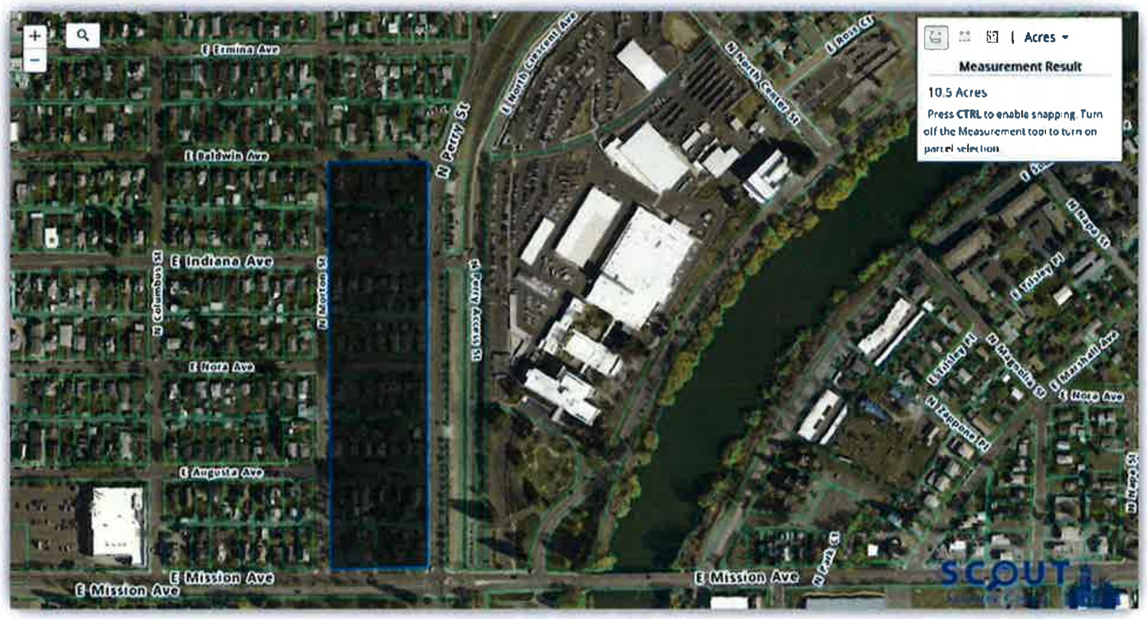
Option 2: Convert Ross Court property into parking to address current deficit

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

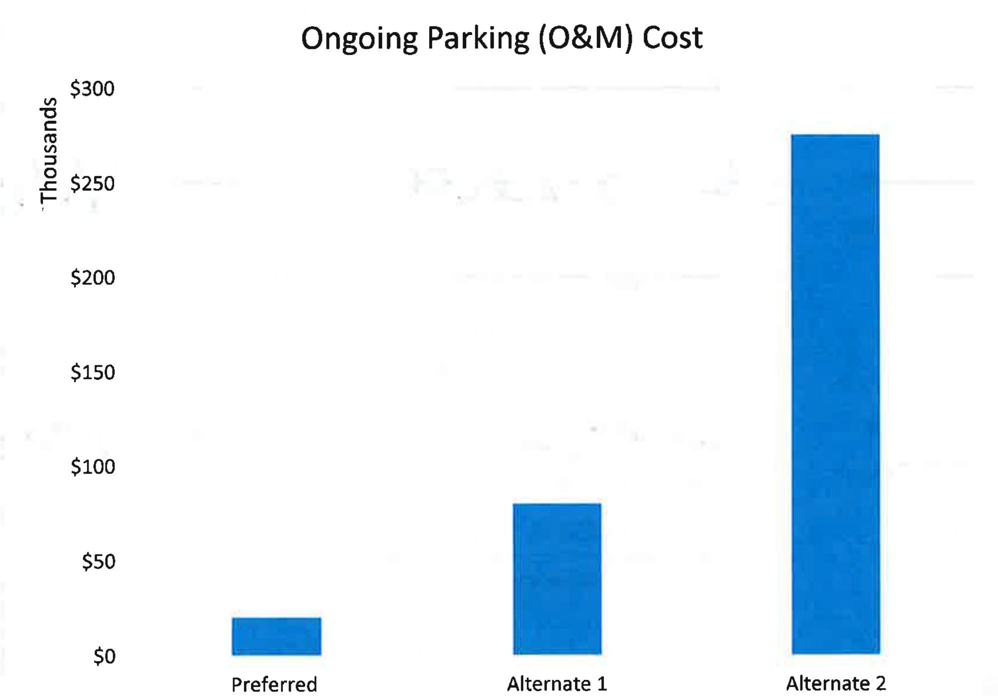
Option 3: Purchase 10 acres to the east and build 500 spaces	
Positive Benefits	**Negatives**
Would net the full 500 spaces	Highest cost option
	High risk of not getting all properties required to build. Risk of street vacations not being approved.
	Increased risk of injury with 500 employees crossing 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

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: 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

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.

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.

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

Aircraft Capital

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: 5-2-17
Print Name: David Robinson
Title: Chief Pilot
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	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.

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:

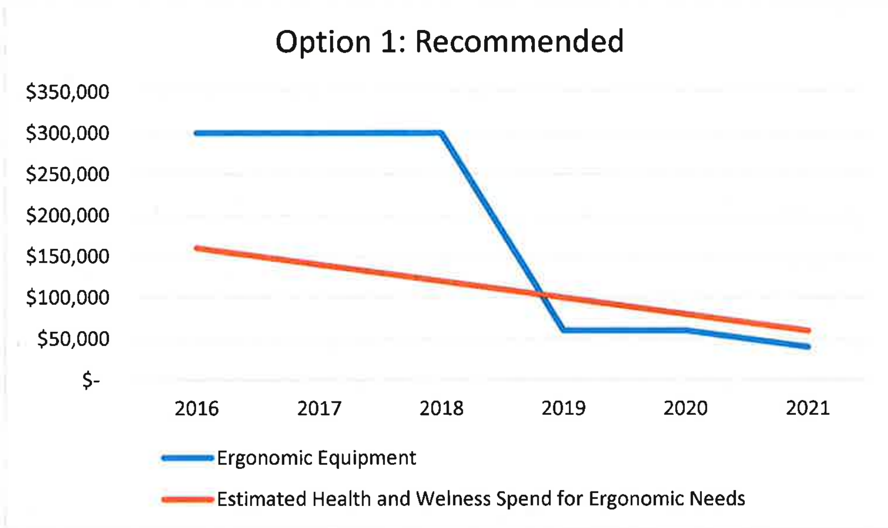
- Increased employee engagement in ergonomic programs and education, by encouraging employees to take responsibility for maintaining their health and wellness at their workplace.
- Decreased time and cost of ergonomic equipment deployment by removing evaluations and approvals and standardizing equipment 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:

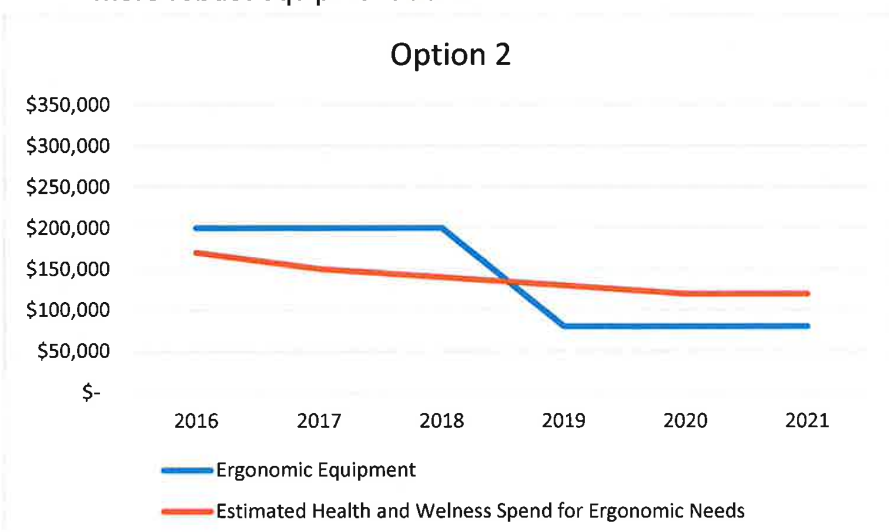
- Participants of the program receive tools including the *Ergonomic Reference Guide*. Employees can use this document as a starting off point for their ergonomic self-assessment. The guide identifies various areas of ergonomics that employees can pinpoint and implement on their own and can also help 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.



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.



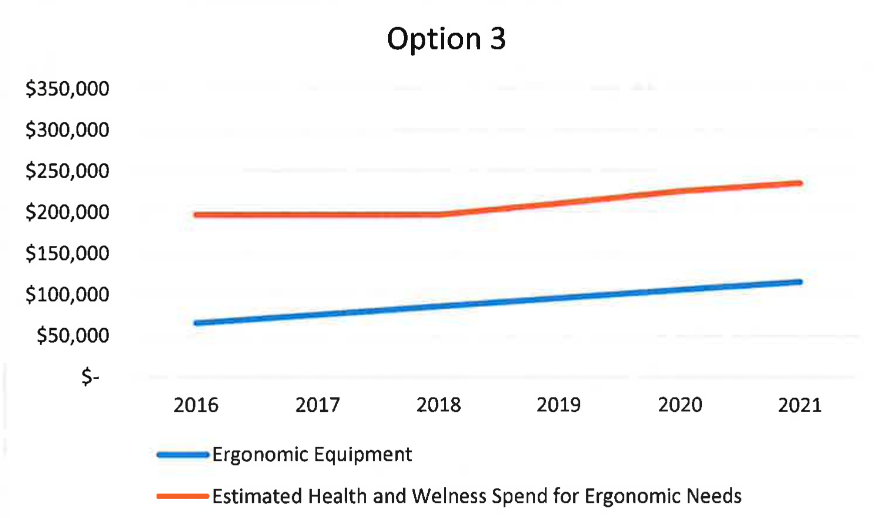
Option 3 – Respond to requests with ergonomic evaluations (as-needed)

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	$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		

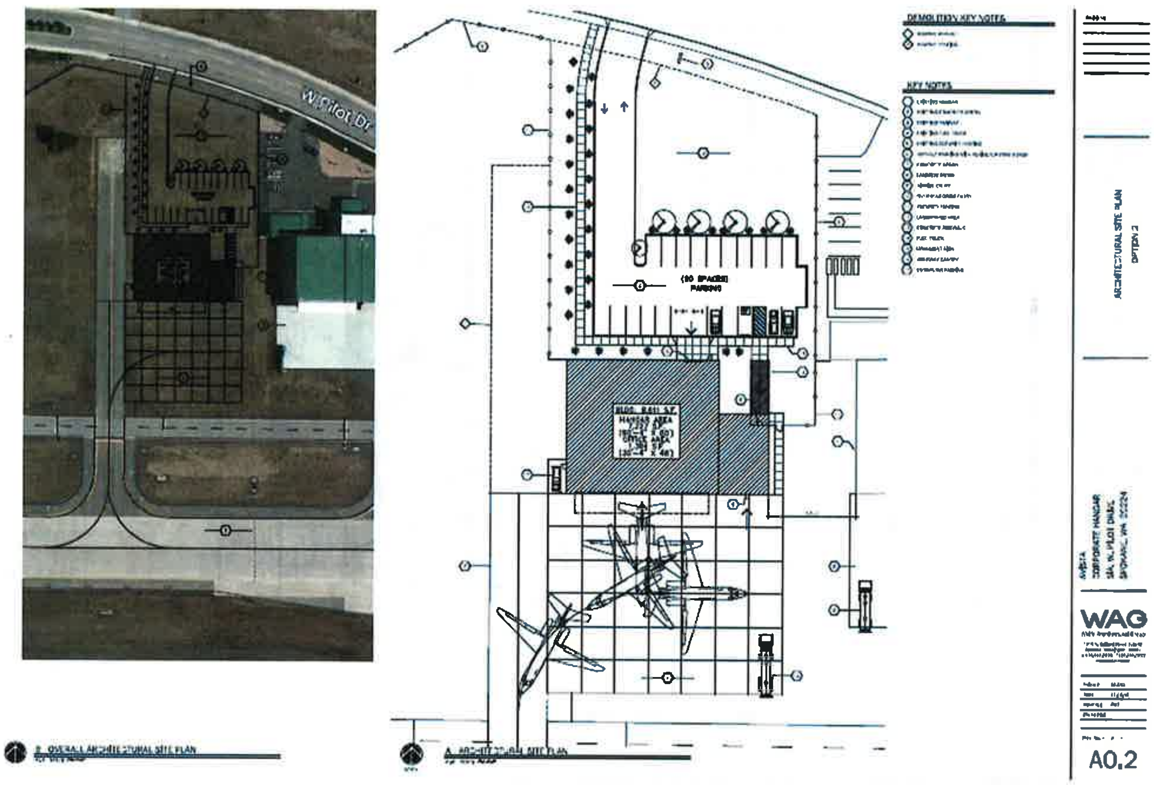
Four options were considered for securing a hangar for the aircraft, including building a new hangar, extending use of the current hangar, relocating to another airport, and co-use of an existing hangar.

Option 1 (Recommended): Build a new Avista-owned hangar on land leased directly from Spokane International Airport.

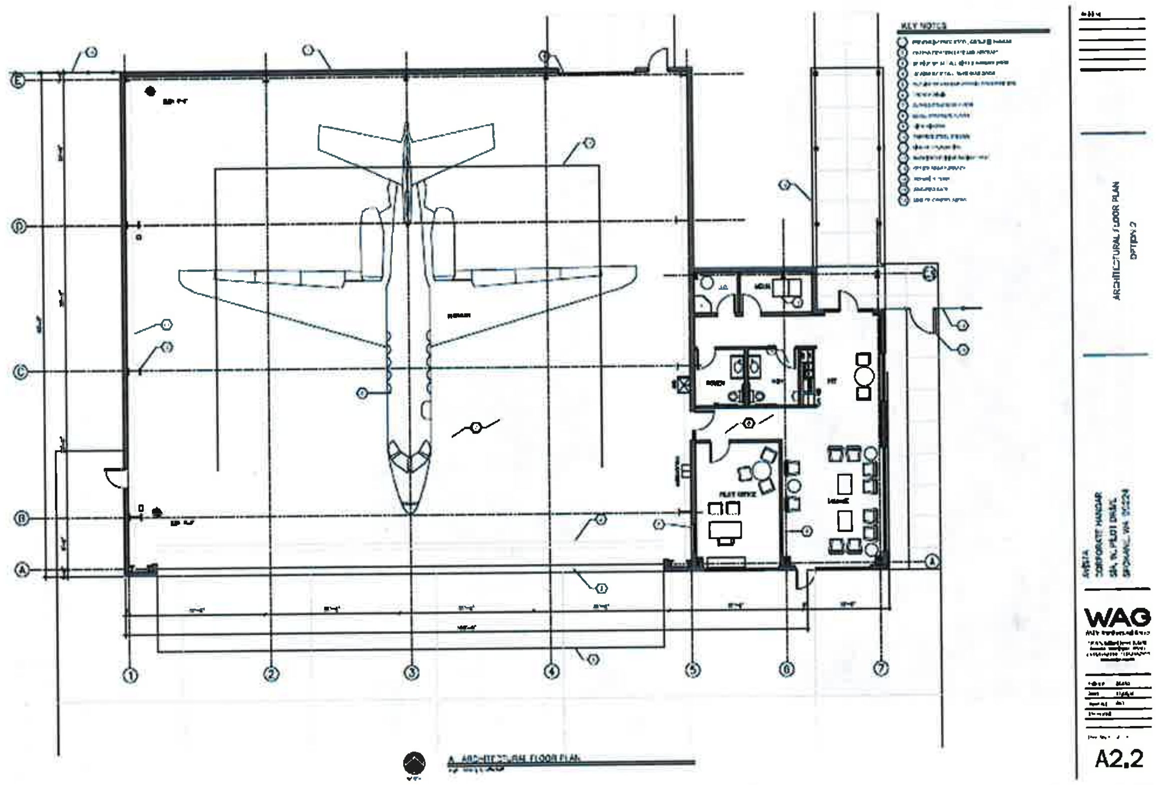
This solution is recommended for the following reasons:

- 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

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

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.

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.

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

Full Budget	2026	2027	2028	2029	2030
Annual Maintenance (Parts, Labor, Vendor) Cost	$6,226,667	$6,411,144	$6,535,809	$6,698,371	$6,853,080
Annual Ownership Cost	$6,549,886	$6,593,568	$6,783,330	$6,851,754	$6,967,321
Annual Capital Budget	$9,764,701	$9,296,048	$10,423,336	$9,731,966	$10,310,050
Units Replaced Annually	112	106	106	103	104
Average Age	8.93	8.95	9.02	9.13	9.22
Units Out of Lifecycle	23	20	16	17	19
Annual Demand Repair Work Orders	6,995	7,048	7,045	7,074	7,082

3.7M Budget	2026	2027	2028	2029	2030
Annual Maintenance (Parts, Labor, Vendor) Cost	$8,099,925	$8,432,876	$8,704,428	$9,019,315	$9,318,223
Annual Ownership Cost	$3,998,122	$3,899,631	$3,982,001	$3,957,415	$3,994,430
Annual Capital Budget	$4,534,552	$3,542,320	$4,993,447	$4,357,539	$4,466,822
Units Replaced Annually	50	44	50	46	47
Average Age	13.34	13.75	14.06	14.41	14.74
Units Out of Lifecycle	422	443	459	477	497
Annual Demand Repair Work Orders	9,136	9,314	9,419	9,555	9,671

No Replacement	2026	2027	2028	2029	2030
Annual Maintenance (Parts, Labor, Vendor) Cost	$11,342,717	$12,068,385	$12,823,413	$13,603,405	$14,412,019
Annual Ownership Cost	$1,417,138	$1,247,603	$1,100,859	$973,611	$863,098
Annual Capital Budget	$-	$-	$-	$-	$-
Units Replaced Annually	-	-	-	-	-
Average Age	19.46	20.41	21.36	22.31	23.25
Units Out of Lifecycle	828	860	889	921	940
Annual Demand Repair Work Orders	12,793	13,343	13,894	14,444	14,994

Methodology

Annualized Total Cost

For each class, Utilimarc's Vehicle Replacement Module (VRM) determines what lifecycle achieves the lowest cost to own and maintain an average asset over its lifetime. This done by calculating the *annualized total cost* for each potential lifecycle. Annualized cost total is the sum of all ownership and maintenance cost a unit obtains over the course of its life, divided by the number of years the unit is in service. Minimizing annualized total cost guarantees the lowest total cost over the life of the asset. As an example, the table below shows the annualized cost for the possible lifecycles of a light duty pickup truck.

Replacement Age	Annualized Total Cost	Deviation
1	$5,964	12.3%
2	$5,759	8.4%
3	$5,598	5.4%
4	$5,476	3.1%
5	$5,390	1.5%
6	$5,337	0.5%
7	$5,313	0.0%
8	$5,316	0.1%
9	$5,345	0.6%
10	$5,397	1.6%
11	$5,472	3.0%
12	$5,567	4.8%
13	$5,682	7.0%
14	$5,816	9.5%

Consider the following three replacement scenarios over a 14-year financial period:

Scenario 1: A fleet manager plans to replace this vehicle every year. The annualized cost of this replacement strategy is $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

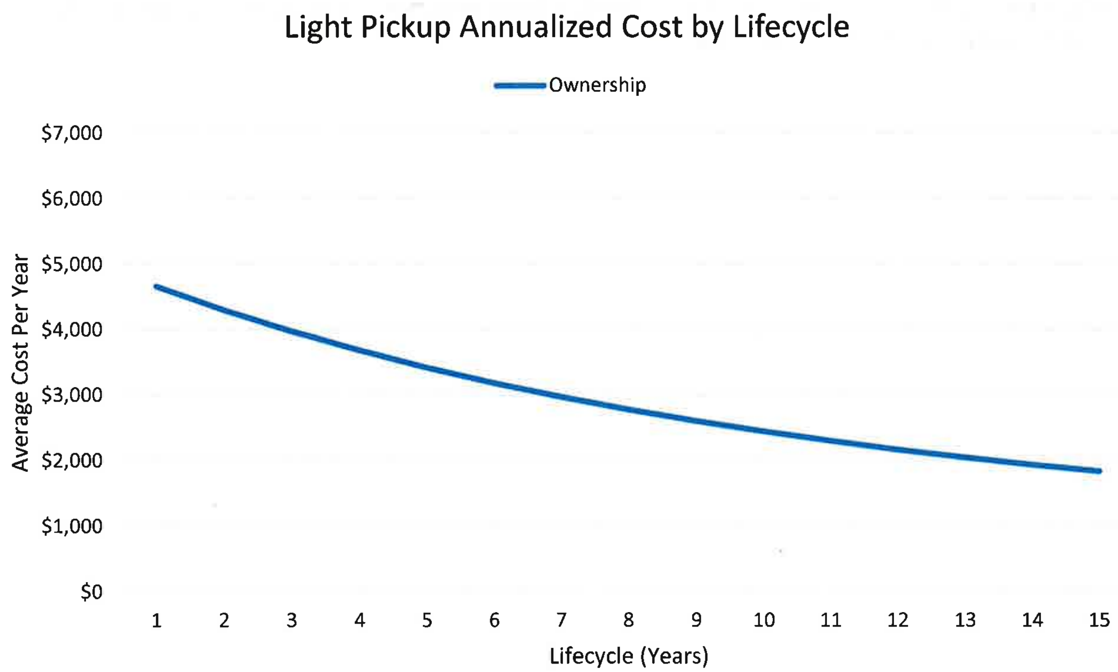
The table below summarizes the calculations in the previous example.

	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.

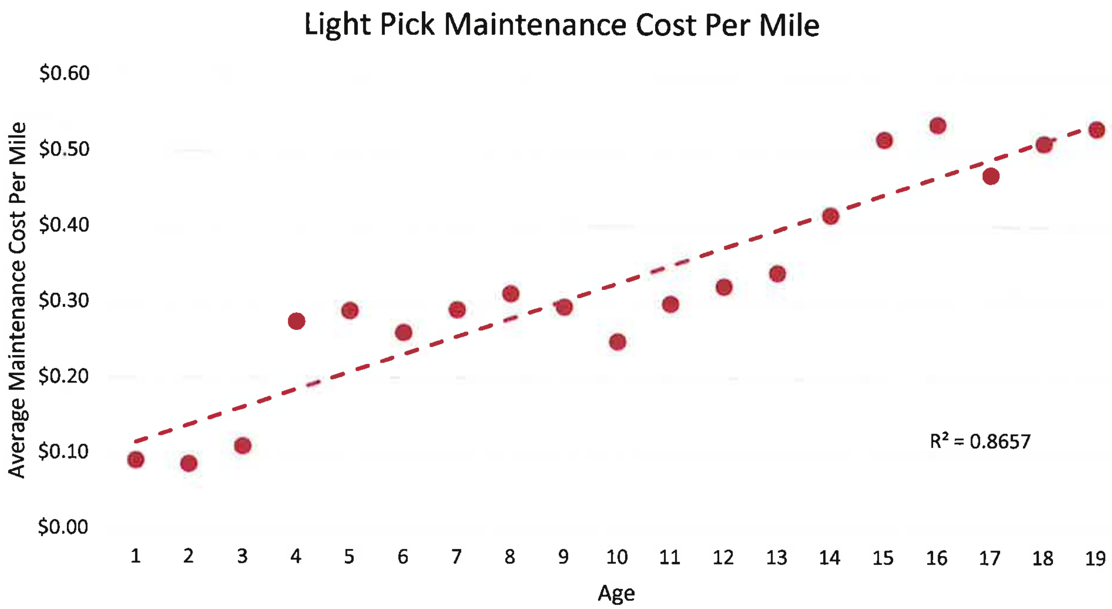
Modeling Ownership Cost

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.

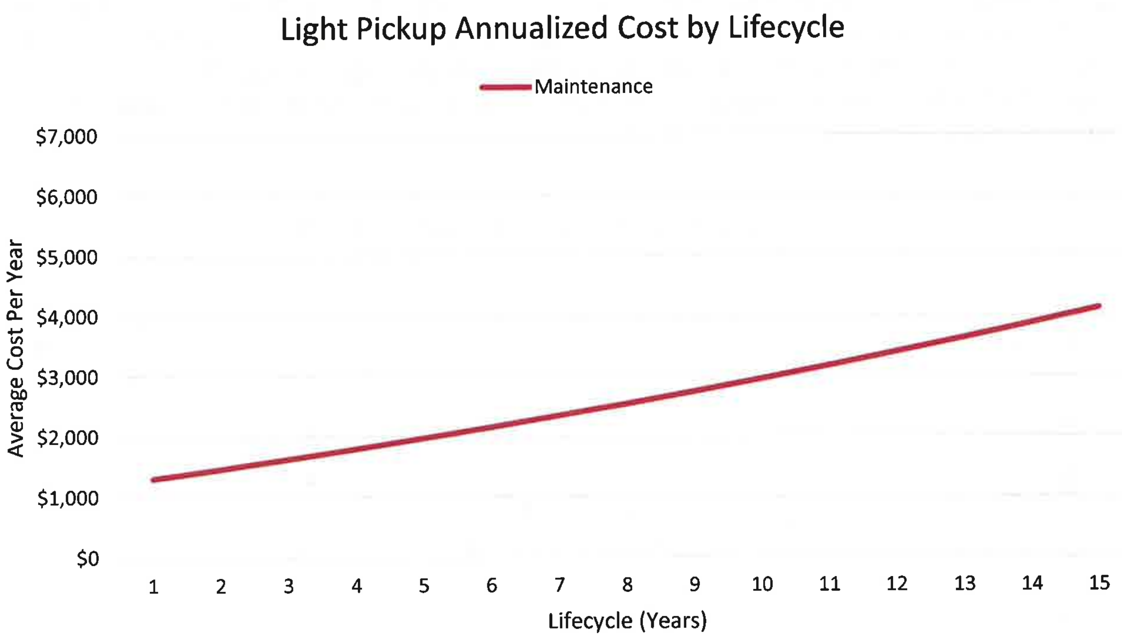


Modeling Maintenance Cost

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.

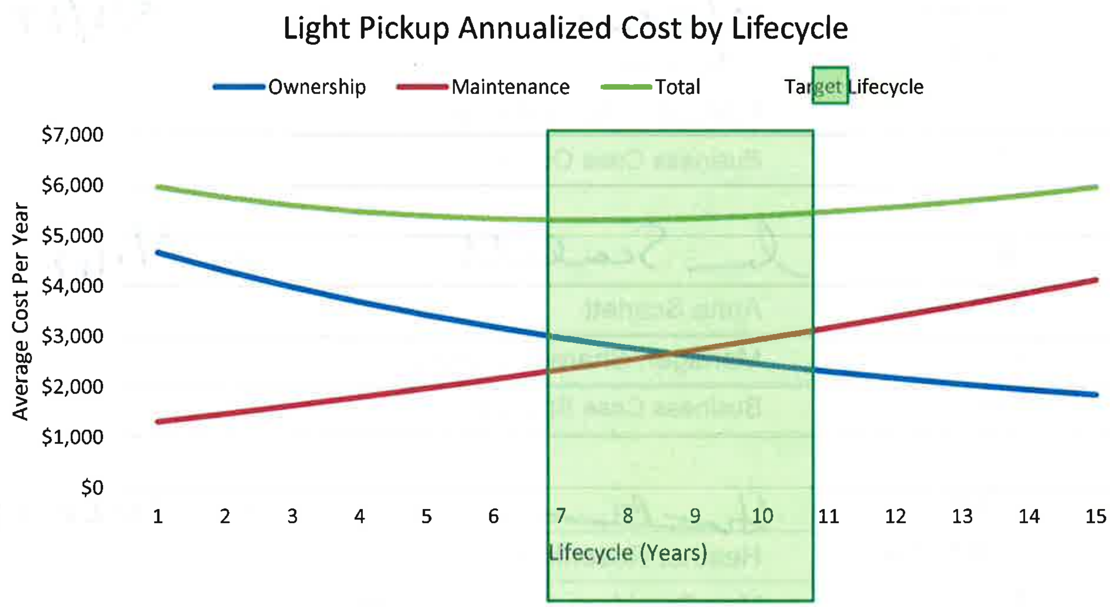


Annualized Maintenance Cost is calculated by taking the cumulative sum of each year of maintenance cost for the asset and dividing by the number of years the asset is in service. The graph below shows the annualized maintenance cost for light pickup trucks, based on the linear regression model and a 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: _______ Date: 5/1/17
Print Name: Greg Loew
Title: Manager, Fleet Services
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	*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