BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-16 _______

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EXHIBIT NO._____(HLR-6)

HEATHER L. ROSENTRATER

REPRESENTING AVISTA CORPORATION

2016

Electric Distribution System 2016 Asset Management Plan

Amber Fowler, Rodney Pickett ,
Dave James, Ross Taylor, and
Mareval Ortiz-Camacho
Avista Corp
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Prepared by: ______________________________

Amber Fowler, Asset Management Engineer

Reviewed by: ______________________________

Rodney Pickett, Asset Management Engineering Manager

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Dave James, Distribution Engineering Manager

____

Glenn Madden, Asset Maintenance Manager

Approved by: ______________________________

Scott Waples, Director of Planning and Asset Management

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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.

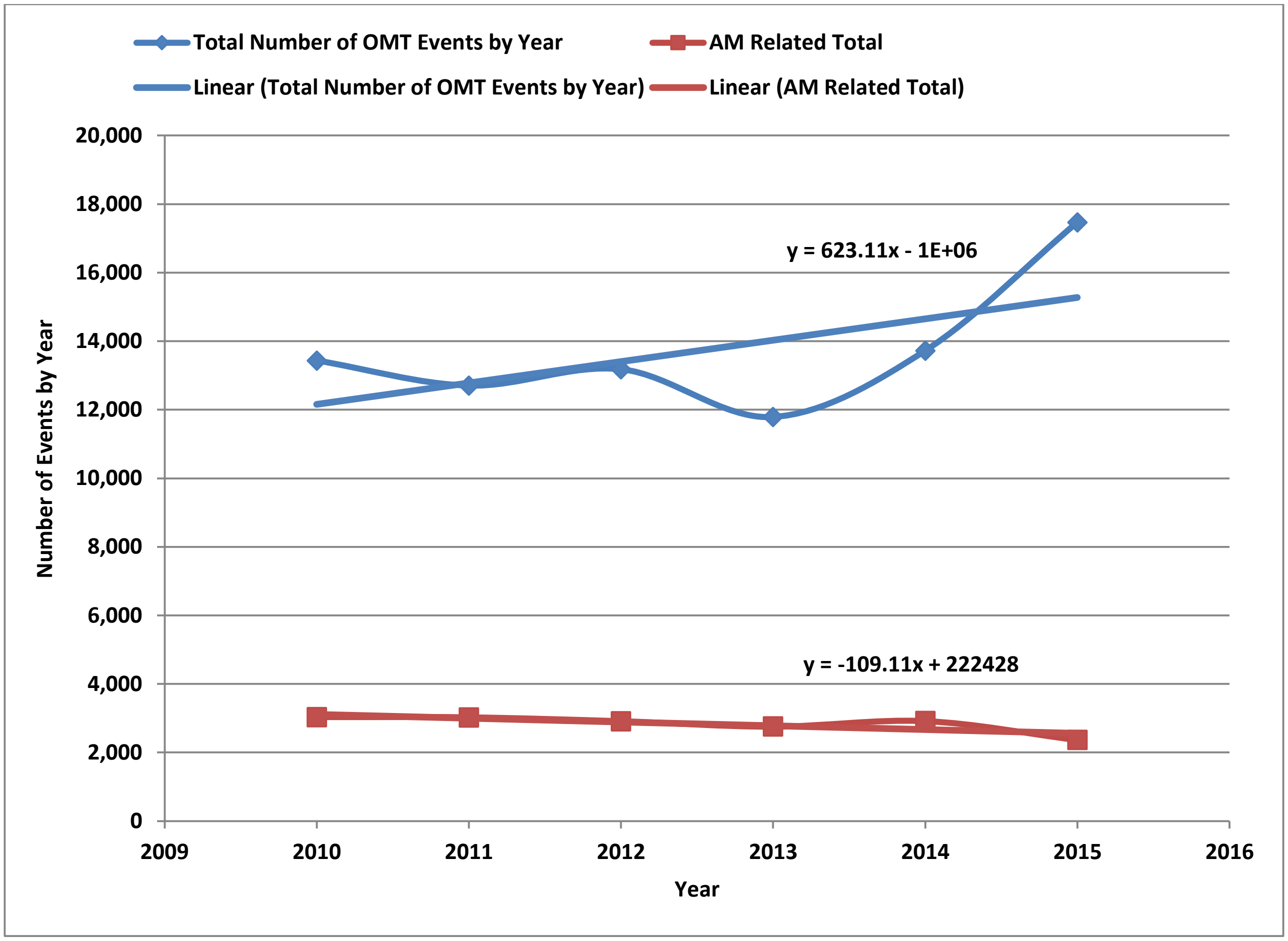

Figure 1, OMT Annual Number of Events and AM Related Event Trends and Trend Lines

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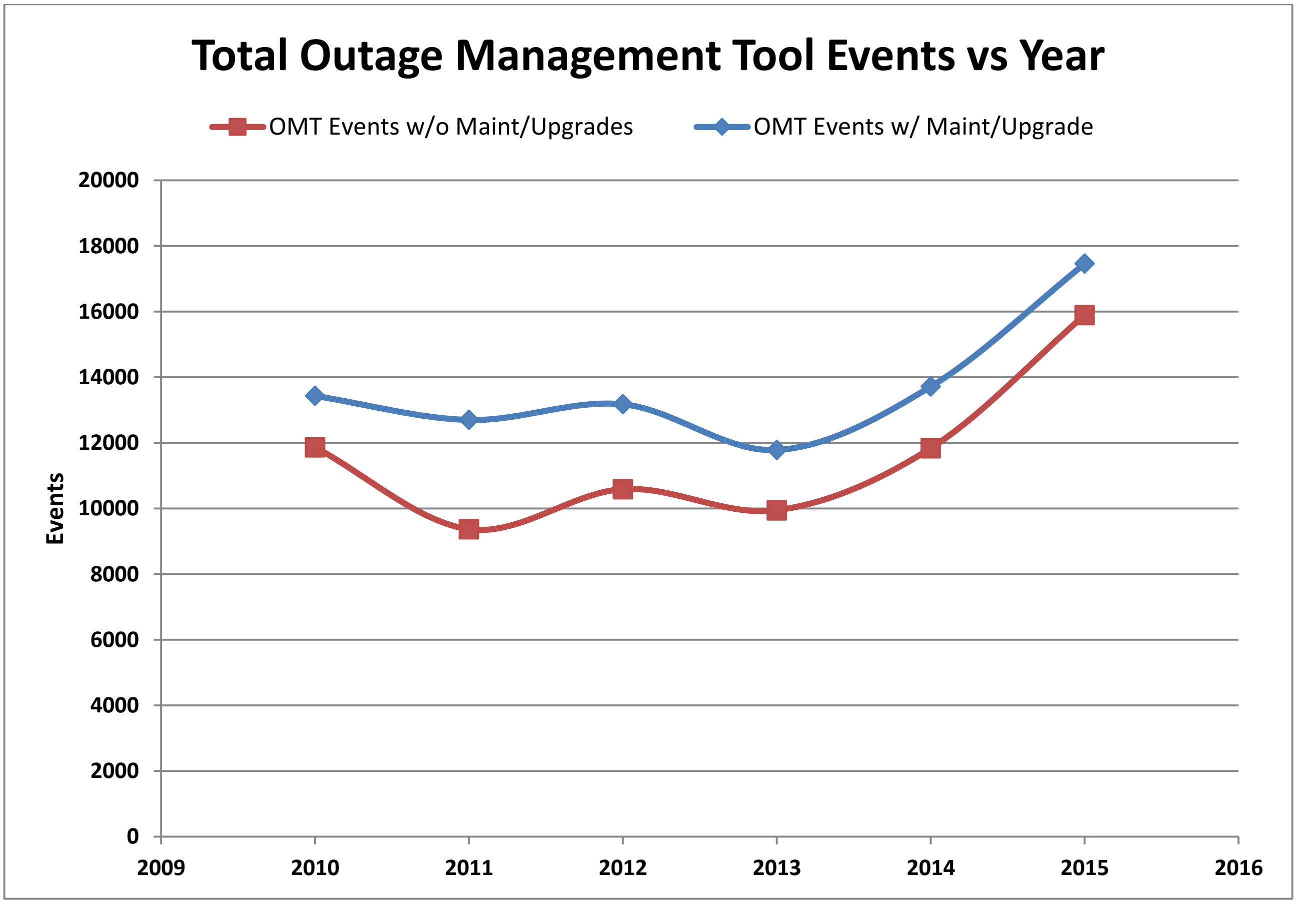

Figure 2, OMT Events with and without Planned Maintenance or Upgrades

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.

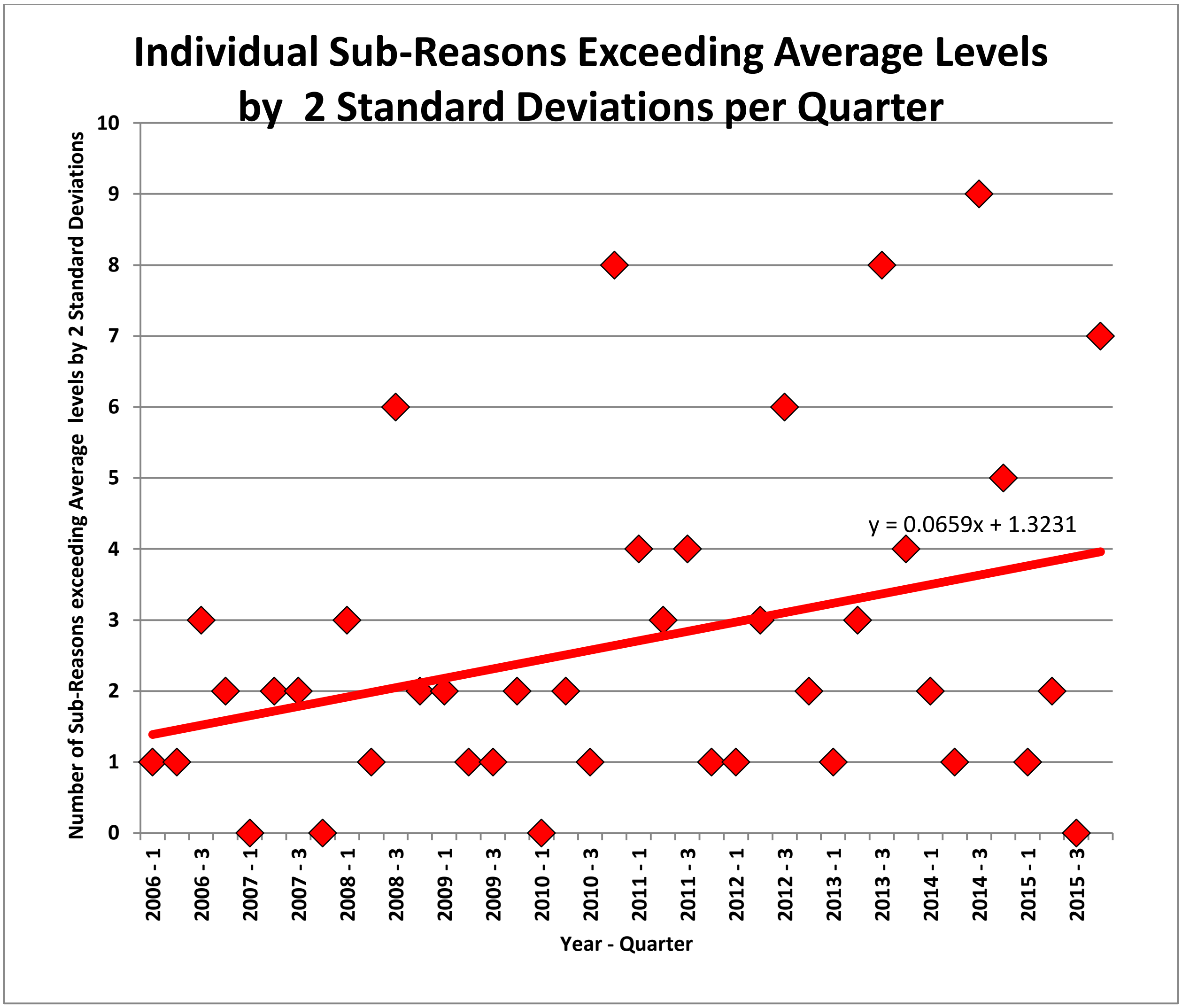

Figure 3, Individual Sub-Reasons exceeding Quarterly High Limits

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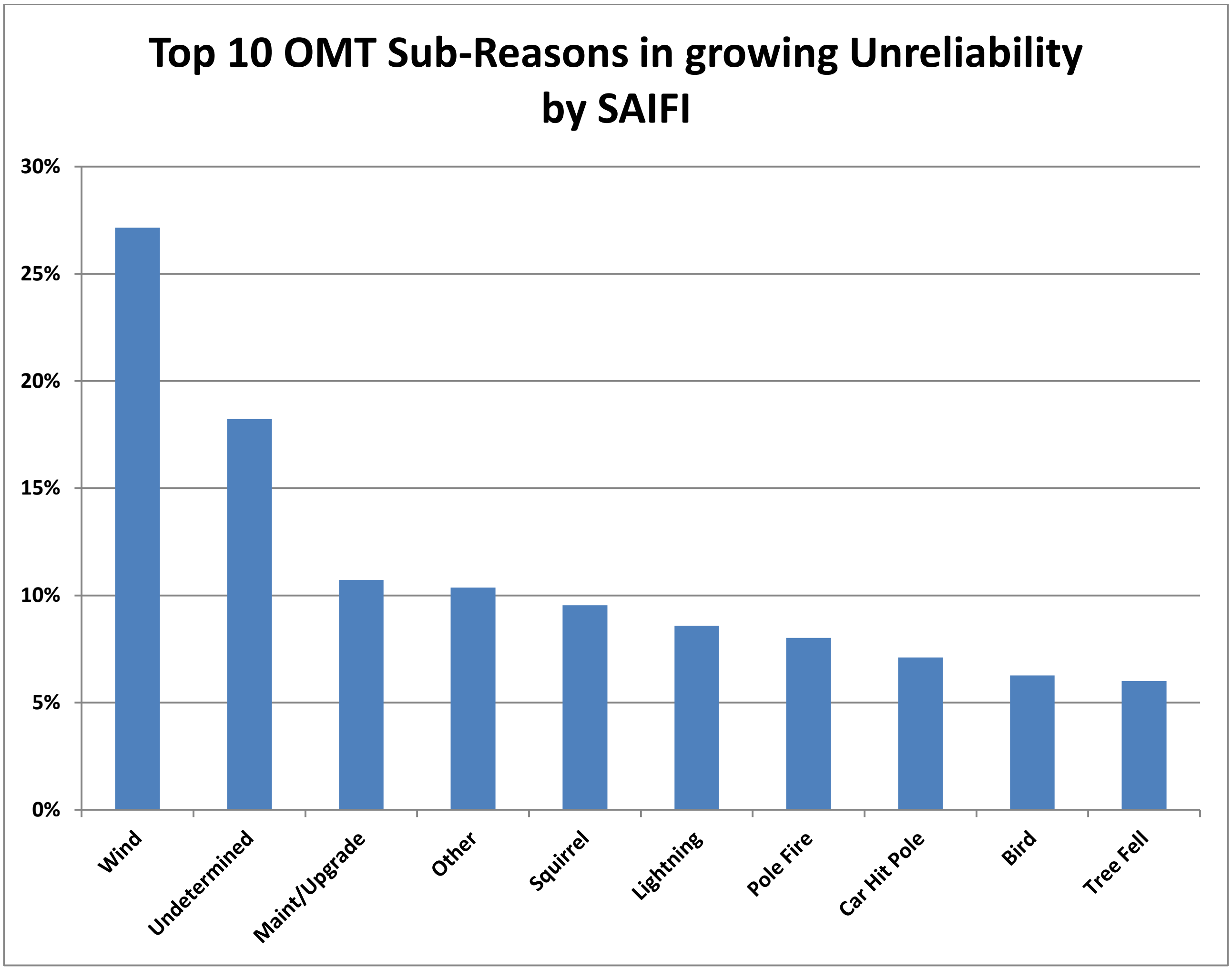

Figure 4, Top 10 Sub-Reasons with the Value of SAIFI Rising over Time

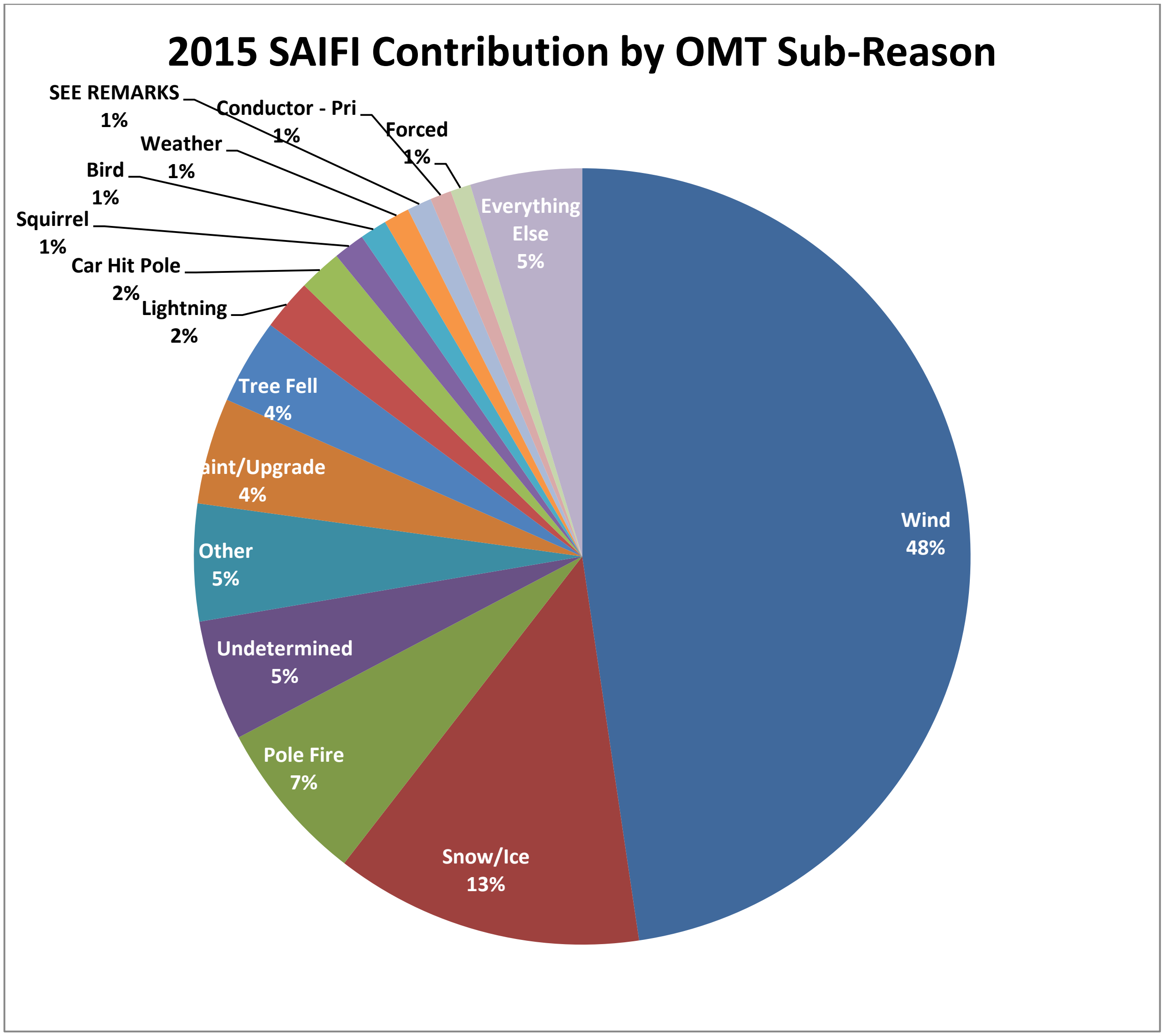

Figure 5, 2015 OMT SAIFI Contribution by Sub-Reason

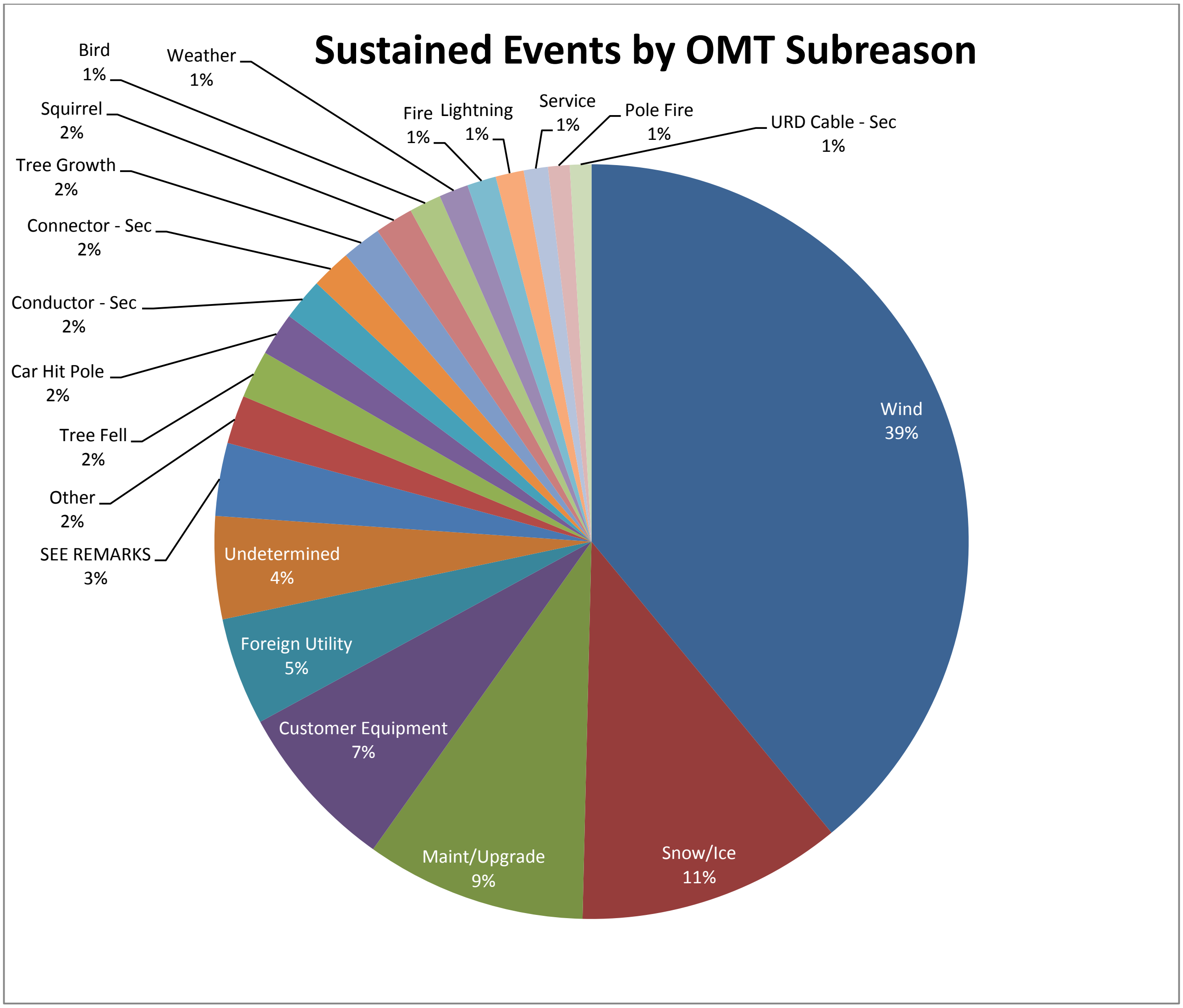

Figure 6, 2015 OMT Sustained Outage Comparisons

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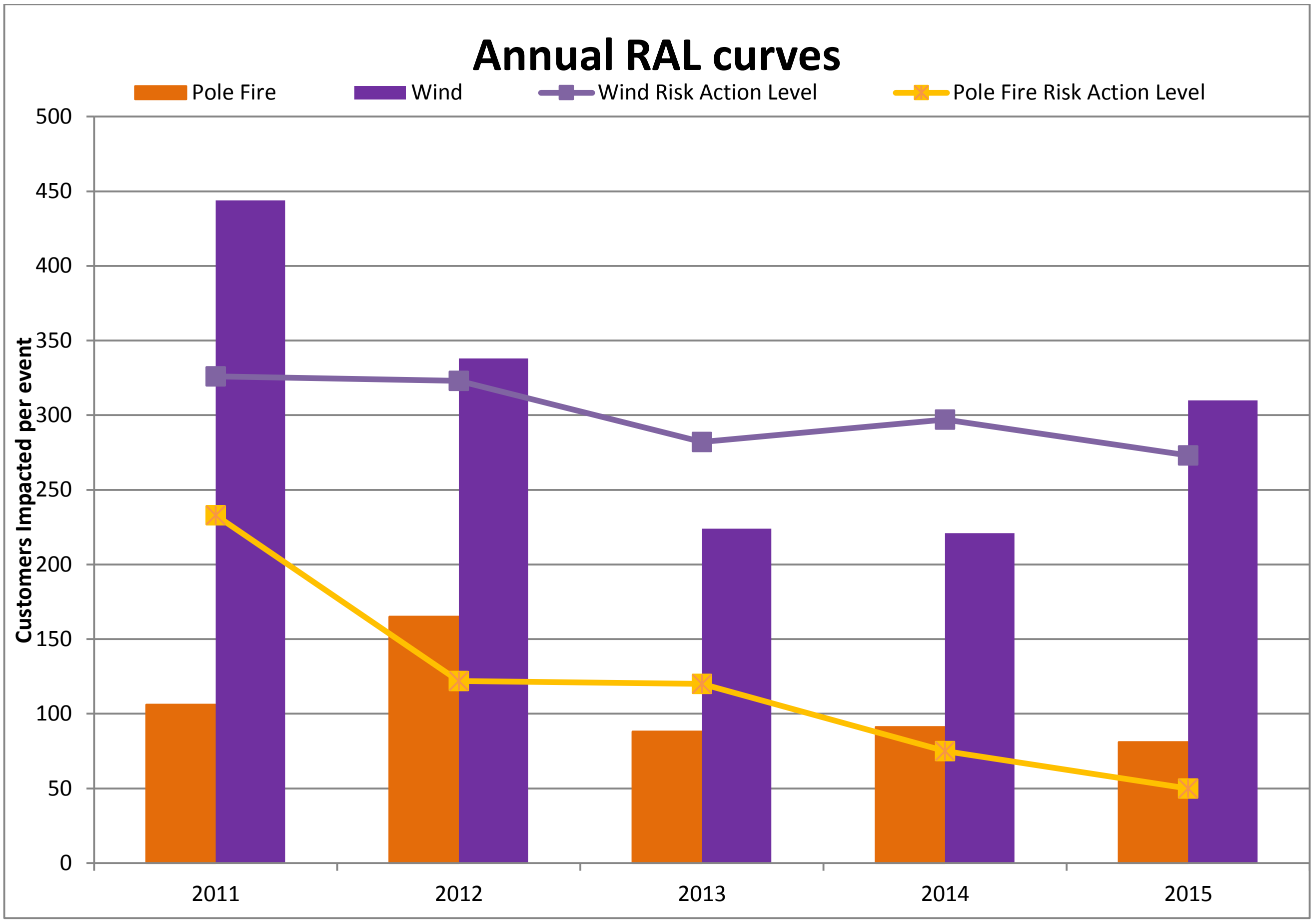

Figure 7, Customers Affected Per Event Exceeding Risk Action Levels

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.

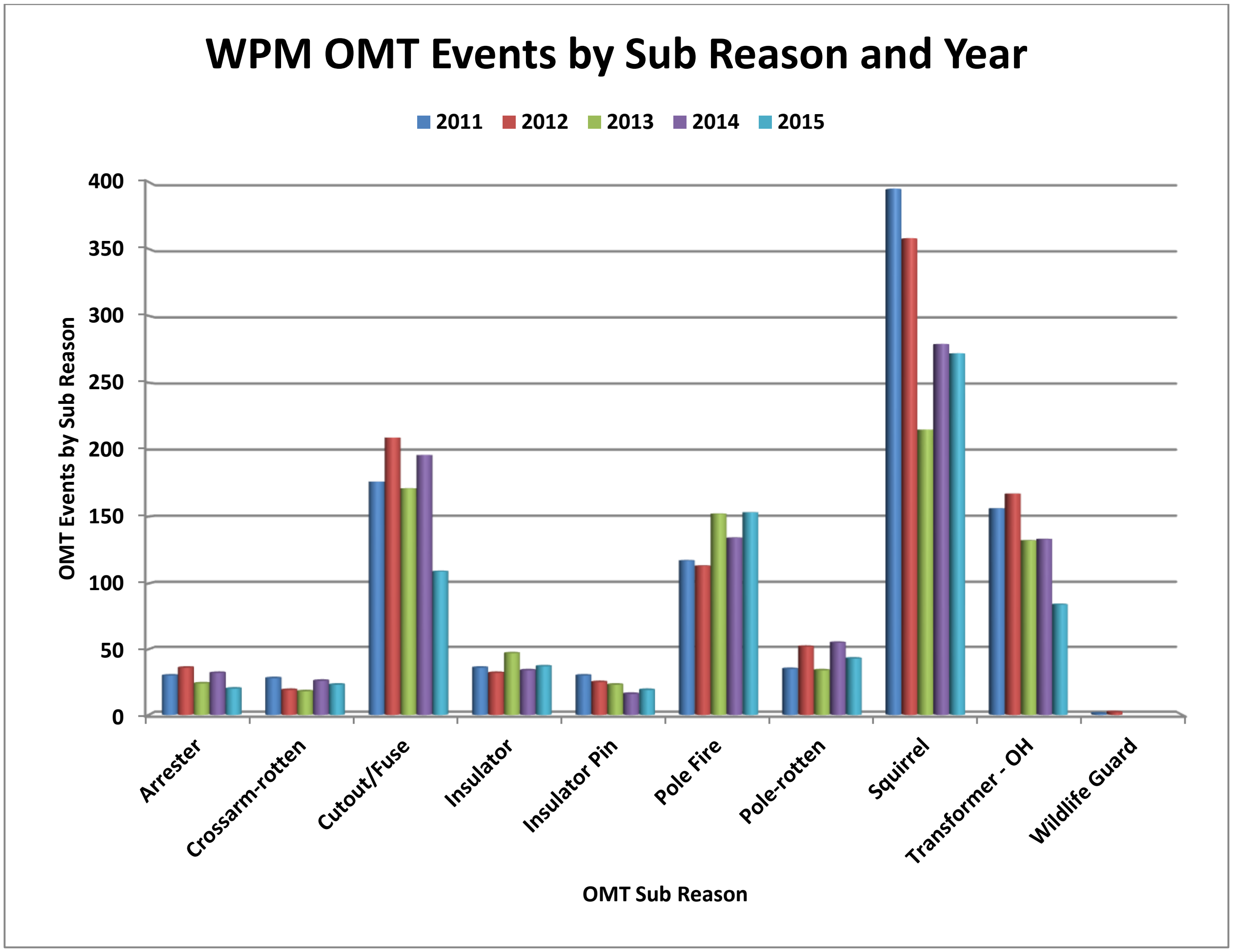

Figure 8, WPM OMT Event Trends

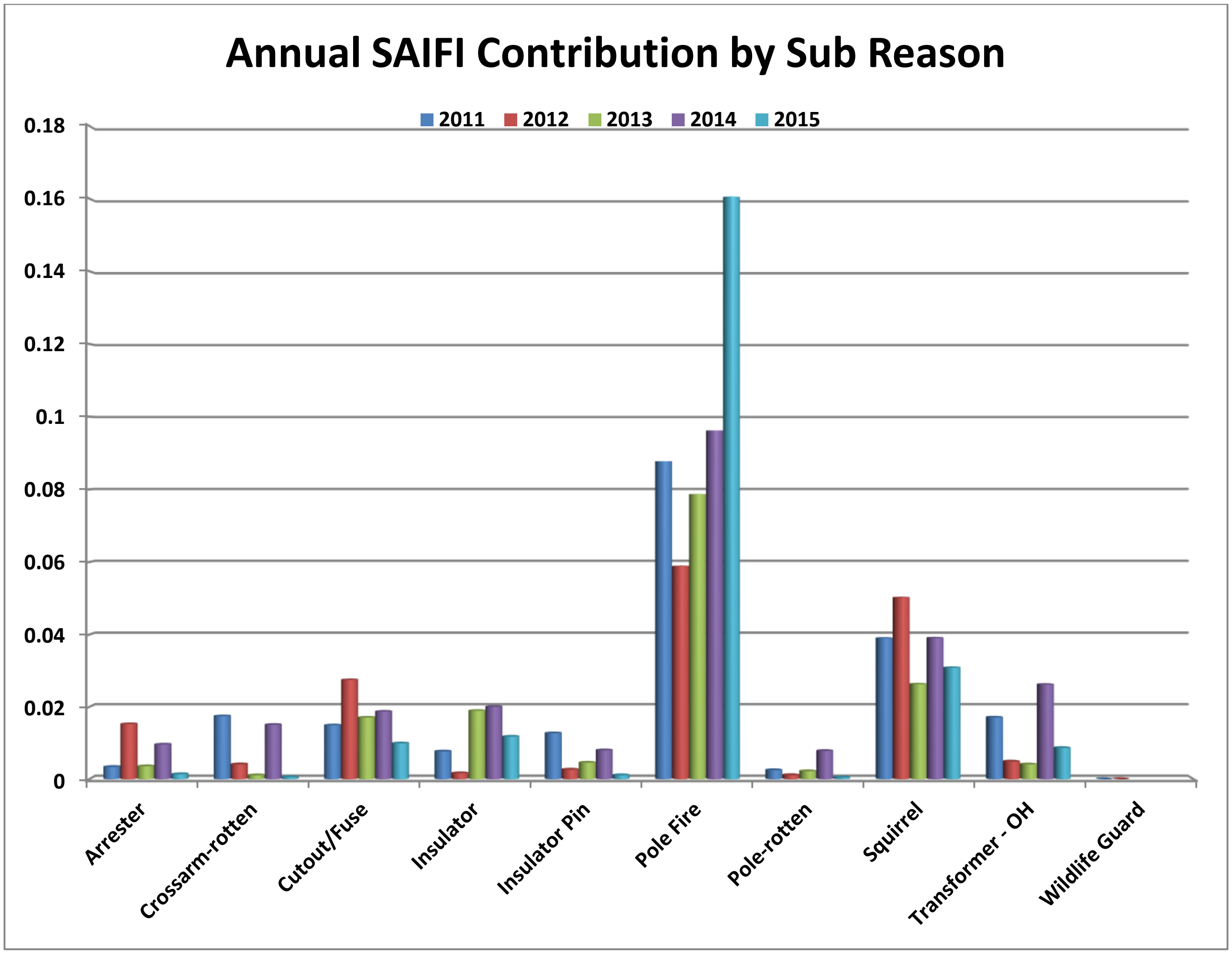

Figure 9, WPM Contribution to Annual SAIFI value by Sub-Reason and Year

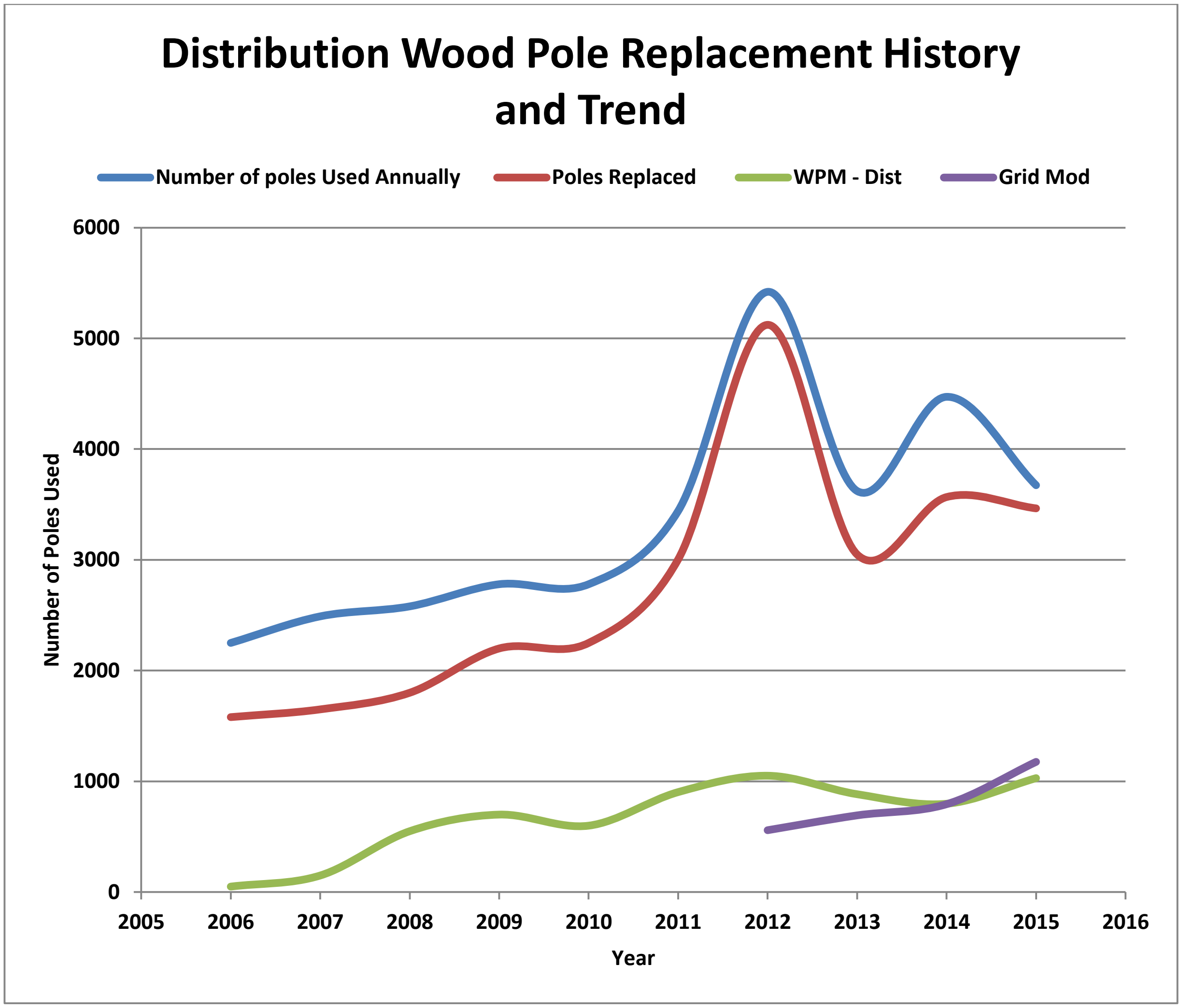

Figure 10, Wood Pole Used by Summarized Activity

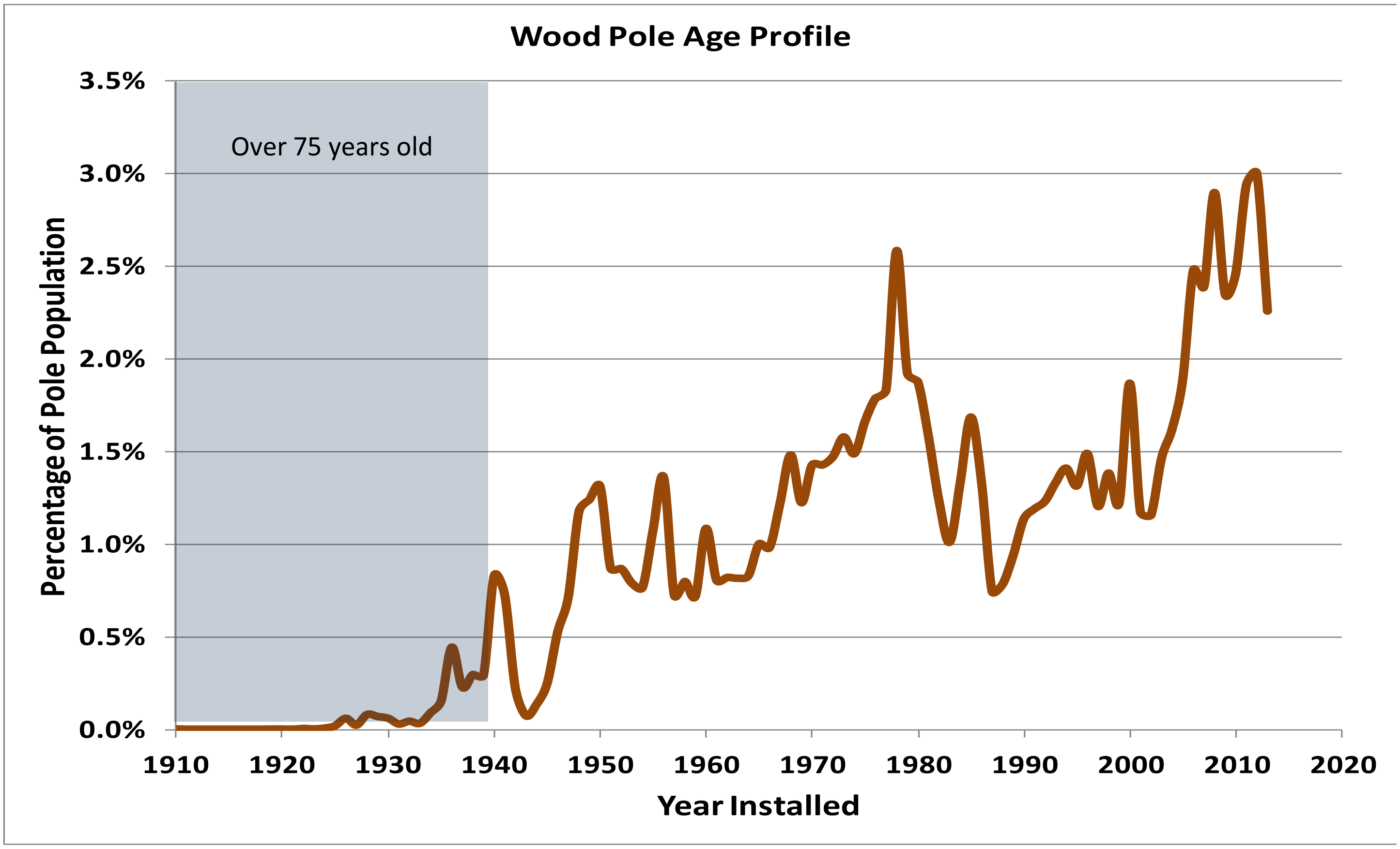

Figure 11, Distribution Wood Pole Age Profile
***Pole age data has not been updated in the past 4 years**

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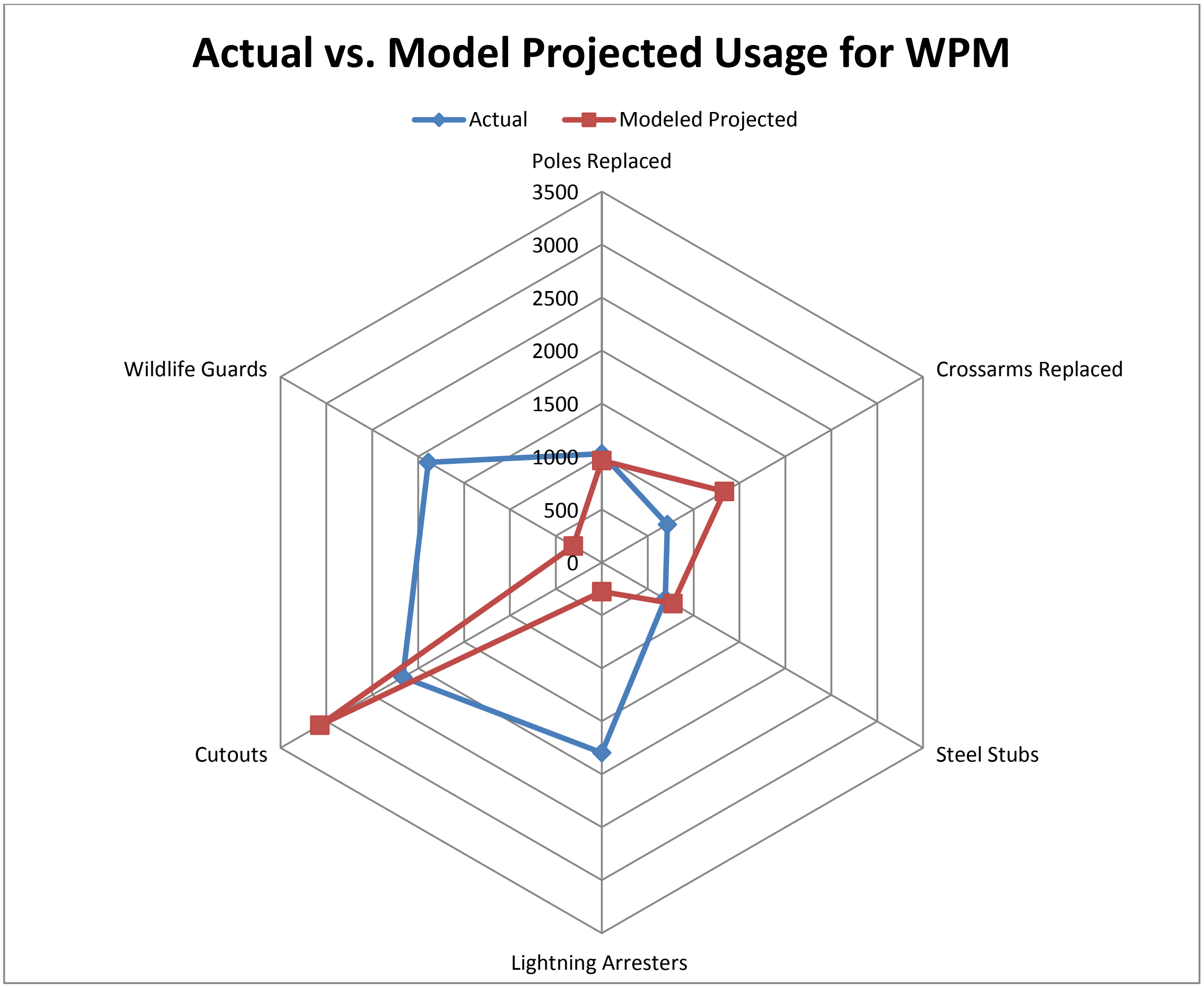

Figure 12, Actual vs. Projected Usage for WPM

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%

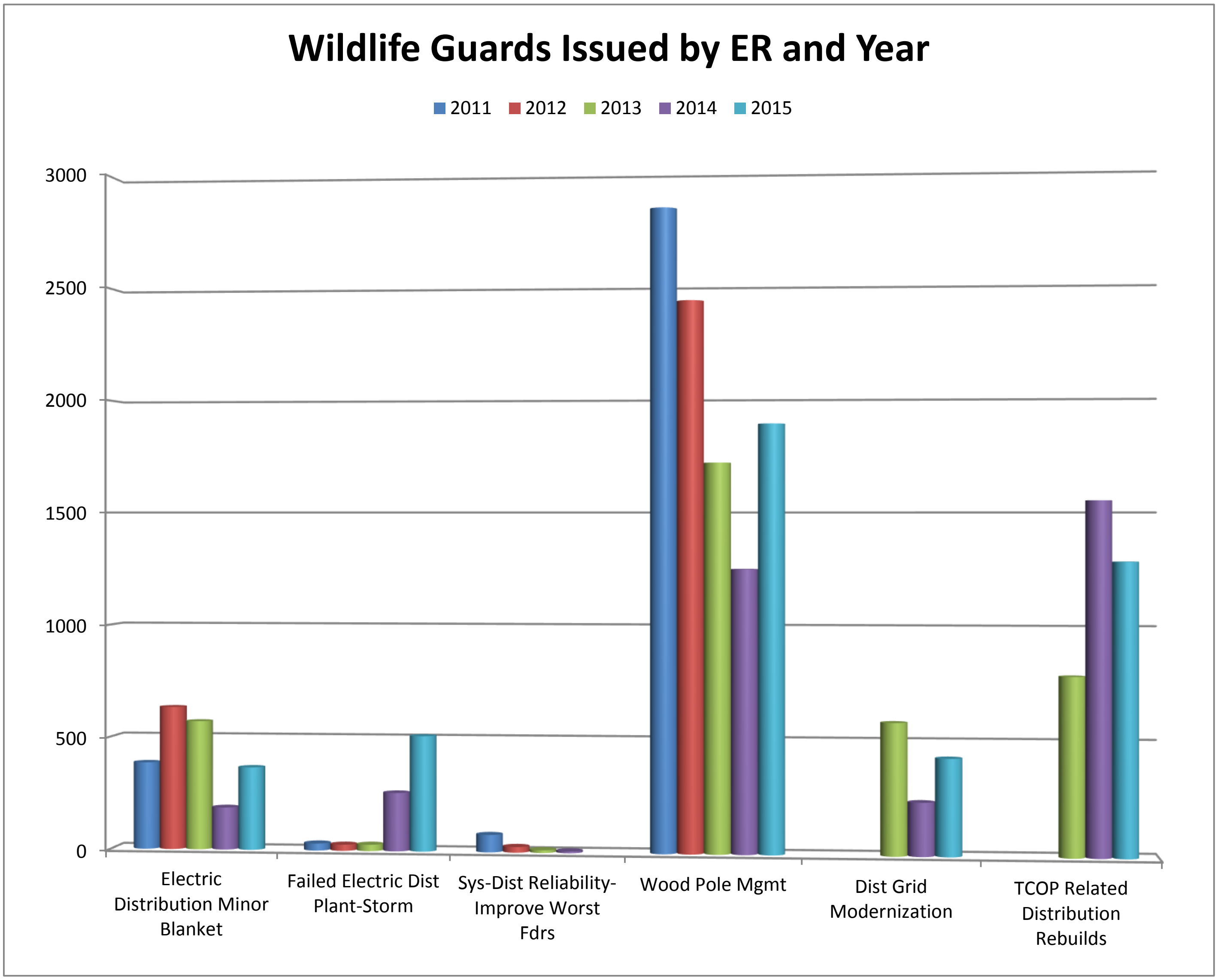

Figure 13, Wildlife Guards Installed by Year and Expenditure Request

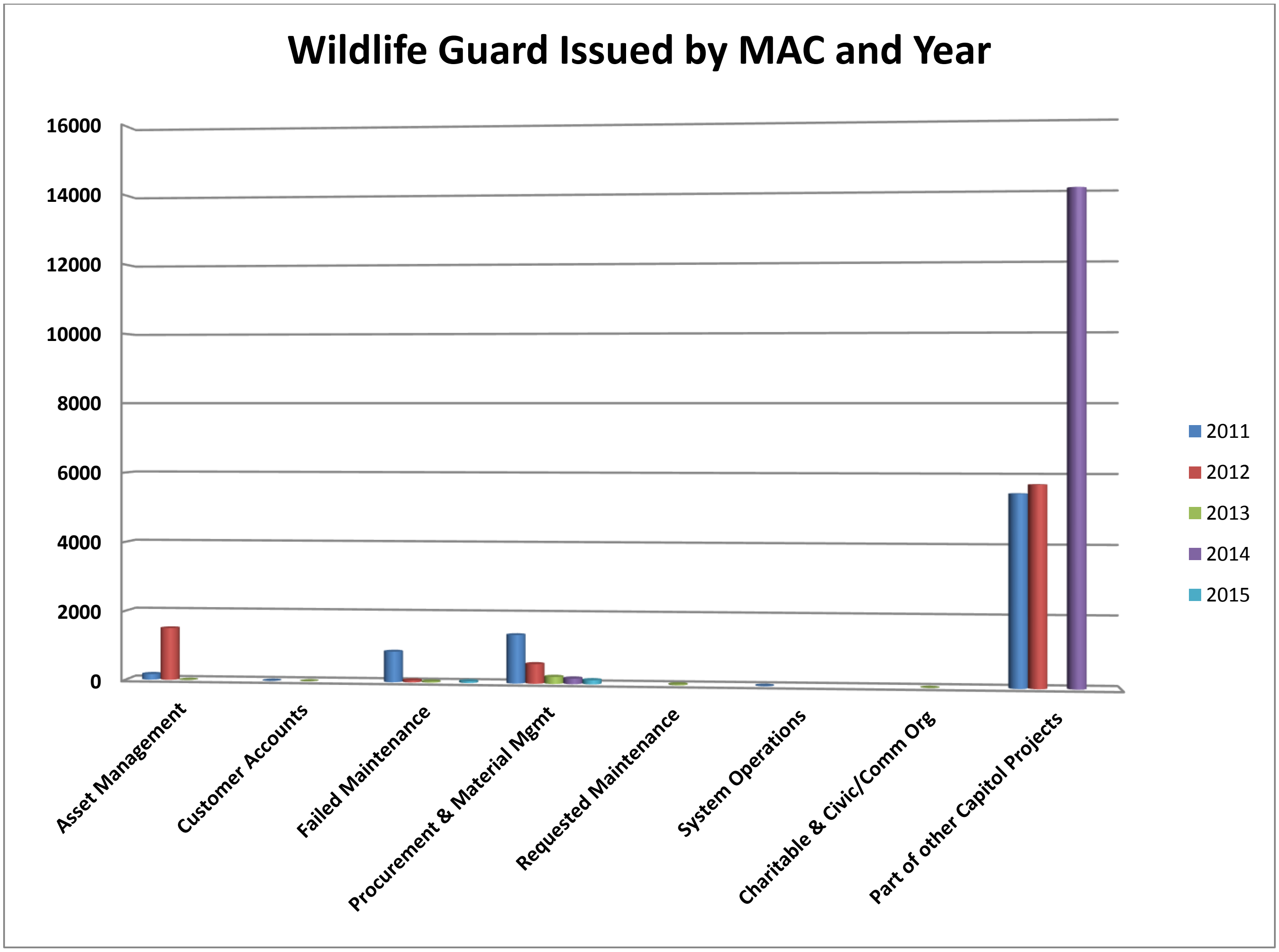

Figure 14, Wildlife Guards Usage by MAC for 2011-2015

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.

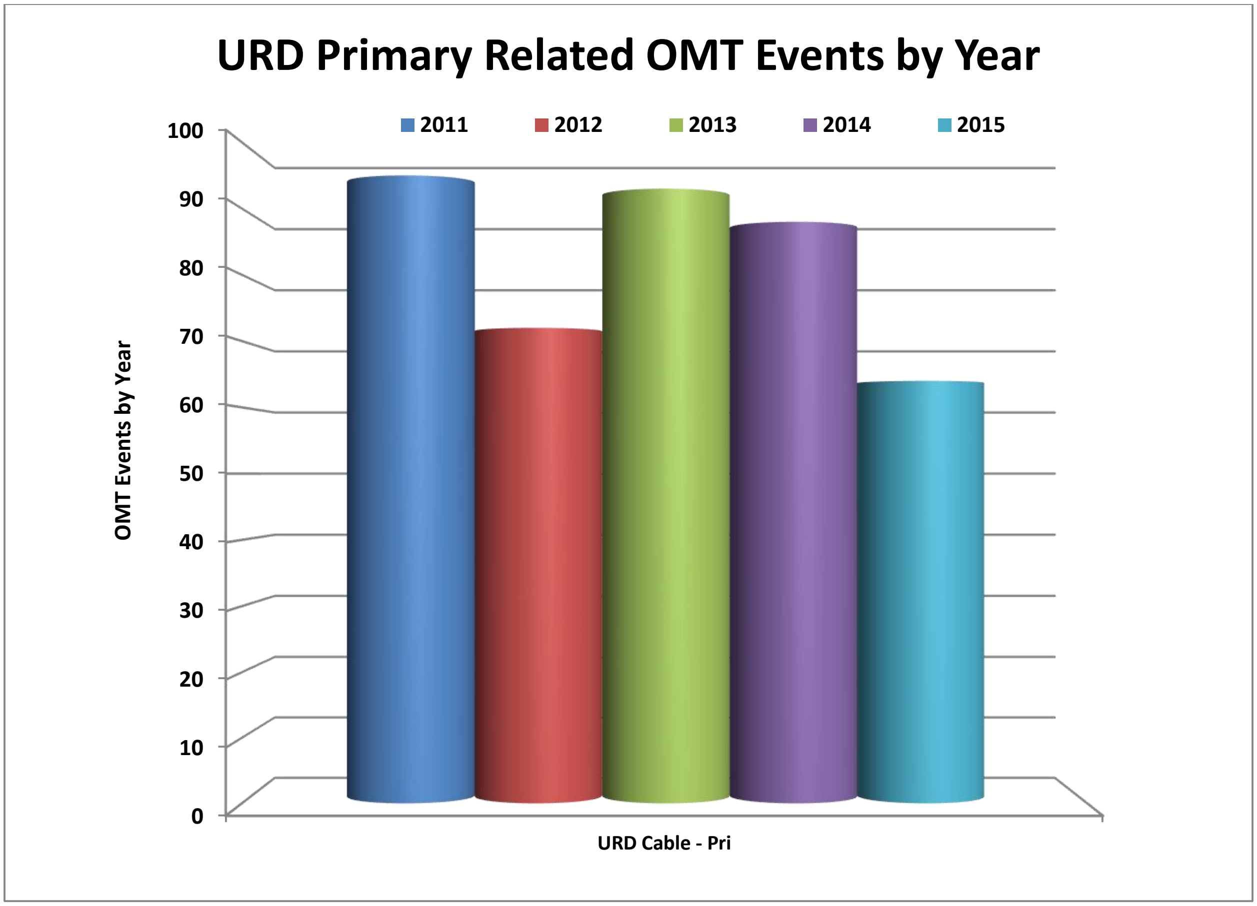

Figure 15, URD Primary Cable OMT Events by Year

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

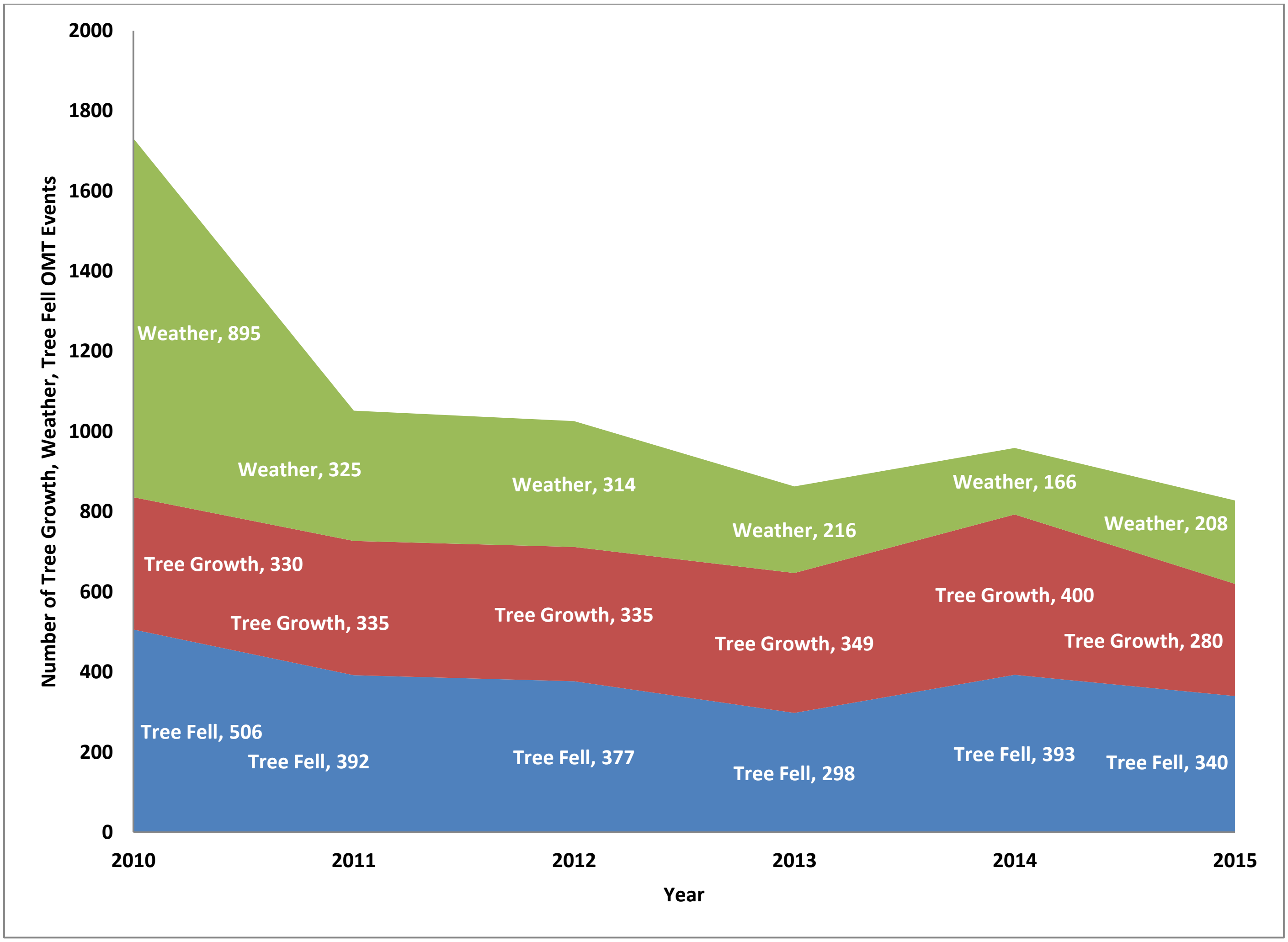

Figure 16, OMT Events Data Trends for Tree-Weather, Tree Growth, and Tree Fell Sub-Reasons

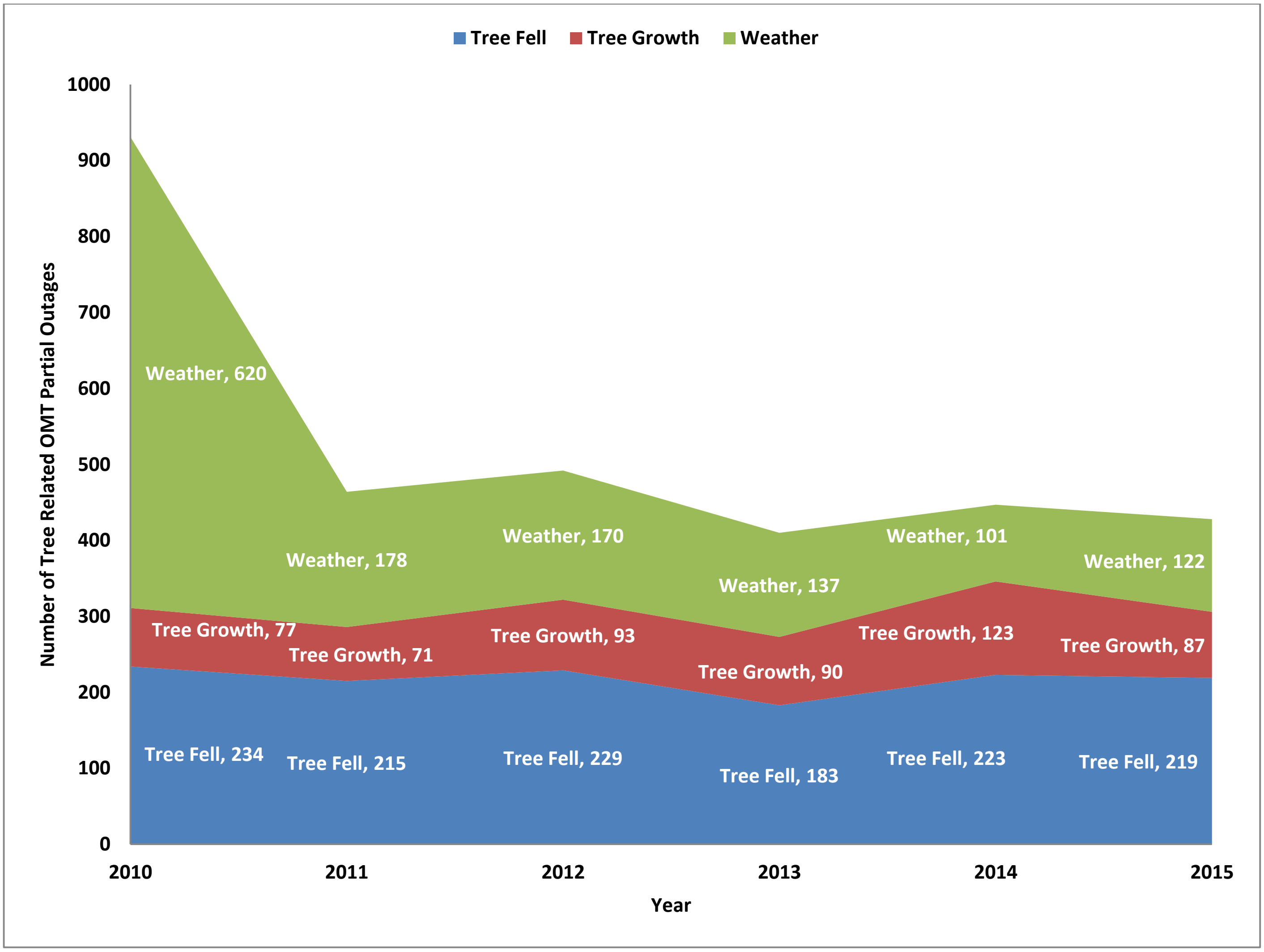

Figure 17, OMT Outage and Partial Outage Data Trends for Tree-Weather, Tree Growth, and Tree Fell Sub-Reasons

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

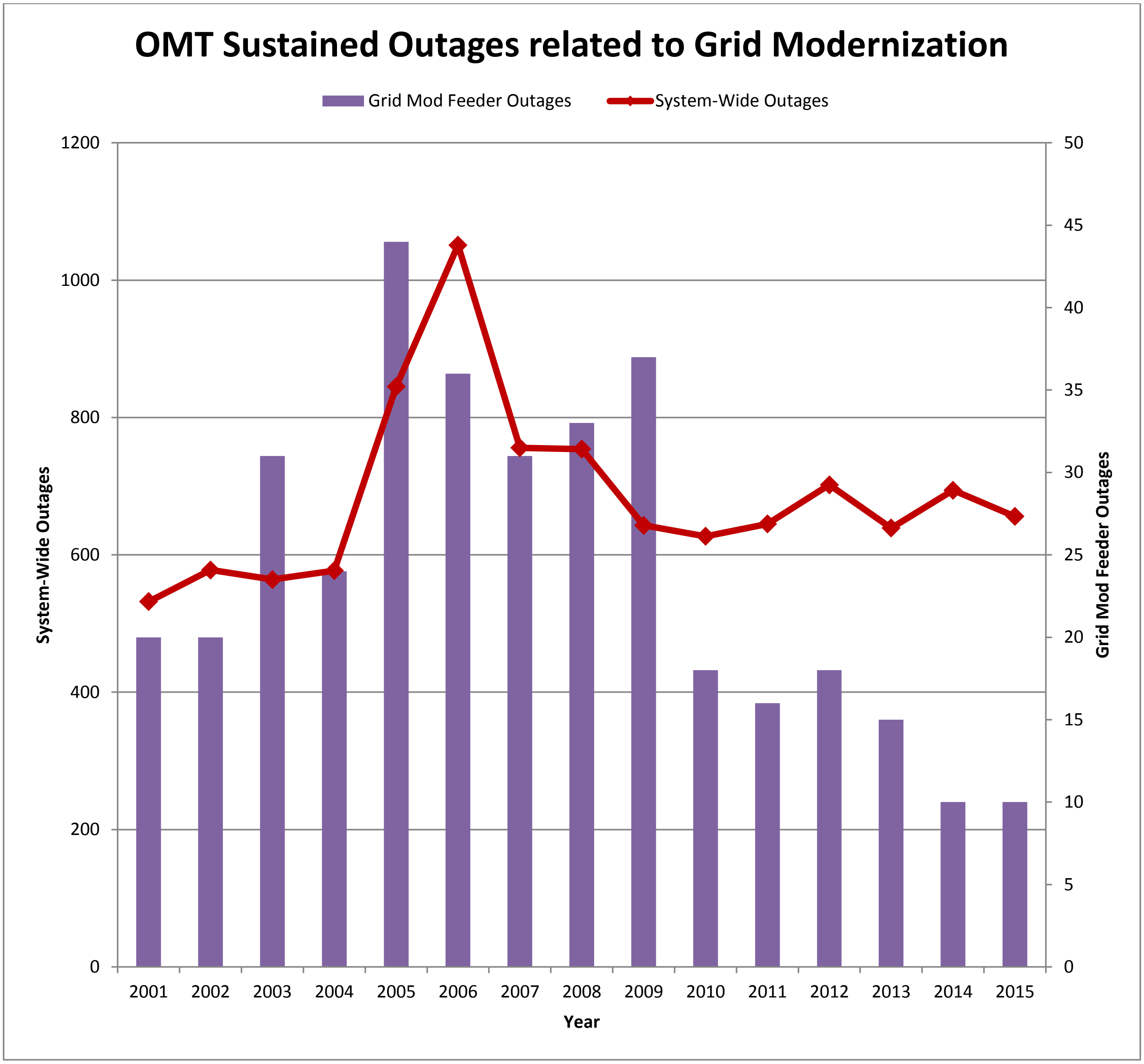

Figure 18, OMT Sustained Outages related to Grid Modernization

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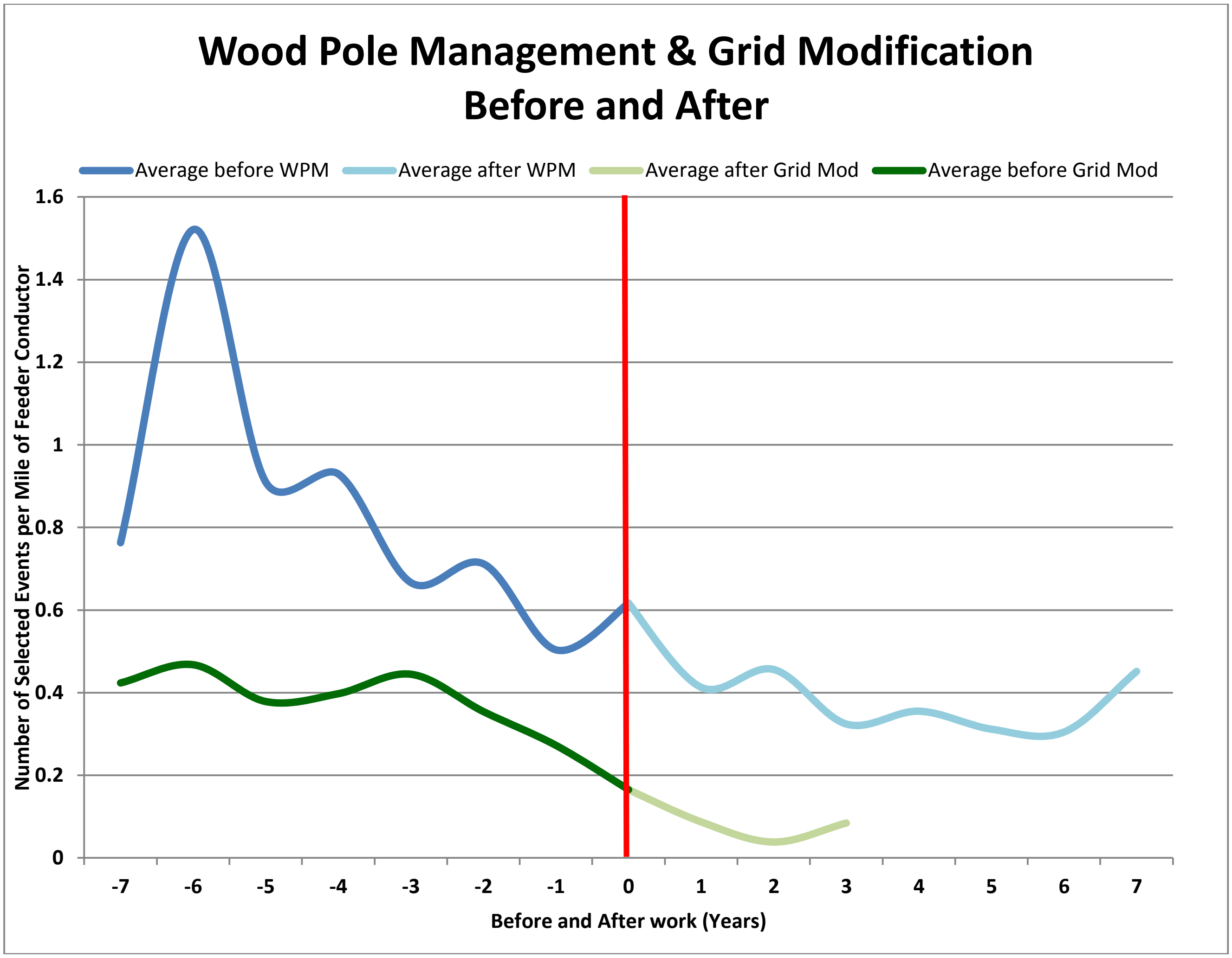


Figure 19, Wood Pole Management and Grid Modernization Before and After

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.

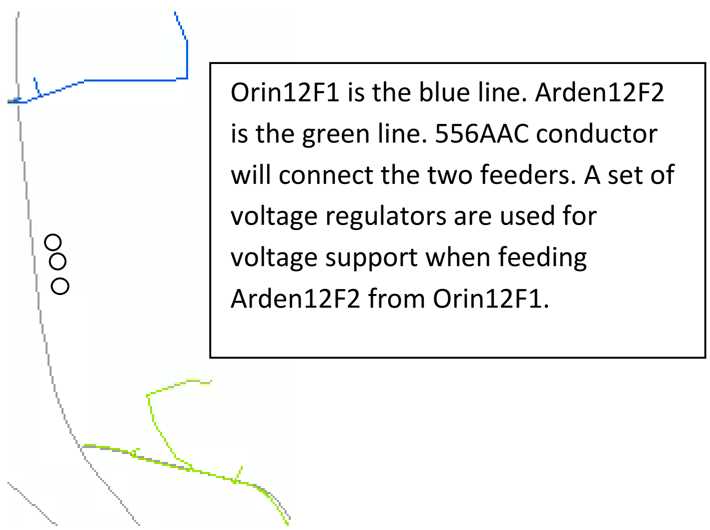


Figure 20, ARD12F2 to ORN12F1 Tie

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.

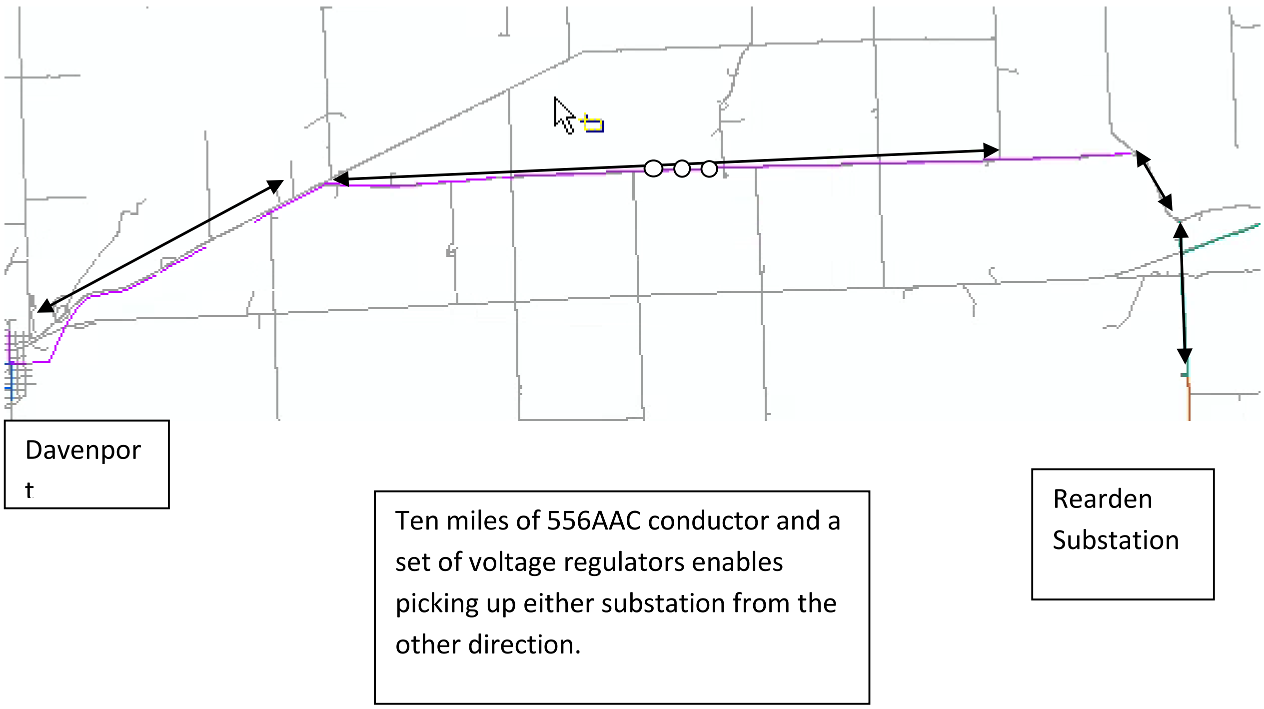


Figure 21, DAV12F2 - RDN12F1 Tie

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

Repair/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.

65

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

AVISTA

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.

80

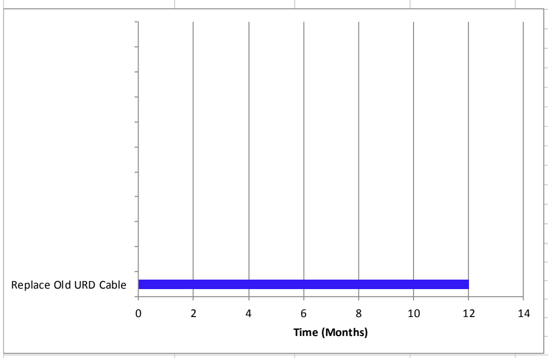
URD Primary Cable

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:

81

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

Recommend Program Description:	**Performance**	**Annual Cost Summary - Increase/(Decrease)** 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

Alternatives:		**Performance**	**Annual Cost Summary - Increase/(Decrease)** 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:

82

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	Annual Cost Summary - Increase/(Decrease) Capital Cost	O&M Cost	Other Costs	Business Risk Score
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	Annual Cost Summary - Increase/(Decrease) Capital Cost	O&M Cost	Other Costs	Business Risk Score
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	**Annual Cost Summary - Increase/(Decrease)**			
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					**Associated Ers (list all applicable):**	
5 years of costs					Current ER	2414
	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		

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:	**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
		Annual Cost Summary - Increase/(Decrease)			
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:		**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
			Annual Cost Summary - Increase/(Decrease)			
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	$ -	$ -	$ -	$ -	$ -	$ -
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					**Associated Ers (list all applicable):**				
5 years of costs					Current ER		2058	2237	2251
	Capital Cost	**O&M Cost**	**Other Costs**	**Approved**			CapX Repl.	Metro PILC	Post St PILC
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						

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**
		Annual Cost Summary - Increase/(Decrease)			
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

Alternatives:		**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**ERM Risk Score**
			Annual Cost Summary - Increase/(Decrease)			
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.