Exhibit No. ___ (HLR-7)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-16 _______

DOCKET NO. UG-16 _______

EXHIBIT NO._____(HLR-7)

HEATHER L. ROSENTRATER

REPRESENTING AVISTA CORPORATION

2016

Electric Transmission System 2016 Asset Management Plan

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Front cover:

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

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Purpose

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

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

Executive Summary

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

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

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

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

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

Notable achievements in 2015 include:

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

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

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

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

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

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

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

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

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

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

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

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

Assets

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

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

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

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

Table 2: Component Assets and Quantities

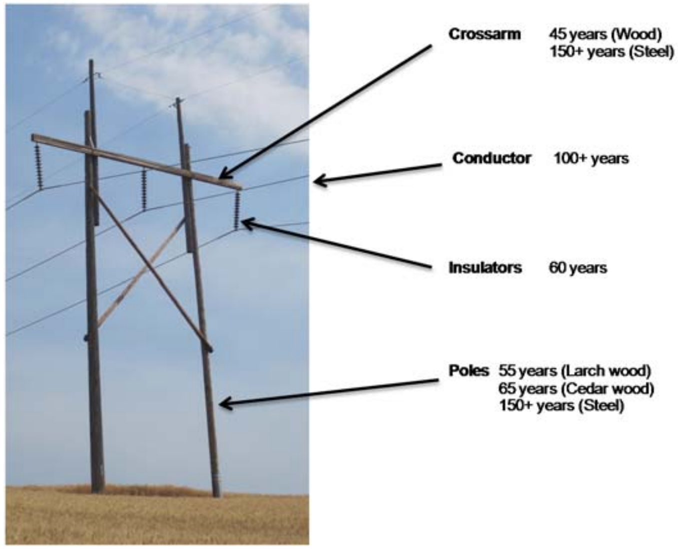
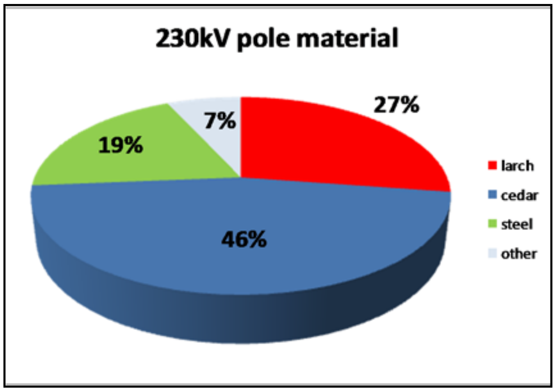
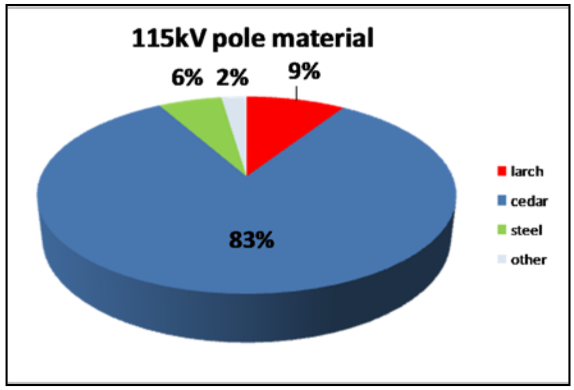


Figure 1: Example Transmission Asset Components and Expected Service Life

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

Table 3: Transmission Structures and Poles





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

Table 4: 115kV vs 230kV Pole Materials

Key Performance Indicators (KPIs)

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

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

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

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

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

Table 5: Transmission KPIs and Unity Box Metrics

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

Additional performance measures are tabulated below since 2010:

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

Table 6: Additional Performance Measures, 2010-2015

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

Capital Replacement and Maintenance Investment

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

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

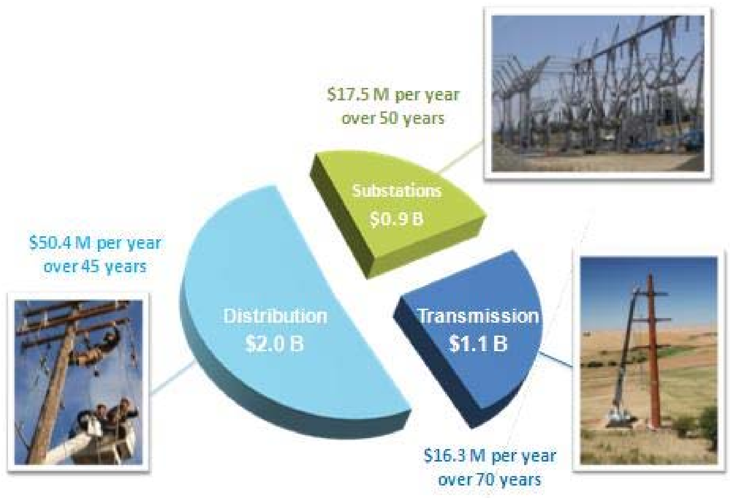


Figure 2: Transmission and Distribution System Replacement Values, Average Service Life, and Levelized Replacement Spending

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

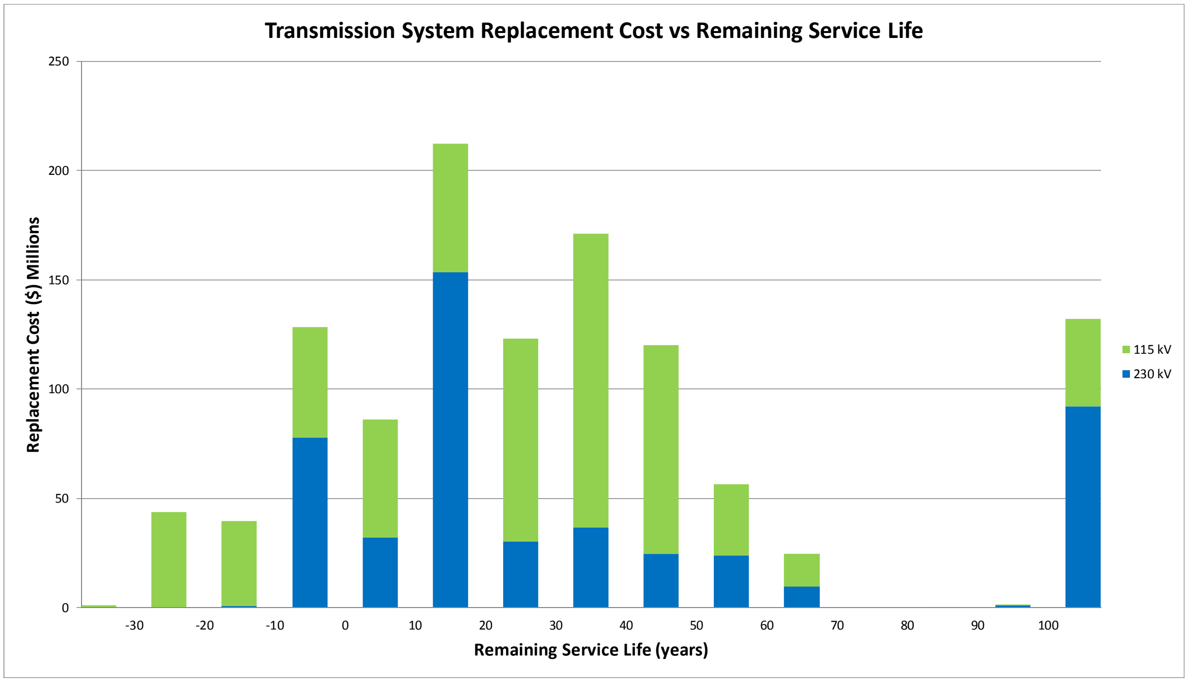


Figure 3: Replacement Cost vs. Remaining Service Life

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

To address this issue, several alternatives present themselves in terms of long-term replacement policies, as shown in the table below. The 30-year replacement period is recommended at $21.1 million per year, split between $11.3 million for 115kV and $9.8 million for 230kV. This policy, when coupled with an ongoing, annual risk assessment and targeting of funds, over the long term will effectively reduce risks and minimize total lifecycle costs.

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

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

Table 7: Levelized Replacement Spending Options

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

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

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

Table 8: 2015 Transmission Spending

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

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

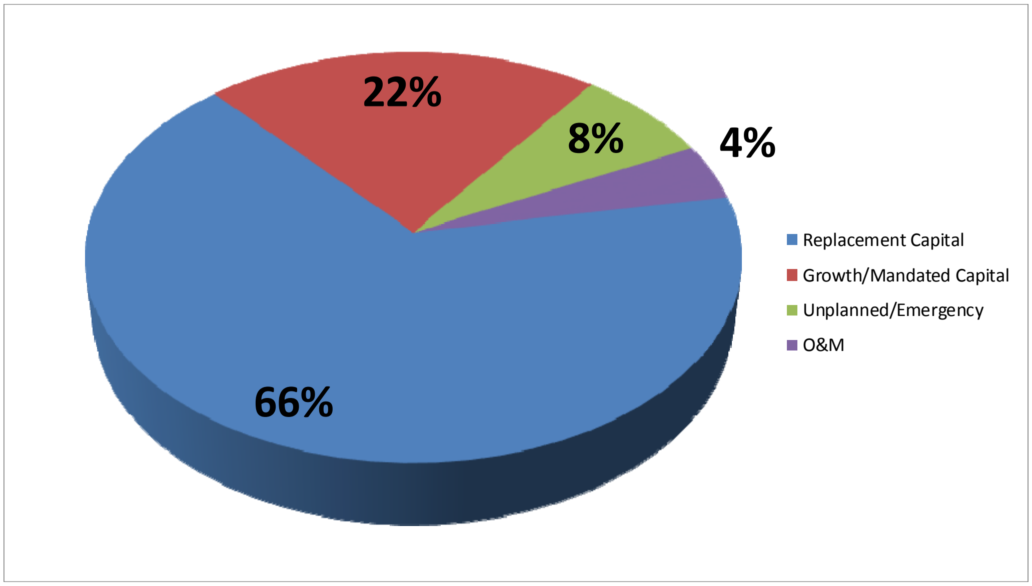


Figure 4: 2014 Planned Capital, O&M, and Emergency Spending

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

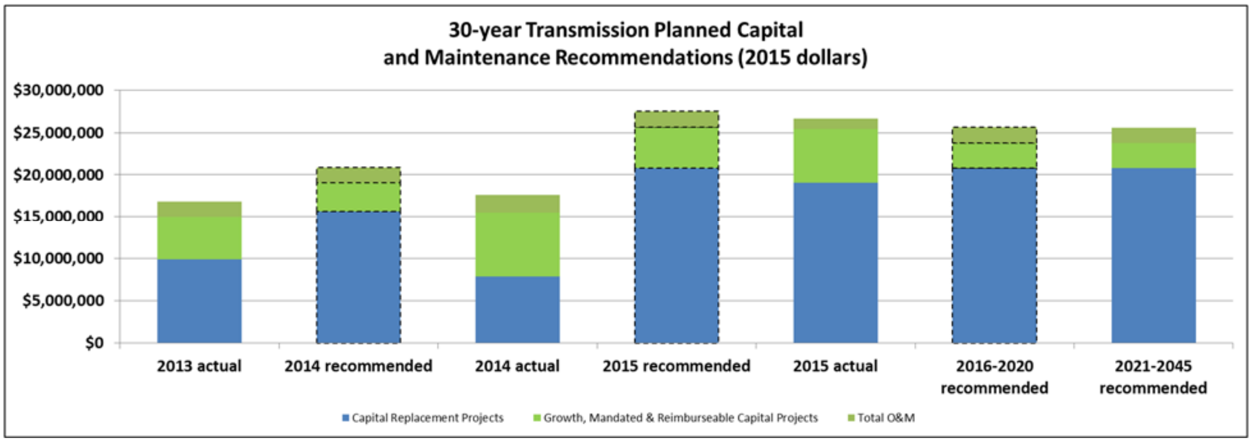


Figure 5: 30-year Transmission Planned Capital and Maintenance Recommendations

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

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

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

Process Capability

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

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

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

Risk Prioritization

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

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

In mathematical form, this is expressed as:

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

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

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

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

Table 11: Probability Index Criteria and Weightings

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

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

Table 12: Consequence Index Criteria

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

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

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

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

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

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

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

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

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

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

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

Unplanned Spending

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

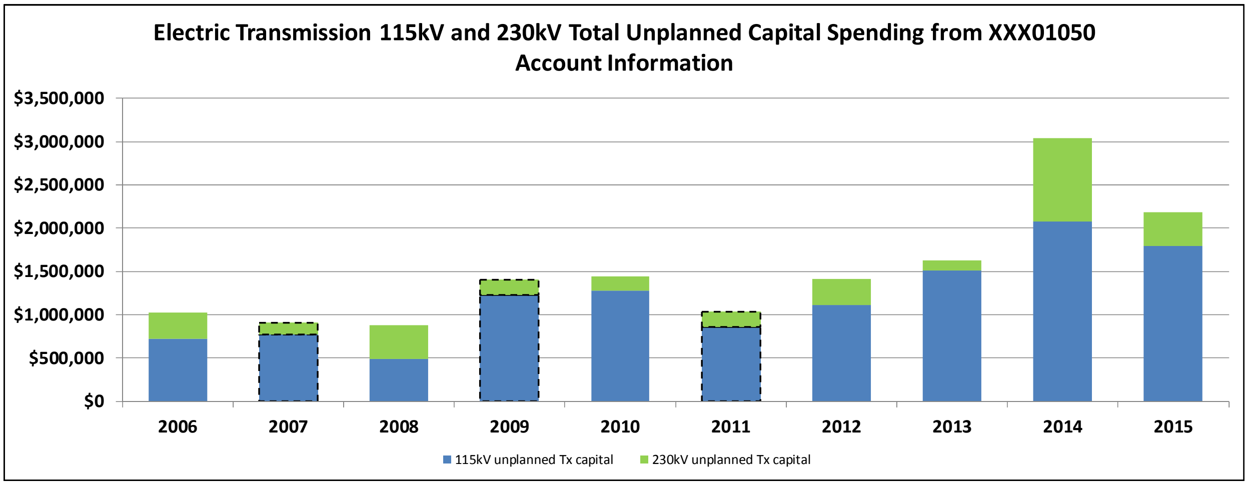


Figure 6: 115kV and 230kV Total Unplanned Capital Spending

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

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

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

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

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

Outages

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

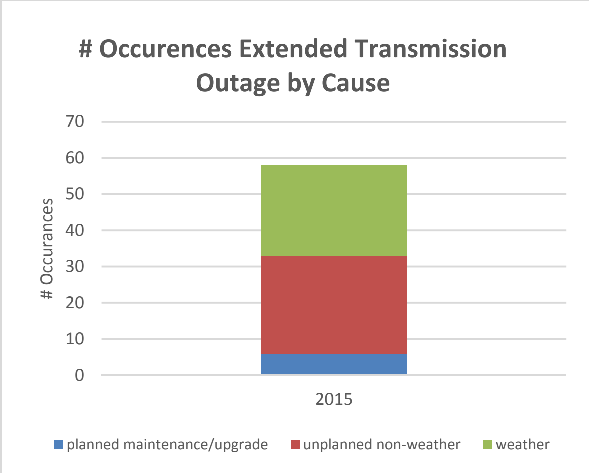
In 2015 there were 162 feeder outages, but only 58 unique transmission events that caused those outages. The 2015 data was analyzed to indicate only the number of unique transmission outages for each subreason.

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

Table 18: Transmission Outage Causes, 2009-2015

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

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



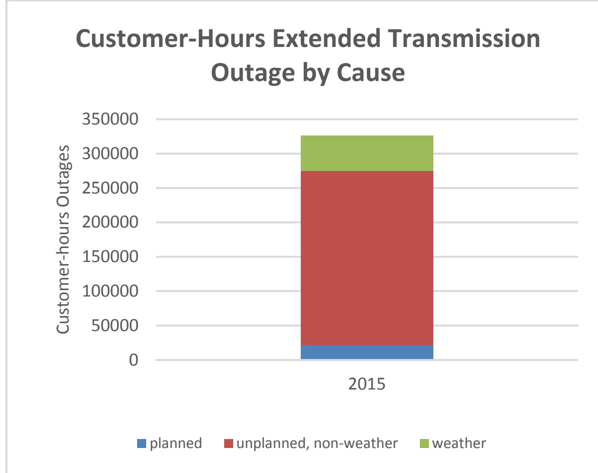


Figure 7: Transmission outage causes affecting customers in 2015

Programs

1. Major Rebuilds

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

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

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

Table 19: Major Rebuild Projects, 2016 – 2020

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

2. Minor Rebuilds

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

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

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

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

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

3. Air Switch Replacements

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

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

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

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

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

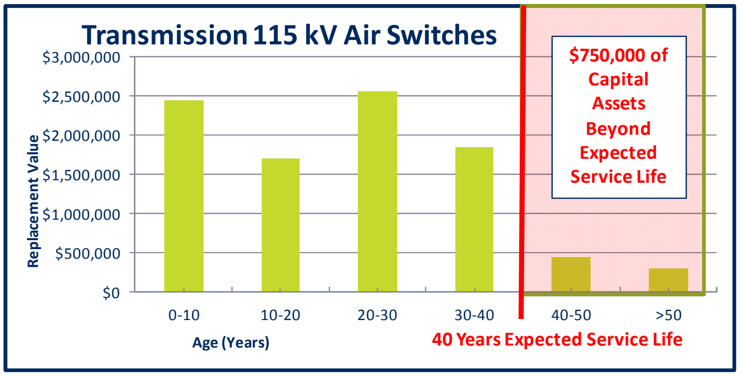


Figure 8: Air Switch Replacement Value vs. Remaining Service Life

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

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

Table 21: Air Switch Priority List for Repairs and Replacements

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

4. Structural Ground Inspections (Wood Pole Management)

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

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

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

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

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

5. Structural Aerial Patrols

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

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

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

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

6. Vegetation Aerial Patrols and Follow-up Work

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

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

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

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

7. Fire Retardant Coatings

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

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

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

8. 230kV Foundation Grouting

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

9. Polymer Insulators

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

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

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

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

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

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

10. Conductor & Compression Sleeves

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

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

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

Program Ranking Criteria

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

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

Table 22: Program Ranking Criteria

The NERC High, Medium, and Low Mitigation programs reconfigure insulator attachments, and/or rebuilds existing transmission line structures, or removes earth beneath transmission lines in order to mitigate ratings/sag discrepancies found between "design" and "field" conditions as determined by LiDAR survey data. This program was undertaken in response to the October 7, 2012, North American Electric Reliability Corporations (NERC) "NERC Alert" - Recommendation to Industry, "*Consideration of Actual Field Conditions in Determination of Facility Ratings*". Mitigation brings lines in compliance with the National Electric Safety Code (NESC) minimum clearances values. These code minimums have been adopted into the State of Washington's Administrative Code (WAC).

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

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

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

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

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

Benchmarking

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

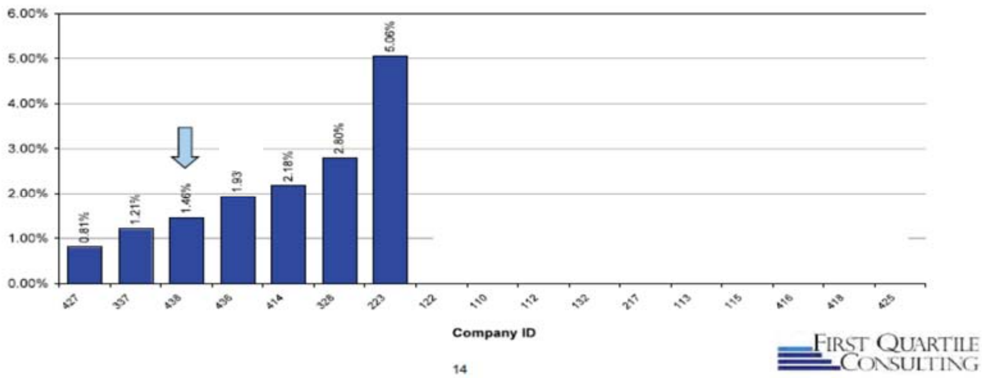


Figure 9: 3-year Transmission Lines Replacement Capital Spending per Asset (First Quartile Consulting, 2008)

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

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

Table 23: Avista Transmission Lines Replacement Capital Spending per Asset

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

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

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

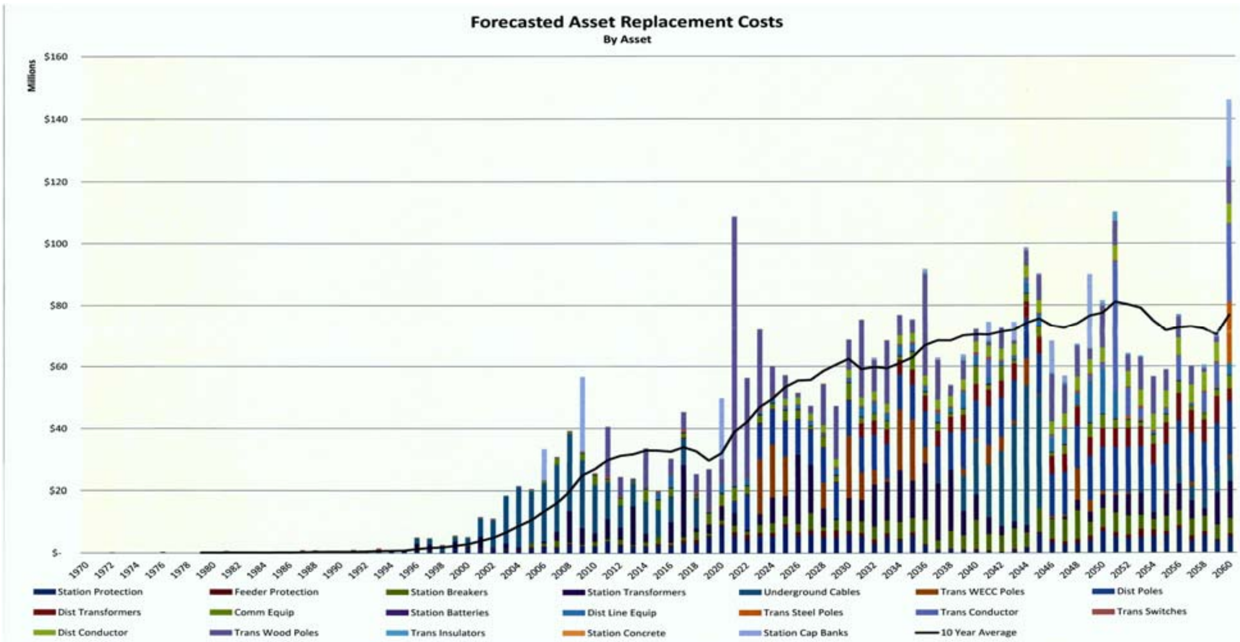
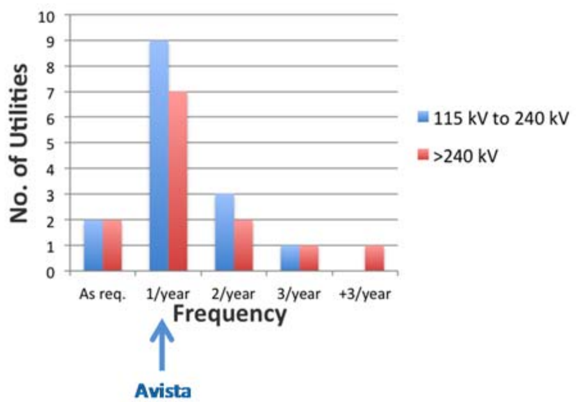


Figure 10: Idaho Power Long-term Replacement Costs

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

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

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



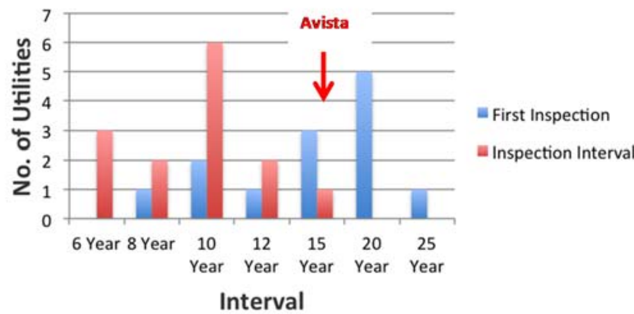


Figure 11: Maintenance Benchmarking: Aerial Patrols (left) and Pole Inspections (right)

Data Integrity

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

Data Integrity - Electric Transmission System

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

Table 24: Transmission Asset Data Integrity

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

Material Usage

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

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

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

Root Cause Analysis (RCA)

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

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

System Planning Projects

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

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

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

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

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

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

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

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

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

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

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

Area Work Plans

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

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

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

Table 30: Project Type Key

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

Table 31: Area Work Plans – Major Projects

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

Table 32: Minor Rebuilds

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

Table 33: Ground Inspection Plan

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Appendix A –Transmission Probability, Consequence & Risk Index

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

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

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

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

Appendix B – Transmission System Outage Data

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