WUTC DOCKET: UE-200900 UG-200901 UE-200894
EXHIBIT: JD-LL-2
ADMIT ☑ W/D ☐ REJECT ☐

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-200900

DOCKET NO. UG-200901

DOCKET NO. UE-200894

(Consolidated)

EXH. JD/LL-2

JOSHUA D. DILUCIANO

LARRY D. LA BOLLE

REPRESENTING AVISTA CORPORATION

Educational Background, Experience and Qualifications

Larry D. La Bolle

I earned a bachelor's degree in Fisheries Resources from the University of Idaho in 1980, and a M.S. degree in Fisheries Science from Oregon State University in 1984.

I was employed by the Idaho Department of Fish and Game from 1984 – 1990 as a research biologist and regional fishery manager.

I joined Avista (then, The Washington Water Power Company Company) in 1990, and served in a range of technical and project-management roles that included facility siting, public involvement and hydropower licensing. In subsequent assignments, I served as director of community and economic development, general manager of Avista/Chelan, LLC, and director of electric and natural gas operations, where I also formed and initially led the Company's asset management group. From 2005-2018 I served as director of federal and regional affairs, and since that time, have served in my current role leading the Company's electric reliability strategy. I have extensive experience in state and federal regulatory matters, including representing the Company in a variety of regulatory processes, preparation of reports, testimony and exhibits, sponsoring testimony as a witness in numerous rates proceedings, and more recently, considerable experience assisting with discovery in this proceeding.

Avista Utilities

2017 Wood Pole Management Program Review and Recommendations

Rodney Pickett
9/20/2017

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Executive Summary

Based on our analysis, Asset Management recommends continuing with our current 20 year cycle for the Wood Pole Management program. We examined several different alternatives and some do provide more a little more value but potentially require very significant initial capital costs well beyond current levels.

Avista has between 233,000 and 244,000 wood poles in our Electric Distribution system. These poles physically support most of the Electric Distribution infrastructure to keep the conductors and other components a safe distance from the population and avoid injuries. We examine here the different strategies for maintaining our wood poles and attached components to find the best strategy.

The Wood Pole Management program inspects and repairs or replaces distribution wood poles, cross-arms, insulator pins, insulators, pole guying, cutouts, primary and secondary connectors, lightning arresters, grounding, and Overhead Distribution transformers. This analysis covers distribution wood poles, cross-arms, insulator pins, insulators, and pole guying. The Transformer Changeout Program analysis will cover the primary and secondary connectors, secondary conductors, lightning arresters, grounding, and Overhead Distribution transformers.

The Wood Pole Management program supports our Safe & Reliable Infrastructure strategy. Specifically, Wood Pole Management strives to invest in our infrastructure to achieve optimum life-cycle performance – safely, reliably and at a fair price. The program meets this objective by providing the best customer internal rate of return that will fit within our capital and Operations and Maintenance budget constraints.

We selected continuing our 20 year inspection and maintenance cycle (see the table below) based on a good customer internal rate of return and alignment with our historical budget limitation of around $22 million in Capital dollars for Wood Pole Management and Grid Modernization.

We examined several alternatives that included a 5 year, 10 year, 20 year, and 25 year inspection cycle time as well as the impact of Grid Modernization work on the related Wood Pole Management work. While the 5 year cycle did provide a better Customer Internal Rate of Return of 8.85%, the 5 year cycle Operations and Maintenance costs exceeded our historical spending constraint. The 20 year inspection cycle provided the best Customer Internal Rate of Return for both the case that includes adding the Transformer Changeout Program work of replacing all pre-1981 Overhead Transformers and our current practice of replacing transformers that functionally have failed while meeting the Operating and Maintenance budget constraints. Any changes to the Transformer Changeout Program are covered in a different document and remains independent of this analysis.

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

Based on the analysis and selection of the 20 year inspection cycle, the table below shows a projection for the Capital and O&M budgets required to support the program.

Budget	Year 1	Year 2	Year 3	Year 4	Year 5
Capital	$11,669,045	$13,025,585	$13,742,601	$14,047,041	$15,078,248
O&M	$803,810	$803,810	$833,885	$847,704	$880,576

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

We recommend continuing the Wood Pole Management program on its 20 year inspection cycle and follow-up work strategy. Any delays in the work will impact reliability and system performance. Ultimately, the Capital Planning Group makes the final budget decisions and selects or modifies the strategy implemented based on current budget constraints and Avista's strategic initiatives.

Purpose

Asset Management maximizes the life-cycle value of Avista's physical assets. Our team researches and collaborates to integrate knowledge, discover insight, and lead with intelligence in order to achieve Avista's strategic objectives. Avista invests in our infrastructure to achieve optimum life-cycle performance – safely, reliably and at a fair price. We focus on sustaining safe systems that deliver energy effectively and efficiently at all times.

Asset Management reviews programs periodically to ensure they accomplish their initial objectives and bring them into alignment with current corporate strategic objectives. Tracy West analyzed the Wood Pole Management (WPM) program in 2012, so five years have elapsed since the last review. Furthermore, our Vice-President, Heather Rosentrator, requested Asset Management analyze and justify our current capital spending on Electric Distribution assets.

Scope

The WPM inspects and repairs or replaces distribution wood poles, cross-arms, insulator pins, insulators, pole guying, cutouts, primary and secondary connectors, lightning arresters, grounding, and Overhead Distribution transformers. This analysis covers distribution wood poles, cross-arms, insulator pins, insulators, and pole guying. The Transformer Changeout Program (TCOP) analysis covers cutouts, the primary and secondary connectors, lightning arresters, grounding, and Overhead Distribution transformers. Primary conductor analysis was analyzed independent of the Wood Pole Management program because WPM addresses very little primary conductor.

While WPM and Grid Modernization are related programs, this documented discusses Grid Modernization as it relates to WPM and leaves its justification for another report. Grid Modernization has several other drivers that are not associated with WPM such as road moves, Distribution automation, re-conductoring, TCOP, and other drivers.

Currently, the WPM program inspects all electric Distribution Wood Poles on a 20 year cycle followed by the work identified to repair or replace components from the inspection. The inspection covers all wood pole and all equipment attached to the pole. Predominately, the inspection covers the wood pole, attached crossarms, insulator, insulator pins, Distribution overhead transformers, grounding, lightning arresters, cutouts, and wildlife guards installed on transformers. The inspection includes a visual inspection of the pole and attached components, boring and checking for internal rot as well of external visual inspection of the pole checking. The specifics of the inspection portion of WPM is outlined in the “Specification for the Inspection of Poles” (Specification S-622). The follow-up work to the inspections is covered specifically by the following documents in the Distribution Feeder Management Plan (DFMP) – Structure-Specific Programs found at Avista’s sharepoint site: DFMP – Structure-Specific Programs – Design Criteria Manual - All Documents.

In order to align the assets better in the analysis, wood poles, attached crossarms, insulators, guying, and insulator pins were analyzed in the WPM models. The overhead transformers, cutouts, grounding, lightning arresters, and wildlife guards were analyzed in different models for the Distribution transformer and combined in the final analysis to reflect the full WPM program budgets and impacts.

Duration of the strategy – 5 years

Objectives, Assumptions, Constraints

Objectives

From Avista's Strategic Plan (Avista, 2017), the Wood Pole Management program supports our Safe & Reliable Infrastructure strategy. Specifically, WPM strives to invest in our infrastructure to achieve optimum life-cycle performance – safely, reliably and at a fair price. WPM meets this objective by providing the best customer internal rate of return (CIRR) that will fit within our capital and Operations and Maintenance (O&M) budget constraints.

Assumptions

Table 1 lists specific assumptions used in the analysis for WPM and the WPM portion of the Grid Modernization program.

Table 1 Model Assumptions

Assumption	Source of Assumption
Average Customer Impact Value per event = $24,431	Combination of average customer outage value, average outage duration, and average number of customers impacted
12,000 randomly selected poles represent all 244,000 wood poles	Simplifying assumption
Ages of the crossarms, insulators, and insulator pins are the same age as the pole	Simplifying assumption
All corrective and planned replacements are performed by contractors using the contractors pricing	Majority of the work is currently completed by contractors. Costs based on weighted average price based on number of units per contract price (Maintenance)

Assumption	Source of Assumption
All poles have one crossarm, four insulators, four insulator pins, and guying	The probability of failures for each of these assets is based on Wood Pole Management inspection results using this assumption so that the probability of failure reflects the probability that the pole has a component and that component has failed. This method is selected because we don't have an inventory for insulators, insulator pins, and guying. So, except for the wood poles themselves, the MTTF's for all components does not reflect the components actual MTTF but two different probabilities, i.e. probability that the pole has the component and the probability that it failed.
All poles have the same failure curve	Simplifying assumption since more than 90% of the Distribution poles are cedar (see Table 10 below)
For the 20 Year WPM Cycle models, the time period between detection of a problem with a component' failure is 20 years with a detection probability of 100%.	Simplifying assumption for the model
For all but the 20 Year WPM Cycle models, the time period between detection of a problem with a component' failure is 20 years with a detection probability of 100%. However, they only replace the components that will fail between the inspection intervals.	Simplifying assumption for the model
The only deteriorated equipment replaced is the components that will fail before the next inspection and follow-up work	This is a follow on assumption based on the assumption directly above.
A pole or crossarm is assumed to have failed when it no longer has the required strength to survive a one in 50 year storm.	No longer meets its design criteria.
Other components replaced are assumed to have indication they no longer meet their functional requirements.	No longer meet their design criteria. As an example, if an insulator shows signs of cracks or ultraviolet damage, they no longer have their full insulation capabilities and are considered functional failures.

Assumption	Source of Assumption
Remaining assumptions are standard assumptions	See the Asset Management Standard Assumptions document for more details

Input for the failure curves shown in Figure 1 through Figure 6 come from the Wood Pole Management Inspection database (Pickett). In order to fully understand what is in the Wood Pole Management Inspection database and how it is used, an Asset Information Strategy is needed and is discussed below in the Gaps in current Strategy and Objectives section below. These failure curve provide the basis for predicting future failures based on the age of an asset and shown the unreliability of the asset as a function of age in hours. Some of the failure curves in Figure 1 through Figure 6 and Table 2 through Table 7 were adjusted from their historical failure curve to represent changes in policy that affect how the future failure curves will appear and the changes are noted for each table as appropriate. Table 2 through Table 7 summarize each of the failure curves into the corresponding failure equations used in the model and the Mean Time To Failure (MTTF) as a point of reference. The MTTF only allows you to simply compare how the reliability of a component compares to a different component. For better explanations of the failure curves and their associated equations, please see the "Training for New Employees - Weibull.pptx" located at: Training for New Employees - Weibull.pptx. The specific equations for all failure curves can also be found in the Availability Workbench Users Guide at AvailabilityWorkbench_Letter.pdf.

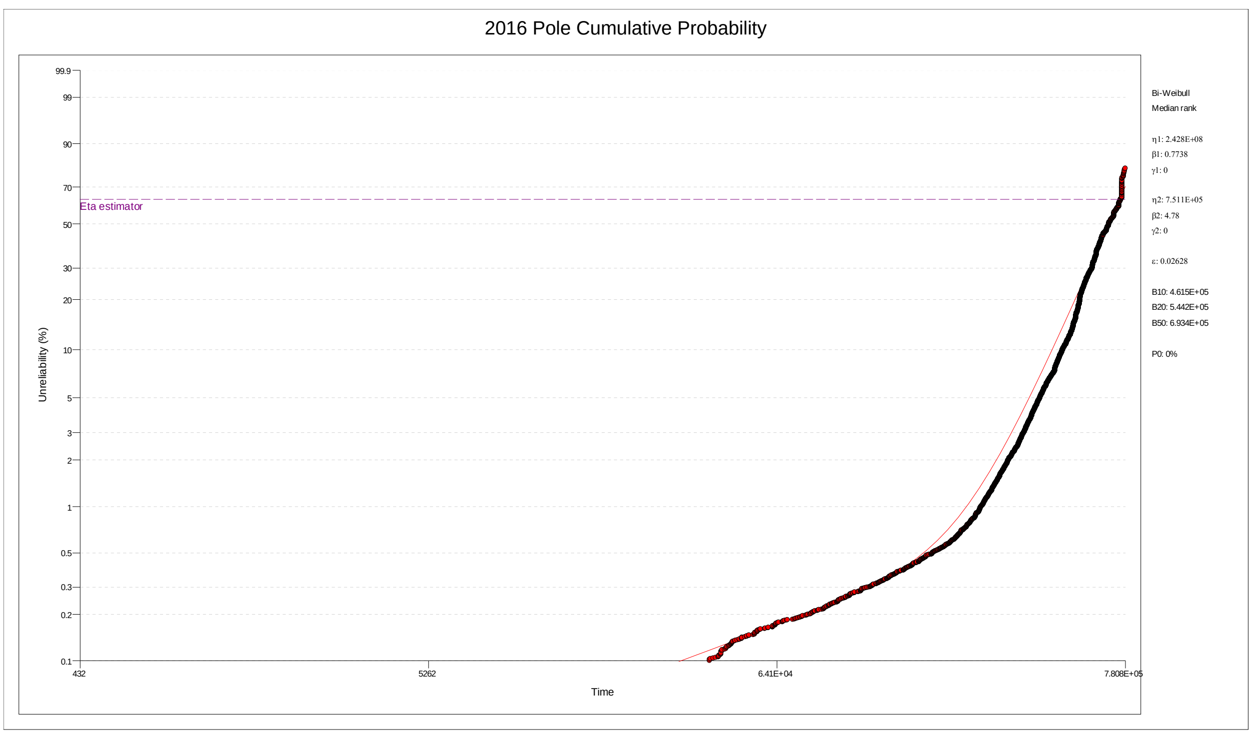

*Figure 1 Cumulative Probability plot for Unreliability for Distribution Wood Pole Replacements from the AWB Models**

*Note: Time is in Hours

Table 2 Failure Curve Values for Distribution Wood Pole Replacements

Bi-Weibull Failure Curve – Wood Poles Replacement	Set #1 Values	Set #2 Values
Characteristic Life - h	5190639 Years	85.74 Years
Shape Parameter - b	0.44	4.78
Offset - g	0	0
Mean Time To Failure (MTTF)	79 Years*	
Source of Data	Wood Pole Management Inspection Data	Wood Pole Management Inspection Data

*Note: These values were adjusted from a MTTF of 85 years to account for changes in WPM Policies that replaces pole in inaccessible areas instead of reinforcing them.

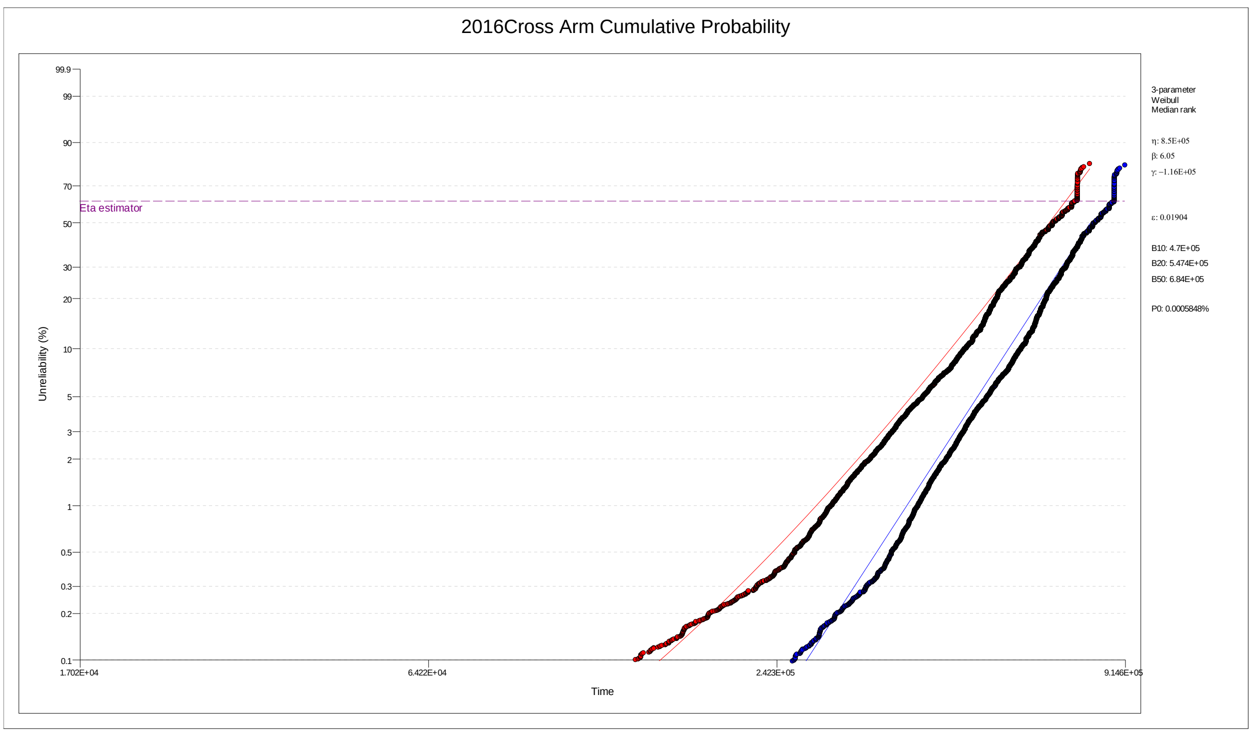

*Figure 2 Cumulative Probability plot for Unreliability for Distribution Crossarms from the AWB Models**

*Note: Time is in Hours

Table 3 Failure Curve Values for Distribution Crossarms

Weibull Failure Curve – Crossarms	Weibull Values
Characteristic Life - h	97 Years

Weibull Failure Curve – Crossarms	Weibull Values
Shape Parameter - b	6.05
Offset - g	-13.24 Years
Mean Time To Failure (MTTF)	78 Years
Source of Data	Wood Pole Management Inspection Data

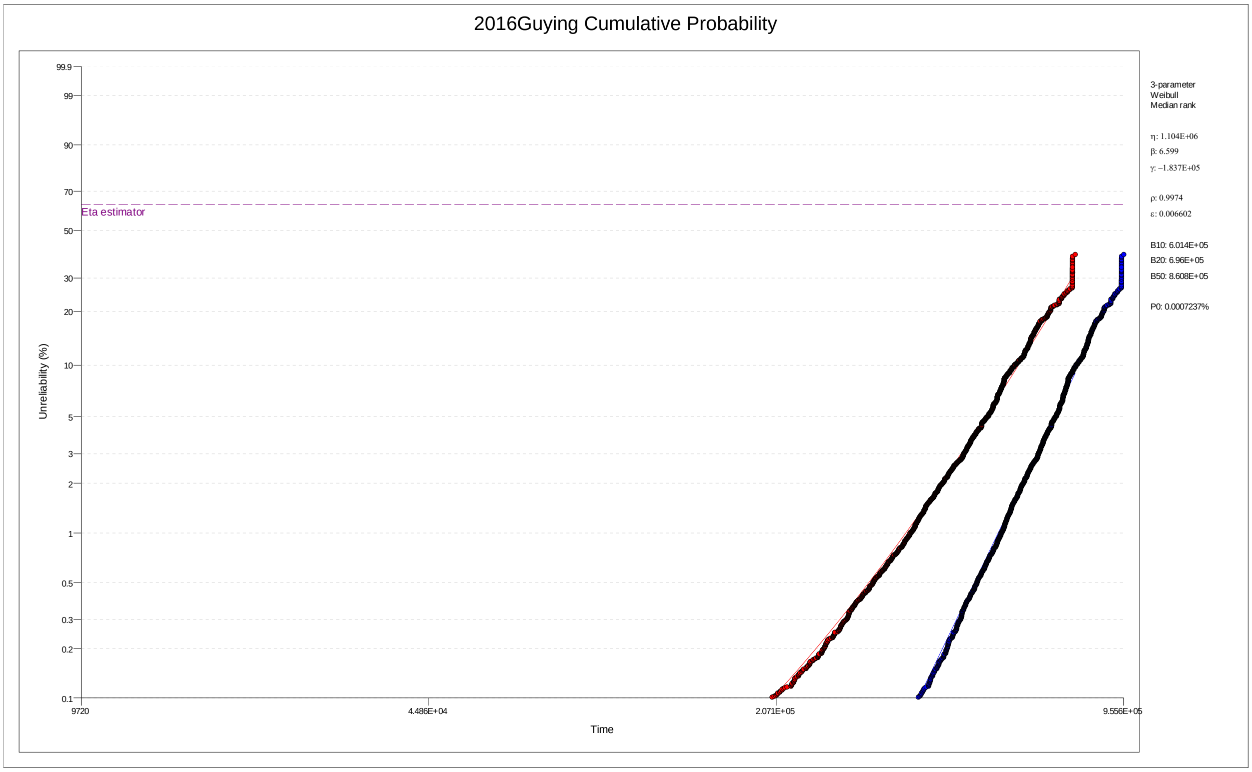

*Figure 3 Cumulative Probability plot for Unreliability for Distribution Pole Guying from the AWB Models**

*Note: Time is in Hours

Table 4 Failure Curve Values for Pole Guying

Weibull Failure Curve – Guying	Weibull Values
Characteristic Life - h	126 Years
Shape Parameter - b	6.599
Offset - g	-20 Years
Mean Time To Failure (MTTF)	98.25 Years

Weibull Failure Curve – Guying	Weibull Values
Source of Data	Wood Pole Management Inspection Data

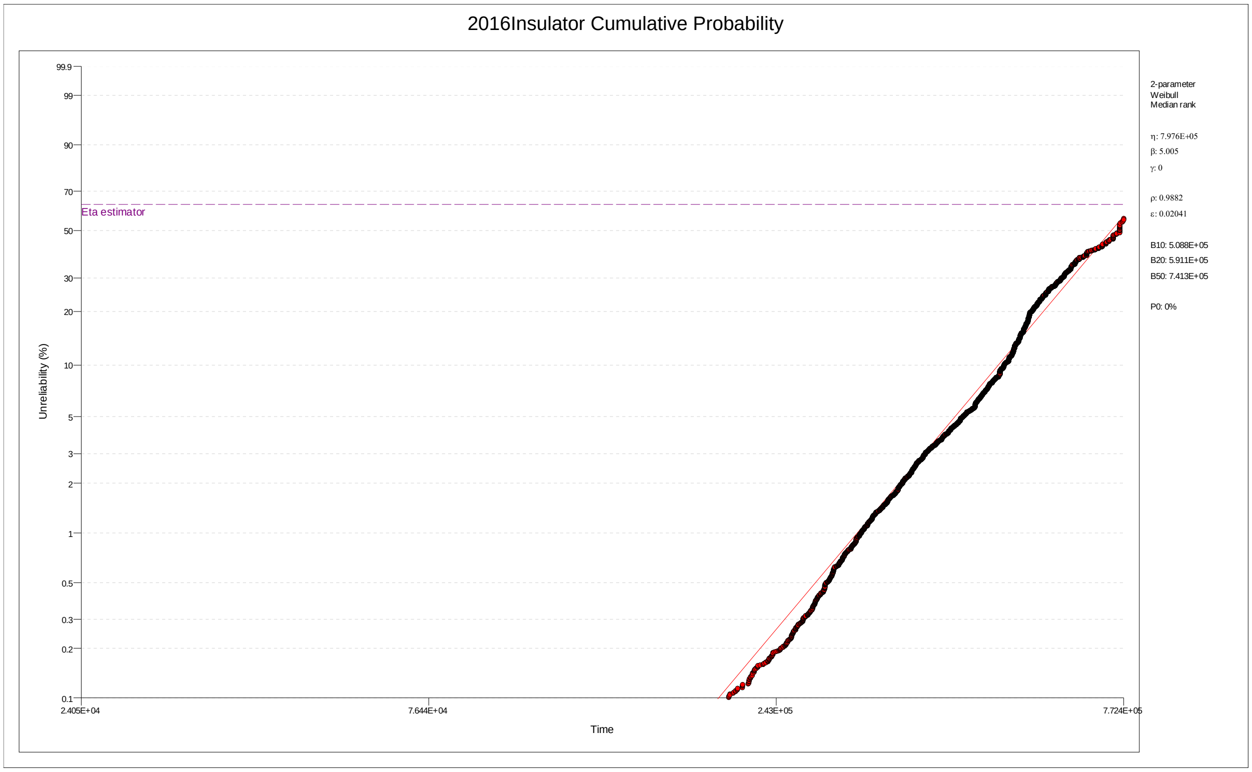

*Figure 4 Cumulative Probability plot for Unreliability for Pin Insulators from the AWB Models**

*Note: Time is in Hours

Table 5 Failure Curve Values for Pin Insulators

Weibull Failure Curve – Insulator	Weibull Values
Characteristic Life - h	91 Years
Shape Parameter - b	5.005
Offset - g	0 Years
Mean Time To Failure (MTTF)	84.6 Years
Source of Data	Wood Pole Management Inspection Data

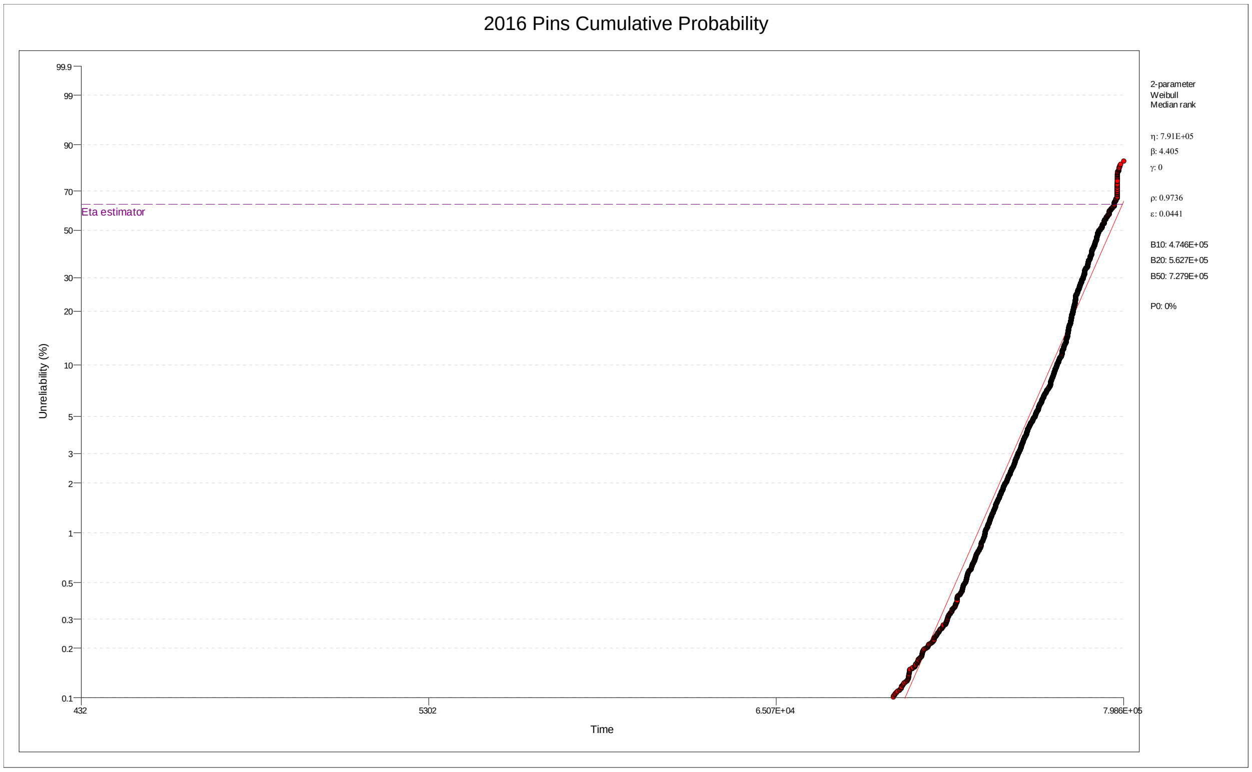

*Figure 5 Cumulative Probability plot for Unreliability for Insulator Pins from the AWB Models**

*Note: Time is in Hours

Table 6 Failure Curve Values for Insulator Pins

Weibull Failure Curve – Insulator Pins	Weibull Values
Characteristic Life - h	90.3 Years
Shape Parameter - b	4.405
Offset - g	0 Years
Mean Time To Failure (MTTF)	83.1 Years
Source of Data	Wood Pole Management Inspection Data

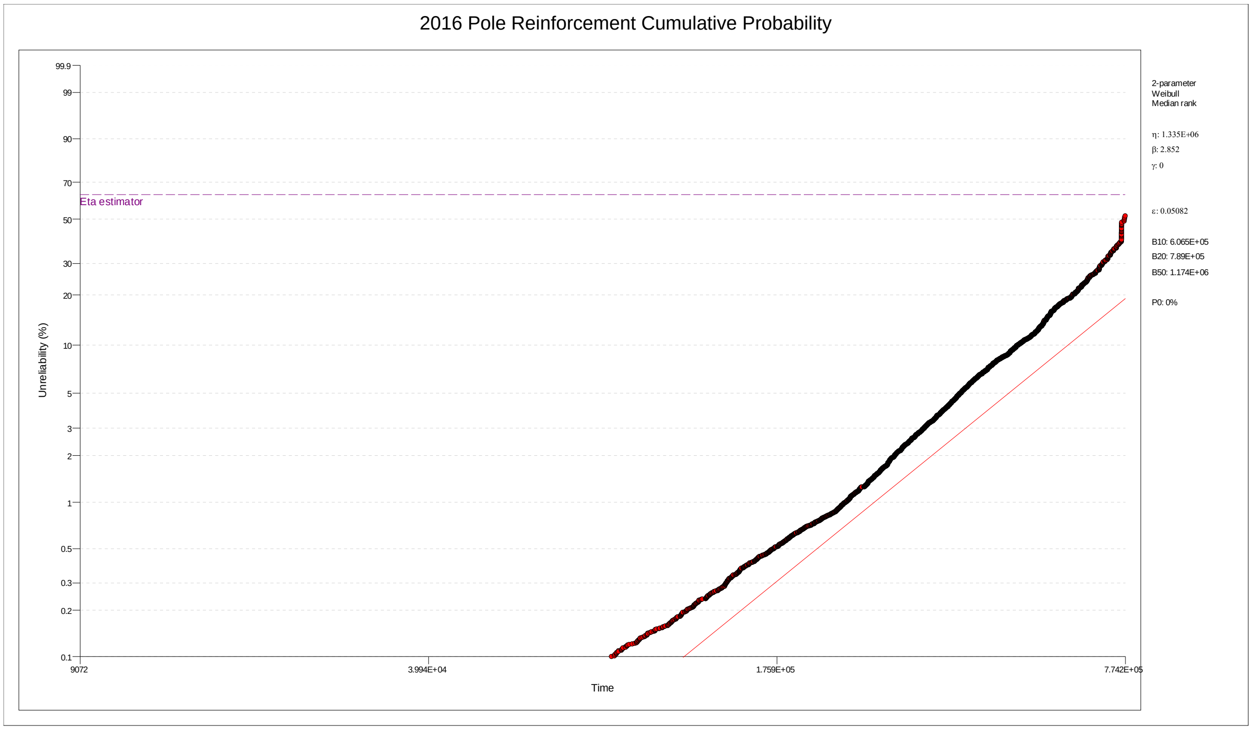

*Figure 6 Cumulative Probability plot for Unreliability for Distribution Wood Pole Reinforcements from the AWB Models**

*Note: Time is in Hours

Table 7 Failure Curve Values for Distribution Wood Pole Reinforcing

Weibull Failure Curve – Reinforce Poles	Weibull Values
Characteristic Life - h	152 Years
Shape Parameter - b	2.852
Offset - g	0 Years
Mean Time To Failure (MTTF)	134 Years**
Source of Data	Wood Pole Management Inspection Data

**Note: These values were adjusted from a MTTF of 109 years to account for changes in WPM Policies that replaces pole in inaccessible areas instead of reinforcing them with stubs.

Constraints

Budget constraints and decisions have generally limited the Capital spending on WPM and Grid Modernization to about $22 million (see Table 9) in the past. These constraints have limited the Grid Modernization the most and prevented the program of achieving the desired 60 year cycle. Based on 2012-2016 of 414 completed miles for

Grid Modernization, Avista is currently averaging ~ 84 year cycle time to complete all feeders instead of the desired 60 year cycle (see the file named “FW Grid Modernization Approximate Cycle Time Based on Current Program Funding .msg” for the calculation of current Grid Modernization cycle time).

Current Position

Avista estimates our system contains between 244,000 to 233,000 Distribution poles. Currently our Maximo system documents just over 200,000 poles. Our ongoing 20 year inspection and inventory of our poles completes its first cycle in 2027 ideally when we should have something that reflect a complete pole inventory of our electric distribution system. Table 8 shows some key facts about the electric distribution system and the WPM program. The quantity of poles in Table 8 is the high end estimate based on an initial estimate from 2006 and the estimate of 233,000 poles comes from the average number of poles per mile multiplied by the number of Overhead Distribution mileage listed in Table 8 (this method does ignore non-wood street and area light poles that are not normally inspected). The Overhead Distribution mileage comes from a data pull of Avista’s Facility Management (AFM) system that is performed periodically. The average wood pole age comes from Maximo data for all poles with a known installation date (see Figure 8 below). The remaining data in Table 8 are standard values derived using the processes outlined in the “Asset Management Standard Assumptions” by the Asset Management group.

Table 8 Distribution Wood Pole Key Facts

Key Facts	2016 Values
Quantity	244,000 Poles (estimated)
Overhead Distribution Mileage	7,702 Miles
20 Year Cycle Time Mileage	385.1 Miles per Year
60 Year Cycle Time Mileage	128.4 Miles per Year
Average Wood Pole Age	31.73 Years
Mean Time To Failure (MTTF) – Wood Poles only	79 Years
5 Year OMT Average – Pole Rotten	43.8 Events per Year
Average Number of Customers Impacted per Event	80.55 Customers
Average Duration of Event	4.82 Hours
Criticality Ranking (1 – Least Critical and 5 – Most Critical)	2 for 2016

Based on data extracted from Avista's financial system, Table 9 shows our historical spending on WPM and Grid Modernization for the past 5 years (see AM - Capital Spending Status - Summary - rev 1.xlsx for Capital Spending, see MAC 215 for 2016.xlsx for 2016 O&M Spending and see AM - MAC Budget Analysis - by Task.xlsx for 2012-2016 O&M Spending in Asset Maintenance tab). Prior to 2012, the Grid Modernization program had not been fully implemented, so we did not find as much value in going back in history beyond 2012. The O&M spending for WPM comes from the same source and splits between WPM and Grid Modernization so that the WPM stays on a 20 year inspection cycle. Historically, the 20 year cycle for WPM has come from the miles completed by WPM and Grid Modernization. The two programs in the past have used the same inspection results for planning and accomplishing the same work of the WPM program. Grid Modernization expands upon the WPM portion and includes many more program drives and work scope beyond what we discuss in this document. What this means is that as the miles of Grid Modernization is changed, the miles of WPM work must change in the opposite direction so we maintain a 20 year cycle. So if we do more miles of Grid Modernization work, we can reduce the number of miles WPM must perform by an equal amount.

Table 9 Historical Spending on Distribution WPM and Grid Modernization Programs

Program	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016	5 Year Average
Wood Pole Management Capital Spending	$10,064,203	$9,258,713	$9,512,319	$9,111,453	$8,601,732	$9,309,684
Wood Pole Management O&M Spending	$758,923	$564,222	$485,930	$455,991	$639,924	$580,998
Wood Pole Management O&M Budgets	Not Provided	$813,178	$818,778	$706,686	$789,631	$782,068
Grid Modernization Capital Spending – ER 2470 Portion Only	$7,362,925	$6,217,686	$8,683,159	$11,944,561	$9,476,167	$8,736,899

The WPM O&M Budgets identified in Table 9 come from the file named, “Budget Requirements OM 4-21-2017.xlsx” and represents the budget needs to maintain the program based on the current program according to Asset Maintenance. O&M budget cuts reduced the available funding, so we modified the inspection scope to reduce the costs by reducing the number of poles inspected and relied upon a backlog of work to keep the program on the 20 year inspection cycle. Figure 7 shows this very fact. You see the number of poles inspected is directly related to the O&M budgets. Additional O&M savings also came from a policy to not inspect poles on Grid Modernization feeders 60 years old or greater since they will be replaced per the Grid Modernization strategy. When you compare the WPM O&M spending to the O&M budget in Table 9, you see the level of the budget cuts equaling an average of $200,000 per year below needed levels. For the past 8 years (2009 through 2016), Avista has inspected an average of 12,370 poles per year which is near the planned number of 12,200 poles per year for a 20 year cycle with a total population of 244,000 poles. In 2017, the backlog will be gone and unless the O&M budget is restored to the WPM program, our cycle time will begin to approach a 25 year cycle.

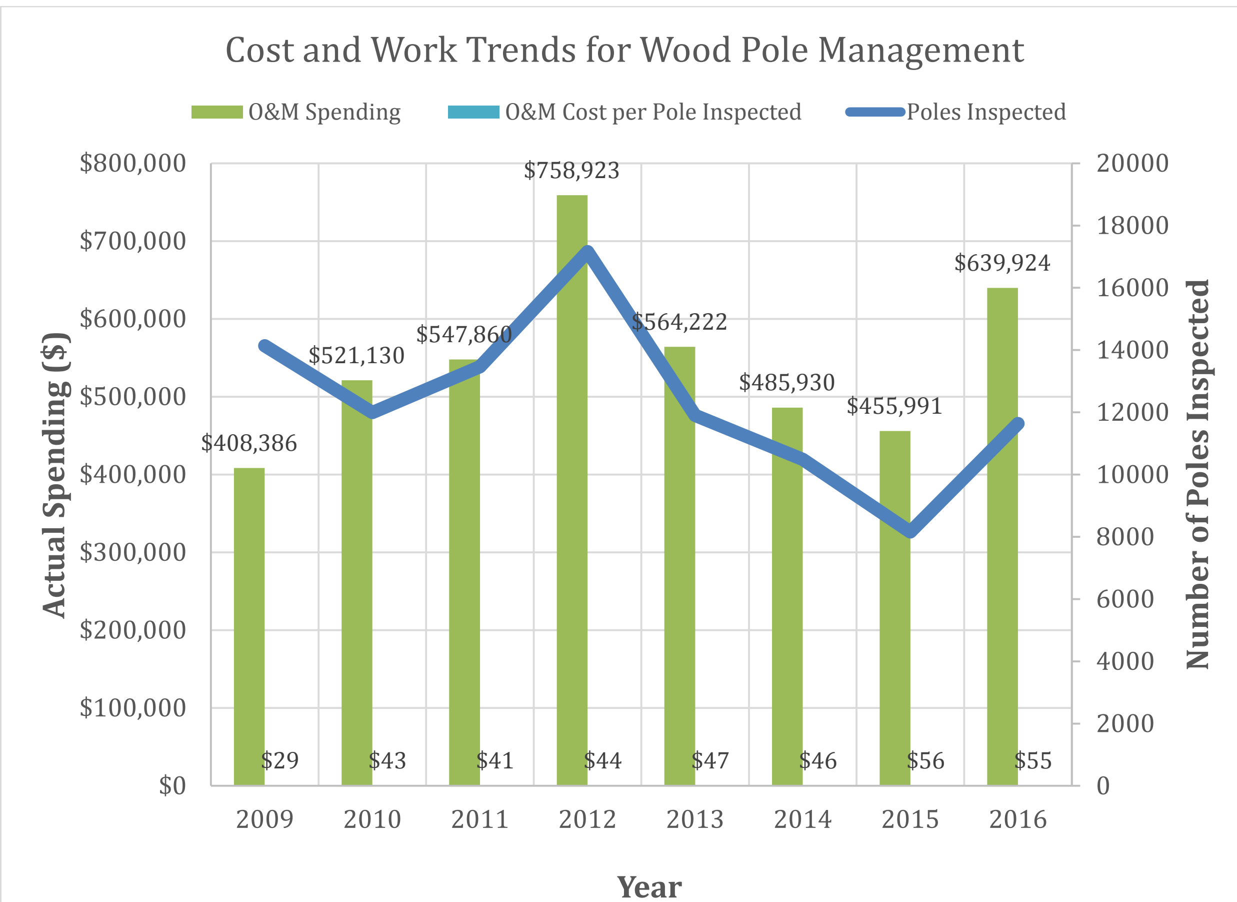

Figure 7 O&M Cost and Inspection Trends for WPM

Table 10 shows the structure types and material types for known poles from the same data used to create the age profile in Figure 8. Cedar poles dominates the pole material

(>90% of the population) and supports the assumption of treating all poles with the same failure curves. Structure types are dominated by Distribution Pole and Service Pole structure types (~ 78% combined of all structure types) and supports treating all poles as the same structure type.

Table 10 Detailed Population by Structure Type and Pole Material

Structure Type	Cedar	Fir	Laminated	Larch	Other	Pine	Steel	Grand Total for Structure Type
Area Light Pole	1.714%	0.015%	0.000%	0.053%	0.000%	0.002%	0.030%	1.814%
Bird Platform	0.003%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.003%
C-Rack	0.007%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.007%
Distribution 2-Pole	0.008%	0.000%	0.000%	0.001%	0.000%	0.000%	0.000%	0.009%
Distribution Pole	68.909%	0.315%	0.014%	5.168%	0.034%	0.003%	0.087%	74.530%
Double Circuit Pole	1.314%	0.001%	0.001%	0.022%	0.000%	0.000%	0.003%	1.341%
Fiberglass Pole	0.000%	0.000%	0.000%	0.000%	0.003%	0.000%	0.000%	0.003%
Guy Pole	1.867%	0.030%	0.001%	0.153%	0.001%	0.000%	0.001%	2.053%
INTERSET POLE	0.003%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.003%
Light	0.695%	0.007%	0.000%	0.143%	0.000%	0.000%	0.002%	0.846%
Nesting Pole	0.022%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.022%
Other	0.015%	0.001%	0.000%	0.003%	0.003%	0.000%	0.000%	0.022%
Platform Pole	0.012%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.012%
Push Brace	0.089%	0.002%	0.000%	0.004%	0.000%	0.000%	0.000%	0.095%
Service Pole	9.990%	0.324%	0.000%	0.891%	0.002%	0.009%	0.018%	11.233%
Street Light Pole	4.552%	0.025%	0.000%	0.861%	0.000%	0.000%	0.286%	5.724%
Trans W/Dist Under	1.978%	0.071%	0.001%	0.073%	0.024%	0.000%	0.135%	2.282%
Vertical Angle Pole	0.001%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.001%
Grand Total for Pole Material	91.179%	0.790%	0.016%	7.372%	0.067%	0.014%	0.562%	100.000%

Figure 8 shows the model age profile based on poles with known ages from Distribution WPM database (see the following file for the data used: Health Index Work rev 1.xlsx). The MTTF and the failure rates based on pole age come from the failure curves developed and shown in Figure 1 and Table 2. Figure 8 shows the model population age profile and demonstrates the changing number of poles approaching the MTTF and entering the region of increasing failure rates. So the age profile shown illustrates that our population is largely younger than the MTTF. The MTTF represent the age at which 50% of the original population has failed. The failure rate begins to noticeable increase after the age of 60 years as seen in Figure 8, so as a larger percentage of poles approach the MTTF, we should see a larger number of pole failures compared to the past. In fact, we do see indications of this in several data sources.

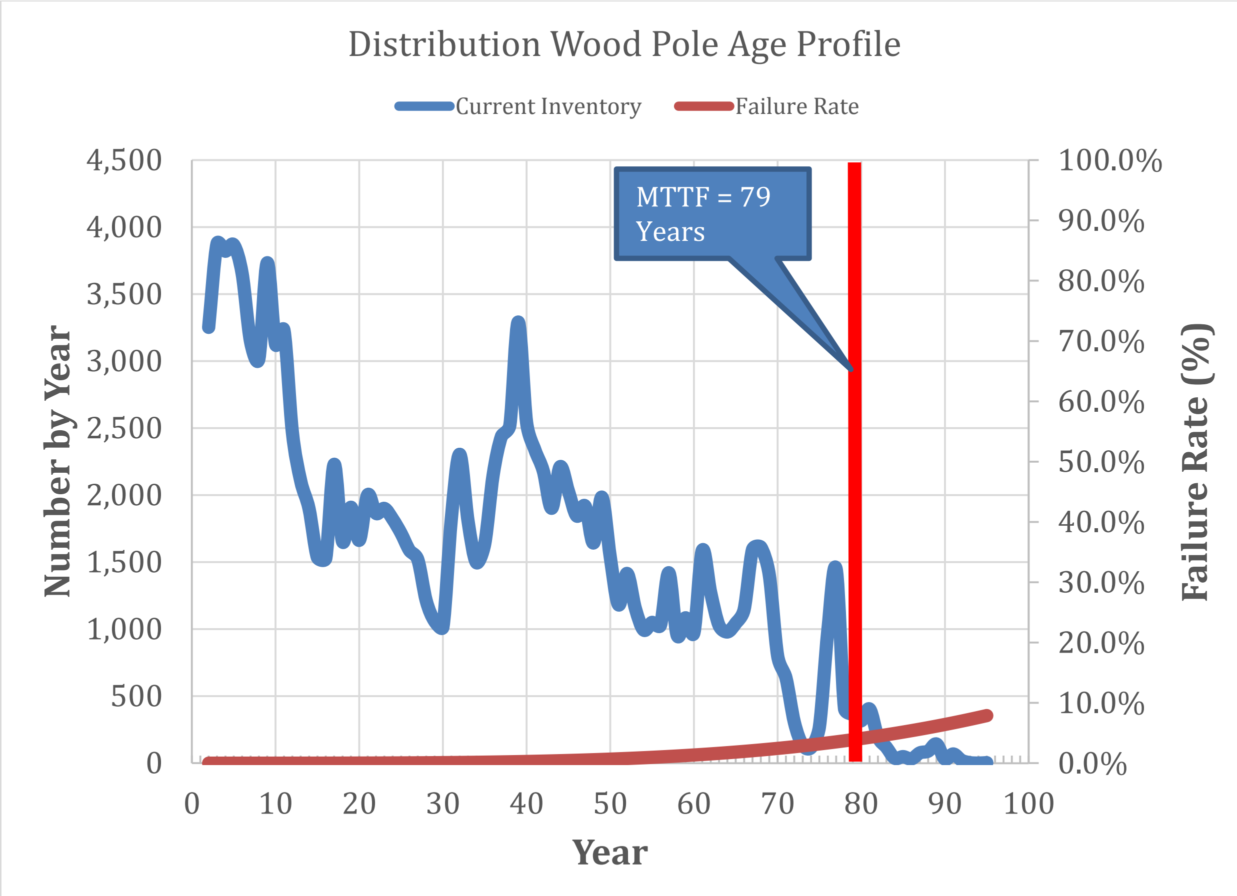

Figure 8 Electric Distribution Wood Pole Population Distribution and Failure Rate based on Pole Age

Figure 11 shows a definite trend upwards in pole usage for Storms. We did see unusual storms in 2014 and 2015 and we also saw an associated increasing trend in the number of Major Event Days (MED) except for 2016. The number of MED contributes to the trend upwards in quantity of material used for each year. However, the year 2016 also used about the same number of poles as 2013 despite not having any MED to contribute to the storm damage. The potential trend of major storm events poses a threat to the entire distribution system. An article titled “ClimateWise launches two reports that warn of growing protection gap in insurance due to rising impact of climate risks” published by the Cambridge Institute for Sustainability Leadership. The article suggests major storm frequencies have increase by 6 fold and anticipates major storms occuring approximately once every 17 years (Cambridge Institute for Sustainability Leadership, 2017). As antidotal evidence, Avista has experienced two storms classified as one of the worst storms in history. The first storm was the 1996 Ice Storm (NOAA National Centers for Environmental Information, 2017) which NOAA identified as the worst ice storm in 60 years and the second storm was the 2015 November wind storm (Brunt, 2017) that broke the record for customer outages set by the 1996 Ice Storm. Further analysis may be warranted in the future.

Figure 12 through Figure 15 continue to show trends upwards in the number of poles used in Grid Modernization and WPM (see Poles Crossarms Cutouts Replaced for 2012-2016 for ERs 2470 2055 2059 2060.xlsx and Stock 2012-2016 for ERs 2470 2054 2055 2060.xlsx for the associated data). Though, we may potentially see the number of poles used in Grid Modernization to drop as future work potentially could include feeders that have been inspected and maintained by WPM in the recent past.

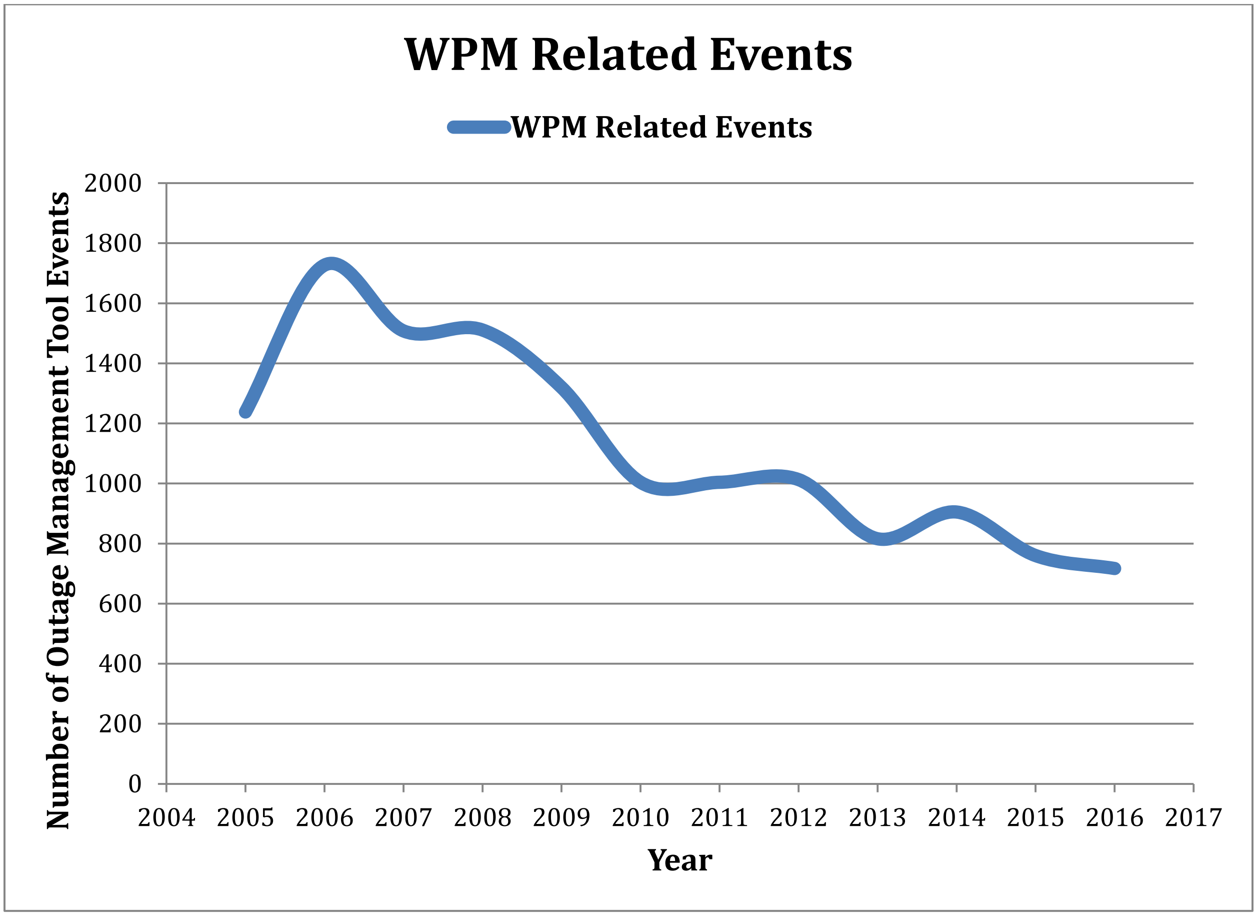

Figure 9 WPM Related OMT Events (Includes Arresters, Crossarm-rotten, Cutout/Fuse, Insulator, Insulator Pin, Pole Fire, Pole-rotten, Squirrel, Transformer - OH, and Wildlife Guard OMT Sub-Reasons)

The current trend in WPM related events in OMT continues to improve as seen in Figure 9 with each year's work on WPM, Grid Modernization, TCOP, and other work. The drivers for this improvement comes from improve trends in Overhead Transformer failures associated with TCOP replacing many older transformers, Squirrel events decreasing as more wildlife guards are installed on Overhead Transformers, and Cutout failures dropping with cutout replacements and better fuse coordination. However, the number of OMT events associated with Pole-rotten is growing a little each year as seen in Figure 10 and Figure 16. The Pole-rotten trend remains small but noticeable and we anticipate it to continue for the near future.

The data for Figure 9 and Figure 10 came from OMT Failure Data\Quarterly\Quarterly OMT Failure Data 2016.xlsx and Figure 16 comes from OMT Data for WPM subset.xlsx.

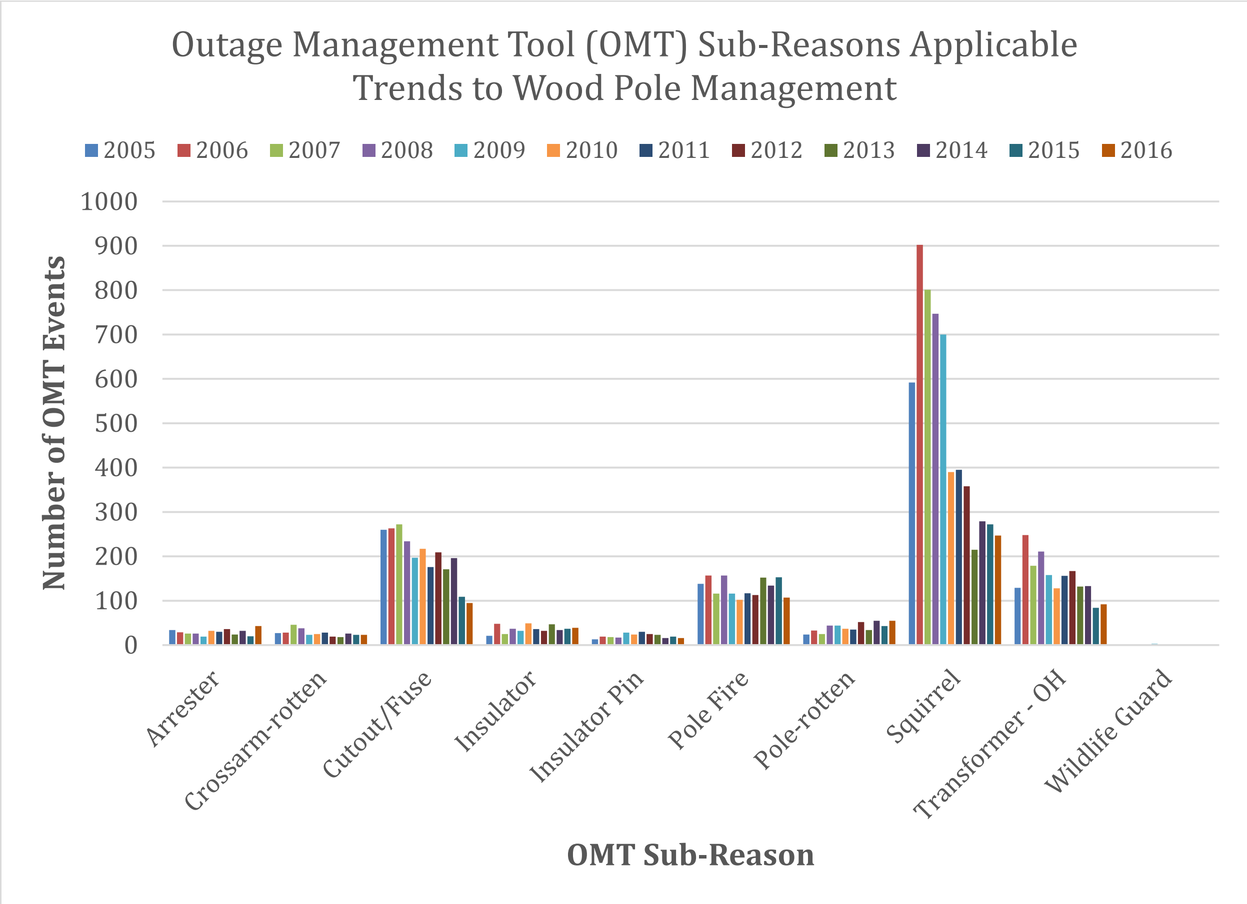

Figure 10 WPM Related OMT Event Trends

When we examine the impacts WPM has had on Distribution Feeders, Figure *17* shows the average number of WPM related Sustained Outages on Feeders prior to completing the WPM work and the results after the work was completed (WPM related events include Arrester, Crossarm-rotten, Cutout/Fuse, Insulator, Insulator Pin, Pole Fire, Pole-rotten, Squirrel, Transformer - OH, and Wildlife Guard OMT Sub-Reasons). The chart in Figure *17* represents all of the feeders where WPM work has been completed. Year 0 represents the year the work was completed. Year -5 represents 5 years before the WPM work was completed and Year 4 represents 4 years after WPM work was completed. As an example, if the WPM work was completed in 2013, Year 0 represents 2013 for that feeder and Year -5 represents 2008 data for that particular feeders. The number of events for each year is summed up by feeder and divided by the number of miles in length for each feeder giving us the number of sustained outages per mile of feeders. Using the number of outages per mile, normalizes the data so that the values are not a function of feeder lengths that can change each year. The value of all the feeders is averaged in outages per mile and plotted in Figure *17* below.

Figure *17* shows that the number of failures experienced by a feeder improves after WPM work is completed. Prior to WPM work, a feeder has about 0.18 outages per mile each year related to WPM type of work. After the work is completed, the outages per mile drop to 0.1 outage per mile. WPM work typically completed over one or two years depending on the schedule and length of the feeder. For the data and development of Figure *17* and Figure 23, see Events per Mile prior to and after WPM.xlsx.

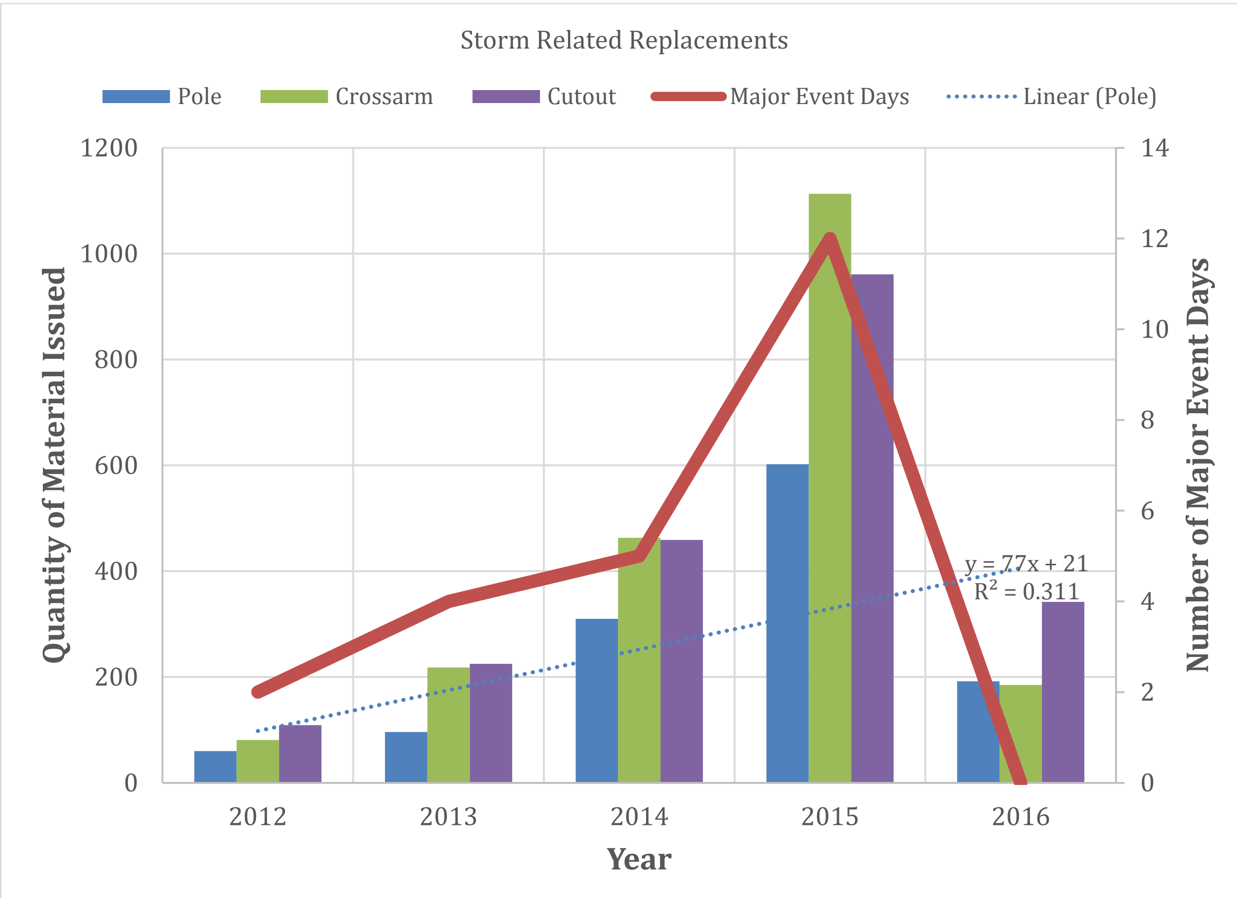

Figure 11 ER 2059 - Electric Distribution Storm Related Material Issued for Poles, Crossarms, and Cutouts (Stubs not used during storm events)

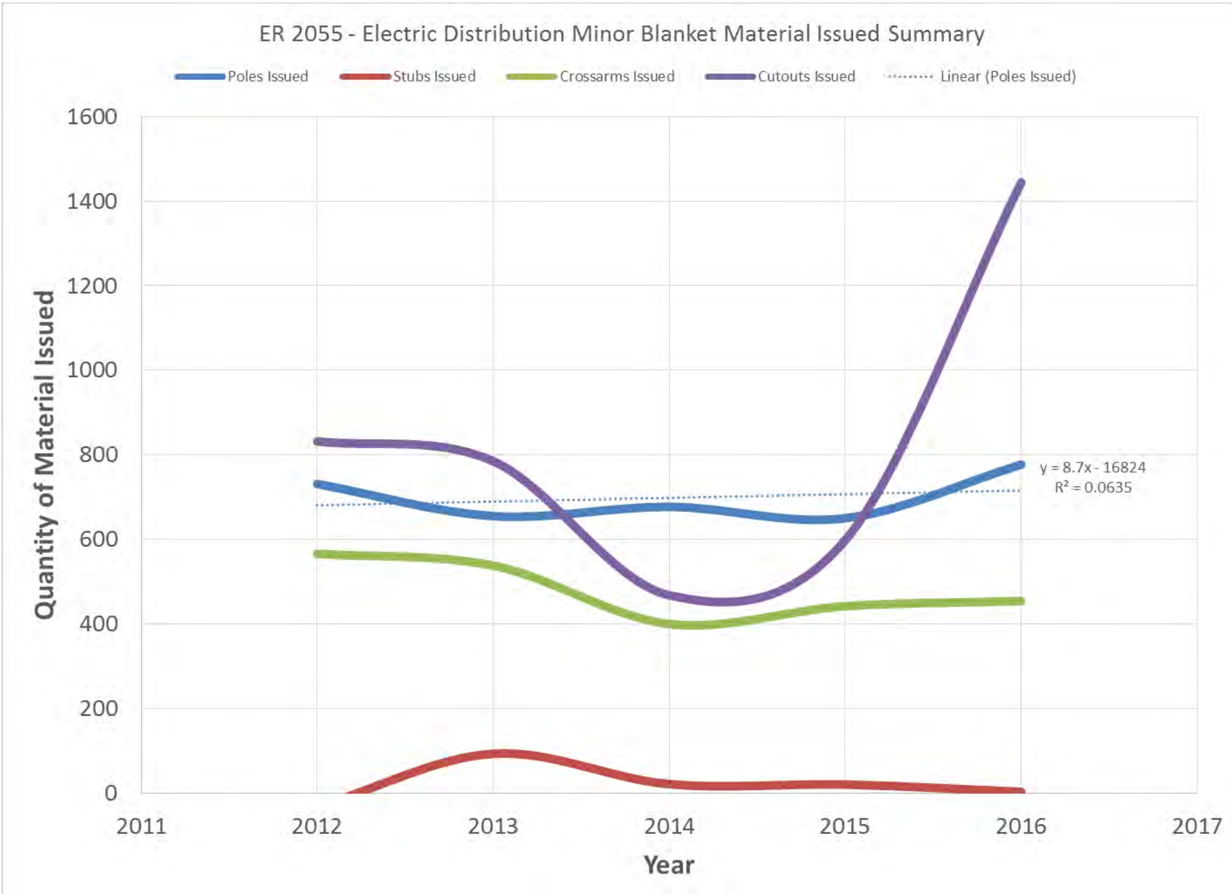

Figure 12 ER 2055 - Electric Distribution Minor Blanket Material Issued for Poles, Stubs, Crossarms, and Cutouts

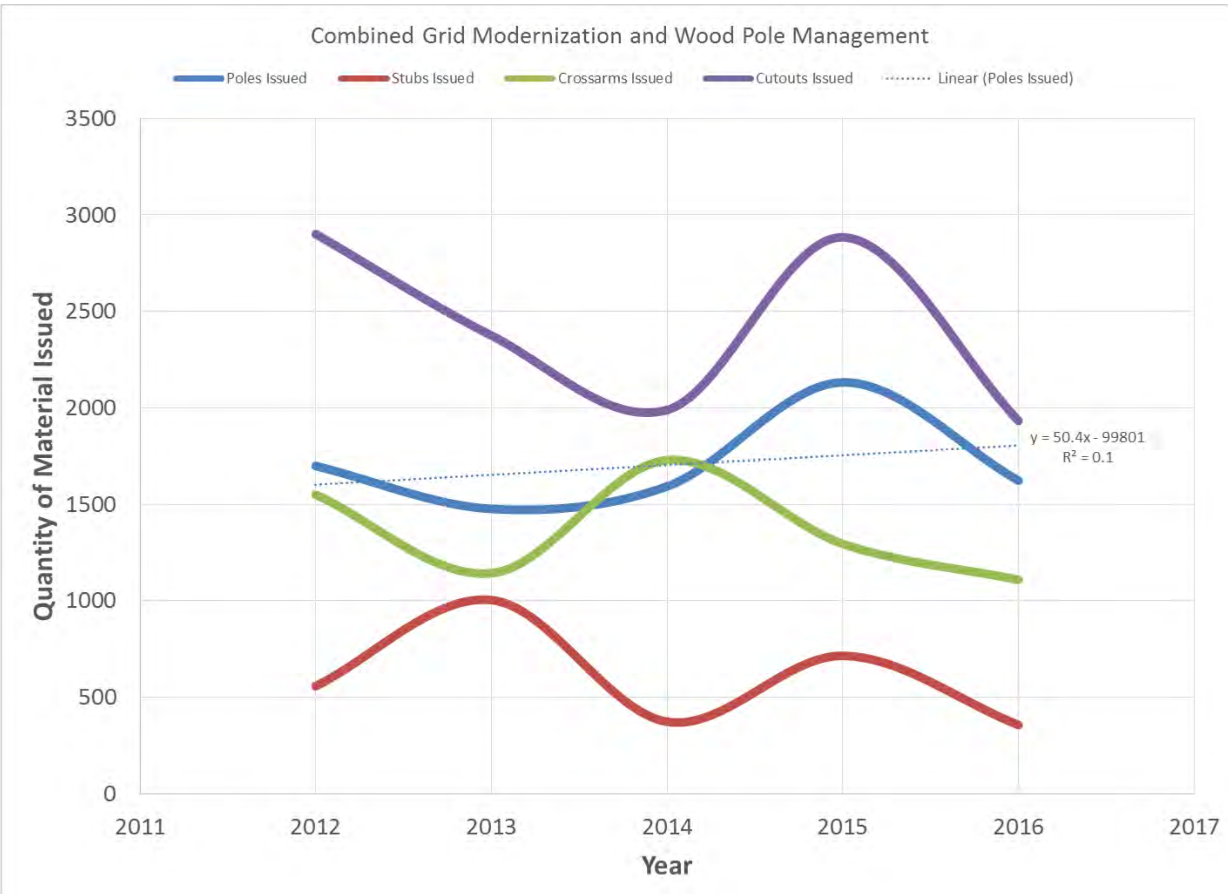

Figure 13 ER 2060 and 2470 - WPM and Grid Modernization Material Issued for Poles, Stubs, Crossarms, and Cutouts

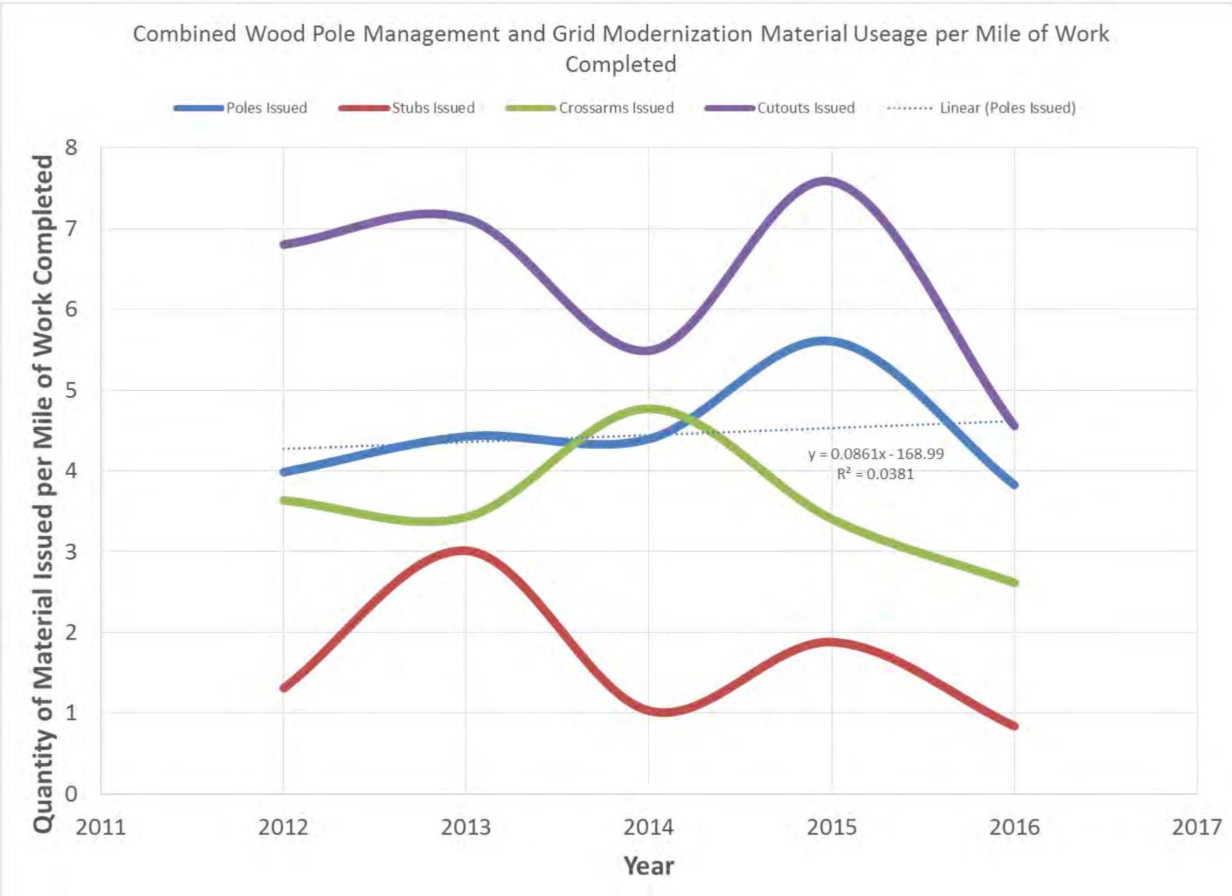

Figure 14 ER 2060 and 2470 - WPM and Grid Modernization Material Issued per Mile of Completed Work for Poles, Stubs, Crossarms, and Cutouts

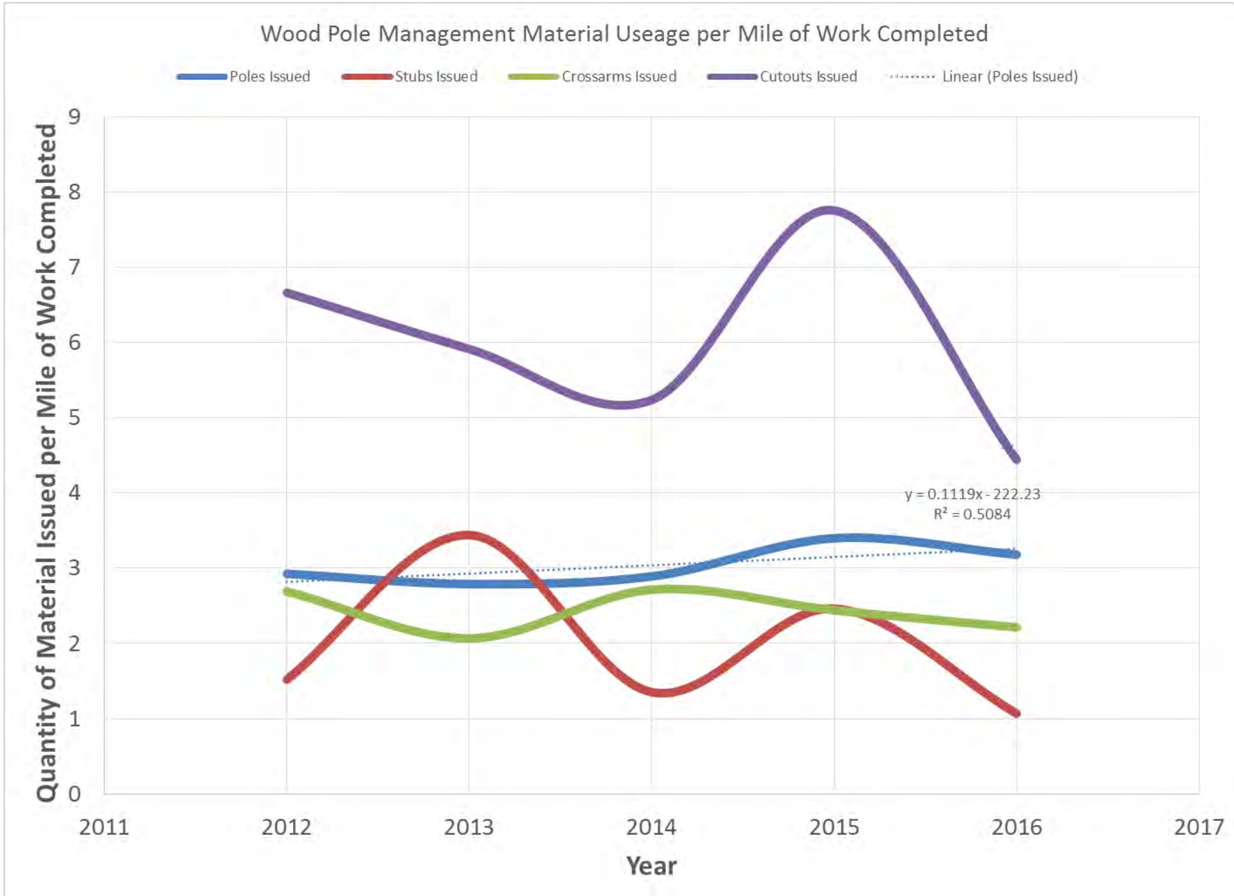

Figure 15 ER 2060 - WPM Material Issued per Mile of Completed Work for Poles, Stubs, Crossarms, and Cutouts

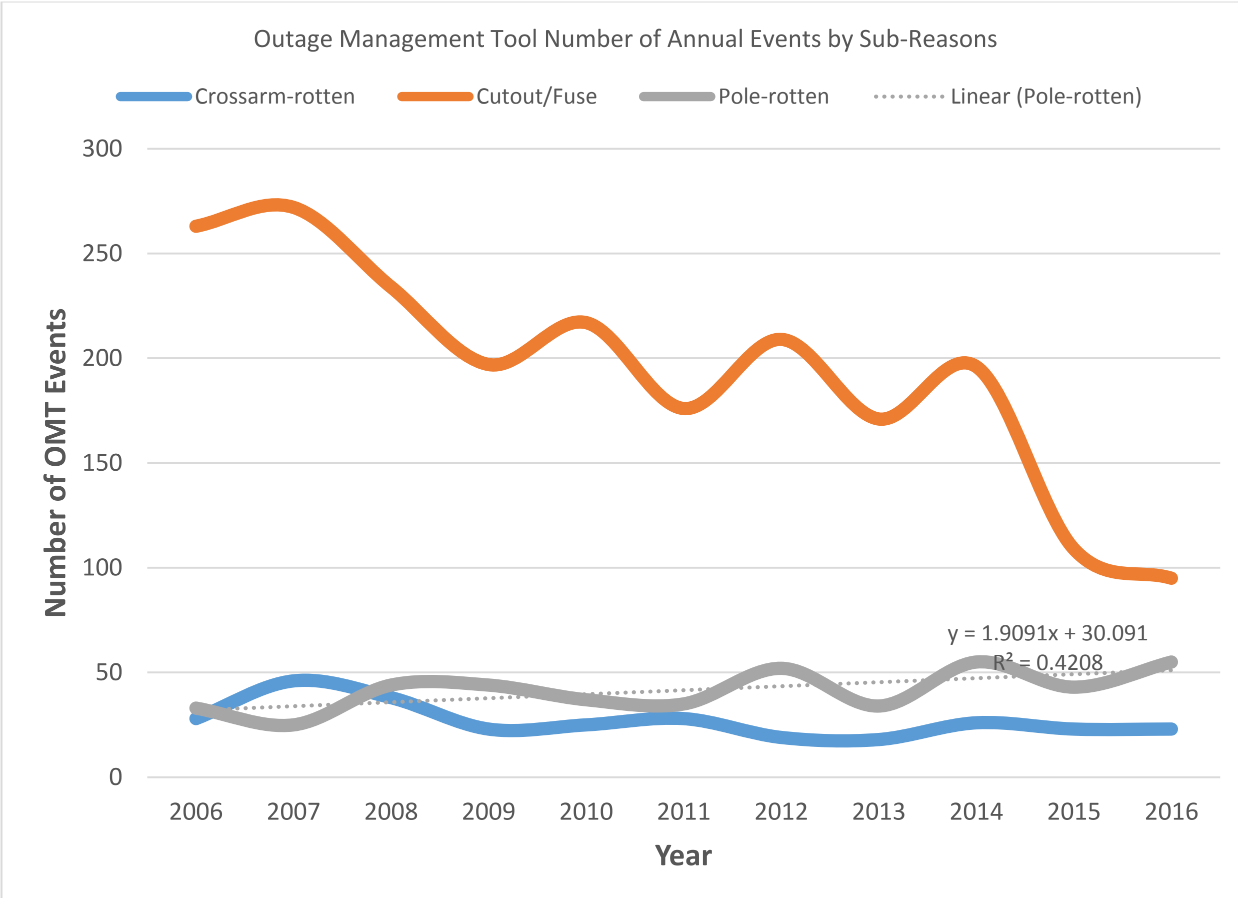

Figure 16 OMT Trend for Crossarm-rotten, Cutout/Fuse, and Pole-rotten

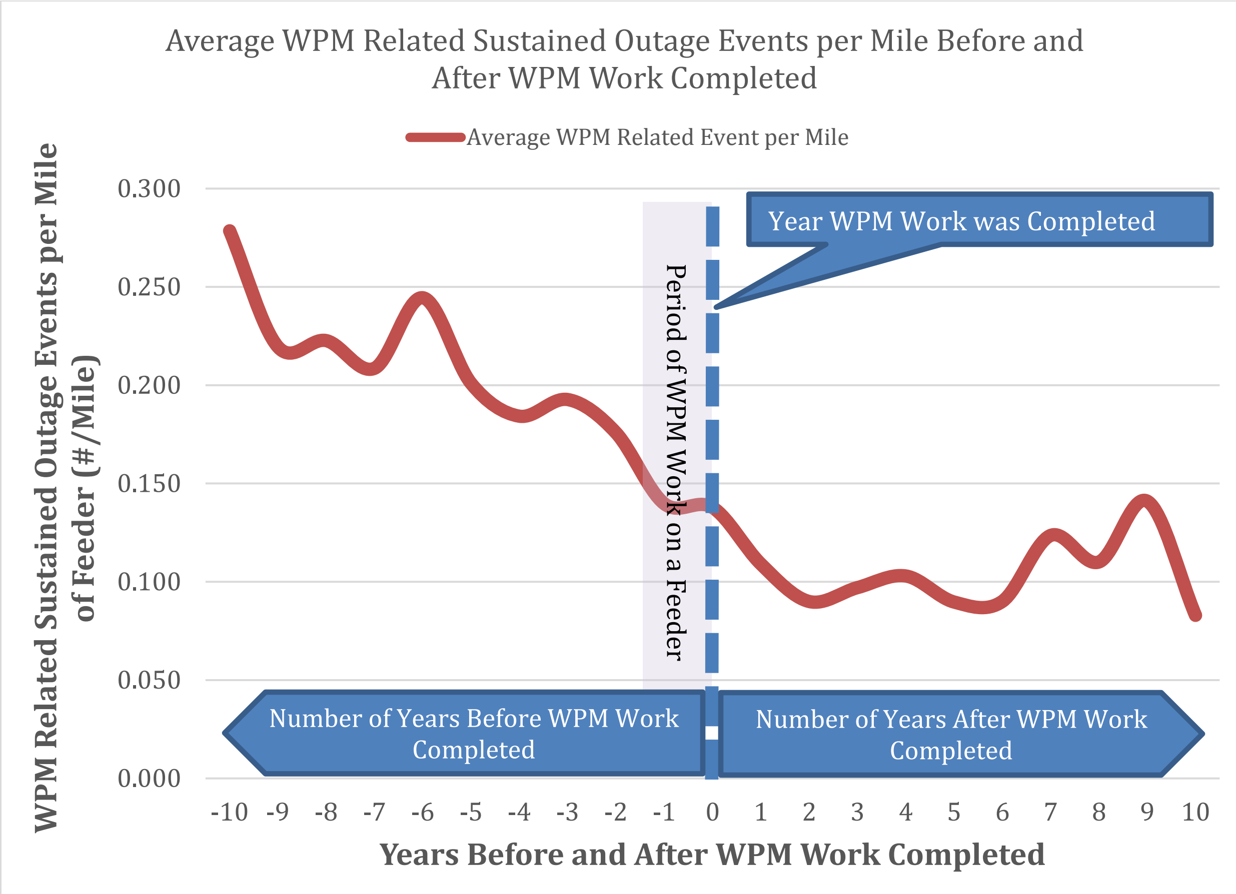

Figure 17 WPM Related Sustained Outages Events per Mile of Distribution Feeder Before and After WPM Work Completed

Gaps in current Strategy and Objectives

The current strategy relies upon visual inspection and boring of poles to determine their condition. Using health indices in the future may further enhance identifying components for replacement or repair by better predicting their future failure probability. Industry is providing better and better tools for determining condition that may allow us to better identify which components need to be replaced and which can stay in the system as is.

The historic objective of the WPM program has been to maintain the current reliability but Avista has enjoyed definite improvement in reliability since the current version of the WPM program was implemented. The objectives for reliability need to be identified to help define what level of spending can be maintained and still keep or improve the overall reliability to the desired level. If the Capital budgets of the future see further constraints, it is likely that the WPM program could perform inspections and follow-up work on an even more non-optimal interval unless a specific reliability goal is established and budgets aligned. In other words, if we establish reliability goals and align the budgets to support that specific goal, the economic optimization no longer drives the WPM cycle time but reliability goals.

Converting from Overhead to Underground Residential Districts may provide better lifecycle costs and reliability when the costs of undergrounding is low enough. This alternative should be analyzed and documented.

The Wood Pole Management Inspection Database requires an Asset Information Strategy document. A lot of work in the past and changes needed for the future require a clear and documented strategy for collecting the data, metrics used in WPM, uses of the data in decision processes, and more. We continually see that as new people enter these fields, they don't understand the why's of data and its role in our processes, so data gaps, errors, and processes changes occur that impact the overall quality and effectiveness of the data.

Data Gaps

The WPM Inspection database must be converted onto a new mobile platform due to the end of life of the existing Trimble units. This is in progress and should be completed in 2017. The data then needs to be imported and retained in Maximo for all future inspections and follow-up work. Once the inspection portion of the data has been completed, the follow-up work planning and quality assurance inspection of completed work must be included in the process and data to properly maintain the data current with current conditions.

The effective Ground Line Circumference (Effective GLC) is not recorded for all poles. This will need to be calculated for each pole if we decide to implement a health index for Distribution wood poles.

Mitigation Plan for Gaps

Examine industry information and evaluate the use of a Health Index in the WPM program. If justified, develop an implementation plan for collecting, analyzing, and using a Health Index in the WPM program. This addresses potential changes in our inspection methods and the Effective GLC issues.

For the reliability driver, this requires work outside of Asset Management, so no action is currently planned to address this gap. This addresses the question of using economic optimization or reliability goals to drive WPM Cycle times.

Examine the lifecycle costs of keeping Overhead Distribution systems in rural areas as compared to Underground Residential Districts (URD). This provides the analysis and documentation to answer the question discussed above.

Develop an Asset Information Strategy based on the "Asset Information – Asset Information, Strategy, Standards and Data Management" Subject Specific Guidance (SSG) from the Institute of Asset Management (IAM, 2015). This addresses the lack of a current Asset Information Strategy for WPM and moves the implementation of moving the WPM Inspection database transition into Maximo for the repository of the information.

Data Changes

For the WPM Related OMT Events and Outages shown in Figure 10, the data used should change going forward. When the WPM Related OMT Events metric was created, the TCOP program did not exist and the equipment was only replaced based on the WPM inspection. Going into the future, the TCOP will track OH – Transformer, Squirrel, Arresters, and Cutout/Fuse OMT Events since they are more directly related to that program now. WPM does drive a significant number of these replacements but many of the repairs and replacements are directly related to the replacement of the overhead transformers.

The Pole Fire OMT events will also be removed since there is no correlation between the WPM and the number of OMT events for a Pole Fire. The vast majority of Pole Fires happen when we have had a long dry spell that causes dust to build up on the insulation followed by some light moisture. The added moisture allows for flashover that causes the pole to ignite. These conditions are quite common in the third quarter near the end of summer and you see this in Figure 18.

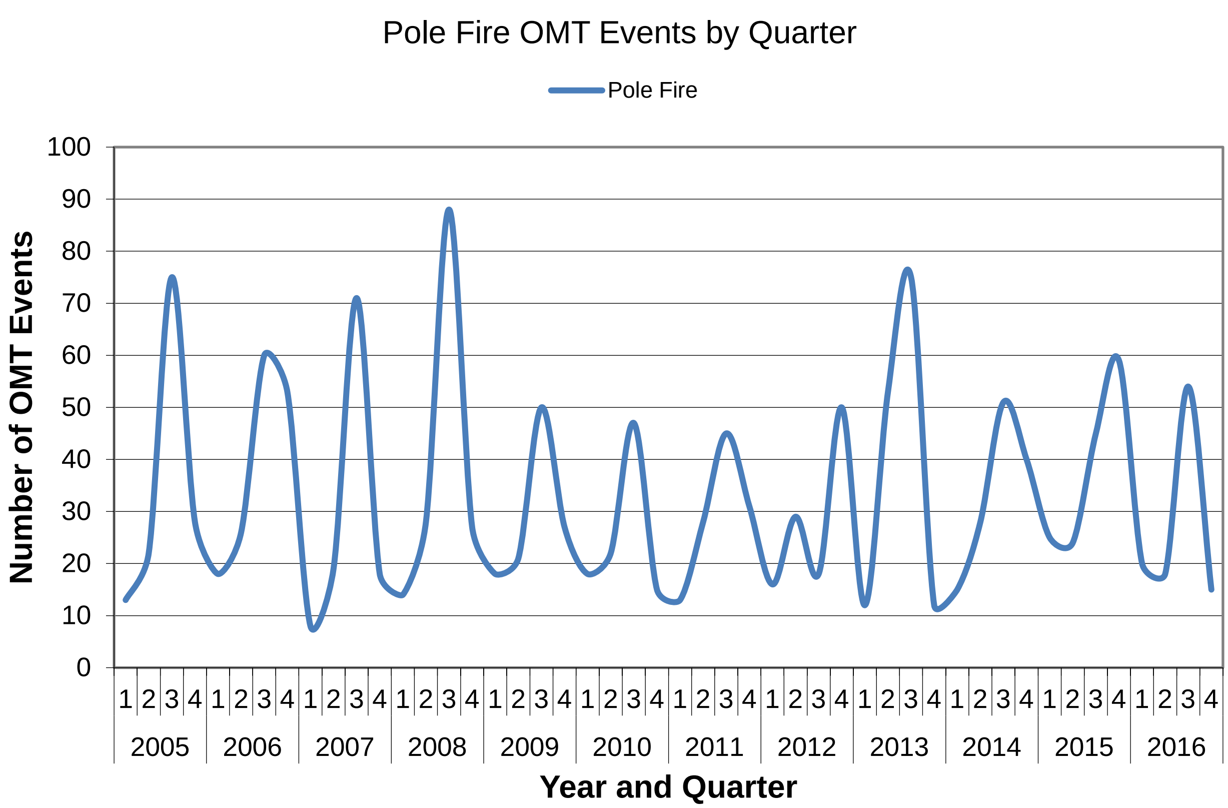

Figure 18 Pole Fire Events in OMT by Year and Quarter

We will also remove Wildlife Guards from the WPM related events since we see so very few wildlife guards causing a failure a seen in Figure 10.

With these changes, we revised Figure 9 that has been used in the past to the new revised WPM related events shown in Figure 19.

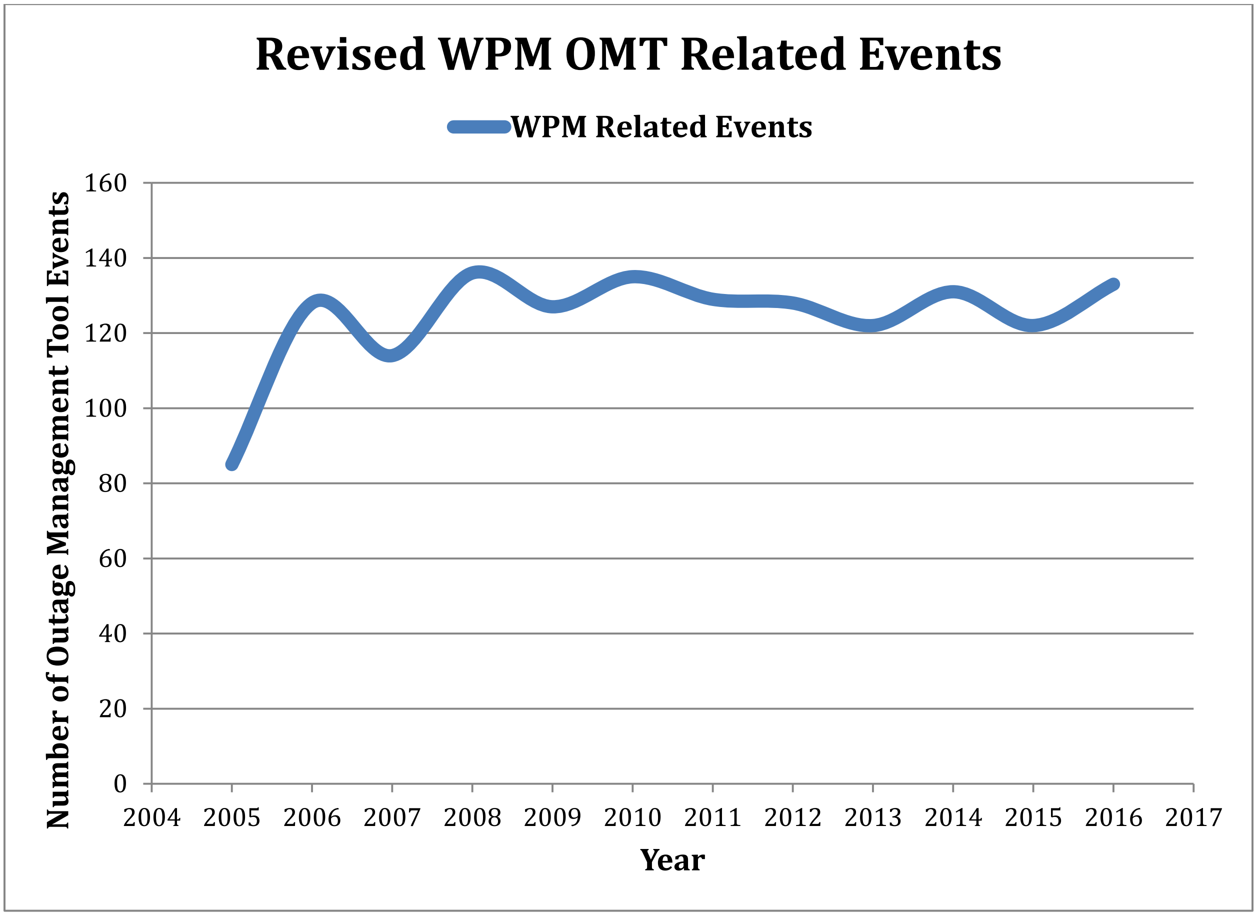

Figure 19 Revised WPM Related OMT Events (Includes Crossarm-rotten, Insulator, Insulator Pin, Pole-rotten OMT Sub-Reasons)

Looking at Figure 19 in more detail, the revised number of OMT Events related to WPM work shows two different trends as illustrated in Figure 20. For 2008 – 2013, the revised number of OMT events for WPM declined. Then for the past 4 years (2013-2016) the trend changed and shows an upward trend. The driver for the upward trend comes from Pole-rotten events. Figure 20 shows the individual contributions to the overall trend and the number of Pole-rotten events continues to rise from 33 events in 2006 to 55 events in 2016. For Figure 19 and Figure 20, see Detailed WPM OMT Data.xlsx

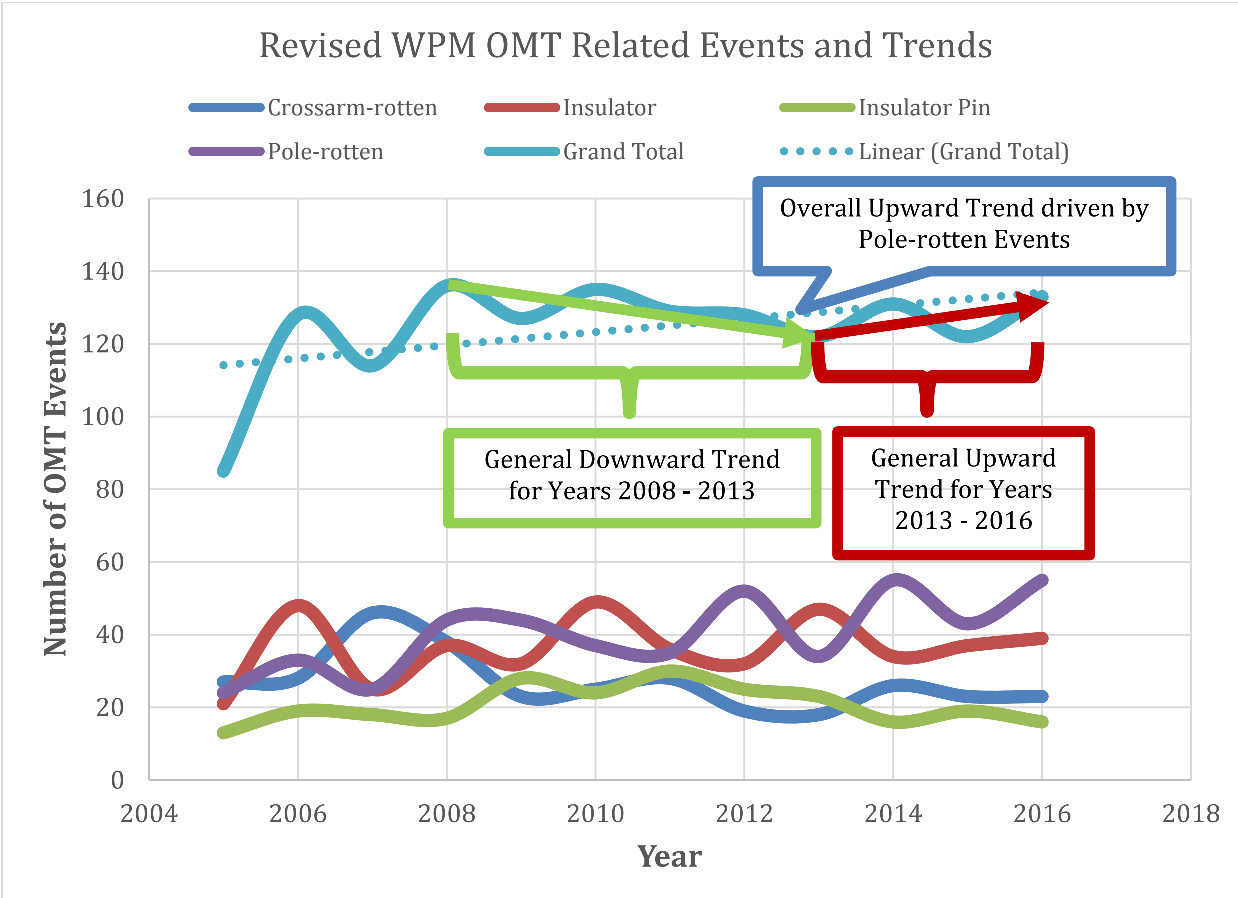

Figure 20 Revised WPM OMT Related Events with Trends

When we examine each Distribution Feeder individually, Figure 21 shows how the feeders bundled by the Year WPM work was completed and shows the performance of feeders without WPM work since 2006 for the worst feeders. Figure 22 shows all of the feeders without WPM work since 2006. We may use data similar to this to help prioritize and select the next feeders for WPM work. Simply using the number of OMT events to prioritize work on a feeder skews all work to the longest feeders because they have the greatest exposure to Pole-rotten, Crossarm-rotten, and similar failures. Normalizing the OMT data to events per mile removes this bias and allows us to prioritize the work to where it will have the greatest impact per unit of work completed. The final method for prioritizing WPM feeder work lies outside the scope of this analysis. An Asset Information Strategy for WPM includes developing the decision process and outlines the data requirements needed to make the decisions.

See Appendix C for the data table for Figure 21 and Figure 22 and the file Pole-rotten OMT Events rev 1.xlsx for the development of the graphs.

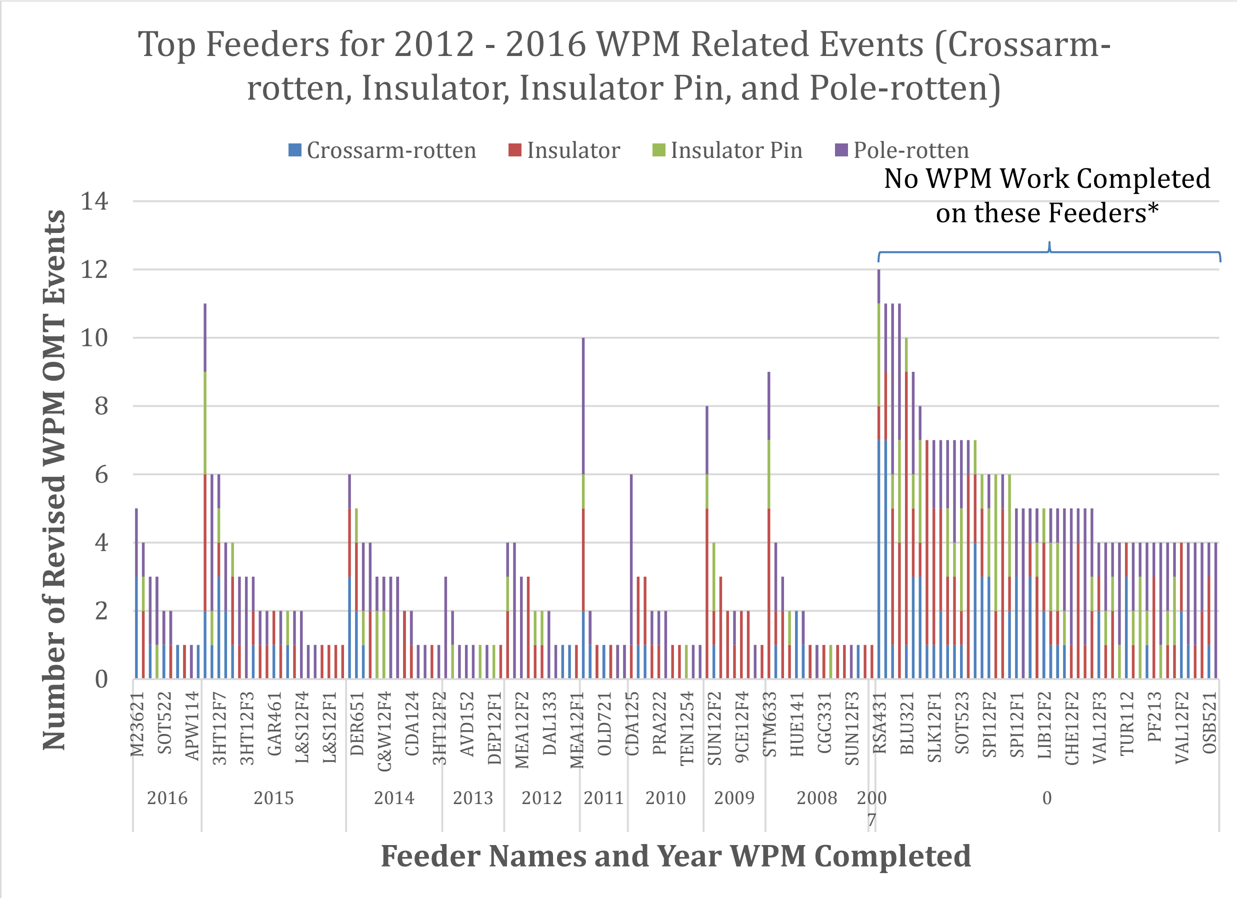

Figure 21 Top Feeders for 2012-2016 WPM Related Events - Revised List

*Note: Many feeders that have had no WPM work completed were truncated from this graph due its size. The full list in shown in Figure 22.

Using the revised list of WPM related event (Crossarm-rotten, Insulator, Insulator Pin, and Pole-rotten), Figure *17* above becomes Figure 23 below. As you can see from the dashed Linear (trend line) in Figure 23. WPM work still improves Distribution feeder outage performance but significantly less than in Figure *17*.

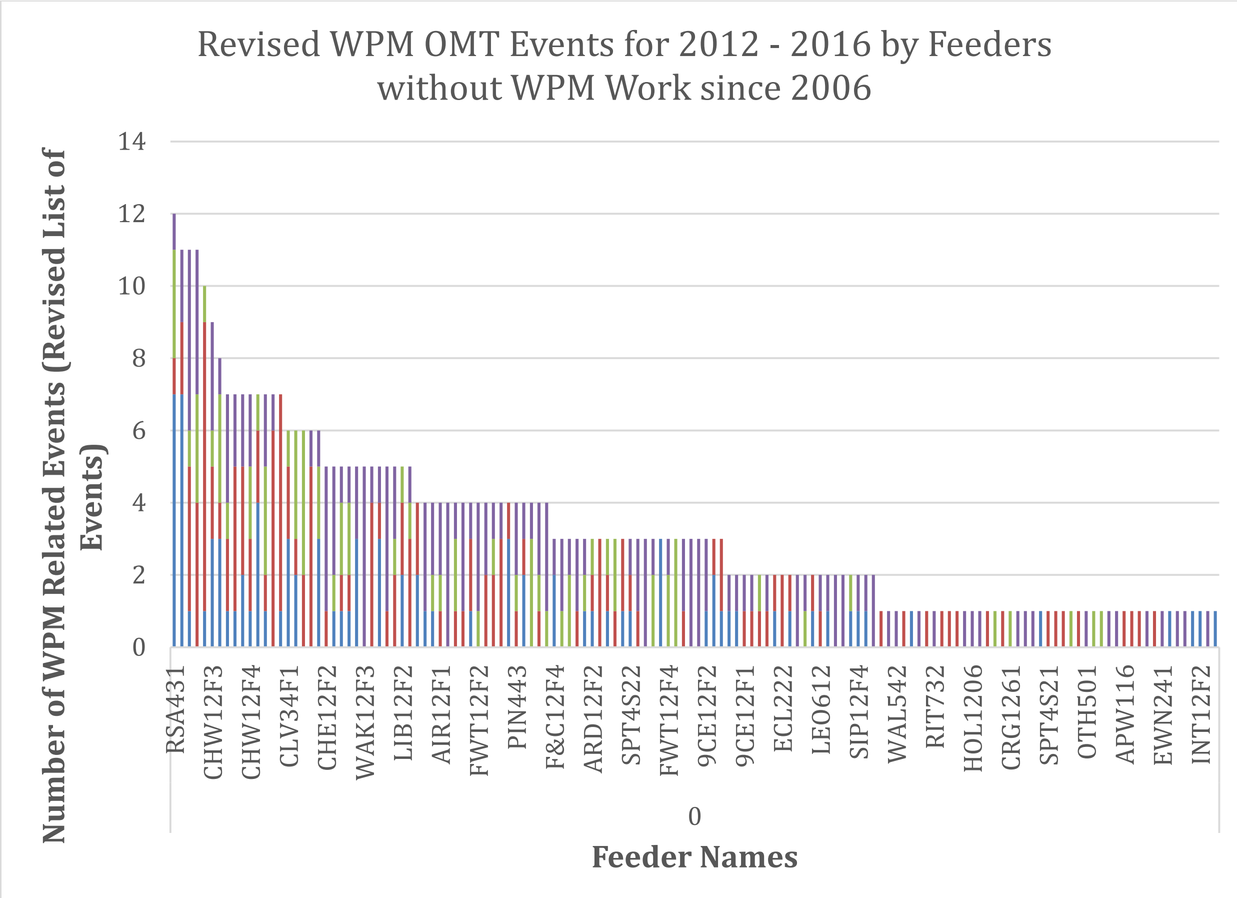

Figure 22 WPM OMT Events (Revised List) for 2012 - 2016 by Feeders without WPM Work Completed since 2006

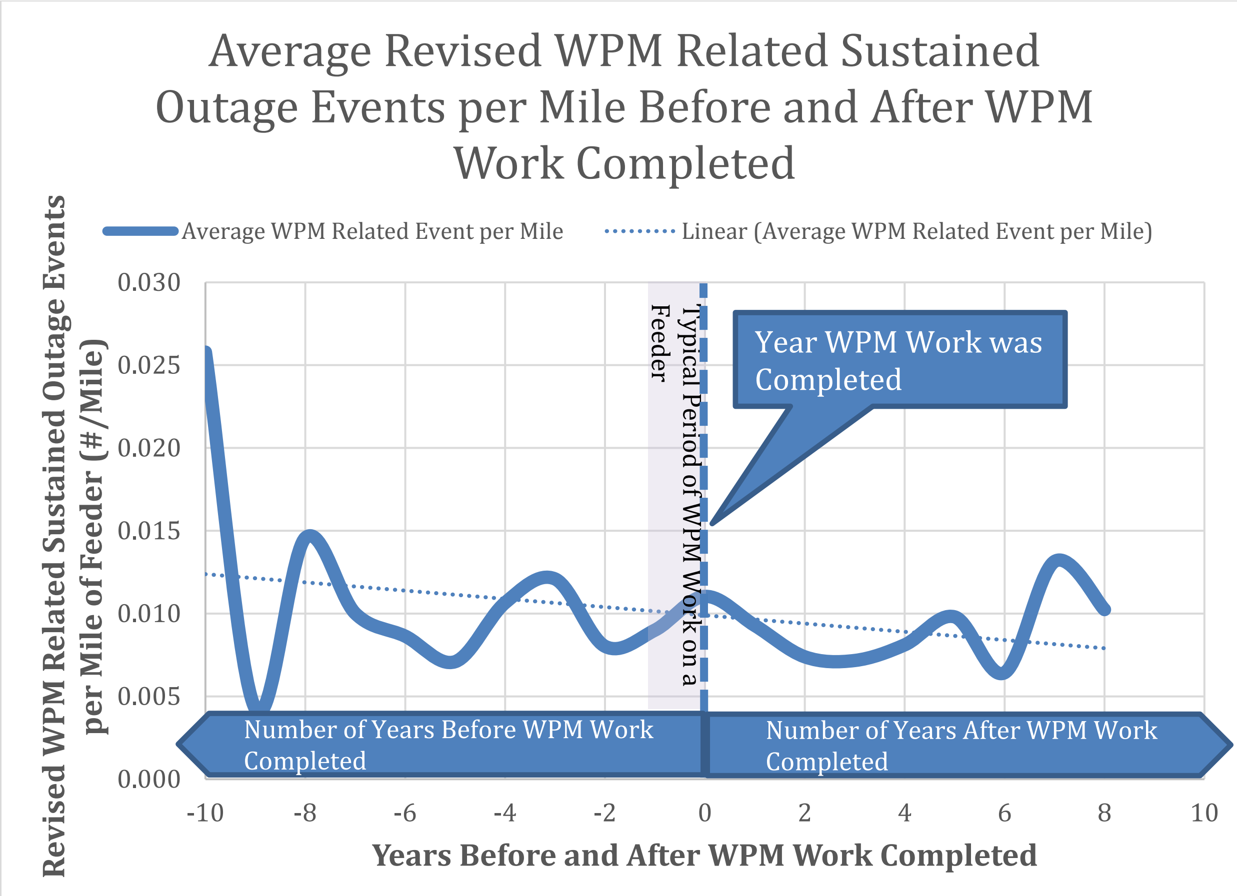

Figure 23 Revised WPM Related Sustained Outages Events per Mile of Distribution Feeder Before and After WPM Work Completed

Future Position

We anticipate continuing the WPM program on a 20 year inspection cycle for reasons we discuss in the Strategy Options section. The future position we describe here reflects a WPM program with a 20 year inspection cycle followed by work to address all issues and does not include work performed as part of Grid Modernization. In actual practice, the Grid Modernization can cover for the WPM program on feeders that have not been inspected by WPM since 2006 and will change the WPM budget depending on the amount of WPM work covered in the Grid Modernization work.

A model developed the future position based on the inputs and assumptions discussed in other portions of this document. For these models, we loaded all of the data and assumptions into Availability Workbench (AWB) from ISOGRAPH and created Reliability Centered Maintenance models (RCMCost module in AWB) and then converted the model results into Capital and O&M budget estimates and risk value estimates using the AWB Life Cycle Cost (LCC) module (LCC). The LCC output then fed into a Revenue Resource Requirement model in an Excel spreadsheet and calculated the Customer Internal Rate of Return (CIRR), Return on Equity (ROE), Benefit Cost Ratio, and Risk Reduction Factor. For the Benefit Cost Ratio and Risk Reduction Factor calculation methods, see the Asset Management Standard Assumptions document. See the current Asset Management Manual for the current model development process and discussion.

While we strive to create accurate models that effectively predict future performance, models have limitations and errors from multiple sources. Models intend to predict the future performance based on the best available information we have today. Unfortunately, current information has errors, missing data, provides a bias to past methods, and a myriad of other sources causing error.

We strive to provide results that are within 80% of actual performance. Predictions also tend to show average values and don't show annual variations we typically see in the data. Models show the overall projected trends. We calibrate our model outputs by comparing them to current values and trends to ensure they are consistent with today's values and help reduce error.

In order to further reduce error, we compare the differences between alternatives using incremental analysis inside the Revenue Resource Requirement model. This approach eliminates common mode errors and helps select the alternative that provides the most value.

As part of the process, we track our model's results against actual results in the future to ensure the models did provide a good picture and identify when models require revision.

Future Performance Levels

We established the current version of the WPM program to maintain the same level of reliability and found it actually improved the system reliability. The work added to the WPM to address Overhead Distribution Transformers, cutouts, missing grounds, and adding wildlife guards helped improve the overall system reliability by reducing the number of associated OMT events each year. However, the underlying structural performance of the poles and crossarms has not improved.

Table 11 and Table 12 show how each of the revised WPM related outages contributed to the overall value of SAIFI and SAIDI. We calculated the average for each OMT Subreason and combined them for an overall average impact to SAIFI of 0.02539 and to SAIDI of 0.08965 hours or 5.38 minutes. Based on a 20 Year Inspection and work plan for all Distribution Feeders, the model projects the future average contribution to SAIFI will be 0.04110 and to SAIDI will be 0.09112 hours or 5.47 minutes. Our analysis indicates we expect these value to increase some over the next few years.

See the Detailed WPM OMT Data.xlsx file for the development of the historical values in Table 11 and Table 12 and Profiles - 20 Year Cycle - 5 year period.xlsx for the model projections for both tables.

Table 11 Annual Contribution to SAIFI by OMT Sub-Reason

Year	SAIFI - Crossarm-rotten	SAIFI - Insulator	SAIFI - Insulator Pin	SAIFI - Pole-rotten	Combined
2012	0.00429	0.00166	0.00274	0.00084	0.00952
2013	0.00104	0.00988	0.00476	0.00197	0.01766
2014	0.01610	0.02123	0.00848	0.00790	0.05371
2015	0.00132	0.01199	0.00108	0.00022	0.01461
2016	0.01209	0.01310	0.00542	0.00084	0.03145
5 Year Average	0.00697	0.01157	0.00307	0.00419	0.02539
Model* Projected Annual Average	0.00801	0.02039	0.00942	0.00328	0.04110

*Note: Based on a model run for the next 5 years

Table 12 Annual Contribution to SAIDI (hours) by OMT Sub-Reason

Year	SAIDI - Crossarm-rotten	SAIDI - Insulator	SAIDI - Insulator Pin	SAIDI - Pole-rotten	Combined
2012	0.00953	0.00648	0.00662	0.00421	0.02684
2013	0.00329	0.00662	0.01173	0.01004	0.06012
2014	0.05539	0.04634	0.02899	0.04171	0.17244
2015	0.00528	0.06202	0.00342	0.00064	0.07136
2016	0.04932	0.05297	0.01129	0.00392	0.11750
5 Year Average	0.02456	0.04058	0.01241	0.01210	0.08965
Model* Projected Annual Average	0.01550	0.04255	0.01663	0.01643	0.09112

*Note: Based on a model run for the next 5 years

Figure 24 plots the historical number of OMT events by Subreason for 2012 through 2016 for Crossarm-rotten, Insulator, Insulator Pin, and Pole-rotten. Figure 24 also shows the projections for the future number of OMT events by Subreason. This projection comes from the 2016 Pole Failure Curves - 20 year cycle scaled up rev 7 model results included in Appendix B. The results show the number of OMT events remaining fairly stable until about 2032. In 2032, enough of the population will reach end of life and be missed by the 20 year inspection cycle to cause the number of OMT events to increase. While the number of poles replaced continues a steady rise as seen in Figure 25, the remaining portion of the first round of inspections and early portion of the second round reaches enough problem poles to contain the number of OMT events until 2032. During our second round of inspections on the 20 year cycle, we begins to see replacement of all of the previously reinforced poles reaching their end of life and the poles installed in the post-World War II building boom of the 1950's reach the MTTF age. This 1950's age group represents a significant portion of the current population profile shown in Figure 8 and drives a larger portions of our Distribution pole population reaching their end of life.

For the data and chart development for Figure 24 through Figure 27, see [WPM Profiles.xlsx].

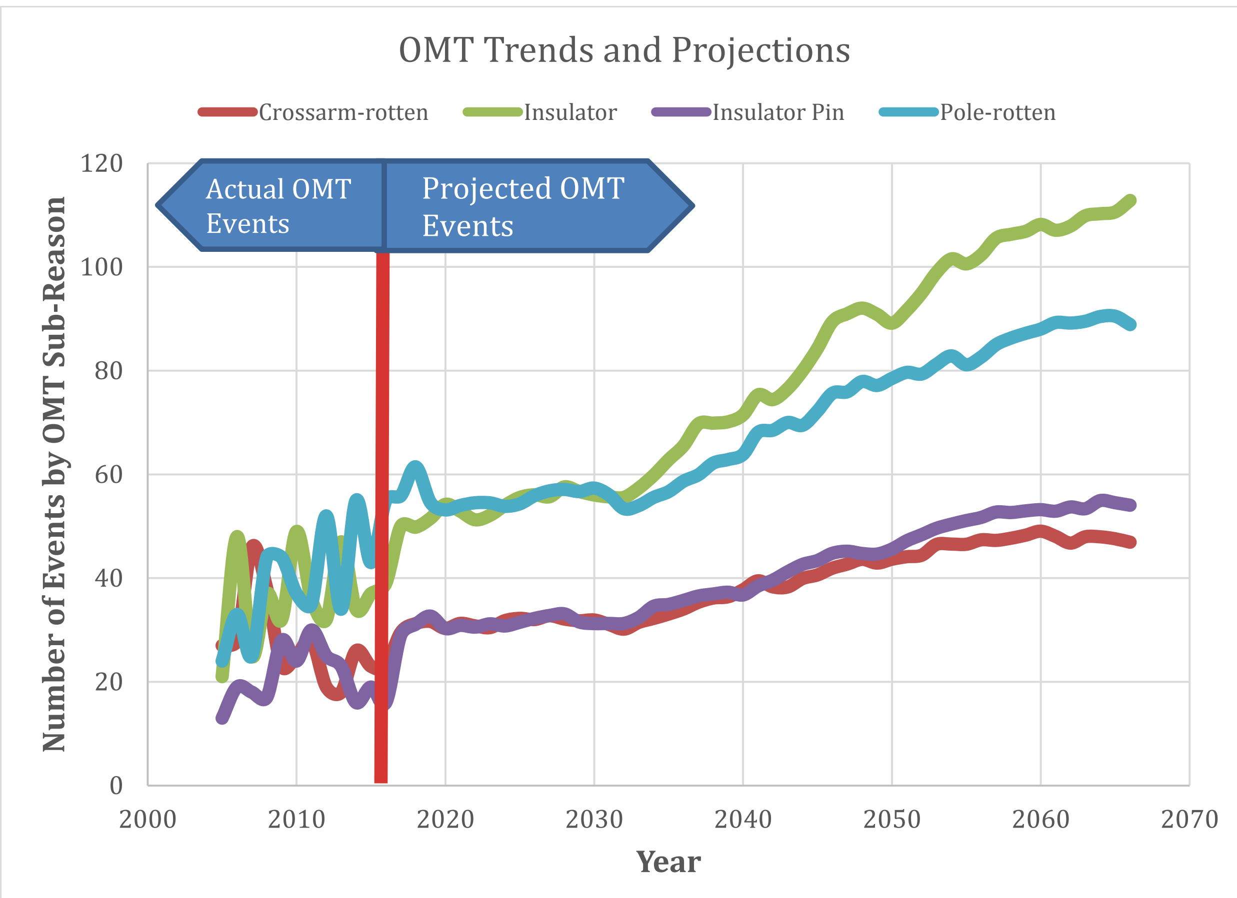

Figure 24 Actual and Projected Number of OMT Events for WPM Related OMT Events

Figure 25 shows the model projections for material usage along with the historical usage for Poles, Stubs (reinforcement), and Crossarms. The model projects these numbers and shows the number of poles replaced or stubbed and crossarms replaced rising with time. The age profile in Figure 8 supports the rising numbers of Poles replaced or stubbed. As larger and larger portions of the current population approach the MTTF point, a larger and larger portion will need to be replaced. The number will not stabilize until after 2060.

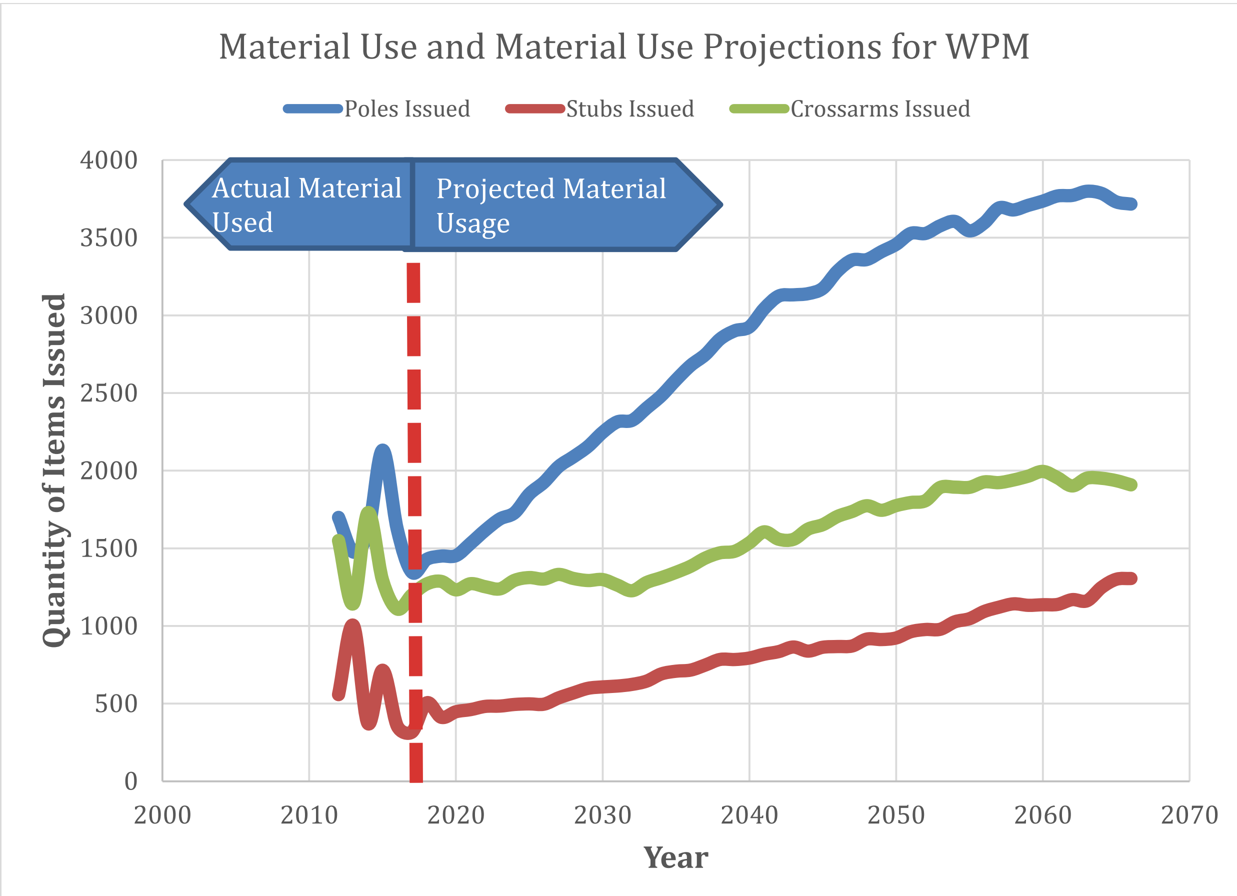

Figure 25 Actual and Projected Material Quantities for WPM Program

Given the trends of Figure 24 and Figure 25, the corresponding capital budget required to maintain the program rises with time as seen in Figure 26 due to the increasing number of components replaced and due to inflation assumed to be 2%. Figure 26 also shows the estimated budget for the Grid Modernization portion of work that ties to the WPM work. The Grid Modernization portion of the budget shown in Figure 26 only represents the amount of work of the program tied to inspecting, repairing and replacing the same components as the WPM program. The WPM budget shown in Figure 26 represents all of the work required by WPM to maintain the system on a 20 year cycle. The actual budget needed by WPM depends upon how much WPM is given and performed by the Grid Modernization on Feeders not inspected since 2006.

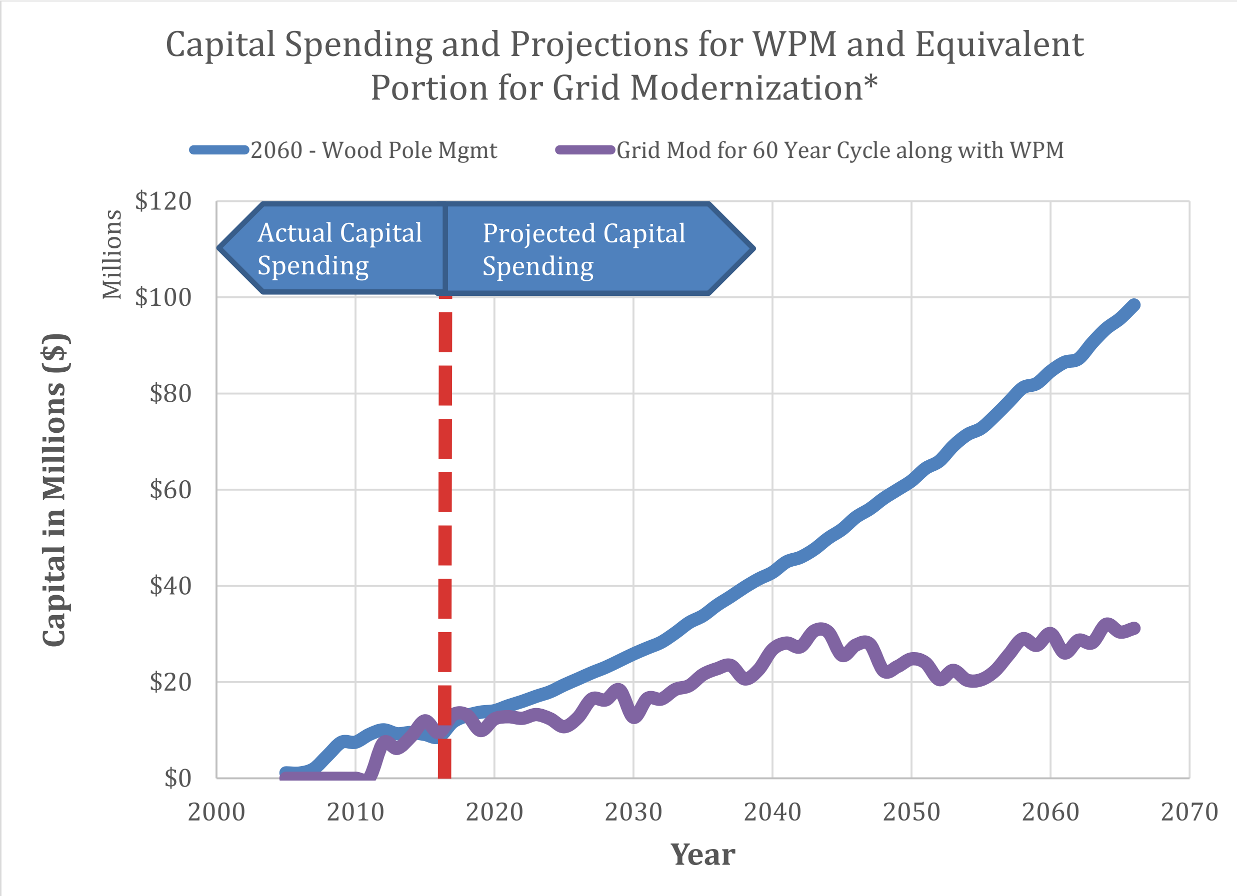

Figure 26 Capital Spending and Projections for Wood Pole Management and Grid Modernization Portion of the Work if Completed on a 60 Year Cycle

*Note: The capital spending on Grid Modernization projected here only equates to the same work scope as WPM and does not cover all aspects of Grid Modernization

Figure 27 shows our model projections for the O&M inspection costs as well as the Asset Maintenance evaluation of budget requirements (see the file “Budget Requirements OM 4-21-2017.xlsx”). Inflation is the sole reason for the rising trends in this costs and we assume an inflation rate of 2%. Between 2013 and 2016, you see a dip in the O&M inspection costs. This dip comes from the amount of the inspection assigned to Grid Modernization from the WPM work scope. Similar to the impacts on the WPM budget caused by the Grid Modernization budget, we see a similar reduction in the O&M costs based on how much of the WPM work gets assigned to Grid Modernization. The values in Figure 27 show the costs assuming no Grid Modernization work covers WPM work scope and only represents the inspection costs associated with WPM.

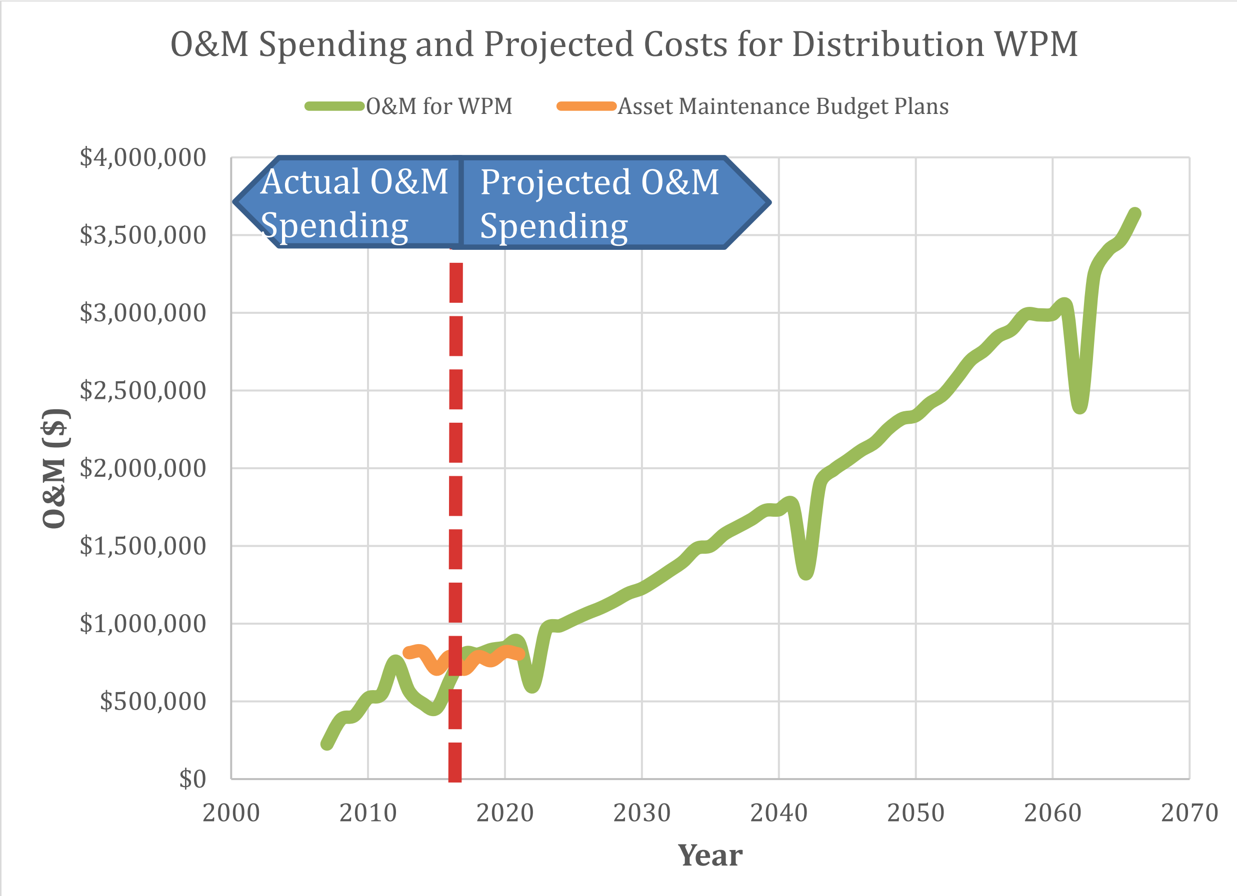

Figure 27 O&M Spending and Projections for Distribution Wood Pole Management for Inspection Costs Only

Impacts of anticipated future demand, innovation, reliability, obsolescence, regulation, and rising costs

Overall, the anticipated future demand analysis is covered in Avista's current Integrated Resource Plan and will not be discussed here. As for WPM, future demand generally does not drive replacement of wood poles unless growth work requires a better class of pole to deal with greater loading from added devices, larger conductor or clearance issues. Since, WPM already deals with these impacts from growth, the program should remain unaffected.

Impacts from innovation and obsolescence have had some small impacts to WPM for the same reasons discussed above. Distribution line automation devices added to our system added loads to a small percentage of poles that required replacing the poles with stronger poles. This work falls within the new technology to address and not WPM.

One impact from new technology and innovation which could alter significantly the WPM and Vegetation Management programs is improvements in the installation of underground cables for Underground Residential Districts (URD). If the cost of undergrounding the electric distribution system reach low enough costs per mile values, they could justify replacing the current Overhead Distribution system with a new URD system. Replacing Overhead Distribution with URD eliminates future Vegetation Management Cost and WPM costs and adds some Underground Equipment Inspection costs.

While we plan to analysis when going from Overhead to Underground, no current studies provide a definite system wide justification, but several localized analysis performed as part of work planning has been completed. Installing URD cables in rural areas where they can plow in the cable have much lower installation costs and potentially meet the cost thresholds today for undergrounding the electric Distribution system while improving system reliability. Examining Figure 28 and Figure 29, you see that 27% of the Electric Distribution system is underground but only contributes 2% to the overall SAIDI value with Major Event Days (MED) excluded. While this is not conclusive proof we should underground the current Overhead system, it drives us to evaluate this in the future. For the details and data behind Figure 28 see the file SAIFI and SAIDI data for 2010 through 2015 excluding MED.xlsx and see the file Conductor Ratio.xlsx for Figure 29.

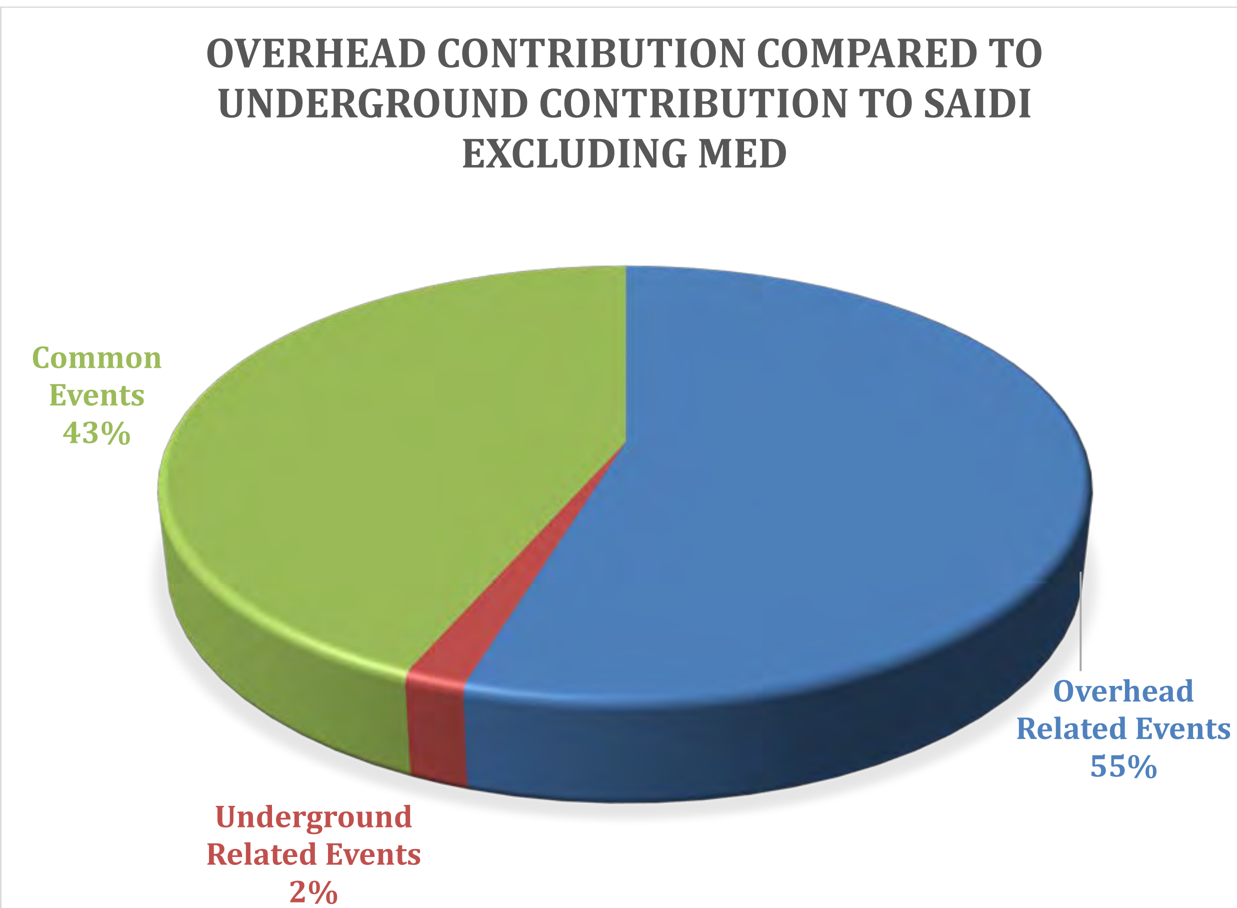

Figure 28 Overhead Contribution to SAIDI Comparison between Underground and Overhead Distribution System excluding MED

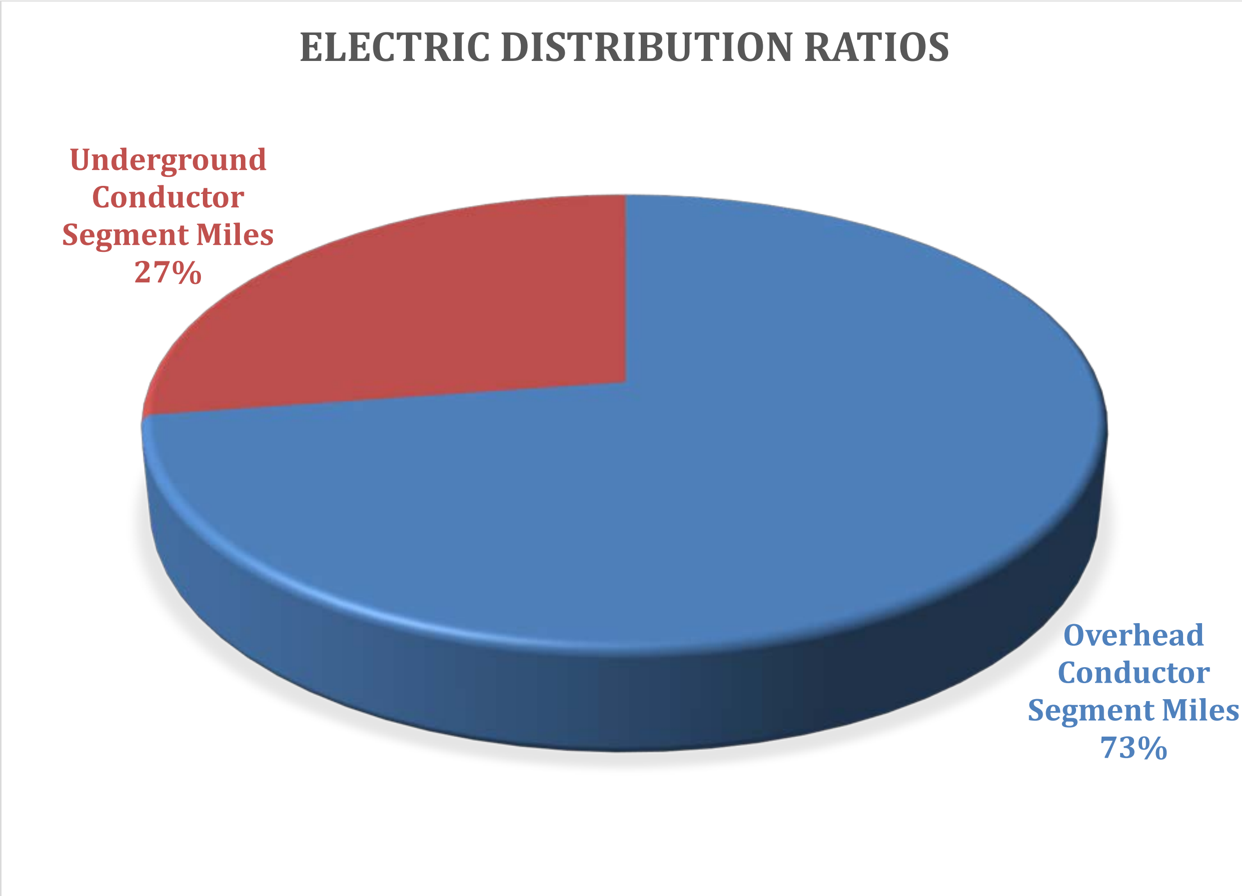

Figure 29 Percentages of the Electric Distribution System that in Underground and Overhead

Recently, the report “Reliability Targets for Washington’s Three Investor-Owned Utilities” completed for the Washington Utilities and Transportation Commission (WUTC) (Power System Engineers, 2017) provides what they believe is the appropriate goals for SAIFI and SAIDI. If the WUTC decided to make these SAIFI and SAIDI goals into performance requirements, the impact to WPM depends upon how the company chooses to meet the goals. Small changes to WPM funding don’t immediately show up in the impacts to reliability or trends. Attempting to use WPM to help improve SAIFI and SAIDI results will prove difficult given the amount of additional work required to see any changes. WPM currently provides a stabilized contribution to SAIFI and SAIDI in the short term but not in the long term as discussed above. Shortening the cycle time to around 5 years for WPM should improve SAIFI and SAIDI but could incur costs for the first time through on this cycle that exceed current budget constraints. This is discussed further below.

Justification for investing

The process for justifying the WPM involves examining several reasonable alternatives and using the Revenue Resource Requirement model to calculate the Customer Internal Rate of Return (CIRR) between the different alternatives. The second criteria constrains the O&M spending to historic levels or trends.

The alternative selected provides better value to customers when compared to a do nothing case and yields a CIRR greater than 7%. A CIRR greater than 7% means that over the life of an asset, the customer's rates will be lower overall even if the costs increase for the early years of the project.

This document focuses on developing a strategy for Distribution Wood Poles and limits the evaluation to different approaches to managing them. Comparing the selected alternative for WPM against other projects and programs at Avista falls to the Capital Planning Group and their methods for ranking projects and programs.

Timing

One alternative examined below is a planned replacement of Wood Poles based on their age. The "2016 Pole Failure Curves - Opt Grid mod 20 year cycle scaled up rev 9" model analyzed the optimum age for replacing poles and found it to be 50 years as shown in Figure 31 (438,000 hours = 50 Years). While the optimum age for replacing a pole is 50 years, other strategies proved to provide more valuable to customers. Figure 31 illustrates the point, though, that if we wait too long to address wood poles that have functionally failed, the costs begin to rise and reduce the value of the approach. The graph in Figure 31 also shows if we do it too soon we lose value.

The optimum time to replace a pole or any other component is immediately before it fails which is nearly impossible to do. Using models allows us to examine different strategies and balance all of the different variables to come up with an optimized approach to the whole Electric Distribution system. You see the effects of delaying work or speeding up work in the results of the different cycle times analyzed in the sections below.

If we chose to suspend the WPM program for either 5 or 10 years for some reason, our capital costs would lower initially but increase our risk exposure due to failures. Table 13 shows how the CIRR, Net Present Value (NPV) of the Lifecycle Cost, NPV of Risk, Benefit/Cost Ratios, and Risk Reduction Ratio's compare between these alternatives (see the Asset Management Standard Assumptions for the calculations methods used (Avista's Asset Management, 2017)). Based on the results shown in Table 13, any pause in the current WPM program adds risk and costs that hurt the CIRR. Figure 30 shows graphically how delaying the WPM work impacts the projected number of OMT events for each year. While delaying the work may provide some budget constraint relief in the short run, the lost value will take 20 years (or one complete WPM cycle) from restarting the work to reach the reliability projected for the current case. In other words, delaying WPM work adds costs in the future and reduces reliability that will impact the results for 20 years.

The calculations for Table 13 are in the file named 20 Year Cycle and delays Options 5-4-17.xlsx and is based on the following models: 2016 Pole Failure Curves - 20 year cycle scaled up rev 7 - 5 year pause, 2016 Pole Failure Curves - 20 year cycle scaled up rev 7 - 10 year pause, and 2016 Pole Failure Curves - 20 year cycle scaled up rev 7. The data from the three models in Table 13 used in Figure 30 are found in file "WPM Profiles.xlsx".

Table 13 Comparison of Impacts of Continuing the 20 Year WPM Cycle, Pausing Program for 5 Years, and Pausing Program for 10 Years over a 50 Year Lifecycle

Alternative	CIRR	NPV of Life-Cycle Costs	NPV of Risk	Benefit/Cost Ratio	Risk Reduction Ratio
20 Year WPM Cycle Case	7.23%	$489,167,584	$210,166,592	1.06	0.05
20 Year WPM Cycle with 5 Year Delay Case	6.73%	$516,967,368	$234,082,522	0.95	-0.05
20 Year WPM Cycle with 10 Year Delay Case	6.55%	$539,552,740	$253,240,357	0.91	-0.08

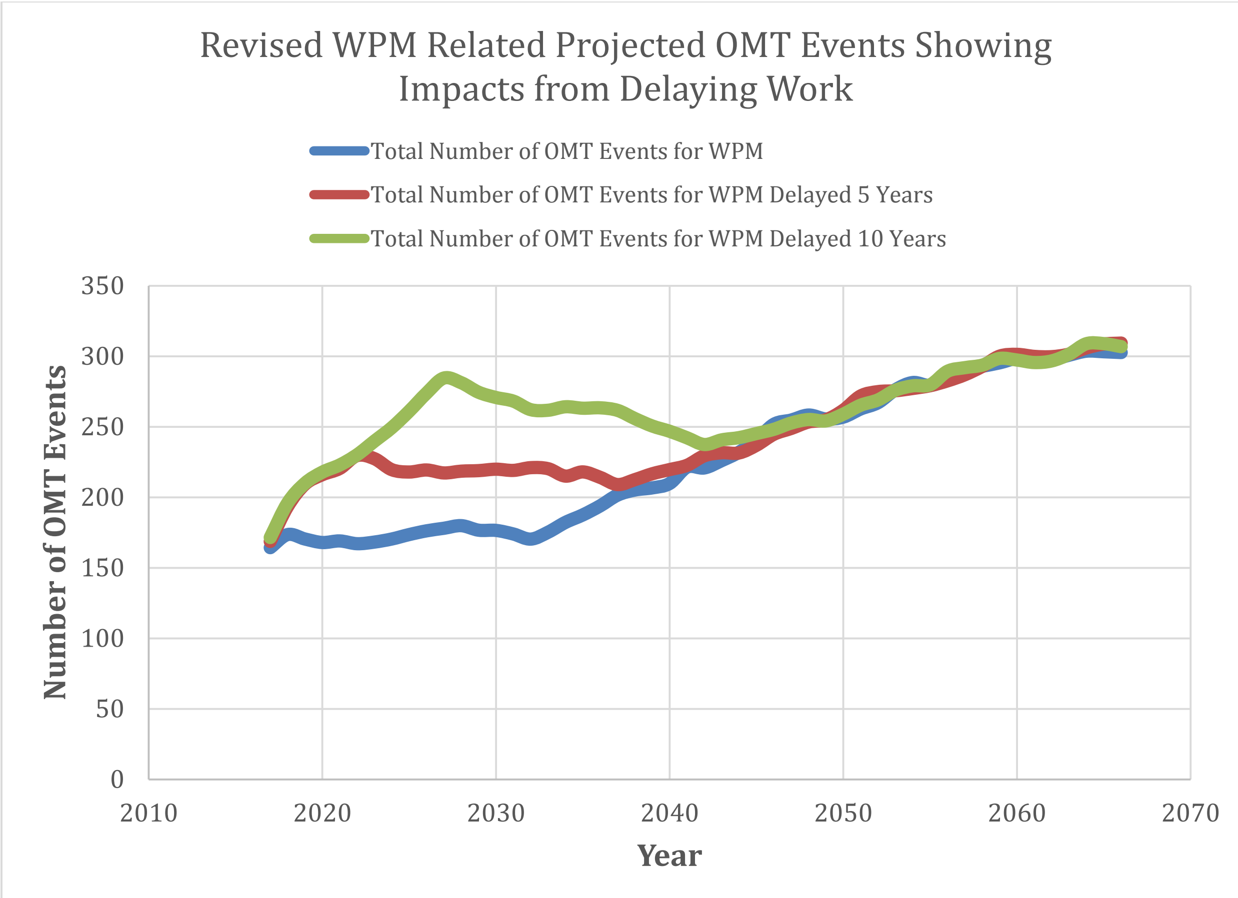

Figure 30 Revised WPM Related Projected OMT Events Showing Impacts from Delaying Work

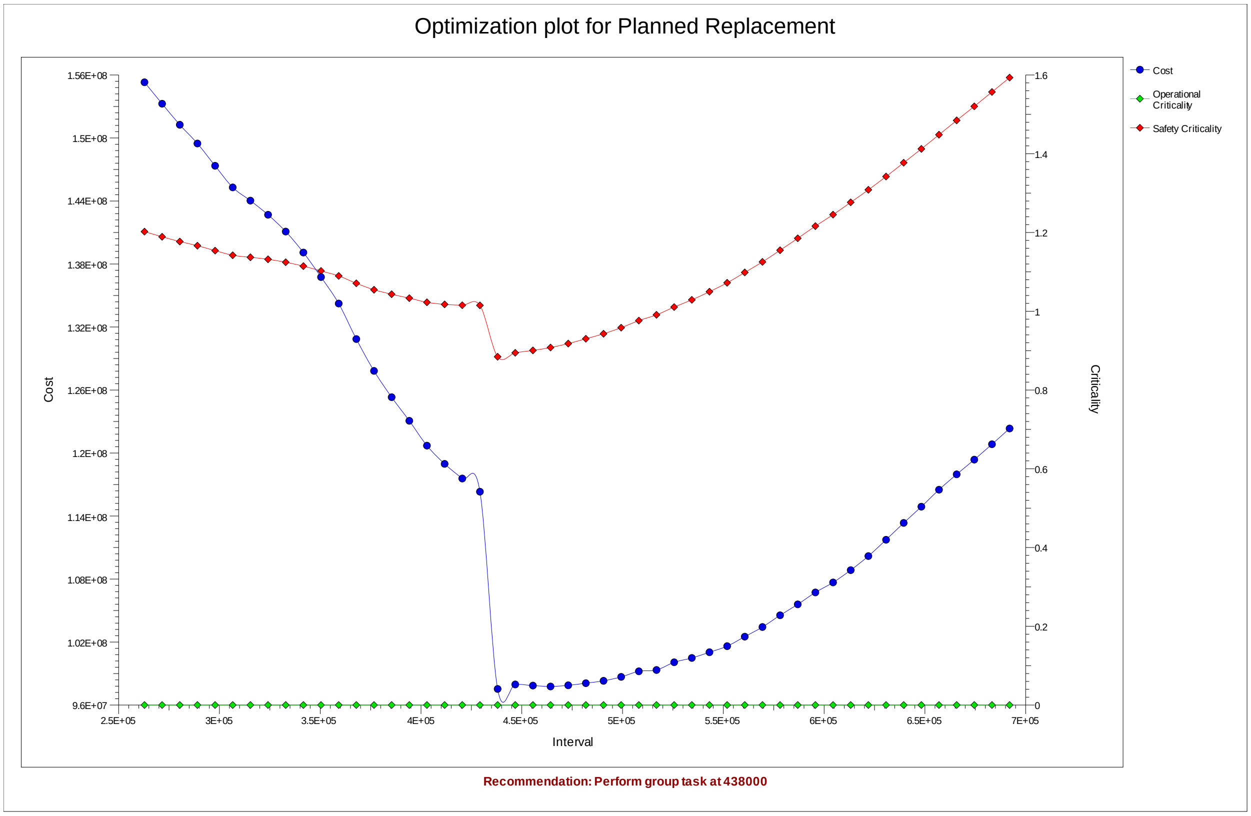

Figure 31 WPM Model Plot of Optimized Planned Replacement Age for a Wood Pole at 50 Years of Age

Strategy Options

The basis for the different WPM cycle time alternatives comes from the 2012 analysis. We added to these alternatives a new alternative that examined Grid Modernization and its impacts with and without WPM. In order to address questions on when and if WPM should be paused for any reason, we added two scenarios showing the impacts of suspending WPM inspections and the subsequence follow on work for 5 and 10 years to understand how this impacts the value of the work.

Electric Distribution Wood Poles Scenarios

Run all Wood Pole and associated components to failure

This alternative provides a base for comparison. While our intentions are not to do this, we use this do nothing case to evaluate all the other alternatives against it. The base case includes the following Components in Table 14.

Table 14 Components included by Program Models

Component	WPM Models	TCOP Models
Cutout		Yes

Secondary Connection		Yes
Primary Connection		Yes
Lightning Arrester		Yes
Grounds		Yes
Overhead Distribution Transformer		Yes
Pole – Replace	Yes	
Pole – Reinforce	Yes	
Pin	Yes	
Crossarm	Yes	
Insulator	Yes	
Guying	Yes	

This model consists of two files, 2016 Pole Failure Curves - Base Case scaled up rev 7 and 2016 TCOP Model for WPM - No Action Base Case 4-24-17. The results of both models are combined in the Revenue Resource Requirement model in file Combined TCOP and WPM 4-24-17.xlsm. In Table 16, this alternative is called the "Base Case".

In the case of evaluating Grid Modernization independent of WPM, only the 2016 Pole Failure Curves - Base Case scaled up rev 7 model is used and is called "Base Case" inTable 16.

Inspect all Wood Poles on a 20 year cycle based on the Feeder

In this alternative, we inspect the Electric Distribution system once every twenty years and follow up the inspection with projects to replace or repair all identified components. Within this alternative, we include four variations. The first variation represents our current program and includes the structural components of the pole, crossarms, insulators, guying, and insulator pins (the model name is 2016 Pole Failure Curves - 20 year cycle scaled up rev 7) as well as the same components as the TCOP models except the TCOP components are only replaced if they have functionally failed. In order to reflect TCOP related components needing replacement identified by the WPM inspection, the model, 2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17, was added to the WPM model results in file Combined TCOP and WPM 4-24-17.xlsm. In Table 16, this is called "WPM 20 Year Cycle without TCOP".

The second variation adds TCOP work which includes cutouts, Overhead transformers, wildlife guard installation, installation and replacement of missing grounds, and lightning arresters that are replaced along with all pre-1981 transformers. This variation added the results of the 2016 TCOP Model for WPM 20 Year Cycle 4-24-17 for the TCOP components in the Revenue Resource Requirements model, Combined TCOP and

WPM 4-24-17.xlsm. In Table 16, this alternative is called "WPM 20 Year Cycle with TCOP".

The third and fourth variations uses the original, 2016 Pole Failure Curves - 20 year cycle scaled up rev 7, model as the base case and then compares the same model with a 5 or 10 year delay in performing the next round of inspections. The file, 2016 Pole Failure Curves - 20 year cycle scaled up rev 7 - 5 year pause represents a 5 year delay in the WPM inspections and the file, 2016 Pole Failure Curves - 20 year cycle scaled up rev 7 - 10 year pause, represents a 10 year delay in the WPM inspections. These two variations excluded the TCOP related work since they are just used to show the impacts of the delay shown only in Table 13.

Inspect all Wood Poles on a 5 year cycle based on the Feeder

This alternative represents the same model as the second variation of 20 year WPM but with a 5 year inspection cycle and follow up work. The two models that make up this alternative are 2016 Pole Failure Curves - 5 year cycle scaled up rev 7 and the 2016 TCOP Model for WPM 5 Year Cycle 4-24-17. The results of these two models are combined in the Revenue Resource Requirements model, Combined TCOP and WPM 4-24-17.xlsm. In Table 16, this alternative is called "WPM 5 Year Cycle with TCOP".

Inspect all Wood Poles on a 10 year cycle based on the Feeder

This alternative represents the same model as the second variation of 20 year WPM but with a 10 year inspection cycle and follow up work. The two models that make up this alternative are 2016 Pole Failure Curves - 10 year cycle scaled up rev 7 and the 2016 TCOP Model for WPM 10 Year Cycle 4-24-17. The results of these two models are combined in the Revenue Resource Requirements model, Combined TCOP and WPM 4-24-17.xlsm. In Table 16, this alternative is called "WPM 10 Year Cycle with TCOP".

Inspect all Wood Poles on a 25 year cycle based on the Feeder

This alternative represents the same model as the second variation of 20 year WPM but with a 25 year inspection cycle and follow up work. The two models that make up this alternative are 2016 Pole Failure Curves - 25 year cycle scaled up rev 7 and the 2016 TCOP Model for WPM 25 Year Cycle 4-24-17. The results of these two models are combined in the Revenue Resource Requirements model, Combined TCOP and WPM 4-24-17.xlsm. In Table 16, this alternative is called "WPM 25 Year Cycle with TCOP".

Inspect all Wood Poles on a 20 year cycle based on the Feeder and replace poles based on an age of 60 Years using the Grid Modernization Program

This alternative represents the same inspection cycle as the 20 year WPM and additionally replaces all poles that are 60 years or older. This model actually represents doing Grid Modernization once every 20 years instead of the programs goal of once every 60 years. This approach simplifies the analysis and ties the WPM and Grid Modernization programs together as we do today, they both use the same inspection cycle but 2/3 of the work goes to WPM and 1/3 should go to Grid Modernization. When we combine the model results in the Revenue Resource Requirement model, we only use 1/3 of the models cost results to reflect the actual amount of work performed each year for the Grid Modernization and reflect the 60 year cycle intent and 2/3 of the WPM Cost to reflect the remaining work completed by the normal WPM program.

The two models that make up this alternative are 2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7 and the 2016 TCOP Model for WPM 20 Year Cycle 4-24-17. The same TCOP model as the normal 20 Year WPM cycle is used here because the scope of the TCOP is the same on the WPM portion of the work changes. The results of these two models are combined in the Revenue Resource Requirements model, Combined TCOP and WPM 4-24-17.xlsm. In Table 16, this alternative is called "WPM 20 Year Cycle with TCOP and Grid Mod".

The first variation of this model is the original option for Grid Modernization discussed above and uses a 20 year inspection and work cycle while replacing all poles based on condition and replacing all poles 60 years or older. This uses the full output of the 2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7 instead of 1/3. It also includes the costs and risks associated with TCOP. This alternative is called "TCOP and Grid Mod on 20 Year Cycle no WPM" in Table 16.

Three other variations of this model were used to only examine what it would look like if WPM program was eliminated in favor of only performing Grid Modernization and then compared to the WPM base case, 2016 Pole Failure Curves - Base Case scaled up rev 7. So the second variation is the same as Grid Modernization alternative discussed above but performs the inspections on a 60 year cycle to coincide with the planned replacement age of 60 years for wood poles. This alternative is called "Grid Mod 60 Year Inspection Cycle 60 Year Old Replace" in Table 16.

The third variation of this model optimizes the replacement age shown in Figure 31 and replaces all poles at 50 years or older on a 50 year cycle. This alternative model is 2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9. In Table 16, this alternative is called "Grid Mod 50 Year Inspection Cycle 50 Year Old Replace".

The fourth and final variation is the original option for Grid Modernization discussed above and uses a 20 year inspection and work cycle while replacing all poles based on condition and replacing all poles 60 years or older. This uses the full output of the 2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7 instead of 1/3. In Table 16, this is called "Grid Mod 20 Year Inspection Cycle 60 Year Old Replace".

Alternative Comparison

For the financial analysis and comparisons, we include the costs and risks associated with both the WPM models and the TCOP models. This approach more accurately reflects the budget requirements. For OMT projections and SAIDI contributions we focused only on the WPM model outputs to accurately reflect the structural needs of the Electric Distribution system.

For comparing a WPM strategy verses a Grid Modernization strategy, we examined the financial impacts of the three variations of the Grid Modernization alternative shown in Table 15 (the 2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev

9, 2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9, and 2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7 models) against the WPM do noting case (the 2016 Pole Failure Curves - Base Case scaled up rev 7 model). Table 15's only functions is to compare Grid Modernization and WPM as a direct replacement and not provide financial analysis of the Grid Modernization program. Grid Modernization provides value in several areas not discussed here. In this comparison, we excluded the TCOP models for the comparison to simplify the process. In order to add TCOP to Table 15 and Table 16 align the data with the data in Table 16 would have required creating two additional TCOP models to align with all of the alternatives in Table 15 that had no bearing on evaluating Distribution wood poles. The alternatives "Grid Mod 20 Year Inspection Cycle 60 Year Old Replace" from Table 15 and "WPM 20 Year Cycle with TCOP and Grid Mod" from Table 16 represent the same alternative. The only difference is that Table 16 includes TCOP related work for the evaluation.

Table 15 Financial Comparison of Grid Modernization Alternative without WPM and excludes TCOP work

Alternatives	CIRR	NPV of Life-Cycle Costs	NPV of Risk	Benefit/Cost Ratio	Risk Reduction Ratio
Base Case	10.21%	$634,905,266	$333,324,749	1.72	-0.06
Grid Mod 60 Year Inspection Cycle 60 Year Old Replace	4.35%	$1,092,532,520	$292,376,730	0.58	0.04
Grid Mod 50 Year Inspection Cycle 50 Year Old Replace	4.39%	$1,071,808,146	$272,069,078	0.59	0.06
Grid Mod 20 Year Inspection Cycle 60 Year Old Replace	5.15%	$848,813,303	$172,184,635	0.75	0.19

Table 16 Financial Comparison of Alternatives

Alternative	CIRR	NPV of Life-Cycle Costs	NPV of Risk	Benefit/Cost Ratio	Risk Reduction Ratio
Base Case	6.03%	$1,016,381,966	$509,538,239	0.804	-0.156
WPM 20 Year Cycle without TCOP	8.00%	$817,592,755	$351,165,376	1.243	0.194
WPM 20 Year Cycle with TCOP	7.94%	$799,251,117	$304,232,511	1.272	0.257

Alternative	CIRR	NPV of Life-Cycle Costs	NPV of Risk	Benefit/ Cost Ratio	Risk Reduction Ratio
WPM 5 Year Cycle with TCOP	8.85%	$650,557,189	$104,155,317	1.562	0.623
WPM 10 Year Cycle with TCOP	7.85%	$812,124,615	$279,737,157	1.252	0.283
WPM 25 Year Cycle with TCOP	7.46%	$894,569,506	$389,231,116	1.136	0.134
WPM 20 Year Cycle with TCOP and Grid Mod	7.10%	$922,761,015	$481,637,684	1.101	0.030
TCOP and Grid Mod on 20 Year Cycle no WPM	5.85%	$1,169,780,812	$261,237,753	0.869	0.212

Table 16 shows the 5 year WPM inspection and follow up provides the best value to customers, because it has the highest CIRR. Unfortunately, it also has the highest O&M Costs as shown in Figure 34. For the CIRR, the higher O&M costs associated with more frequent inspections and follow up work is offset by the lower risk values (see Table 16, Figure 32, and Figure 36), lower material usage (Figure 33) and improve reliability (Table 17). The increased inspection finds more problems and pending failures before they actual cause an outage. A five year WPM inspection interval allows the components to remain in the system longer by replacing them closer to their actual point of failure. However, the TCOP portion of this alternative drives replacing all pre-1981 overhead transformers within a 5 year period and drives the capital costs up significantly in the short run (see Figure 35). The results yield a better CIRR. This alternative and the other shorter inspection cycle time alternatives face a significant risk based on the assumption that only the components that will fail between the inspection interval are replaced. Our inspection program may not be able to tell the difference between a component that will fail in the next one year from a component that will fail in twenty years. The results could cause the initial capital costs to be four times the current 20 year WPM inspection cycle without TCOP (see Figure 35). The CIRR is very sensitive to this cost risk in the first inspection cycle, and the initial capital cost risk could ultimately make it less attractive than our current program.

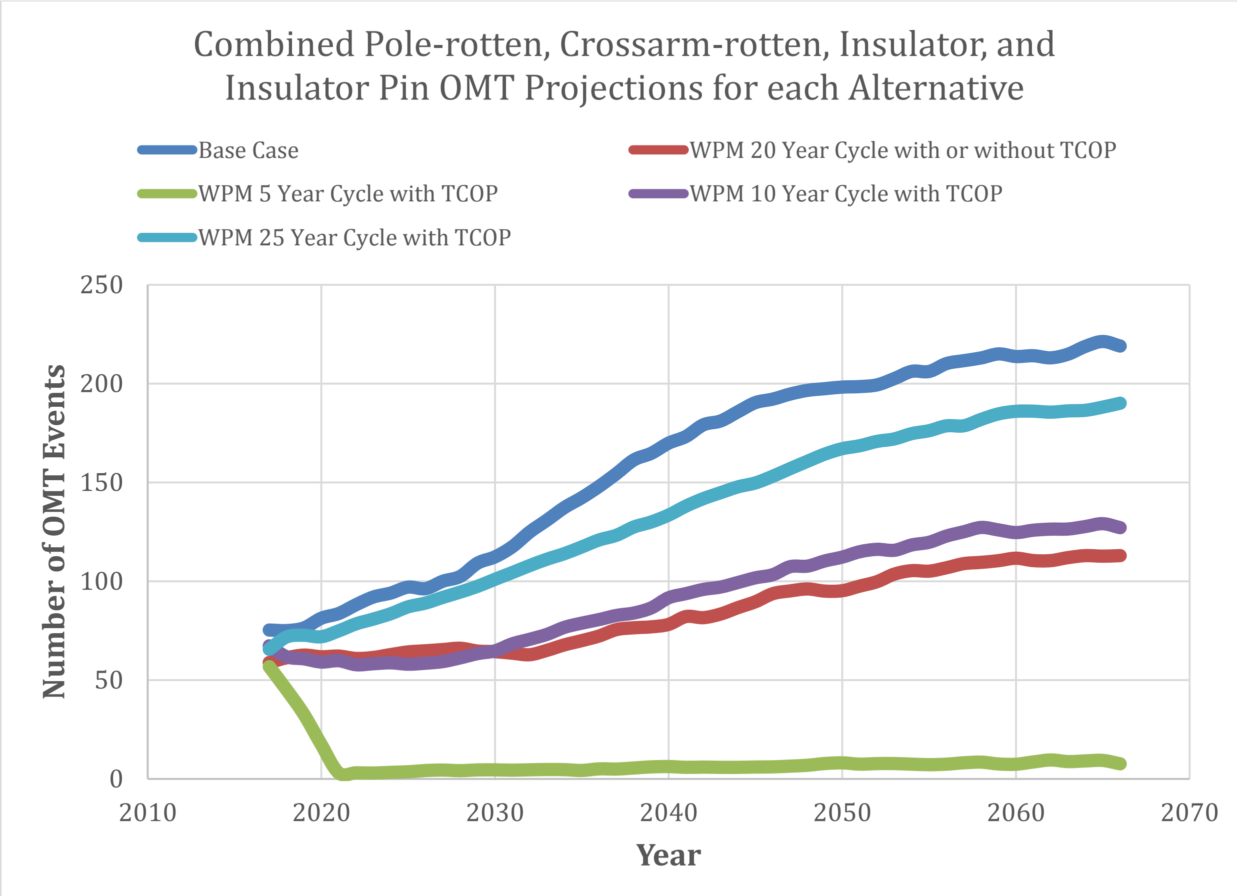

Figure 32 OMT Projections for each Alternative WPM Inspection Cycle Time

Based on the results in Table 16, the next best alternative is our current WPM program, the WPM 20 Year Cycle without TCOP alternative. Our current plans drive the WPM program to replace all pre-1981 Overhead Distribution transformers as part of their regular work starting in 2019. Including TCOP in WPM drives the CIRR down a little (0.06%) when you examine the WPM 20 Year Cycle with TCOP alternative. The WPM 20 Year Cycle with TCOP alternative adds Capital costs to the program (see Figure 35) but reduces the risk value (see Figure 36). The O&M cost increase in Figure 34 come from TCOP component failures repaired or replaced on O&M.

Compared to the WPM 10 Year Cycle with TCOP alternative, the WPM 20 Year Cycle with TCOP alternative appears about equivalent in Table 16, Table 17, Figure 32, Figure 33, and Figure 36. The 10 year and 20 year inspection cycle times appear to trade benefits and costs between them in nearly equal proportions except for the O&M costs shown in Figure 34. Given the 20 year inspection cycle alternatives for WPM are within 1% of the 5 year inspection cycle alternative, it provides a very good CIRR and alternative.

The WPM 10 Year Cycle with TCOP alternative's CIRR of 7.85% is only 1% less than the 5 year cycle time option. This alternative compares well with the two 20 year inspection options as discussed above. The 10 year inspection cycle option improves the risk value in Table 16 Financial Comparison of Alternatives but less than the negative impact of the increased O&M costs shown in Figure 34 that ultimately drive the CIRR lower than the 5 year and both 20 year inspection options. The 10 year inspection cycle alternatives drives the annual O&M and Capital costs down in the near term similar to the 5 year inspection alternative, but the sensitivity of the analysis to the early years of the program reduces it CIRR. This alternative also faces the same initial capital risk costs that could drive the first few year's costs up to two times current 20 year WPM inspection cycle without TCOP (see Figure 35). Our inspection program may not be able to tell the difference between a component that will fail in the next one year from a component that will fail in twenty years.

The 25 year WPM inspection alternative shows a more significant change than compared to the alternatives already discussed above. This option still provides value to customers with a CIRR >7% (see Table 16). It reduces the initial and longer term O&M costs as seen in Figure 34. However, the capital projections show higher anticipated future costs than all other options except the Base Case alternative. This alternative provide lower reliability performance (Figure 32 and Table 17) which also drives more material usage (Figure 33). Responding to failures uses more material in general because a pole failure usually ends up replacing more components. For example, we only need to stub a pole if its strength is restored by the stub, but if a pole fails, the pole, crossarm, insulators, insulator pins, and other components attached to the pole generally must be replaced as well. This drives material usage up when compared to planned repair and replacement. This option also provides the lowest risk reduction of all the options when compared to the Base Case per Figure 36.

The base case or do nothing, i.e. no WPM, no TCOP, and no Grid Modernization, defines the basis for comparing all of the other alternatives. The CIRR compared to the WPM 20 Year Cycle without TCOP alternative shows the second lowest CIRR. This alternative performs worse than all other options in reliability (Figure 32 and Table 17), material usage (Figure 33), and capital cost projects (Figure 35). The O&M cost projections show an interesting behavior as it rises very significantly starting in the next few years and the declines significantly after about 2042. We attribute this O&M behavior to the bow wave of working coming from the TCOP related work as the Overhead Distribution transformers and their associated equipment reach their end of life and get replaced.

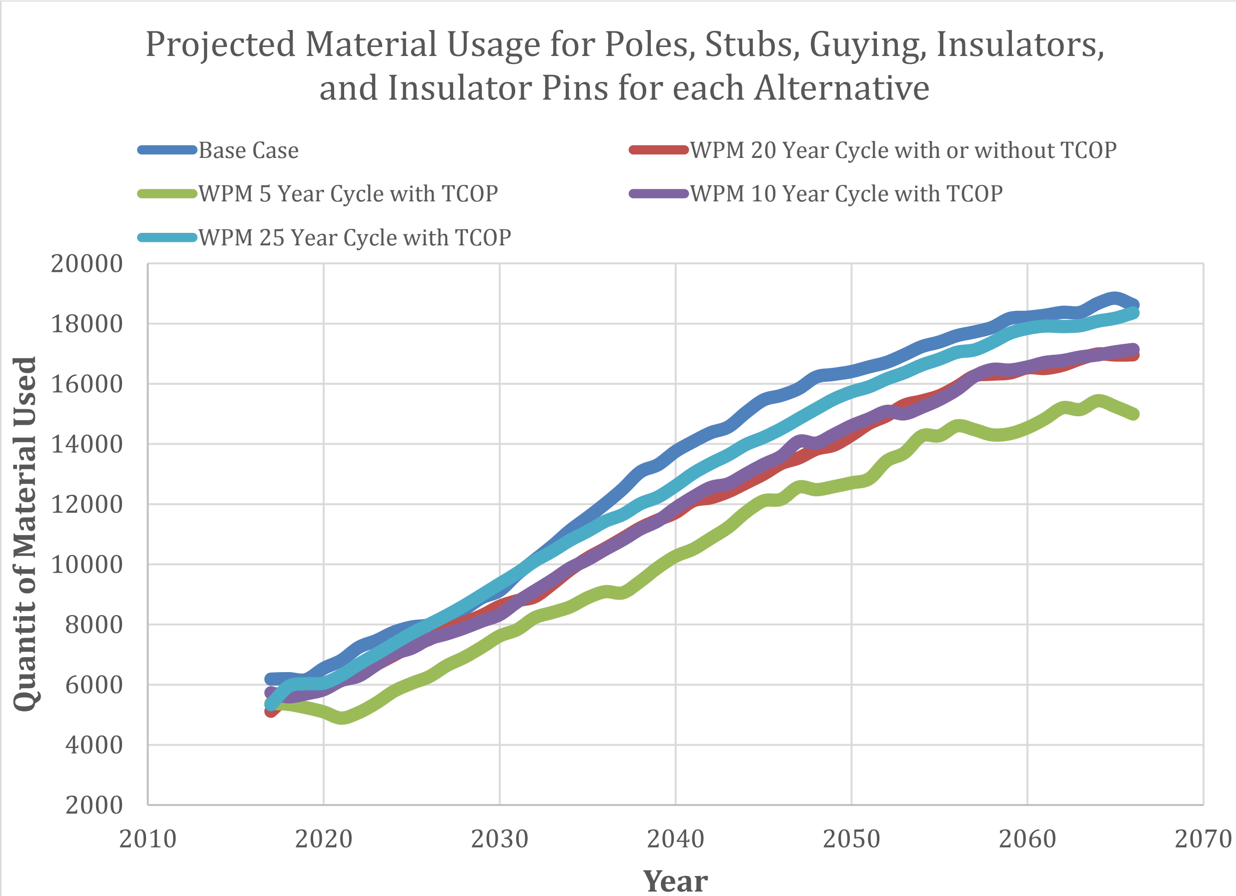

Figure 33 Projected Material Usage for each Alternative

Table 17 Average Contribution to SAIFI and SAIDI for each Alternative over 50 Years due to Pole-rotten, Crossarm-Rotten, Insulator, and Insulator Pin

	Base Case	WPM 20 Year Cycle	WPM 5 Year Cycle	WPM 10 Year Cycle	WPM 25 Year Cycle
Contribution to SAIFI	0.103	0.054	0.006	0.060	0.088
Contribution to SAIDI (hours)	0.226	0.119	0.013	0.138	0.203

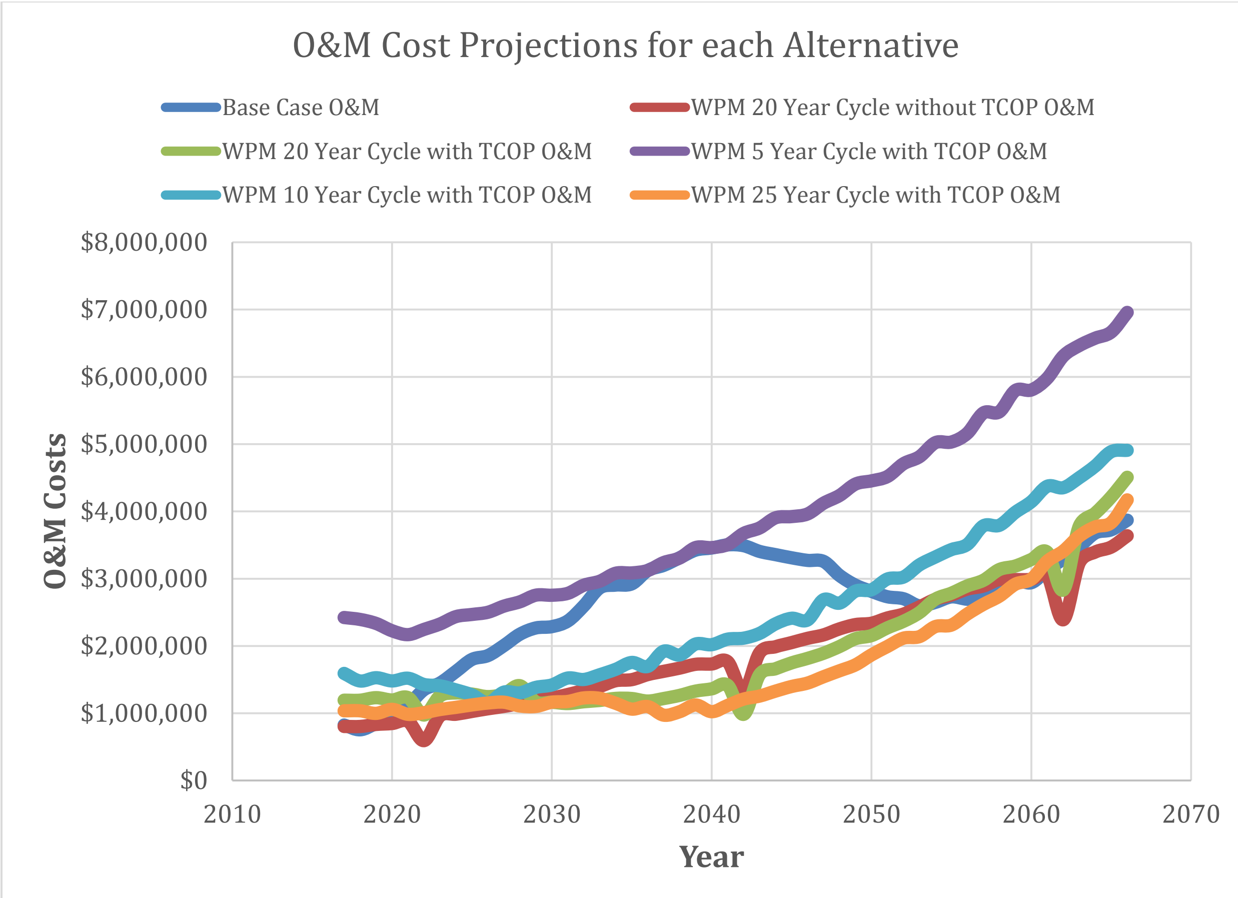

Figure 34 O&M Cost Projections for each Alternative

Table 16 includes two other alternatives not covered in Table 17 or in Figure 32 through Figure 36. The WPM 20 Year Cycle with TCOP and Grid Mod alternative and the TCOP and Grid Mod on 20 Year Cycle no WPM. These two options allow us to compare how WPM and Grid Modernization interact and change the results. Grid Modernization includes drives outside of the discussion in this report and we only include them to show how the two programs interact and compare.

Our current WPM program with a 20 year inspection cycle, the soon to be added TCOP work for WPM, and the current related Grid Modernization work is covered by the WPM 20 Year Cycle with TCOP and Grid Mod alternative in Table 17. Table 17 shows that the CIRR for this alternative still exceeds the 7% threshold and provides value to our customers.

The TCOP and Grid Mod on 20 Year Cycle no WPM alternative modifies the current program by replacing all wood poles at 60 years or older and retains all other portions of the WPM program. This alternative provide the second best reduction of risk (see Table 16) but at a very large costs which drives it to have the lowest CIRR of all alternatives examined.

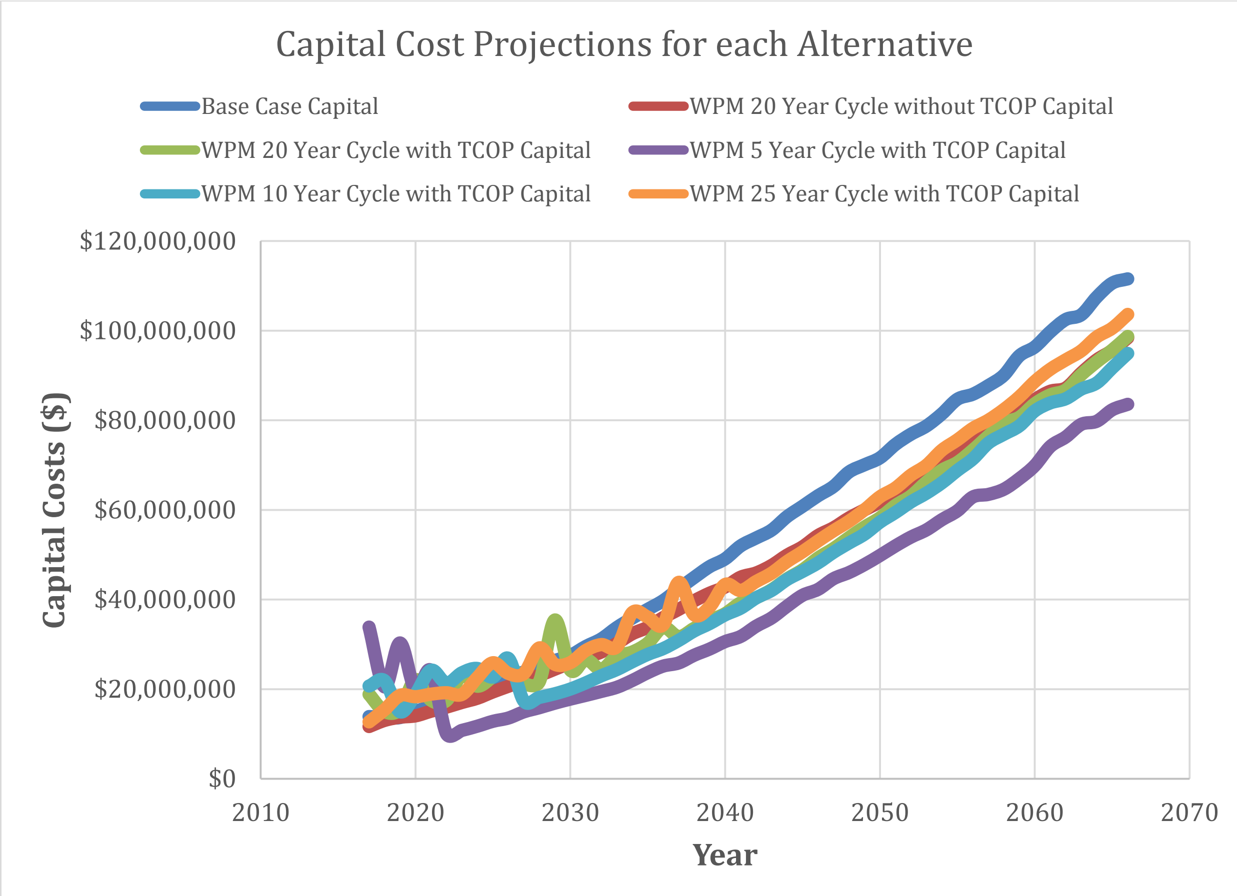

Figure 35 Capital Cost Projections for each Alternative

Table 15 takes a further look at Grid Modernization alternatives. These alternatives exclude all work related to TCOP components and evaluates alternative Grid Modernization approaches to replace WPM related work. The first alternative in Table 15 is the same Base Case as Table 16 minus the portion related to TCOP. The second alternative represents our current approach with a 60 year Grid Modernization cycle and a strategy to replace all poles that are 50 years old or older. The second alternative represents the Grid Modernization on a 50 year cycle and replacing all poles that are 50 years old or older. The final alternative represents the same alternative as the TCOP and Grid Mod on 20 Year Cycle no WPM alternative in Table 16 minus the TCOP related work. In all cases, the Base Case provides more value to our customers through the highest CIRR and demonstrates that the Grid Modernization program should not replace the current WPM strategy without considering other factors outside the current scope of WPM.

For more specifics and data details, see the fileCombined TCOP and WPM 4-24-17.xlsm for the data supporting Table 16, Figure 36, Figure 34 and Figure 35. For Figure 32, Figure 33, and Table 17, see file Combined WPM Model Projections.xlsx. The source data for both files is located in Appendix B.

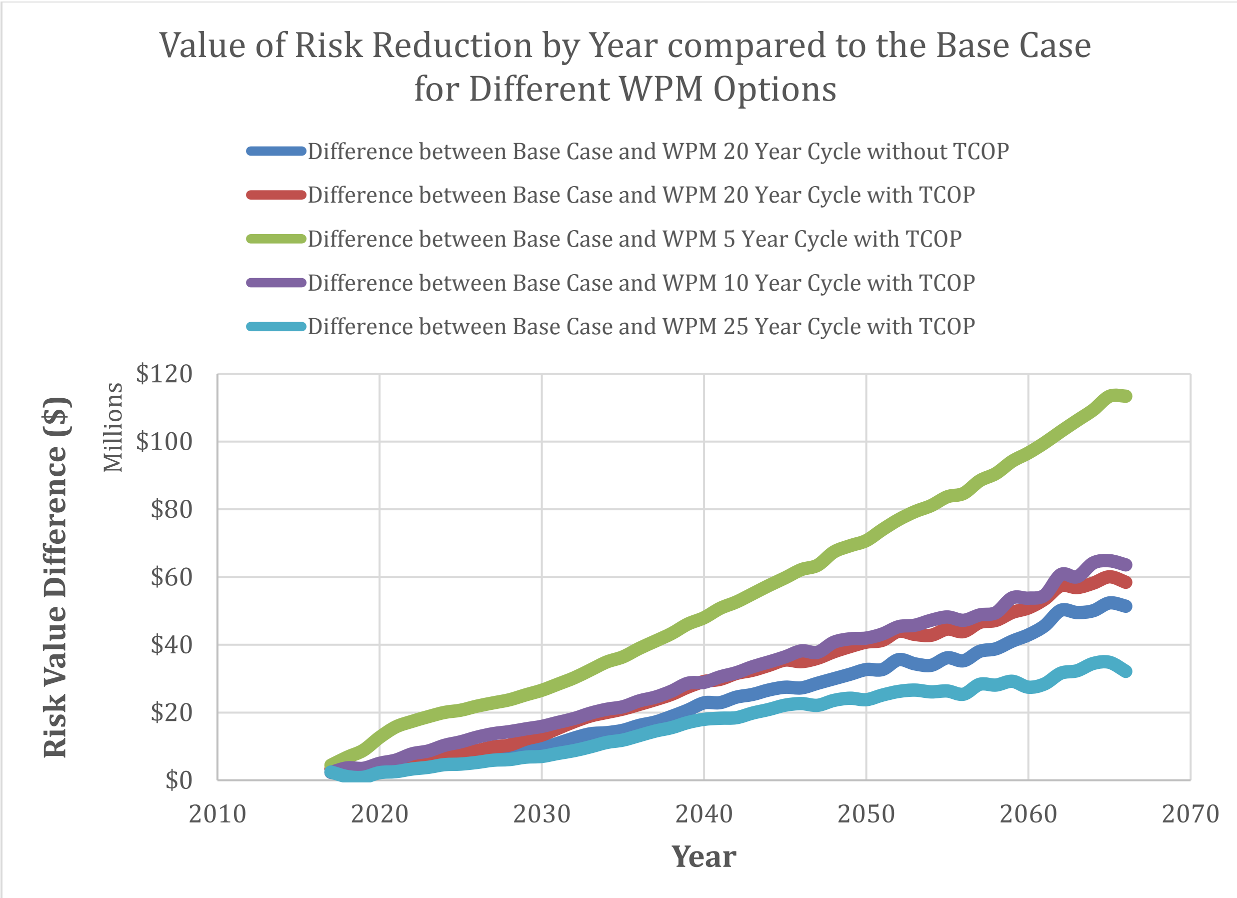

Figure 36 Value of Risk Reduction by Year compared to the Base Case for Different WPM Options

Strategy Selection

Given the criteria of best CIRR while staying in line or below historic O&M program costs, we selected to continue with the current 20 year inspection cycle for the WPM program. This strategy provides the second best CIRR as shown in Table 16 and aligns with historical spending as seen in Figure 34. The projected performance is discussed in sections above.

The projected budget needs for ER 2060 and the program O&M Costs are shown in Table 18. Table 18 shows the cost projections with and without the TCOP program implemented. We provided both with and without TCOP so this report would not rely upon the TCOP report outcomes. The decision whether to implement the next phase of TCOP into WPM or take another alternative is outside the scope of this paper. Table 18 provides model based cost projections that we will monitor and report on as part of our annual reviews, but detailed work planning, un-anticipated changes to costs and model errors will drive the actual values to move from these specific values. We consider the analysis successful if the actual costs for the projected work is within 20% of estimated given the assumptions and error potential. The cost projections exclude the volume of work associated with WPM assigned to Grid Modernization. The amount of work assigned to Grid Modernization will drive changes to the amount budgeted to WPM as long as the number of miles actually completed meets the WPM objectives.

Table 18 Capital and O&M Budget Projections for WPM 20 Year Cycle with and without TCOP Work Scope

	WPM 20 Year Cycle without TCOP		WPM 20 Year Cycle with TCOP	
Year	**Capital**	**O&M**	**Capital**	**O&M**
2017	$11,669,045	$803,810	$18,854,197	$1,194,173
2018	$13,025,585	$803,810	$15,012,412	$1,194,173
2019	$13,742,601	$833,885	$15,514,281	$1,231,681
2020	$14,047,041	$847,704	$22,123,558	$1,197,474
2021	$15,078,248	$880,576	$17,536,465	$1,232,031
2022	$15,990,379	$593,203	$17,477,067	$973,800
2023	$17,035,907	$961,525	$23,178,303	$1,257,104
2024	$17,982,969	$985,914	$20,657,211	$1,301,619
2025	$19,388,742	$1,026,983	$22,827,290	$1,285,068
2026	$20,651,486	$1,066,738	$25,504,624	$1,247,586
2027	$21,933,303	$1,102,010	$21,346,050	$1,286,464
2028	$23,083,970	$1,145,501	$21,696,609	$1,409,309
2029	$24,462,229	$1,194,949	$35,432,608	$1,167,284
2030	$25,853,518	$1,226,307	$24,274,809	$1,163,392
2031	$27,092,104	$1,279,239	$26,638,989	$1,144,464
2032	$28,294,481	$1,338,443	$24,447,462	$1,171,457
2033	$30,210,643	$1,398,744	$27,375,116	$1,190,335
2034	$32,368,974	$1,483,989	$28,288,338	$1,221,174
2035	$33,810,632	$1,499,797	$30,260,734	$1,219,065
2036	$35,978,328	$1,574,987	$33,771,025	$1,181,509
2037	$37,807,073	$1,623,520	$31,724,862	$1,219,246
2038	$39,736,694	$1,671,033	$33,580,376	$1,266,123
2039	$41,431,149	$1,728,080	$35,356,073	$1,329,740
2040	$42,819,628	$1,732,325	$36,844,192	$1,362,974

Year	WPM 20 Year Cycle without TCOP		WPM 20 Year Cycle with TCOP	
	Capital	O&M	Capital	O&M
2041	$44,991,507	$1,766,328	$39,268,486	$1,416,535
2042	$45,935,988	$1,320,934	$40,418,321	$984,371
2043	$47,613,382	$1,898,959	$42,194,470	$1,574,716
2044	$49,905,429	$1,989,480	$44,614,858	$1,662,442
2045	$51,756,558	$2,050,291	$46,626,050	$1,749,100
2046	$54,287,232	$2,113,936	$49,273,938	$1,815,657
2047	$56,009,790	$2,165,167	$51,367,679	$1,892,150
2048	$58,204,891	$2,254,576	$53,830,138	$1,991,977
2049	$60,018,349	$2,318,425	$56,176,774	$2,109,047
2050	$61,855,848	$2,338,516	$58,246,076	$2,154,559
2051	$64,413,167	$2,417,055	$61,004,837	$2,270,341
2052	$65,959,926	$2,474,064	$63,100,641	$2,366,721
2053	$69,093,014	$2,580,155	$66,215,546	$2,496,157
2054	$71,436,551	$2,694,404	$68,885,506	$2,696,692
2055	$72,763,583	$2,758,003	$70,594,593	$2,784,684
2056	$75,363,833	$2,846,480	$73,359,566	$2,893,595
2057	$78,268,859	$2,891,708	$76,471,455	$2,975,904
2058	$81,185,739	$2,988,557	$79,401,034	$3,136,331
2059	$82,076,752	$2,986,840	$80,668,068	$3,188,476
2060	$84,615,823	$2,990,264	$83,688,661	$3,285,170
2061	$86,478,600	$3,044,214	$85,669,143	$3,392,886
2062	$87,206,381	$2,389,762	$86,757,657	$2,832,616
2063	$90,543,214	$3,234,023	$90,169,480	$3,780,636
2064	$93,487,125	$3,396,688	$93,059,963	$3,972,833
2065	$95,579,516	$3,470,648	$95,684,234	$4,215,587
2066	$98,413,139	$3,638,373	$98,712,863	$4,507,533

The analysis for this program should be reviewed annually in the annual Asset Management Plan Review and the analysis updated in 2022 or sooner if indicated by the annual Asset Management Plan Review.

Metrics

The objective of metrics or key performance indicators is to ensure the right behavior is in place and working, to ensure successful execution, to continually improve tools and processes, and to ensure the systems operate as intended.

The goal is to provide a minimum of one leading and one lagging indicator. Lagging indicators measures or monitors the past performance and leading indicators predict future performance in order to avoid incidents and failures (IAM, 2015). The diagram in Figure 37 helps illustrate this point.

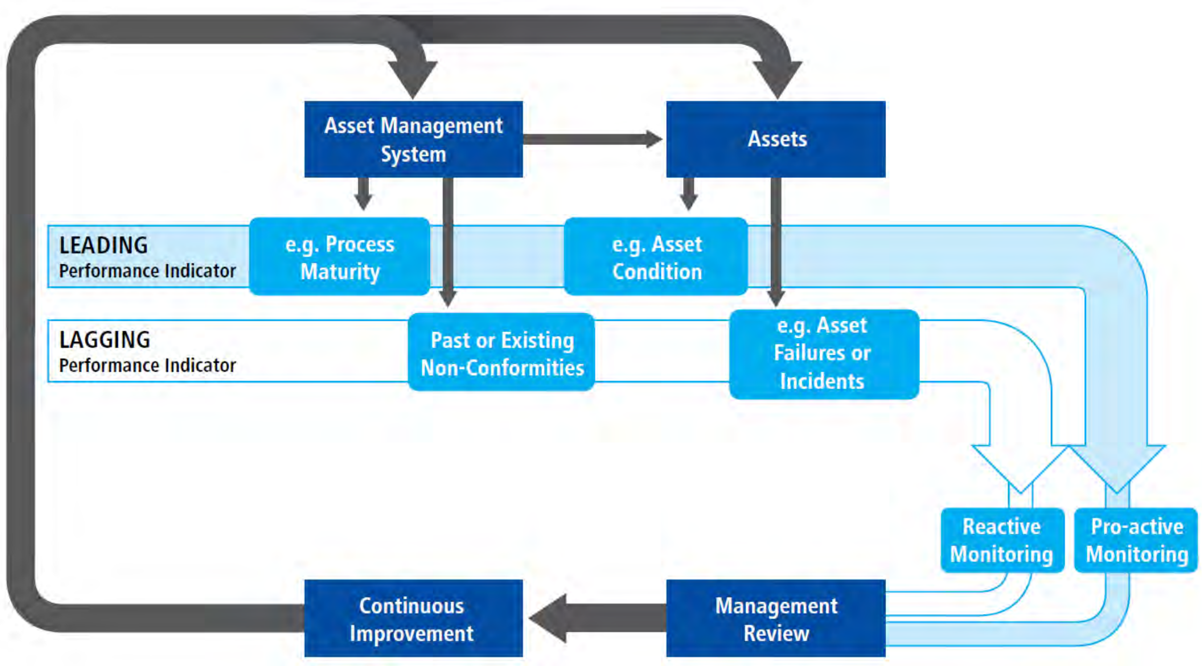

Figure 37 Leading and Lagging Performance measurements for assets and the Asset Management System from IAM (IAM, 2015)

The following metrics in Table 19 are planned for the annual Asset Management Plan Review. For the details on the data sources and calculations, see the Asset Information Strategy for Wood Pole Management.

Table 19 Metrics for Tracking WPM Performance

Metric	Annual Goal	Leading/Lagging Indicator
Actual miles of WPM follow up completed (includes Grid Modernization Miles if they support the WPM goal)	385.1 Miles	Leading
Actual Capital Spending by Year	Within 20% of projection	Lagging
Actual O&M Spending by Year	Within 20% of projection	Lagging
Combined Revised WPM Related OMT Events	Within 20% of projection	Lagging
Annual Contribution of Revised WPM related OMT Events to SAIFI	0.054	Lagging
Annual Contribution of Revised WPM related OMT Events to SAIDI	0.119 (hours)	Lagging

Revisions, additions and removal of metrics may occur and be documented as part of the annual Asset Management Plan Review along with the justifications for the changes.

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Appendix A

The Business Case template is currently under revision and not available for use.

Appendix B - Model output reports for labor, spares, Lifecycle Cost summary, effects, and others as appropriate

Due to the file sizes, a list of the files is provided here. Consult the files listed in Table 20 for all of the details.

Table 20 Model Output Files for Supporting Information

Model the Files Supports	File Name
2016 Pole Failure Curves - 10 year cycle scaled up rev 7	2016 Pole Failure Curves - 10 year cycle scaled up rev 7 - Cause Cost Predictions.pdf
2016 Pole Failure Curves - 10 year cycle scaled up rev 7	2016 Pole Failure Curves - 10 year cycle scaled up rev 7 - Cost Nodes.pdf
2016 Pole Failure Curves - 10 year cycle scaled up rev 7	2016 Pole Failure Curves - 10 year cycle scaled up rev 7 - Effects Predictions by Time Interval.pdf
2016 Pole Failure Curves - 10 year cycle scaled up rev 7	2016 Pole Failure Curves - 10 year cycle scaled up rev 7 - Effects Predictions.pdf
2016 Pole Failure Curves - 10 year cycle scaled up rev 7	2016 Pole Failure Curves - 10 year cycle scaled up rev 7 - Equipment Predictions by Time Interval.pdf
2016 Pole Failure Curves - 10 year cycle scaled up rev 7	2016 Pole Failure Curves - 10 year cycle scaled up rev 7 - Equipment Predictions.pdf
2016 Pole Failure Curves - 10 year cycle scaled up rev 7	2016 Pole Failure Curves - 10 year cycle scaled up rev 7 - Labor Predictions by Time Interval.pdf
2016 Pole Failure Curves - 10 year cycle scaled up rev 7	2016 Pole Failure Curves - 10 year cycle scaled up rev 7 - Labor Predictions.pdf
2016 Pole Failure Curves - 10 year cycle scaled up rev 7	2016 Pole Failure Curves - 10 year cycle scaled up rev 7 - Project Predictions by Time Interval.pdf
2016 Pole Failure Curves - 10 year cycle scaled up rev 7	2016 Pole Failure Curves - 10 year cycle scaled up rev 7 - Spares Predictions by Time Interval.pdf
2016 Pole Failure Curves - 10 year cycle scaled up rev 7	2016 Pole Failure Curves - 10 year cycle scaled up rev 7 - Spares Predictions.pdf
2016 Pole Failure Curves - 10 year cycle scaled up rev 7	2016 Pole Failure Curves - 10 year cycle scaled up rev 7.awb
2016 Pole Failure Curves - 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 20 year cycle scaled up rev 7 - 10 year pause - Cost Nodes.pdf
2016 Pole Failure Curves - 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 20 year cycle scaled up rev 7 - 10 year pause.awb
2016 Pole Failure Curves - 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 20 year cycle scaled up rev 7 - 5 year pause - Cost Nodes.pdf
2016 Pole Failure Curves - 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 20 year cycle scaled up rev 7 - 5 year pause.awb
2016 Pole Failure Curves - 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 20 year cycle scaled up rev 7 - Cause Cost Predictions.pdf
2016 Pole Failure Curves - 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 20 year cycle scaled up rev 7 - Cost Nodes.pdf
2016 Pole Failure Curves - 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 20 year cycle scaled up rev 7 - Effects Predictions by Time Interval.pdf
2016 Pole Failure Curves - 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 20 year cycle scaled up rev 7 - Effects Predictions.pdf

Model the Files Supports	File Name
2016 Pole Failure Curves - 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 20 year cycle scaled up rev 7 - Equipment Predictions by Time Interval.pdf
2016 Pole Failure Curves - 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 20 year cycle scaled up rev 7 - Equipment Predictions.pdf
2016 Pole Failure Curves - 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 20 year cycle scaled up rev 7 - Labor Predictions by Time Interval.pdf
2016 Pole Failure Curves - 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 20 year cycle scaled up rev 7 - Labor Predictions.pdf
2016 Pole Failure Curves - 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 20 year cycle scaled up rev 7 - Project Predictions by Time Interval.pdf
2016 Pole Failure Curves - 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 20 year cycle scaled up rev 7 - Spares Predictions by Time Interval.pdf
2016 Pole Failure Curves - 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 20 year cycle scaled up rev 7 - Spares Predictions.pdf
2016 Pole Failure Curves - 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 20 year cycle scaled up rev 7.awb
2016 Pole Failure Curves - 25 year cycle scaled up rev 7	2016 Pole Failure Curves - 25 year cycle scaled up rev 7 - Cause Cost Predictions.pdf
2016 Pole Failure Curves - 25 year cycle scaled up rev 7	2016 Pole Failure Curves - 25 year cycle scaled up rev 7 - Cost Nodes.pdf
2016 Pole Failure Curves - 25 year cycle scaled up rev 7	2016 Pole Failure Curves - 25 year cycle scaled up rev 7 - Effect Predictions by Time Interval.pdf
2016 Pole Failure Curves - 25 year cycle scaled up rev 7	2016 Pole Failure Curves - 25 year cycle scaled up rev 7 - Effect Predictions.pdf
2016 Pole Failure Curves - 25 year cycle scaled up rev 7	2016 Pole Failure Curves - 25 year cycle scaled up rev 7 - Equipment Predictions by Time Interval.pdf
2016 Pole Failure Curves - 25 year cycle scaled up rev 7	2016 Pole Failure Curves - 25 year cycle scaled up rev 7 - Equipment Predictions.pdf
2016 Pole Failure Curves - 25 year cycle scaled up rev 7	2016 Pole Failure Curves - 25 year cycle scaled up rev 7 - Labor Predictions by Time Interval.pdf
2016 Pole Failure Curves - 25 year cycle scaled up rev 7	2016 Pole Failure Curves - 25 year cycle scaled up rev 7 - Labor Predictions.pdf
2016 Pole Failure Curves - 25 year cycle scaled up rev 7	2016 Pole Failure Curves - 25 year cycle scaled up rev 7 - Project Predictions by Time Interval.pdf
2016 Pole Failure Curves - 25 year cycle scaled up rev 7	2016 Pole Failure Curves - 25 year cycle scaled up rev 7 - Spares Predictions by Time Interval.pdf
2016 Pole Failure Curves - 25 year cycle scaled up rev 7	2016 Pole Failure Curves - 25 year cycle scaled up rev 7 - Spares Predictions.pdf
2016 Pole Failure Curves - 25 year cycle scaled up rev 7	2016 Pole Failure Curves - 25 year cycle scaled up rev 7.awb
2016 Pole Failure Curves - 5 year cycle scaled up rev 7	2016 Pole Failure Curves - 5 year cycle scaled up rev 7 - Cause Cost Predictions.pdf
2016 Pole Failure Curves - 5 year cycle scaled up rev 7	2016 Pole Failure Curves - 5 year cycle scaled up rev 7 - Cost Nodes.pdf

Model the Files Supports	File Name
2016 Pole Failure Curves - 5 year cycle scaled up rev 7	2016 Pole Failure Curves - 5 year cycle scaled up rev 7 - Effects Predictions by Time Interval.pdf
2016 Pole Failure Curves - 5 year cycle scaled up rev 7	2016 Pole Failure Curves - 5 year cycle scaled up rev 7 - Effects Predictions.pdf
2016 Pole Failure Curves - 5 year cycle scaled up rev 7	2016 Pole Failure Curves - 5 year cycle scaled up rev 7 - Equipment Predictions by Time Interval.pdf
2016 Pole Failure Curves - 5 year cycle scaled up rev 7	2016 Pole Failure Curves - 5 year cycle scaled up rev 7 - Equipment Predictions.pdf
2016 Pole Failure Curves - 5 year cycle scaled up rev 7	2016 Pole Failure Curves - 5 year cycle scaled up rev 7 - Labor Predictions by Time Interval.pdf
2016 Pole Failure Curves - 5 year cycle scaled up rev 7	2016 Pole Failure Curves - 5 year cycle scaled up rev 7 - Labor Predictions.pdf
2016 Pole Failure Curves - 5 year cycle scaled up rev 7	2016 Pole Failure Curves - 5 year cycle scaled up rev 7 - Project Predictions by Time Interval.pdf
2016 Pole Failure Curves - 5 year cycle scaled up rev 7	2016 Pole Failure Curves - 5 year cycle scaled up rev 7 - Spares Predictions by Time Interval.pdf
2016 Pole Failure Curves - 5 year cycle scaled up rev 7	2016 Pole Failure Curves - 5 year cycle scaled up rev 7 - Spares Predictions.pdf
2016 Pole Failure Curves - 5 year cycle scaled up rev 7	2016 Pole Failure Curves - 5 year cycle scaled up rev 7.awb
2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7 - Cause Cost Predictions.pdf
2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7 - Cost Nodes.pdf
2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7 - Effects Predictions by Time Interval.pdf
2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7 - Effects Predictions.pdf
2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7 - Equipment Predictions by Time Interval.pdf
2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7 - Equipment Predictions.pdf
2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7 - Labor Predictions by Time Interval.pdf
2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7 - Labor Predictions.pdf

Model the Files Supports	File Name
2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7 - Project Predictions by Time Interval.pdf
2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7 - Spares Predictions by Time Interval.pdf
2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7 - Spares Predictions.pdf
2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7	2016 Pole Failure Curves - 60 Year Grid mod 20 year cycle scaled up rev 7.awb
2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9	2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9 - Cause Cost Predictions.pdf
2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9	2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9 - Cost Nodes.pdf
2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9	2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9 - Effects Predictions by Time Interval.pdf
2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9	2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9 - Effects Predictions.pdf
2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9	2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9 - Equipment Predictions by Time Interval.pdf
2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9	2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9 - Equipment Predictions.pdf
2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9	2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9 - Labor Predictions by Time Interval.pdf
2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9	2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9 - Labor Predictions.pdf
2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9	2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9 - Project Predictions by Time Interval.pdf
2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9	2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9 - Spares Predictions by Time Interval.pdf

Model the Files Supports	File Name
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2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9	2016 Pole Failure Curves - 60 Year Grid mod 60 year cycle scaled up rev 9.awb
2016 Pole Failure Curves - Base Case scaled up rev 7	2016 Pole Failure Curves - Base Case scaled up rev 7 - Cause Cost Predictions.pdf
2016 Pole Failure Curves - Base Case scaled up rev 7	2016 Pole Failure Curves - Base Case scaled up rev 7 - Cost Nodes.pdf
2016 Pole Failure Curves - Base Case scaled up rev 7	2016 Pole Failure Curves - Base Case scaled up rev 7 - Effects Predictions by Time Interval.pdf
2016 Pole Failure Curves - Base Case scaled up rev 7	2016 Pole Failure Curves - Base Case scaled up rev 7 - Effects Predictions.pdf
2016 Pole Failure Curves - Base Case scaled up rev 7	2016 Pole Failure Curves - Base Case scaled up rev 7 - Equipment Predictions by Time Interval.pdf
2016 Pole Failure Curves - Base Case scaled up rev 7	2016 Pole Failure Curves - Base Case scaled up rev 7 - Equipment Predictions.pdf
2016 Pole Failure Curves - Base Case scaled up rev 7	2016 Pole Failure Curves - Base Case scaled up rev 7 - Labor Predictions by Time Interval.pdf
2016 Pole Failure Curves - Base Case scaled up rev 7	2016 Pole Failure Curves - Base Case scaled up rev 7 - Labor Predictions.pdf
2016 Pole Failure Curves - Base Case scaled up rev 7	2016 Pole Failure Curves - Base Case scaled up rev 7 - Project Predictions by Time Interval.pdf
2016 Pole Failure Curves - Base Case scaled up rev 7	2016 Pole Failure Curves - Base Case scaled up rev 7 - Spares Predictions by Time Interval.pdf
2016 Pole Failure Curves - Base Case scaled up rev 7	2016 Pole Failure Curves - Base Case scaled up rev 7 - Spares Predictions.pdf
2016 Pole Failure Curves - Base Case scaled up rev 7	2016 Pole Failure Curves - Base Case scaled up rev 7.awb
2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9	2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9 - Cause Cost Predictions.pdf
2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9	2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9 - Cost Nodes.pdf
2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9	2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9 - Effect Predictions by Time Interval.pdf
2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9	2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9 - Effect Predictions.pdf
2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9	2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9 - Equipment Predictions by Time Interval.pdf
2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9	2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9 - Equipment Predictions.pdf
2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9	2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9 - Labor Predictions by Time Interval.pdf

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2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9	2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9 - Project Predictions by Time Interval.pdf
2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9	2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9 - Spares Predictions by Time Interval.pdf
2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9	2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9 - Spares Predictions.pdf
2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9	2016 Pole Failure Curves - Opt Grid mod 50 year cycle scaled up rev 9.awb
2016 TCOP Model for WPM - No Action Base Case 4-24-17	2016 TCOP Model for WPM - No Action Base Case 4-24-17 - Cause Cost Predictions.pdf
2016 TCOP Model for WPM - No Action Base Case 4-24-17	2016 TCOP Model for WPM - No Action Base Case 4-24-17 - Cost Nodes.pdf
2016 TCOP Model for WPM - No Action Base Case 4-24-17	2016 TCOP Model for WPM - No Action Base Case 4-24-17 - Effects Predictions by Time Interval.pdf
2016 TCOP Model for WPM - No Action Base Case 4-24-17	2016 TCOP Model for WPM - No Action Base Case 4-24-17 - Effects Predictions.pdf
2016 TCOP Model for WPM - No Action Base Case 4-24-17	2016 TCOP Model for WPM - No Action Base Case 4-24-17 - Equipment Predictions by Time Interval.pdf
2016 TCOP Model for WPM - No Action Base Case 4-24-17	2016 TCOP Model for WPM - No Action Base Case 4-24-17 - Equipment Predictions.pdf
2016 TCOP Model for WPM - No Action Base Case 4-24-17	2016 TCOP Model for WPM - No Action Base Case 4-24-17 - Labor Predictions by Time Interval.pdf
2016 TCOP Model for WPM - No Action Base Case 4-24-17	2016 TCOP Model for WPM - No Action Base Case 4-24-17 - Labor Predictions.pdf
2016 TCOP Model for WPM - No Action Base Case 4-24-17	2016 TCOP Model for WPM - No Action Base Case 4-24-17 - Project Predictions by Time Interval.pdf
2016 TCOP Model for WPM - No Action Base Case 4-24-17	2016 TCOP Model for WPM - No Action Base Case 4-24-17 - Spares Predictions by Time Interval.pdf
2016 TCOP Model for WPM - No Action Base Case 4-24-17	2016 TCOP Model for WPM - No Action Base Case 4-24-17 - Spares Predictions.pdf
2016 TCOP Model for WPM - No Action Base Case 4-24-17	2016 TCOP Model for WPM - No Action Base Case 4-24-17.awb
2016 TCOP Model for WPM 10 Year Cycle 4-24-17	2016 TCOP Model for WPM 10 Year Cycle 4-24-17 - Cause Cost Predictions.pdf
2016 TCOP Model for WPM 10 Year Cycle 4-24-17	2016 TCOP Model for WPM 10 Year Cycle 4-24-17 - Cost Nodes.pdf
2016 TCOP Model for WPM 10 Year Cycle 4-24-17	2016 TCOP Model for WPM 10 Year Cycle 4-24-17 - Effects Predictions by Time Interval.pdf
2016 TCOP Model for WPM 10 Year Cycle 4-24-17	2016 TCOP Model for WPM 10 Year Cycle 4-24-17 - Effects Predictions.pdf
2016 TCOP Model for WPM 10 Year Cycle 4-24-17	2016 TCOP Model for WPM 10 Year Cycle 4-24-17 - Equipment Predictions by Time Interval.pdf

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2016 TCOP Model for WPM 10 Year Cycle 4-24-17	2016 TCOP Model for WPM 10 Year Cycle 4-24-17 - Equipment Predictions.pdf
2016 TCOP Model for WPM 10 Year Cycle 4-24-17	2016 TCOP Model for WPM 10 Year Cycle 4-24-17 - Labor Predictions by Time Interval.pdf
2016 TCOP Model for WPM 10 Year Cycle 4-24-17	2016 TCOP Model for WPM 10 Year Cycle 4-24-17 - Labor Predictions.pdf
2016 TCOP Model for WPM 10 Year Cycle 4-24-17	2016 TCOP Model for WPM 10 Year Cycle 4-24-17 - Project Predictions by Time Interval.pdf
2016 TCOP Model for WPM 10 Year Cycle 4-24-17	2016 TCOP Model for WPM 10 Year Cycle 4-24-17 - Spares Predictions by Time Interval.pdf
2016 TCOP Model for WPM 10 Year Cycle 4-24-17	2016 TCOP Model for WPM 10 Year Cycle 4-24-17 - Spares Predictions.pdf
2016 TCOP Model for WPM 10 Year Cycle 4-24-17	2016 TCOP Model for WPM 10 Year Cycle 4-24-17.awb
2016 TCOP Model for WPM 20 Year Cycle 4-24-17	2016 TCOP Model for WPM 20 Year Cycle 4-24-17 - Cause Cost Predictions.pdf
2016 TCOP Model for WPM 20 Year Cycle 4-24-17	2016 TCOP Model for WPM 20 Year Cycle 4-24-17 - Cost Nodes.pdf
2016 TCOP Model for WPM 20 Year Cycle 4-24-17	2016 TCOP Model for WPM 20 Year Cycle 4-24-17 - Effects Predictions by Time Interval.pdf
2016 TCOP Model for WPM 20 Year Cycle 4-24-17	2016 TCOP Model for WPM 20 Year Cycle 4-24-17 - Effects Predictions.pdf
2016 TCOP Model for WPM 20 Year Cycle 4-24-17	2016 TCOP Model for WPM 20 Year Cycle 4-24-17 - Equipment Predictions by Time Interval.pdf
2016 TCOP Model for WPM 20 Year Cycle 4-24-17	2016 TCOP Model for WPM 20 Year Cycle 4-24-17 - Equipment Predictions.pdf
2016 TCOP Model for WPM 20 Year Cycle 4-24-17	2016 TCOP Model for WPM 20 Year Cycle 4-24-17 - Labor Predictions by Time Interval.pdf
2016 TCOP Model for WPM 20 Year Cycle 4-24-17	2016 TCOP Model for WPM 20 Year Cycle 4-24-17 - Labor Predictions.pdf
2016 TCOP Model for WPM 20 Year Cycle 4-24-17	2016 TCOP Model for WPM 20 Year Cycle 4-24-17 - Project Predictions by Time Interval.pdf
2016 TCOP Model for WPM 20 Year Cycle 4-24-17	2016 TCOP Model for WPM 20 Year Cycle 4-24-17 - Spares Predictions by Time Interval.pdf
2016 TCOP Model for WPM 20 Year Cycle 4-24-17	2016 TCOP Model for WPM 20 Year Cycle 4-24-17 - Spares Predictions.pdf
2016 TCOP Model for WPM 20 Year Cycle 4-24-17	2016 TCOP Model for WPM 20 Year Cycle 4-24-17.awb
2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17	2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17 - Cause Cost Predictions.pdf
2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17	2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17 - Cost Nodes.pdf
2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17	2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17 - Effects Predictions by Time Interval.pdf

Model the Files Supports	File Name
2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17	2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17 - Effects Predictions.pdf
2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17	2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17 - Equipment Predictions by Time Interval.pdf
2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17	2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17 - Equipment Predictions.pdf
2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17	2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17 - Labor Predictions by Time Interval.pdf
2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17	2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17 - Labor Predictions.pdf
2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17	2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17 - Project Predictions by Time Interval.pdf
2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17	2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17 - Spares Predictions by Time Interval.pdf
2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17	2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17 - Spares Predictions.pdf
2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17	2016 TCOP Model for WPM 20 Year Cycle No TCOP Case 4-21-17.awb
2016 TCOP Model for WPM 25 Year Cycle 4-24-17	2016 TCOP Model for WPM 25 Year Cycle 4-24-17 - Cause Cost Predictions.pdf
2016 TCOP Model for WPM 25 Year Cycle 4-24-17	2016 TCOP Model for WPM 25 Year Cycle 4-24-17 - Cost Nodes.pdf
2016 TCOP Model for WPM 25 Year Cycle 4-24-17	2016 TCOP Model for WPM 25 Year Cycle 4-24-17 - Effects Predictions by Time Interval.pdf
2016 TCOP Model for WPM 25 Year Cycle 4-24-17	2016 TCOP Model for WPM 25 Year Cycle 4-24-17 - Effects Predictions.pdf
2016 TCOP Model for WPM 25 Year Cycle 4-24-17	2016 TCOP Model for WPM 25 Year Cycle 4-24-17 - Equipment Predictions by Time Interval.pdf
2016 TCOP Model for WPM 25 Year Cycle 4-24-17	2016 TCOP Model for WPM 25 Year Cycle 4-24-17 - Equipment Predictions.pdf
2016 TCOP Model for WPM 25 Year Cycle 4-24-17	2016 TCOP Model for WPM 25 Year Cycle 4-24-17 - Labor Predictions by Time Interval.pdf
2016 TCOP Model for WPM 25 Year Cycle 4-24-17	2016 TCOP Model for WPM 25 Year Cycle 4-24-17 - Labor Predictions.pdf
2016 TCOP Model for WPM 25 Year Cycle 4-24-17	2016 TCOP Model for WPM 25 Year Cycle 4-24-17 - Project Predictions by Time Interval.pdf
2016 TCOP Model for WPM 25 Year Cycle 4-24-17	2016 TCOP Model for WPM 25 Year Cycle 4-24-17 - Spares Predictions by Time Interval.pdf
2016 TCOP Model for WPM 25 Year Cycle 4-24-17	2016 TCOP Model for WPM 25 Year Cycle 4-24-17 - Spares Predictions.pdf
2016 TCOP Model for WPM 25 Year Cycle 4-24-17	2016 TCOP Model for WPM 25 Year Cycle 4-24-17.awb
2016 TCOP Model for WPM 5 Year Cycle 4-24-17	2016 TCOP Model for WPM 5 Year Cycle 4-24-17 - Cause Cost Predictions.pdf

Model the Files Supports	File Name
2016 TCOP Model for WPM 5 Year Cycle 4-24-17	2016 TCOP Model for WPM 5 Year Cycle 4-24-17 - Cost Node.pdf
2016 TCOP Model for WPM 5 Year Cycle 4-24-17	2016 TCOP Model for WPM 5 Year Cycle 4-24-17 - Effect Predictions by Time Interval.pdf
2016 TCOP Model for WPM 5 Year Cycle 4-24-17	2016 TCOP Model for WPM 5 Year Cycle 4-24-17 - Effect Predictions.pdf
2016 TCOP Model for WPM 5 Year Cycle 4-24-17	2016 TCOP Model for WPM 5 Year Cycle 4-24-17 - Equipment Predictions by Time Interval.pdf
2016 TCOP Model for WPM 5 Year Cycle 4-24-17	2016 TCOP Model for WPM 5 Year Cycle 4-24-17 - Equipment Predictions.pdf
2016 TCOP Model for WPM 5 Year Cycle 4-24-17	2016 TCOP Model for WPM 5 Year Cycle 4-24-17 - Labor Predictions by Time Interval.pdf
2016 TCOP Model for WPM 5 Year Cycle 4-24-17	2016 TCOP Model for WPM 5 Year Cycle 4-24-17 - Labor Predictions.pdf
2016 TCOP Model for WPM 5 Year Cycle 4-24-17	2016 TCOP Model for WPM 5 Year Cycle 4-24-17 - Project Predictions by Time Interval.pdf
2016 TCOP Model for WPM 5 Year Cycle 4-24-17	2016 TCOP Model for WPM 5 Year Cycle 4-24-17 - Spares Predictions by Time Interval.pdf
2016 TCOP Model for WPM 5 Year Cycle 4-24-17	2016 TCOP Model for WPM 5 Year Cycle 4-24-17 - Spares Predictions.pdf
2016 TCOP Model for WPM 5 Year Cycle 4-24-17	2016 TCOP Model for WPM 5 Year Cycle 4-24-17.awb

Appendix C

Table 21 Complete list of Feeders by Year WPM work completed since 2006 Ranked based on OMT Events for 2012-2016 by Subreason

Year WPM Work Completed on Feeder	FEEDER	Crossarm-rotten	Insulator	Insulator Pin	Pole-rotten	Grand Total
2016	M23621	3			2	5
	LOL1359		2	1	1	4
	NLW1222	1			2	3
	MLN12F2			1	2	3
	SOT522	1			1	2
	SPT4S23		1		1	2
	CHE12F4	1				1
	CLA56		1			1
	APW114				1	1
	MLN12F1	1				1
2015	GIF34F1	2	4	3	2	11
	NW12F3	1		1	4	6
	3HT12F7	3	1	1	1	6
	NW12F1	2			2	4
	L&S12F2	1	2	1		4
	APW111		1		2	3
	3HT12F3				3	3
	C&W12F6	1	1		1	3
	SAG742		1		1	2
	LOL1266		1		1	2
	GAR461	1	1			2
	NW12F4		1		1	2
	3HT12F5	1		1		2
	L&S12F3		1		1	2
	L&S12F4				2	2
	AIR12F3				1	1
	LKV342				1	1
	L&S12F5		1			1
	L&S12F1		1			1

	LKV343		1			1
	3HT12F1		1			1
2014	C&W12F1	3	2		1	6
	DER651	2	2	1		5
	NE12F3	1		1	2	4
	NW12F2		2		2	4
	WAS781			2	1	3
	C&W12F4			2	1	3
	C&W12F5				3	3
	CDA123				3	3
	SAG741		2			2
	CDA124		1		1	2
	TUR113				1	1
	CDA122				1	1
	C&W12F3		1			1
	3HT12F2				1	1
2013	SPU121				3	3
	WIL12F2			1	1	2
	MIL12F4				1	1
	AVD152				1	1
	SE12F2				1	1
	AVD151			1		1
	3HT12F4				1	1
	DEP12F1			1		1
	DEP12F2		1			1
2012	TEN1256		2	1	1	4
	SE12F5				4	4
	MEA12F2				3	3
	TEN1257		3			3
	COB12F1		1	1		2
	COB12F2		1	1		2
	DAL133				2	2
	BEA12F1				1	1
	TVW132	1				1
	F&C12F2	1				1
	MEA12F1		1			1
2011	VAL12F1	2	3	1	4	10
	SUN12F6	1			1	2
	M15515		1			1
	OLD721	1				1

	CHE12F3		1			1
	MIL12F3				1	1
	ODN731				1	1
2010	CDA125		1		5	6
	BKR12F1	1	2			3
	LL12F1	1	2			3
	CKF711		1		1	2
	PRA222		1		1	2
	CKF712				2	2
	KET12F2		1			1
	PRA221		1			1
	TEN1254			1		1
	ODN732				1	1
	LOO12F1				1	1
2009	GRV1273		5	1	2	8
	SUN12F2	1	1	2		4
	DIA231		3			3
	M15514		2			2
	SUN12F4		1		1	2
	9CE12F4		2			2
	HAR4F2		2			2
	SLW1368				1	1
	HAR4F1		1			1
2008	STM633		5	2	2	9
	BUN426	1	1		2	4
	HUE142		2		1	3
	BUN422		1	1		2
	HUE141	2				2
	NMO521	1			1	2
	SUN12F1		1			1
	SLW1358				1	1
	CGC331		1			1
	BKR12F2			1		1
	BUN423		1			1
	PDL1201		1			1
	SUN12F3				1	1
	ROX751	1				1
	SE12F1		1			1
2007	GRV1272		1			1
0	RSA431	7	1	3	1	12

	GIF34F2	7	2		2	11
	BEA12F2	1	4	1	5	11
	STM631		4	3	4	11
	BLU321	1	8	1		10
	CHW12F3	3	2	1	3	9
	LAT421	3	1	3	1	8
	SWT2403	1	2	1	3	7
	SLK12F1	1	4		2	7
	CHW12F2	2	3		2	7
	CHW12F4	1	2	2	2	7
	FOR12F1	4	2	1		7
	SOT523	1	1	3	2	7
	CLV12F2		6		1	7
	LF34F1	1	6			7
	CLV34F1	3	2	1		6
	ORI12F3	2	1	3		6
	COT2401		2	4		6
	ORI12F1		5		1	6
	SPI12F2	3		2	1	6
	CHE12F2		1		4	5
	PAL312	1		1	3	5
	OGA611	1	1	2	1	5
	SPR761	1	1	2	1	5
	SPI12F1	3			2	5
	WAK12F3				5	5
	PRV4S40		4		1	5
	DVP12F2	3	1		1	5
	RDN12F2		1		4	5
	ROS12F5		2	1	2	5
	LIB12F2	2	2	1		5
	MIS431		3	1	1	5
	VAL12F2	2	2			4
	GLN12F1	1			3	4
	ROS12F6	1		1	2	4
	AIR12F1		1	1	2	4
	L&R512				4	4
	DER652		1	2	1	4
	WAK12F2		1		3	4
	OSB521	1	2		1	4
	FWT12F2			1	3	4

	PDL1203		2		2	4
	SPL361		2	1	1	4
	PF213		3		1	4
	TUR112	3	1			4
	PIN443		1	1	2	4
	VAL12F3	2	1		1	4
	RDN12F1			3	1	4
	FWT12F1		1	1	2	4
	ROS12F1			1	3	4
	F&C12F4	2			1	3
	H&W12F2			1	2	3
	BLA311			2	1	3
	LEO611		1		2	3
	JPE1287	1		1	1	3
	ARD12F2	1	1	1		3
	RAT233		3			3
	WEI1289	1	1	1		3
	WAL543		1	2		3
	ECL221	1	2			3
	SPT4S22	1	1		1	3
	FWT12F3		1		2	3
	CHE12F1				3	3
	SLK12F2			2	1	3
	PST12F1	3				3
	FWT12F4			2	1	3
	BLU322			3		3
	BKR12F3		1		2	3
	WAK12F4				3	3
	NE12F1				3	3
	9CE12F2	1			2	3
	NEZ1267	2	1			3
	NE12F5	1	2			3
	F&C12F6	1			1	2
	SLK12F3	1			1	2
	9CE12F1		1		1	2
	ORO1281		1		1	2
	LAT422		1	1		2
	GRV1271		1		1	2
	FOR2.3	1	1			2
	ECL222		2			2

	L&R511	1	1			2
	ROS12F4				2	2
	F&C12F1			1	1	2
	KAM1292	1	1			2
	LEO612		1		1	2
	KAM1293	1			1	2
	TEN1255				2	2
	OPT12F1				2	2
	WAK12F1	1		1		2
	SIP12F4	1			1	2
	KOO1298	1			1	2
	SE12F3				2	2
	IDR252		1			1
	CFD1210				1	1
	WAL542				1	1
	BEA12F3		1			1
	9CE12F3	1				1
	RIT731				1	1
	PVW243		1			1
	RIT732				1	1
	COT2402		1			1
	KAM1291		1			1
	POT321		1			1
	ROS12F2				1	1
	HOL1206				1	1
	ROS12F3				1	1
	N131222		1			1
	ORO1280			1		1
	CHW12F1		1			1
	CRG1261			1		1
	WAL544				1	1
	ORO1282				1	1
	CLV12F1				1	1
	KET12F1	1				1
	SPT4S21		1			1
	WIK1279		1			1
	SPT4S30		1			1
	BEA12F4			1		1
	LOO12F2		1			1
	OTH501				1	1

	TKO411			1		1
	GRA12F1			1		1
	TUR116				1	1
	GRN12F1				1	1
	APW116		1			1
	ORI12F2		1			1
	IDR253		1			1
	SLW1348				1	1
	NLW1321		1			1
	EWN241				1	1
	NMO522	1				1
	SPA442				1	1
	WAL545				1	1
	PIN441	1				1
	INT12F2	1				1
	PIN442				1	1
	SIP12F2	1				1

Appendix D – Life Extension Impact Analysis of Reinforcing Electric Distribution Wood Poles

Avista chose as part of our strategy to reinforce poles when they have any signs of ground line decay on an otherwise physical sound structure. Some people question why this option makes sense compared to just replacing the pole.

Figure 38 and Table 22 show the failure curve and failure curve characteristics for a pole replacement. The failure curve in Figure 38 shows the failure rate driving poles replaced with the current reinforcement strategy shown in Figure 39 and Table 23.

For comparison, we recreated the pole replacement failure curve assuming that we only replace poles and the new failure curve and failure characteristics in Figure 40 and Table 24. Examining the MTTF for Table 22 and Table 24 we see that by reinforcing poles where we can extends the MTTF for replacing poles by 9 years for the whole population. In order for reinforcing some of the poles to drive the overall population MTTF by 9 years, the extension of the life of a reinforced pole must be well beyond 9 years since our current practice approximately replaces 2 pole for every one pole reinforced.

Figure 41 compares the two different failure curves and shows the 9 year difference between the two different strategies.

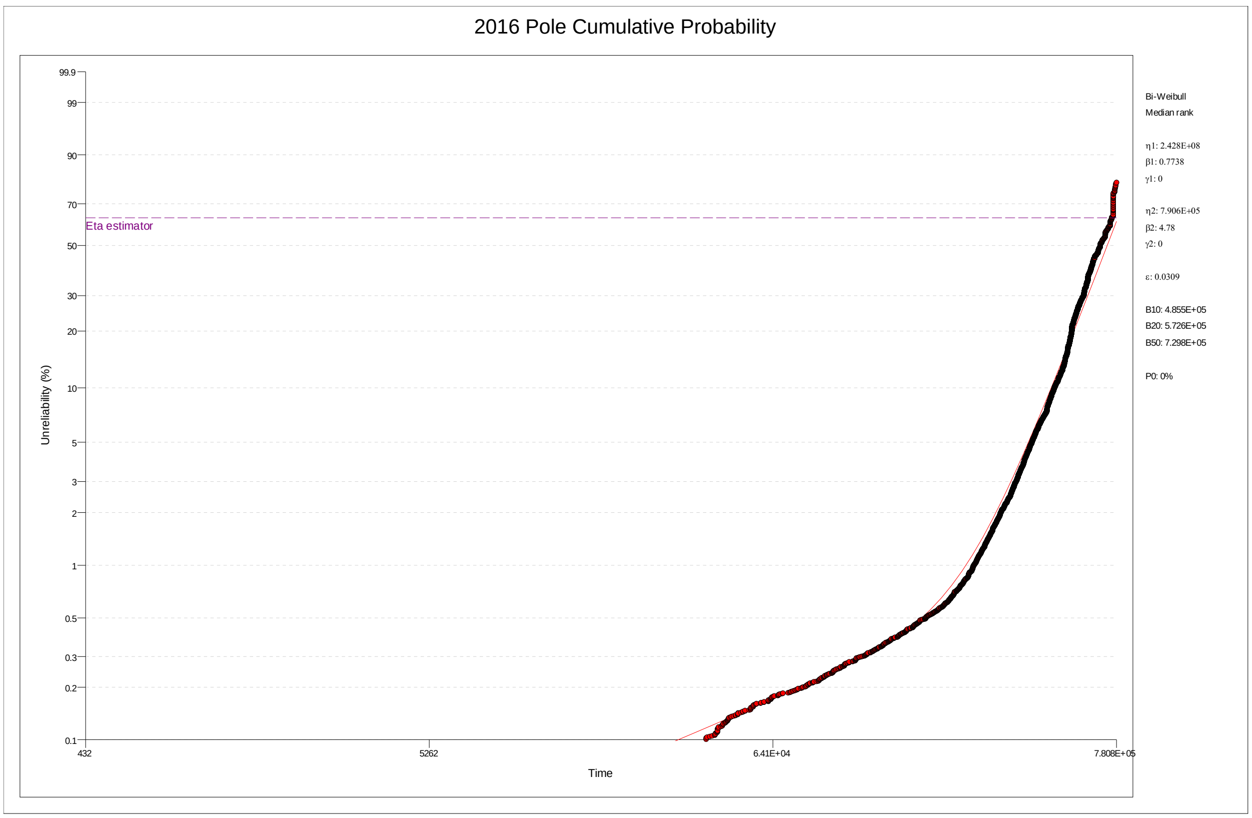


Figure 38 Cumulative Probability plot for Unreliability for Distribution Wood Pole Replacements from the AWB Models - Historical*

*Note: Time is in Hours

Table 22 Failure Curve Values for Distribution Wood Pole Replacements - Historical

Bi-Weibull Failure Curve – Wood Poles Replacement	Set #1 Values	Set #2 Values
Characteristic Life - h	5190639 Years	90.25 Years
Shape Parameter - b	0.44	4.78
Offset - g	0	0
Mean Time To Failure (MTTF)	83.3 Years	
Source of Data	Wood Pole Management Inspection Data	Wood Pole Management Inspection Data

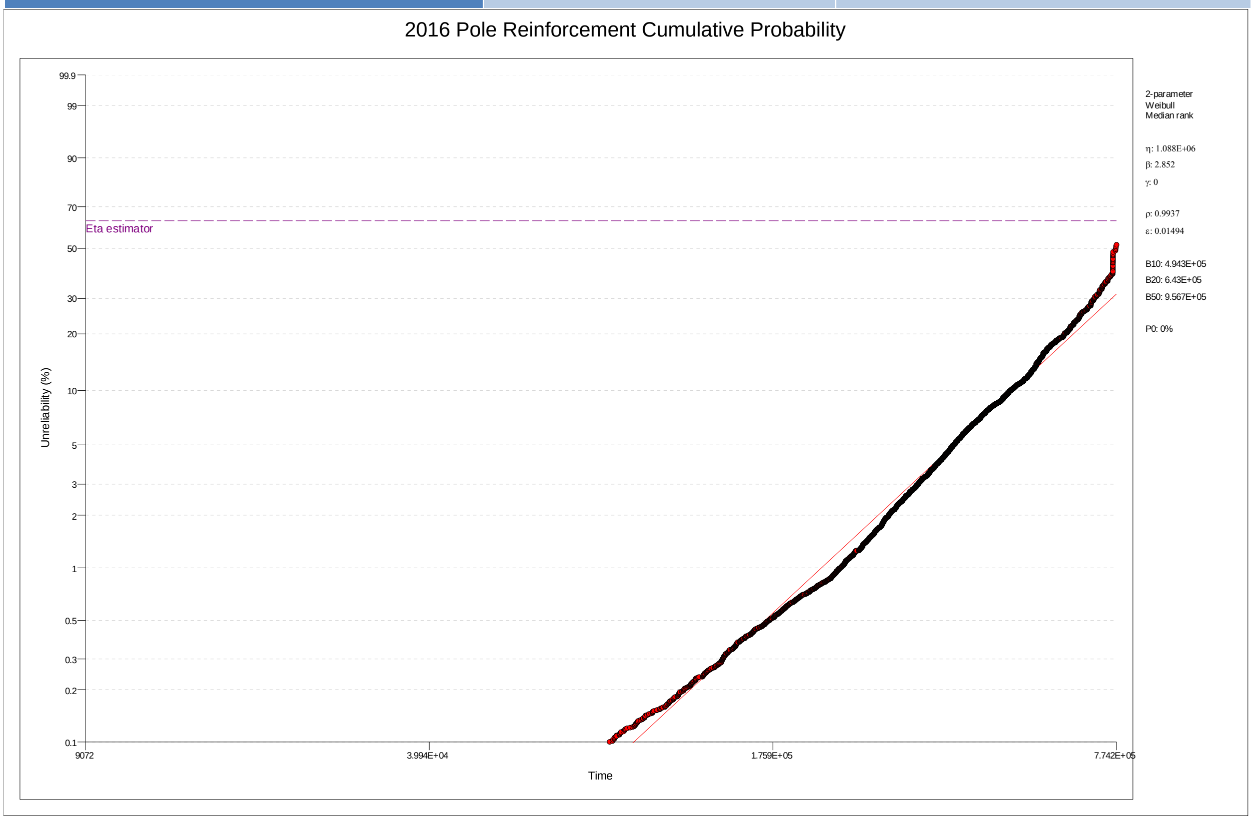


Figure 39 Cumulative Probability plot for Unreliability for Distribution Wood Pole Reinforcements from the AWB Models - Historical*

*Note: Time is in Hours

Table 23 Failure Curve Values for Distribution Wood Pole Reinforcing - Historical

Weibull Failure Curve – Reinforce Poles	Weibull Values
Characteristic Life - h	124 Years

Shape Parameter - b	2.852
Offset - g	0 Years
Mean Time To Failure (MTTF)	109 Years
Source of Data	Wood Pole Management Inspection Data

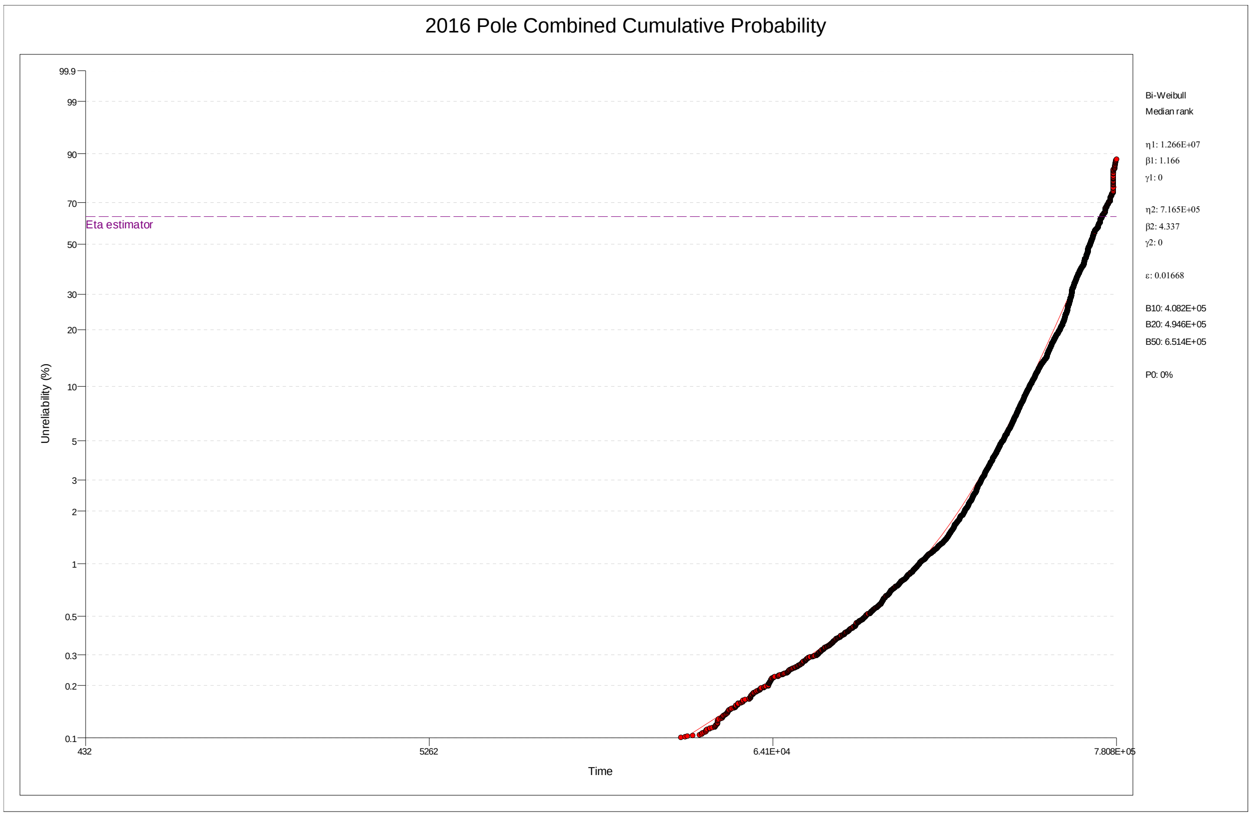


*Figure 40 Cumulative Probability plot for Unreliability for Distribution Wood Pole Replacements and Replacing instead of Reinforcing Poles from the AWB Models**

*Note: Time is in Hours

Table 24 Failure Curve Values for Distribution Wood Pole Replacements - Historical

Bi-Weibull Failure Curve – Wood Poles Replacement	Set #1 Values	Set #2 Values
Characteristic Life - h	1445 Years	81.79 Years
Shape Parameter - b	1.166	4.337
Offset - g	0	0
Mean Time To Failure (MTTF)	74.4 Years	

Source of Data	Wood Pole Management Inspection Data	Wood Pole Management Inspection Data

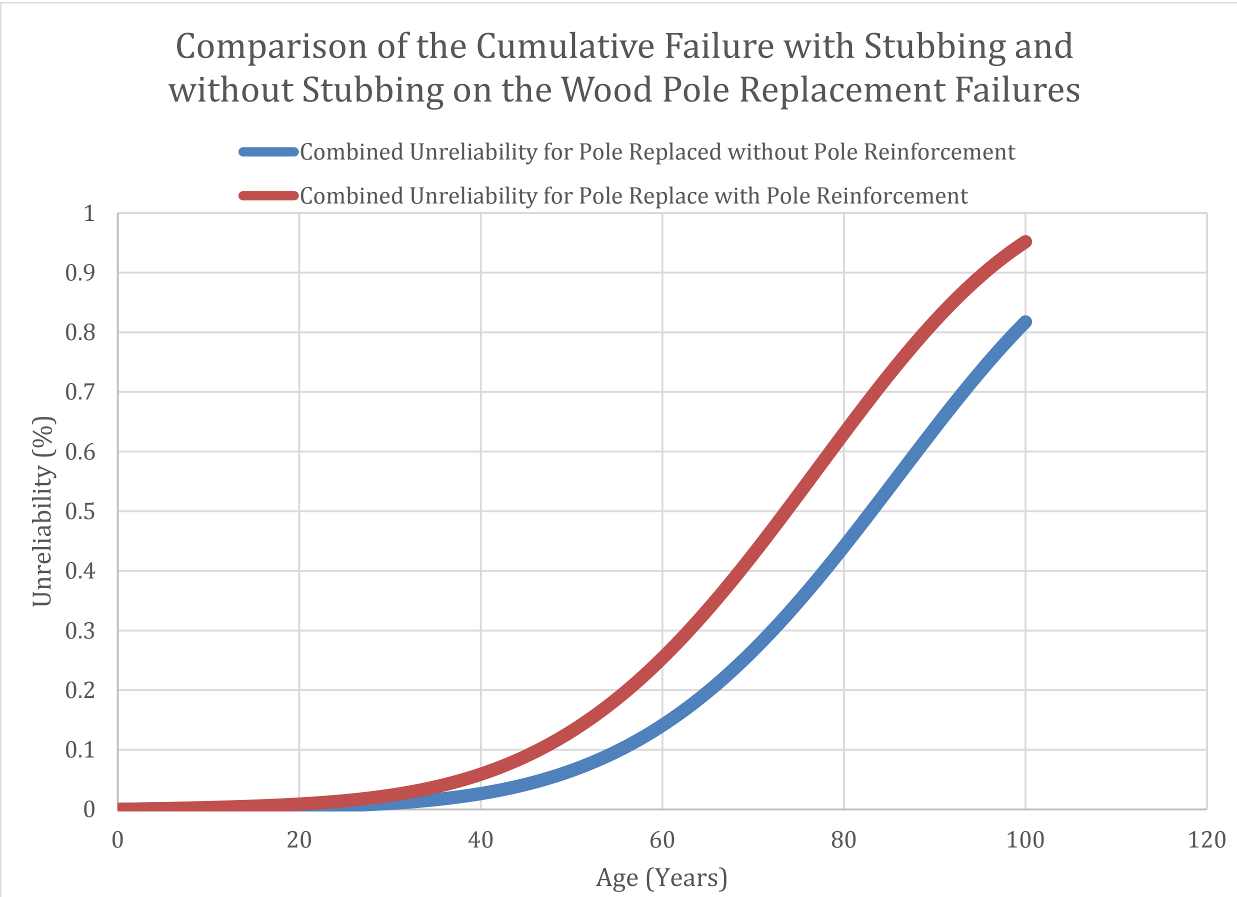


Figure 41 Comparison of the Cumulative Failure with Stubbing and without Stubbing on Wood Pole Replacement Failures

Using the 20 year WPM inspection model above, we isolated a single 36 year old pole to compare the two different strategies. Estimation of Life extension due to stubbing - With Stubbing model examined a pole over approximately 2 lifetimes of 150 years using a stubbing strategy one time followed by a pole replacement strategy. The Estimation of Life extension due to stubbing - Without Stubbing model represent replacing the pole two times over two lifetimes. The results were then analyzed using the Revenue Resource Requirement Model (see file Stubbing vs Replace 5-9-17.xlsm). The results of the model yielded the financial results shown in Table 25.

Based on the results in Table 25, the strategy to reinforce poles were possible provides more value to customers with a CIRR of 7.73% when compared to only replacing poles.

Table 25 Financial Analysis on Replace and Stubbing Poles verses Only Replacing Poles

Alternative	CIRR
Replace and Stub Poles	7.73%
Only Replace Poles	6.37%

AVISTA Corp.

Operating Procedure
Transmission Operations

SOP 19

SUBJECT: Transformer Alarms and Short Term Loading

Contents

Introduction

Three types of alarms can be generated by a transformer. Minor Alarms typically indicate an abnormal condition, but not a serious enough problem to warrant removing the transformer from service. Major Alarms indicate a more serious condition, such as a hot spot alarm, loss of auxiliary cooling, or some other failure. A Major Alarm can result in serious loss of life to the transformer if the transformer continues to operate with a Major Alarm condition. Generally, a transformer that has a Major Alarm should be taken out of service.

A high amp, watt, or var limit alarm can also be associated with a transformer. These alarms are based on the SCADA Variable Limits (SVL). There are two alarm points, Operating Limit and Rated Limit. Operating Limit alarms are set at 80% of the SVL, and Rated Limit alarms are set at the SVL. An Operating Limit Alarm indicates the equipment is operating between 80% and 100% of its SVL. A Rated Limit Alarm indicates the equipment is operating at a level exceeding the SVL, or beyond its continuous thermal rating. The SVL's are calculated based on 24 hour continuous operation at a given ambient temperature. This is appropriate for equipment such as transmission lines, busses, breakers, and other equipment that have minimal thermal time constants and reach maximum operating temperatures within minutes.

A transformer, with its large oil tank, has a thermal time constant that is much longer than most other equipment. As such, a transformer is rated at 30C (86F) ambient temperature for a 55C or 65C winding temperature rise. The 55C/65C nameplate rating is based on a 24 hour average ambient temperature of 30C, with an ambient temperature not to exceed 40C (104F) during that 24 hour period. The 55C/65C rise is an average winding temperature, not to exceed 95C for a 55C rise transformer, and not to exceed 105C on a 65C rise transformer.

The Winding Hot Spot will alarm when the winding temperature reaches 100C/115C on a 55C/65C rise transformer, respectively. When the winding temperature exceeds 100C/115C, loss of life begins to occur due to thermal degradation of the insulation within the transformer. The Winding Hot Spot is connected to the transformer Major Alarm circuit. When this alarm occurs, it is necessary to take the transformer out of service or significantly unload it to allow it to cool. It is not necessary to unload the transformer until the Major Alarm is received.

Short term ratings are based on 90% preload. It is expected that transformers may operate in the 80-90% range under normal operation.

Transformer Minor Alarms

Transformer Minor Alarms are typically:

- Oil temperature
- Loss of AC to pumps and fans
- Low oil flow
- Mechanical pressure relief
- Nitrogen pressure abnormal

Any one of these alarm conditions will bring in a transformer Minor Alarm.

Generally, a Minor Alarm does not require that the transformer be unloaded or taken out of service. However, appropriate personnel should be called out to investigate as soon as possible.

Transformer Major Alarms

Transformer Major Alarms are typically:

- Winding Hot Spot (set at 100°C for 55°C rise units and 115°C for 65°C rise units)
- Low oil level (added in 1994)
- Loss of AC to pumps and fans for units with FOA rating only
    - Typically older autotransformers and Generator Step Ups (GSU) such as Westside, Beacon, Lolo, PineCreek, and Noxon
- Low oil flow (for units with FOA rating only)

Any one of these alarm conditions will bring in a transformer Major Alarm.

Generally, for a Major Alarm, the transformer should be taken out of service. Operation of the transformer with a Major Alarm will result in loss of life to the transformer. Appropriate personnel should be called out immediately to assess the situation.

If a 230/115 autotransformer or a GSU is removed from service, notify the Reliability Coordinator.

Transformer Operating and Rated Limit Alarms

Operating and Rated Limit alarms are defined by the SVL's. An Operating Limit Alarm indicates that the transformer is operating between 80% and 100% of its Rated Limit. A Rated Limit Alarm indicates the transformer is operating at a level exceeding its SVL. However, SVL's are calculated based on continuous ratings over a 24 hour period and do not take any thermal time constants into account. Therefore, the transformer can be operated at high loads, with no loss of life, until the Winding Hot Spot keys the Major Alarm.

If an Operating Limit or Rated Limit alarm is present on a transformer, no action is necessary unless a Major Alarm occurs on that transformer. When a Major Alarm occurs, the transformer should be taken out of service as described above for a Major Alarm.

If a 230/115 autotransformer is removed from service, notify the Reliability Coordinator.

230/115 Autotransformer Short Term Ratings

If a 230/115 autotransformer exceeds its Rated Limit, the following seasonal short term ratings apply. If a Transformer Major alarm occurs, take the transformer out of service. Short term ratings are based on 90% preload.

230/115 Autotransformer	Continuous MVA	4-Hour Rating MVA	1-Hour Rating MVA
Beacon 230/115 #1	320 Winter	320 Winter	320 Winter
	305 Spring/Fall	320 Spring/Fall	320 Spring/Fall
	280 Summer	320 Summer	320 Summer
Beacon 230/115 #2	360 Winter	360 Winter	360 Winter
	312 Spring/Fall	355 Spring/Fall	360 Spring/Fall
	286 Summer	332 Summer	360 Summer
Benewah 230/115	183 Winter	211 Winter	220 Winter
	149 Spring/Fall	179 Spring/Fall	199 Spring/Fall
	134 Summer	168 Summer	189 Summer
Boulder 230/115 #1	381 Winter	439 Winter	440 Winter
	312 Spring/Fall	374 Spring/Fall	428 Spring/Fall
	286 Summer	351 Summer	398 Summer
Boulder 230/115 #2	381 Winter	440 Winter	440 Winter
	313 Spring/Fall	380 Spring/Fall	440 Spring/Fall
	278 Summer	361 Summer	398 Summer
Cabinet 230/115	194 Winter	233 Winter	239 Winter
	157 Spring/Fall	189 Spring/Fall	210 Spring/Fall
	143 Summer	176 Summer	197 Summer
Dry Creek 230/115	381 Winter	440 Winter	440 Winter
	313 Spring/Fall	382 Spring/Fall	431 Spring/Fall
	281 Summer	361 Summer	398 Summer

230/115 Autotransformer	Continuous MVA	4-Hour Rating MVA	1-Hour Rating MVA
Lolo 230/115 #1	159 Winter 123 Spring/Fall 109 Summer	159 Winter 144 Spring/Fall 131 Summer	159 Winter 153 Spring/Fall 141 Summer
Lolo 230/115 #2	159 Winter 141 Spring/Fall 128 Summer	159 Winter 159 Spring/Fall 151 Summer	159 Winter 159 Spring/Fall 159 Summer
Moscow 230/115	386 Winter 315 Spring/Fall 281 Summer	444 Winter 379 Spring/Fall 357 Summer	478 Winter 431 Spring/Fall 397 Summer
NorthLewiston 230/115 (H-X)	376 Winter 308 Spring/Fall 282 Summer	398 Winter 352 Spring/Fall 328 Summer	398 Winter 383 Spring/Fall 359 Summer
NorthLewiston 230/115 (X-H)	199 all seasons all times		
Pine Creek 230/115 #1	185 Winter 151 Spring/Fall 134 Summer	213 Winter 181 Spring/Fall 171 Summer	238 Winter 204 Spring/Fall 195 Summer
Pine Creek 230/115 #2	174 Winter 141 Spring/Fall 128 Summer	198 Winter 166 Spring/Fall 155 Summer	213 Winter 178 Spring/Fall 167 Summer
Rathdrum 230/115 #1	309 Winter 252 Spring/Fall 231 Summer	319 Winter 288 Spring/Fall 269 Summer	319 Winter 310 Spring/Fall 291 Summer
Rathdrum 230/115 #2	371 Winter 313 Spring/Fall 291 Summer	398 Winter 356 Spring/Fall 336 Summer	398 Winter 380 Spring/Fall 361 Summer
Rathdrum 230/15 (X-H)	239 all seasons all times		
Shawnee 230/115	375 Winter 317 Spring/Fall 295 Summer	398 Winter 366 Spring/Fall 346 Summer	398 Winter 396 Spring/Fall 376 Summer
Shawnee 230/115 (X-H)	280 all seasons all times		
Westside 230/115 #1	389 Winter 319 Spring/Fall 285 Summer	450 Winter 396 Spring/Fall 368 Summer	478 Winter 431 Spring/Fall 397 Summer

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/08/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Elizabeth Andrews
REQUESTER:	Public Counsel	RESPONDER:	Liz Andrews
TYPE:	Data Request	DEPT:	Regulatory Affairs
REQUEST NO.:	PC - 098	TELEPHONE:	(509) 495-8601
		EMAIL:	Liz.andrews@avistacorp.com

REQUEST:
RE: Capital Additions, Test Year (Electric)
Please refer to several components of the Direct Testimony of Heather L. Rosentrater, Exhibit HLR-1T:
• Table No. 2 — Major Projects for 2018 and 2019, at 15;
• Table No. 3 — Pro Forma Capital Additions for 2020 (system), at 51;
• Heather L. Rosentrater, Exhibit HLR-2, Distribution Plan (2021–2024);
• Heather L. Rosentrater, Exhibit HLR-6, Transmission Plan (2021–2024);
• Heather L. Rosentrater, Exhibit HLR-7, Substation Plan (2021–2024).

Please refer also to the attached MS Excel workbook developed by Public Counsel, "Public Counsel Table 1.xlsx".
Public Counsel is developing a trend of historical vs. proposed spending by Plan (Distribution, Transmission, Substation); Business Driver (Customer Request, Mandatory & Compliance, Service Quality & Reliability, etc.); Major Projects; and Sub Projects (for example, within Distribution, "Grid Mod" vs. "wood pole" vs. "electric relocation"). The items referenced above serve as sources for the dollars in years 2018-2024 in Public Counsel Table 1 as indicated.
a) Complete Public Counsel's table, entering actual dollars added to rate base for years 2015, 2016, and 2017 for the projects, programs, and/or Plan items indicated. Be sure to complete the "Total Dollars" line for each of these years, adding projects (such as "Integrations") and/or programs as needed to tie to Total Dollars for these years.
b) Complete Column D "Electric Plan Category", and Column E "Business Driver", for each line item. Mark any line item which cannot be categorized as an electric Plan (for example, corporate or natural gas line items) with an "NA". Please also correct any errors in these columns. (Public Counsel has attempted to assign Plans and Drivers in some cases).

RESPONSE:
While Avista has generally provided information about its planned levels of capital spending on electric infrastructure for years 2021 and beyond in its various infrastructure plans (Exh. HLR-2, HLR-6, and HLR-7) and applicable business cases provided in Exh. HLR-11 previously filed in this case, Avista objects to this request because it seeks future information this is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. Note the only capital projects included for cost recovery that are in the period of 2021 and beyond, relate to Wildfire costs, Colstrip, EIM and AMI only.

Avista also objects to the request for completion of MS Excel workbook developed by Public Counsel, "Public Counsel Table 1.xlsx" for the period 2015-2017. The Company does not have the information as requested by Public Counsel for the years 2015-2017, this data is outside the scope of this case, and is would

be overly broad and unduly burdensome, requiring an unreasonable expenditure of time and effort to produce the requested information as specified.
As noted, Public Counsel has prepared their own excel file with specific data from our filed case for the period 2018-2020, and the period 2021-2024 already provided from Exh. HLR-2, 6 and 7.

However, attached as PC-DR-098 Attachment A, is available data by capital expenditure functional group which provides data that can be viewed for the period 2013 – 2020 (actual) and budgeted through 2025. Please note, budgeted data by functional group as provided in PC-DR-098 Attachment A or as provided in more detail in Exh.HLR-2, 6 and 7 is as of a point in time and is subject to change. Additional information on each Distribution, Transmission and Substation capital addition can be found in individual business cases for each project in Rosentrater Exh. HLR-11.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 099	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Table No. 2 of the Direct Testimony of Heather L. Rosentrater, Exhibit HLR-1T, at 15, and the "Substation Rebuilds Program", which indicates spending of $17.857 million in 2018 and $17.774 million in 2019. Please refer also to Table No. 3 of the Direct Testimony of Heather L. Rosentrater, Exhibit HLR-1T, at 51, which indicates spending of $13.741 million in the Substation Rebuilds Program in 2020. For each year from 2018 through 2020, complete a table in the format shown below (2018 example), which indicates the substations in which equipment was replaced, the type of equipment replaced, the capital cost of replacement, the reason for the replacement, and the age upon replacement:

2018 Substation Replacement Program Activity				
Substation	**Equipment**	**Capital Cost**	**Reason**	**Age upon Replacement**
12345	**Breaker #1**	**$125,000**	**Aged**	
	Breaker #2	**$125,000**	**Failed test**	
	Relay #4	**$65,000**	**Obsolete**	
13456	**Transformer #2**	**$1,345,000**	**Aged**	
etc	**etc**	**etc**	**etc**	**etc.**
Total:		**$17.857 million**		

RESPONSE:

Please refer to the spreadsheet provided as PC-DR-099 Attachment A.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/08/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 100	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather, L. Rosentrater, Exhibit HLR-11 and the Substation Rebuilds program generally, at 33–38.

a) Provide a list of equipment types Avista typically replaces in this Program (transformers, relays, breakers, etc.).
b) For each type of equipment listed in response to subpart (a), describe Avista's testing and inspection policies, practices, procedures, frequencies, and related information.
c) For each type of equipment listed in response to subpart (a), describe the criteria Avista uses to determine whether an individual asset is "obsolete".
d) For each type of equipment listed in response to subpart (a), provide a list of models and ages (in years) Avista has determined meets Avista's obsolescence criteria. For each such equipment type/model/age, provide evidence that (i) a replacement item is not available from the manufacturer; and (ii) a replacement item is not available from any manufacturer.
e) For each type of equipment listed in response to subpart (a), provide the count of failures in service resulting in a service outage by year from 2014 through 2020.
f) Provide the system-wide impact on SAIDI, SAIFI, CAIDI, and MAIFI of substation equipment failures by year from 2014-2020.
g) For each failure in service counted in response to subpart (a), provide (i) the number of customers impacted by the failure; and (ii) the duration of the outage caused by the failure.

RESPONSE:

a) The equipment types Avista typically replaces in the Substation Rebuilds program are; Air Switches, Batteries, Battery Chargers, Breaker Reclosers, Capacity Banks, Circuit Switchers, Current Transformers, Distribution Transformers, High Voltage Circuit Breakers, High Voltage and Low Voltage Bushings, Auxiliary Equipment, Perimeter Security items, Power Transformers, Potential Transformers, Substation-Generation Meters, Surge Arresters, Timber Structures, and Voltage Regulators.

b) Avista utilizes two types of inspections while the equipment is energized. The first type is a general substation inspection, which allows us to be aware of the visual condition of the equipment. The second type of inspection is an Infrared Inspection. Infrared Inspections have helped us identify issues such as loose connections, bad bushings and low oil levels. Each type of equipment has their own maintenance and testing practices. The practices are built around manufacturer recommendations, compliance requirements, and company experiences.

c) Avista utilizes a combination of tools and data to determine when a piece of equipment has met the criteria to be obsolete. The tools can include health indexes, life-cycle cost analysis, equipment test reports, age, and work management system work orders.

d) Avista does not have an equipment list of models and ages that we have determined to be obsolete.

e) For the substation outages experienced each year for the period 2014-2020 that resulted in an outage for customers please see PC_DR_100 Attachment A. Among the outage reasons, where applicable, are the equipment failures noted in association with the event.

f) The table below includes the Company's system values for SAIFI and SAIDI for 2014-2020 (excluding outages associated with major events), and the percentage of these system values attributed to substation outages of all causes, as shown in PC-DR-100 Attachment A. CAIDI = SAIDI/SAIFI, and the Company does not track MAIFI as a system number because we do not have the capability of recording momentary events in all parts of our system.

Year	System SAIFI	(%) Impact of Substation Outages	System SAIDI	(%) Impact of Substation Outages
2014	1.11	0.61	2.32	5.85
2015	1.04	0.74	2.71	6.69
2016	0.86	0.93	2.21	7.94
2017	1.20	0.77	3.06	8.98
2018	0.81	0.30	2.11	2.78
2019	0.94	0.47	2.27	10.30
2020	0.87	0.37	2.15	3.87

g) The number of customers impacted by the failure and the associated customer outage hours are provided in PC-DR-100 Attachment A.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 101	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11 and the Substation Rebuilds program generally, at 33–38.

a) Provide a list of equipment Avista replaced in this program from 2018 through 2020 due to obsolescence.
b) For each item listed in response to subpart (a), provide the capital cost of the replacement.
c) Provide a list of equipment Avista replaced in this program from 2018 through 2020 due to overloading.
d) For each item listed in response to subpart (c), provide (i) the current capacity; (ii) the year in which the current capacity is expected to be exceeded; (iii) the forecast amount of overload in that year and in the three subsequent years; (iv) the forecast duration period for the overload amount; and (v) the overload rating for the item.
e) For each item listed in response to subpart (c), provide the capital cost of the replacement.
f) Provide a list of equipment Avista replaced in this program from 2018 through 2020 due to the "need to meet updated equipment spacing and operating standards".
g) For each item listed in response to subpart (f), provide the equipment spacing and/or operating standard which *required* that the item be replaced.
h) For each item listed in response to subpart (f), provide the capital cost of the replacement.
i) Provide a list of equipment Avista replaced in this program from 2018 through 2020 due to the need to meet "updated design and construction standards".
j) For each item listed in response to subpart (i), provide the design standard and/or construction standard which *required* that the item be replaced.
k) For each item listed in response to subpart (i), provide the capital cost of the replacement.
l) Provide a list of equipment Avista replaced in this program from 2018 through 2020 due to "operational and maintenance requirements".
m) For each item listed in response to subpart (l), provide the operational and maintenance requirement which *required* the item be replaced.
n) For each item listed in response to subpart (l), provide the capital cost of the replacement.
o) Provide a list of equipment Avista replaced in this program from 2018 through 2020 due to support for "SCADA communications", "Grid Modernization", or "Other Programs".
p) For each item listed in response to subpart (o), provide documentation that no alternative to replacement was available for "SCADA communications", "Grid Modernization", or "Other Programs" support.
q) For each item listed in response to subpart (o), provide the capital cost of the replacement.

RESPONSE:

a), b), c), e) Please refer to the data provided in response to PC-DR-099 Attachment A.

d) For substation equipment listed in PC-DR-099, Attachment A, with the Reason listed as Overloading, the equipment was considered to be already overloaded by the time that it was replaced. Note that Avista considers anything loaded at or above 80% as being "overloaded."

f), g), h) Equipment replaced in the Substation Rebuilds Program during 2018-2020 was not specifically designated as being replaced due to only the "need to meet updated equipment spacing and operating standards." The need to meet updated equipment spacing and operating standards is a consideration in replacing equipment as part of an entire substation being rebuilt. Please refer to the Engineering Roundtable (ERT) Engineering Project Request documents for information on specific substation rebuilds, provided as PC-DR-101 Attachments A-J.

i), j), k) Equipment replaced in the Substation Rebuilds Program during 2018-2020 was not specifically designated as being replaced due to only the "updated design and construction standards." The need to meet updated equipment design and construction standards is a consideration in replacing equipment as part of an entire substation being rebuilt. Please refer to the Engineering Roundtable (ERT) Engineering Project Request documents for information on specific substation rebuilds, provided in PC-DR-101 Attachment A.

l), n), o), q) Please refer to PC-DR-099 Attachment A.

m), p) Please refer to PC-DR-101 Attachment A.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 103	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Capital Additions, Test Year

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11 and the Substation Rebuilds program generally, at 33–38.
For each of the years 2014 through 2020, provide:

a) The number of customer complaints related to substation equipment failures, and a description of each event.
b) The number of safety-related incidents involving substation equipment, and a description of each incident.
c) The number of power quality standard violations attributed to substation equipment, and a description of each violation.

RESPONSE:

a) Avista is very attentive to the service and satisfaction of its customers and to carefully addressing issues they have, particularly those that rise to the level of a formal complaint. In its experience, however, the Company has not found individual customer complaints to be a useful metric in helping to guide infrastructure planning or investments.

b) The same can be said for safety incidents, where we carefully evaluate the root cause and take appropriate steps to help ensure risks to our employees and/or customers are effectively reduced and managed. But individual safety incidents typically do not rise to the level of being useful in systematic infrastructure planning.

c) In the same way, power quality issues that arise with our customers are evaluated on a case-by-case basis, are appropriately investigated, and are timely and effectively resolved. Resolving power quality issues naturally requires infrastructure solutions in some cases (typically at the customers' service or feeder section), but they do not rise to the level of being useful in systematic infrastructure planning, particularly at the substation level.

Accordingly, the information in this subject request is not among the data used by Avista to support its decision-making related to Substation Rebuilds, and consequently, we do not track the information in the form it has been requested.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 104	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Capital Additions, Test Year

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11 and the Substation Rebuilds program generally, at 33–38.
Public Counsel understands that substation equipment which fails testing must be replaced. However, the Substation Rebuilds program appears to replace substation equipment in the absence of failed test results. Provide all business cases, worksheets, models, cost-benefit analyses, calculations, presentations, requests, or other documentation Avista uses to determine that an asset has reached its "end of life" in the absence of failed test results.

RESPONSE:

The Substation Rebuilds Business Case has four components that are listed, briefly described, and documented below.

1) The first component of the Substation Rebuilds Business Case is the rebuilding of entire substations because a sufficient amount of the equipment in the station is obsolete. Please see PC-DR-100 for criteria used by the Company to determine if individual equipment is obsolete. For support of the justification for rebuilding entire substations, please see the Substation Rebuilds Business Case, Engineering Roundtable (ERT) Engineering Project Request documents, provided as PC-DR-101 Attachments A-J.

2) The second component of the Substation Rebuilds Business Case is the planned replacements of individual pieces of substation equipment. The criteria for determining if an individual piece of equipment should be replaced is discussed in the Company's response to PC-DR-100.

3) The third component of the Substation Rebuilds Business Case is the emergency replacement of individual pieces of substation equipment. This action may be prompted by crews responding to damage or a service outage, or by conditions discovered in systematic inspections.

4) The fourth component of the Substation Rebuilds Business Case is the purchase of spare critical equipment, which provides for timely emergency replacement as needed without procurement delays.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Larry La Bolle
TYPE:	Data Request	DEPT:	Transm Ops/System Planning
REQUEST NO.:	PC - 105	TELEPHONE:	(509) 495-4710
		EMAIL:	larry.labolle@avistacorp.com

SUBJECT: Capital Additions, Test Year

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 2, which references the "Avista Utilities Electric Distribution Infrastructure Plan June 2017".

Provide a copy of this Plan.

RESPONSE:

Please see PC-DR-105 Attachment A.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/06/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Larry La Bolle
TYPE:	Data Request	DEPT:	Transm Ops/System Planning
REQUEST NO.:	PC - 106	TELEPHONE:	(509) 495-4710
		EMAIL:	larry.labolle@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 2, which states "Reliability improvements have been quantified that are a direct benefit to the customers in feeders that the GMP has addressed.
The analysis was performed by comparing reliability metrics in years before and after the GMP for all feeders completed through 2018."

a) Provide a report which counts Avista's outages by cause type (weather, equipment failure, human error, lightning, animals — whatever categories Avista uses routinely) for each year from 2015 through 2020.
b) Provide a copy of the guidelines or other tool Avista instructs grid operators to follow when categorizing outages by cause/completing outage reports.
c) Provide random samples of 10 outage reports from 2018, 10 outage reports from 2019, and 10 outage reports from 2020.

RESPONSE:

a) Please find the following count of sustained outage events, which does not include outages associated with qualifying major events.

Sub-Reason	2015	2016	2017	2018	2019
Arrester	19	38	48	57	67
Bird	275	237	344	267	274
Capacitor		1	2	3	1
Car Hit Pad	36	51	53	41	36
Car Hit Pole	177	198	201	151	152
Conductor - Primary	69	100	73	74	83
Conductor – Second	104	139	105	92	100
Connector - Primary	45	46	58	72	69
Connector - Second	67	61	74	86	70
Crossarm					
Crossarm-rotten	19	19	17	26	22
Cutout/Fuse	104	82	91	92	95
Dig In	78	74	78	92	59
Elbow	8	7	3	1	4

Fill In		749	740	743	591
Fire	144	132	147	159	119
Forced	39	139	116	148	98
Highside Breaker					5
Highside Fuse		1			
Insulator	28	31	13	30	14
Insulator Pin	12	9	14	19	10
Junctions			2	1	
Lightning	212	123	110	103	184
Lowside OCB/Recloser	4	6		5	2
Maint/Upgrade	1767	2676	2081	2211	1835
Other	203	216	238	231	257
Pole Fire	199	72	92	77	68
Pole-rotten	19	17	8	4	14
Primary Splice		1	1		
Protected	4	3	2	3	6
Recloser	1	5	8	2	4
Regulator	9	4	1	1	2
Relay Misoperation	1	1	4		
SEE REMARKS	2	47	56	10	32
Service	52	50	32	46	61
Snow/Ice	569	157	586	218	277
Squirrel	364	236	345	259	262
Switch/Disconnect	5	2	11	4	11
Termination	7	13	12	10	11
Transformer			5		
Transformer - OH	84	75	85	64	69
Transformer UG	52	33	44	58	58
Tree	41	37	24	31	26
Tree Fell	244	266	279	284	373
Tree Growth	80	113	114	97	94
Underground					3
Undetermined	711	655	742	675	596
URD Cable - Primary	88	58	74	58	84
URD Cable - Second	47	55	78	78	89
Weather	86	44	185	129	90
Wildlife Guard			1	1	
Wind	682	117	237	86	539

b) When coding the reasons in the outage management system, Avista's operators learn through on the job training to record reasons and sub-reasons based on root cause. These root causes are determined through field inspection and relayed from the responding line crew(s) to the operator on shift. The root cause is defined as the acting person/place/thing that caused the electrical fault. As such, the root cause is not the protection device that operated, such as a fuse, to stop the fault, unless it can be determined by inspection to have failed outside its design criteria. The operators' assignments of reasons are reviewed and corrected as needed each month, and the operators are coached accordingly.

c) Please find the subject outage reports for the years requested in PC-DR-106 Attachment A.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/06/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Heather Webster
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 107	TELEPHONE:	(509) 495-8930
		EMAIL:	heather.webster@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 2, regarding the Distribution Grid Modernization program, which cites the following among the benefits of the program: "Automation devices produce results immediately optimizing system performance, reducing costs, and reducing outages" and "Cost effective work due to program efficiencies and long-term planning".

a. Provide the number of headcount reductions, by department (distribution field crews, engineering, etc.), Avista was able to execute as a result of the Program in 2018, 2019, and 2020.

b. Quantify the O&M savings which resulted from these headcount reductions by year.

RESPONSE:

a) Avista's staffing for the various activities listed is a function of the amalgam of many different business needs, which naturally vary over time. While the subject program does produce efficiencies and financial savings as noted in the business case, it is not possible to tease out one function such as Grid Modernization and to tie that to staffing levels, which are the result of so many different business needs and factors. In addition to this, the annual variability in feeder reliability performance, as noted in Avista's response to PC-DR-111, adds to this overall variability in resource demands. Accordingly, the Company has not attempted to forecast what employment levels would look like in a scenario where it would be assumed that no Grid Modernization investments had been made.

b) Please see the response to part (a), above.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/16/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC – 108 Supplemental	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

RE:
Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 2–13, and the Distribution Grid Modernization program generally.

a) Confirm that the program will address every circuit, feeder, and tap at least once every 60 years. If this cannot be confirmed, please explain.
b) Provide the number of distribution line miles which are overhead, and the number of distribution line miles which are underground, as of 12-31-2020.
c) Provide a list of the types of equipment that are reviewed in the 60-year cycle, such as poles, conductor, transformers, switch cabinets, cable, etc.
d) For each type of equipment listed in response to subpart (c), provide the average age (in years) of that type of equipment on all of Avista's system as of 12/31/2020.
e) For each type of equipment listed in response to subpart (c), provide the age of the newest item of that type of equipment on all of Avista's system as of 12/31/2020.
f) For each type of equipment listed in response to subpart (c), provide the age of the oldest item of that type of equipment on all of Avista's system as of 12/31/2020.
g) Provide the policies, processes, methods, criteria, tests, or other means Avista uses to determine that equipment (conductor, cable, switches, etc.) is "aged" or has reached the end of "its useful life".

RESPONSE:

a) At this time the program will not address every feeder on a 60-year cycle. The 60-year cycle was an initial target at the inception of the program; it has not been scaled to meet that goal.

b) According to the most recent data, there are 7,598.18 overhead circuit miles and 4,457.85 underground circuit miles.

c) The list of equipment reviewed in the program's 60-year cycle is documented in Avista's Distribution Feeder Management Plan (DFMP), provided here as PC-DR-108 Attachment A. These include (but are not limited to) arresters, avian/raptor protection, cross arms, cutouts, devices, fusing, grounds, guying, insulators, overhead conductor, open wire secondary, steel poles, street and area lights, transformers, underground cable, and wood poles.

d) The average ages of wood poles and transformers are approximately 41 years and 21 years, respectively. The age of the remaining equipment listed in subpart (c) is often included as part of larger assemblies of equipment and materials referred to as compatible units (CUs). The age of each compatible unit is not used as a metric for, or tracked by, the Grid Modernization program. When additional information on attached equipment is not available, the Company will consider the age of equipment to be the same as that of the pole.

e) The newest wood pole and attached equipment was installed on December 30, 2020 and the newest transformer on record was installed on December 23, 2020.

f) According to company records, the oldest wood pole is approximately 111 years old, and the oldest transformer is 93 years old.

g) The policies and guidelines Grid Modernization used for determining whether equipment is aged or has reached the end of its useful life can be found in PC-DR-108 Attachment A, and elsewhere in the documents provided in this case, such as the Wood Pole Management program, for example, found in Exh. HLR-11.

SUPPLEMENTAL RESPONSE 02/16/2021

Avista has been asked to provide several internal documents that were identified by links in Exh. HLR-11, but which were not available to Public Counsel or the other Parties. Several of these papers refer to the Company's Grid Modernization program and have been provided here as PC-DR-108 Supplemental, Attachments A .

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/06/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 109	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to the Direct Testimony of Heather L. Rosentrater, Exhibit HLR-1T, at 15, Table No. 2, which indicates Distribution Grid Modernization Program spending of $14.789 million in 2018 and $10.113 million in 2019. Please refer also to the Direct Testimony of Heather L. Rosentrater, Exhibit HLR-1T, at 51, Table No. 3, which indicates spending of $7.897 million in this Program in 2020. For each year from 2018 through 2020, complete a table in the format shown below (2018 example), which identifies the types of equipment replaced, the quantities of each (a count of items, or miles of conductor or cable, as examples), the cost of each, and the purpose of the new equipment.

2018 Distribution Grid Modernization Program Activity			
Type	**Equipment**	**Capital Cost**	**Purpose**
Transformers			
OH Cable			
UG Conduit			
etc	etc	etc	etc.
Total:		$14.789 million	

RESPONSE:

Avista does not track the capital cost of replacing each type of equipment that is replaced during a Grid Modernization project, rather, we track the total project cost, which includes analysis, design, new equipment, labor, construction equipment costs, AFUDC as applicable, and other costs as described below. Grid Modernization equipment costs are estimated after a design process in which a project coordinator surveys the condition and configuration of existing infrastructure. A design is then created that is estimated in the Company's Work and Asset Management System (Maximo) before being sent to construction services. An example of one of these estimates is provided as PC-DR-109 Attachment A for a project constructed on the feeder F&C12F1 in 2020. The purposes of the wide array of equipment are consistent with uses across the industry. Transformers alter voltage, overhead conductor conveys energy for the purpose of serving customers, underground conduit protects underground cable, poles support overhead conductors and devices, etc. It is important to note that the Program's spending each year consists of more than the equipment which is installed. Other elements of the Program's costs include planning, design, and coordination efforts, vegetation management, construction labor costs, traffic control, permitting, auditing, and restoration to name a few.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/09/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Heather Webster Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 110	TELEPHONE:	509 495-8930 509-495-2695
		EMAIL:	heather.webster@avistacorp.com kyle.jonas@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 2–13, and the Distribution Grid Modernization program generally.

a) Provide a list of feeders addressed by the program by year for 2018, 2019, and 2020.
b) For each feeder listed by year in response to subpart (a), provide (i) the miles of OH conductor that existed before "modernization" and (ii) the miles of OH conductor that existed after "modernization".
c) For each feeder listed by year in response to subpart (a), provide (i) the miles of UG cable that existed before "modernization" and (ii) the miles of UG cable that existed after "modernization".
d) For each feeder listed by year in response to subpart (a), provide a list of replaced equipment types, and the quantity (count or miles) of each which was classified as "failing" at the time of replacement.
e) For each equipment type replaced listed in response to subpart (d), provide the policies, processes, methods, methods, criteria, tests, or other means Avista uses to determine that each type was to be classified as "failing".
f) For each feeder listed by year in response to subpart (a), estimate the energy saved (in kWh) as a result of the work performed.
g) For each feeder listed by year in response to subpart (a), provide (i) the number of customers served by the feeder; and (ii) the number of customers served by the feeder submitting a reliability complaint in the five years preceding the year in which the feeder was "modernized".
h) For each feeder listed by year in response to subpart (a), provide a count of safety incidents related to replaced equipment in the five years preceding the year in which the feeder was "modernized", and identify the equipment replaced.
i) For each feeder listed by year in response to subpart (a), list the power quality issues observed in the five years preceding the year in which the feeder was "modernized".
j) For each feeder listed by year in response to subpart (a), provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, or other documentation which support of the statement "Over decades, many of these were built to different construction standards using a wide variety of materials. These factors contribute to increased outages that **take longer to restore** and **fall short of modern expectations** that utilities face."

k) For each feeder listed by year in response to subpart (a), provide the total cost of the work completed on the feeder in the year of "modernization".

l) For each feeder listed by year in response to subpart (a), provide, for each of the five years preceding the year of modernization, (i) the number of outages; (ii) the average duration of the outages.
m) For each feeder "modernized" in 2018, provide, for 2019 and 2020, (i) the number of outages; and (ii) the average duration of the outages.
n) For each feeder "modernized" in 2019, provide, for 2020, (i) the number of outages; and (ii) the average duration of the outages.
o) For each feeder listed by year in response to subpart (a), provide the number and types of "automation devices" that were installed on each.
p) Regarding "automation devices", provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, or other documentation in support of the statement "Automation devices produce results immediately optimizing system performance, reducing costs, and reducing outages."
q) Regarding "automation devices", provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, or other documentation which show that automation devices "provide(d) value in dollars to rate payers" in excess of the cost of the devices in dollars to rate payers.
r) For each feeder listed by year in response to subpart (a), provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, or other documentation which show that the work "provide(d) value in dollars to rate payers" in excess of the cost of the work in dollars to rate payers.
s) For each feeder listed by year in response to subpart (a), provide the annual O&M savings estimated from the work completed in the "modernization" year. Provide all calculations, assumptions, worksheets, and other work completed to develop these estimates.

RESPONSE:

a) The table below shows the feeders addressed during 2018, 2019, and 2020. As explained in other responses, Avista's feeders are often addressed across multiple years in a Grid Modernization project through the process of analysis, selection, design and construction. The feeders on this list are either in design or in construction.

Table (a)1		
2018	2019	2020
BEA12F2	BEA12F2	BEA12F2
F&C12F1	F&C12F1	F&C12F1
HOL1205	M15514	M15514
M15514	MIS431	MIS431
MIS431	RAT233	NE12F4
ORO1280	SIP12F4	ORO1282
PDL1201	SPR761	RAT233
RAT233	TUR112	ROS12F4
SPI12F1		ROS12F5
SPR761		SIP12F4
TUR112		SPR761
		TUR112

b) The miles of overhead conductor that existed prior to modernization for each feeder can be found in the attached Grid Modernization Feeder Baseline Reports, attached for the subject feeders, as PC-DR-110 Attachments A-N. Miles of overhead conductor post treatment are described in cases in the baseline report, but are also included in the design and asbuilt drawings and spec sheets for each feeder. Examples of one design sheet for one sub-polygon of one feeder project are provided in PC-DR-110 Attachments O and P, respectively. Depending on the feeder length, there can be up to a range of 30 polygons, with many of the polygons subdivided as in the examples provided. An example of one asbuilt sheet is provided in PC-DR-110 Attachment Q. The Grid Modernization project does not track this information in the form requested because it is not a useful metric for the management of the program.

c) The miles of underground conductor that existed prior to modernization for each feeder can be found in the attached Grid Modernization Feeder Baseline Reports, attached for the subject feeders, as PC-DR-110 Attachments A-N. Miles of underground conductor post treatment are described in cases in the baseline report, but are also included in the design and asbuilts for each feeder. Examples of one design sheet for one sub-polygon of one feeder project are provided in PC-DR-110 Attachments O and P, respectively. An example of one asbuilt sheet is provided in PC-DR-110 Attachment Q. The Grid Modernization project does not track this requested information because it is not a useful metric for the management of the program.

d) The list equipment replaced on the feeders in subpart (a) is consistent with the equipment identified in the Company's response to PC-DR-108 Attachment A. These parts are replaced based on the criteria outlined in the Distribution Feeder Management Plan, including assessments based on asset condition. The replaced equipment types that existed prior to modernization for each feeder can be found in the attached Grid Modernization Feeder Baseline Reports, attached for the subject feeders, as PC-DR-110 Attachments A-N. Lists of equipment types installed during the program are described in cases in the baseline report, but are also included in the design and asbuilts for each feeder. Examples of one design sheet for one sub-polygon of one feeder project are provided in PC-DR-110 Attachments O and P, respectively. An example of one asbuilt sheet is provided in PC-DR-110 Attachment Q. The Grid Modernization project does not track this requested information because it is not a useful metric for the management of the program.

e) Standard means of evaluating equipment for failure consist of visual inspections for signs of damage or substandard performance and inspections performed by Wood Pole Management. Please see also the guidelines in the Company's Distribution Feeder Management Plan provided in PC-DR-108. Please also see the Company's response to part (d), above, which documents include equipment to be replaced, including the rationale for end-of-life assets in particular instances, during a Grid Modernization project.

f) The table below shows the estimated kWh energy savings expected after completion of each project. These calculations are conservative in that not every energy efficiency improvement made during design and construction can be anticipated in the initial assessment. These estimates are derived from the initial assessments noted in the feeder baseline reports found in PC-DR-110 Attachment A-O. The primary reconductor savings are for trunk reconductor work only.

Table
(f)1

Feeder	State	Estimated Annual Pri. Reconductor MWh Savings	Estimated Annual Transformer Loss MWh Savings	Total Estimated Annual MWh Savings[1,2,3]
BEA 12F2	WA	8.8	260.5	269.3
F&C 12F1	WA	1.8	258.5	260.3
HOL 1205	ID	0	65.5	65.5
M15 514	ID	0	245.6	245.6
MIS 431	ID	128.8	128.3	257.1
ORO 1280	ID	3.5	108.2	111.7
ORO 1282	ID	TBD	103.0	TBD
PDL 1201	WA	23.5	165.5	189.0
RAT 233	ID	90.3	381.4	471.7
ROS 12F4	WA	2.6	64.1	66.8
ROS 12F5	WA	6.1	145.9	152.1
SIP 12F4	WA	10.5	272.8	283.3
SPI 12F1	WA	31.6	83.2	114.8
SPR 761	WA	49.9	55.7	105.6
TUR 112	WA	140.1	92.7	232.8

[1] Additional MWh savings estimated through Distribution Automation enabled improvements are not included in these figures

[2] Additional MWh savings estimated through the removal of Open Wire Secondary districts are not included in these figures

[3] Additional MWh savings estimated through power factor correction initiatives with capacitors, IVVC, or CVR are not included in these figures

g) The table below provides the density of customers on feeders* selected for Grid Modernization. Some of these feeders have completed construction, others are still in progress, and some are in the design phase.

Feeder	Customer Density (Customer/mi).	Customer Count
BEA12F2	115	2965
F&C12F1	145	3066
HOL1205	177	648
M15514	77	3230
MIS431	8	947
ORO1280	51	584
PDL1201	130	1639

RAT233	25	2560
SPI12F1	5	826
SPR761	7	457
TUR112	46	2451
SIP12F4	62	2094
NE12F4	62	1343
ORO1282	38	578
ROS12F4	159	967
ROS12F5	154	2021

**Data source 2019 Feeder Status Report*

Regarding the number of customer complaints, please see the Company's response to PC-DR-130, part (a).

h) Regarding the number of safety incidents, please see the Company's response to PC-DR-130, part (b).

i) Regarding the number of power quality issues, please see the Company's response to PC-DR-130, part (c). Each feeder selected for the Grid Modernization program undergoes an analysis by a distribution engineer which includes a review of voltage quality, among other factors. These power quality and other evaluations are described and documented in PC-DR-110 Attachments A-O. In addition to the subject reports, a summary of the analyses performed on selected feeders is described below. The following criteria are used in the investigation for the Analysis & Engineering segment for Avoided Cost in the Feeder Upgrade program. Each item corresponds to a specific section of the same name in each feeder's Baseline Report.

- Load Balancing
  Imbalanced load on a feeder has the ability to create or worsen numerous problems which contribute to inefficiency. Unbalanced load can unnecessarily burden one conductor, potentially causing the highest loaded phase conductor to be overloaded or approach its ampacity limit. This can in turn create voltage quality concerns with low voltage scenarios, which are amplified when loads are higher. The exercise of load balancing also promotes the switching of balanced load between feeders during switching scenarios, which will mitigate the problem of overloading a particular phase on an adjacent feeder when load is transferred. Load will be approximately balanced on multi-phase laterals, between sectionalized switching devices or reclosers, and between strategic points on the feeder trunk. These balancing efforts will commence toward the end(s) of the feeder and roll up to nearly balanced load on each phase at the substation breakers.

- High Loss Conductors
  High loss conductors (such as 6A, 8A, 6CR, 8CR) are inefficient conductors that result in line losses, especially where there is moderate to heavy loading. They are also some of the older conductors on the system that can have reliability concerns due to physical wear and damage over the years. The Distribution Feeder Management Plan calls attention to higher loss conductors, with emphasis on replacing conductors that have a resistance greater than 5 ohms per mile. The Grid Modernization program analyzes all conductor sizes on a feeder to target and locate these higher loss conductors. An Engineering decision

can immediately be made to replace the conductor based on loading, voltage drop, or line losses; however, a Designer may also decide to reconductor based on the effects of pole conditions and classifications, the results from the Wood Pole Management (WPM) reports, condition of the primary and neutral overhead conductors, and potential benefits from relocation as part of the targeted replacement of these conductors.

- Trunk Conductors
  Primary trunk conductors have the ability to negatively affect the reliability and efficiency of a distribution circuit. Primary trunk conductors will be analyzed to determine if they are in acceptable physical condition and modeled to assess if they are appropriately sized to: serve peak loading demands, provide adequate voltage levels, and do not cause significant and unnecessary line losses. In addition, Primary trunk conductors are analyzed to determine if they are sized appropriately for the system to be operated in an automated restoration scheme (FDIR). Primary trunk conductors that do not meet these criteria will be replaced with the most appropriate standard conductor size to improve the feeder's operability, reliability, and energy efficiency.

- Lateral Conductors
  Lateral trunk conductors have the ability to negatively affect the reliability of a distribution circuit. Lateral conductors will be analyzed to determine if they are in acceptable physical condition and modeled to assess if they are appropriately sized to: serve peak loading demands, provide adequate voltage levels, and insure that they do not cause significant and unnecessary line losses. Primary lateral conductors that do not meet these criteria will be replaced with the most appropriate standard conductor size to improve the feeder's operability and reliability.

- Voltage Quality
  Service voltage at the point of delivery between the utility and the customer should be consistent to allow the safe and reliable operation of electrical equipment. Over-voltage and under-voltage situations negatively affect the service voltage that is provided, and can also be associated with inefficient operation of the distribution circuit. The Grid Modernization Program analyzes feeders to identify sections of the feeder where the service voltage level fell outside of the allowable ANSI 84.1 Range A or B operating limits. The feeders are modeled in Synergi during both peak loading and average loading conditions, with both normal and abnormal circuit configurations. Improvements to voltage quality can first be addressed by balancing load on the phases between numerous strategic locations on the feeder to eliminate the unnecessary overloading of phases that may worsen line losses caused by loading. In addition, primary laterals and trunks are reconductored with more efficient conductors to increase sagging voltage levels. In some scenarios, an additional conductor phase(s) may be installed to offload a heavily loaded phase and assist in supporting the voltage.

- Voltage Regulator Settings
  As a complement to the efforts of providing optimal voltage quality, the Grid Modernization Program analyzes and recalculates the substation and midline voltage regulator settings. This is performed to reflect the changes to loading and to address the

conductor characteristics that the Program is proposing as part of the holistic upgrade and rebuild of the circuit. The feeders are modeled during both peak loading and average loading conditions, with both normal and abnormal circuit configurations. The result of the analysis is the establishment of regulator settings that bring the voltage quality back into the permissible ANSI 84.1 ranges for all customers during the modeled scenarios, and to eliminate over-voltage and under-voltage situations.

- Line Losses
  The distribution of electricity at medium voltage results in energy lost to resistance, which varies depending on the current magnitude, the resistive characteristic of the conductor(s), and the length of the conductor(s). The greater the line losses on a feeder, the higher the inefficiency. Line losses can be minimized by replacing higher loss conductors with more efficient conductors. Grid Modernization analyzes and sizes primary conductors appropriately to meet peak loading conditions, minimize line losses at peak and average loading conditions during normal system configuration, and to improve voltage levels on feeders. Line losses are generally first addressed by balancing load on the phases between numerous strategic locations on the feeder. This action eliminates the unnecessary overloading of phases that may worsen line losses caused by loading. Line losses are then further minimized by replacing wire with more efficient conductor where conductor resistivity is high and/or where loading levels are moderate to high.

- Power Factor
  Power factor is defined as the ratio of the real power in a circuit to the apparent power. The difference between the two values is caused by the presence of reactance in the circuit and represents reactive power that does not perform useful work. Power factor is a value that can fluctuate with the variations in loading. The Grid Modernization Program analyzes the historical power factor scenario of over 17,000 hourly data pars covering at least a 24 month span to calculate the apparent power and power factor. This results in comprehensive tabular and graphical representations that detail and explain the power factor performance of the feeder, the percent occurrence of lagging and leading power factors, and the severity to which a circuit could be lagging and leading – both in terms of time and quantity.

- Power Factor Correction
  The power factor of a circuit can be corrected to offset the reactance in the system to a more optimal level and bring the circuit closer to unity. A unity power factor is desirable in a power system to reduce losses and improve voltage regulation. The Grid Modernization Program corrects the circuit power factor and lowers line losses from reduced reactive power flow by analyzing the historical power factor scenarios and enacting a solution. The historical raw Watt and VAR data is reanalyzed with a variable VAR to adjust the resulting power factor with the known capacitors values. This exercise allows the ideal amount of capacitance to be modeled on the circuit for the loads to optimize the power factor at variable times. In scenarios with significant or unnecessary leading power factors, existing fixed capacitor banks are removed or reduced in size. In scenarios with significant or unnecessary lagging power factors, fixed capacitor banks are installed in more severe situations to raise the power factor to a reasonable base value, and

then switched capacitor banks are installed to supplement the power factor when required by loading. This approach optimizes the correction of the power factor and reduces line losses.

j) The ability to maintain system reliability, reduce power quality issues, and restore service in a timely manner are among the many expectations of a modern utility. Standardized construction and materials provide more confidence in the grid's ability to perform because it reduces the number of variables in the system that could cause issues. An assortment of many different materials, equipment and designs in the distribution system results in a need for more craft training, supply chain management, and array of tools, resulting in increased efforts to maintain the same level of service. Furthermore, it is not practical to keep a business case or perform a study on every element on the system when a general application of lean business practices will suffice. Bringing existing lines up to more-current standards during Grid Modernization projects takes the proactive step of reducing outdated and obsolete parts of the system, improving code compliance, and reducing the risk of system failures. Please see also the discussions of this topic in the feeder baseline reports, provided as PC-DR-110 Attachments A-O.

k) Costs in the table below represent a combination of design and construction efforts undertaken in the Grid Modernization program during 2018, 2019, and 2020.

Table (k)1

2018 Feeders		2019 Feeders		2020 Feeders	
Feeder	Annual Cost	Feeder	Annual Cost	Feeder	Annual Cost
BEA12F2	$ 52,756.59	BEA12F2	$ 284,332.68	BEA12F2	$ 92,004.18
F&C12F1	$ 1,623,406.54	F&C12F1	$ 1,667,168.00	F&C12F1	$ 1,365,447.37
HOL1205	$ 1,351,586.30	M15514	$ 223,441.17	M15514	$ 992,586.28
M15514	$ 126,953.97	MIS431	$ 207,592.10	MIS431	$ 903,799.82
MIS431	$ 1,369,429.46	RAT233	$ 1,180,171.76	NE12F4	$ 28,579.03
ORO1280	$ 622,678.29	SIP12F4	$ 139,629.99	ORO1282	$ 69,926.24
PDL1201	$ 2,703,668.86	SPR761	$ 2,451,801.53	RAT233	$ 1,168,861.02
RAT233	$ 1,367,210.87	TUR112	$ 4,286,313.70	ROS12F4	$ 21,764.87
SPI12F1	$ 1,173,566.73			ROS12F5	$ 14,064.60
SPR761	$ 2,375,834.47			SIP12F4	$ 4,055.86
TUR112	$ 1,925,589.89			SPR761	$ 2,277,112.05
				TUR112	$ 317,241.25

l) Please see the Company's response to PC-DR-111.

m) Please see response above in part (l).

n) Please see response above in part (l).

o) The table below lists automated devices installed by Grid Modernization on the feeders listed in subpart (a).

Table (o)1

Feeder	Viper Switch	Viper Recloser	Switched Cap Bank	Fixed Capacitor	Smart Midline Regulators
BEA 12F2	0	0	0	0	0
F&C 12F1	0	0	0	0	0
HOL 1205	1	1	1	1	0
M15 514	5	1	1	3	0
MIS 431	1	4	0	0	0
ORO 1280	1	1	1	1	0
ORO 1282	0	0	0	0	0
PDL 1201	3	1	1	1	0
RAT 233	2	4	0	1	0
ROS 12F4	0	0	0	0	0
ROS 12F5	0	0	0	0	0
SIP 12F4	1	1	0	0	0
SPI 12F1	0	3	1	0	0
SPR 761	0	1	1	1	0
TUR 112	0	1	1	1	1

Note: Not all devices listed were installed between the years 2018 and 2020.

p) For each automation device listed above, please refer to the applicable feeder baseline report, provided as PC-DR-110 Attachments A-O, wherein the potential value of automation has been assessed, and when recommended, the cost-effectiveness of the application has been demonstrated. Automation devices provide benefit by allowing for the isolation of outages and have the potential to reduce the number of customers experiencing an outage. The reduction in the duration of outages can be achieved through the installation of devices with communications that can either be controlled remotely or through a distribution management system (DMS). In addition, time and cost savings can be achieved through the remote application of hot-line-holds. FDIR, CVR, and IVVC can also be achieved through Grid Modernization when the necessary substation equipment and components are in place. Remote application of holds reduces the number of callouts for manual switching.

q) Please see the Company's response to part (p) above. The installation of automation devices does provide cost savings to customers. In 2019, an analysis was performed on the number of switching events that had occurred on each device that had been installed to date by the Grid Modernization Program. Table (q)1, below, shows the calculated O&M cost savings for each year based on the observed switching events. Utilization of automation devices varies based on outage events and the number of switching orders, so analysis included the total switching operations. Potential savings associated with any single switching action will depend on distance to travel and the time of day (because overtime rates might apply). The analysis used vehicle mileage rates, direct costs associated with labor, tools, and loadings based on average response time of 5 hours. The analysis did not include savings associated with outage reductions, only cost associated with labor and vehicle utilization and is considered a conservative estimate.

Table (q)1

Year	2017	2018	2019 (through Sept)
Conservative O&M cost savings	$ 139,067	$ 324,252	$ 288,145

Analysis and assumptions for the reported savings are included in Automation device activation data and hard O&M costs spreadsheet, which is provided as PC-DR-110 Attachment R.

r) Please refer to the feeder baseline reports provided for each feeder, attached as PC-DR-110 Attachments A-O, for the comprehensive evaluation of the cost effectiveness for our customers of each Grid Modernization project.

s) The Company's evaluation of the cost effectiveness of this program is performed in the analysis included in the attached feeder baseline reports (PC-DR-110 Attachments A-O). As noted earlier for feeder costs, and elsewhere in our responses pertaining to the use of comparative reliability data (e.g. PC-DR-111), each Grid Modernization feeder is addressed in a phased approach over a period of multiple years. As such, there is not a "modernization year" where costs savings can be strictly evaluated. In addition to this overlap in years, there is the annual variability we experience in factors that can drive outages and otherwise affect feeder performance. At this point in the program, the Company has not proposed to evaluate long-term capital and O&M costs just for Grid Modernization feeders, apart from our ongoing evaluation of the performance of electric distribution assets.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/08/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Heather Webster
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 111	TELEPHONE:	(509) 495-8930
		EMAIL:	heather.webster@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L. Rostentrater, Exhibit HLR-11, at 3, Figure 1, "*Average CEMI3 on feeders that have been fully addressed by GMP*".
What is the value in dollars, to the rate payers, for the improvement shown in this figure? Provide all calculations, assumptions, worksheets, and other work completed to develop these estimates. If the DOE's Interruption Cost Estimate model is used, provide all model inputs utilized.

RESPONSE:

Outages vary substantially from year to year and area to area across the Company's service territory, based on the interaction of a wide range of factors (wind, equipment failure, major events, wind, vegetation, etc.). Because of this significant annual variability, the reliability improvement provided by an investment must generally be evaluated over several years, against several years' data on the historic reliability performance. As Grid Modernization is a relatively new program, there is not enough data available to make outages on a per feeder basis meaningful at this point. Because of this, Avista has evaluated reliability indices before and after Grid Modernization by looking at the average across all feeders addressed by the program to date. This helps to normalize the impact of year to year and local variability as well as the number of years' data available for each feeder. As was discussed in the business case, there has been a reduction in the average CEMI3 post Grid Modernization (with and without major event days included in the analysis). In the future, when more outage data is available post treatment, the Company will be able to generate more meaningful reliability data on a feeder-by-feeder basis.

The analysis used for the comparison (including indices, number of sustained outages per year, and number of momentary outages a year) is included in the spreadsheet provided as PC-DR-111 Attachment A.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/08/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Heather Webster
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 112	TELEPHONE:	(509) 495-8930
		EMAIL:	heather.webster@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 3, Figure 2, "*Average SAIFI on feeders that have been fully addressed by GMP*."
What is the value in dollars, to the rate payers, for the improvement shown in this figure? Provide all calculations, assumptions, worksheets, and other work completed to develop these estimates. If the DOE's Interruption Cost Estimate model is used, provide all model inputs utilized.

RESPONSE:

Please see the Company's response to PC-DR-111 regarding the measurement of reliability improvements on feeders that have been rebuilt under the subject program. The analysis used for the comparison (including indices, number of sustained outages per year, and number of momentary outages a year) is included in the spreadsheet provided in PC-DR-111 Attachment A. Accordingly, the Company has not calculated the financial value to customers associated with individual feeders or the results shown in the subject figure.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/06/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Heather Webster
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 113	TELEPHONE:	(509) 495-8930
		EMAIL:	heather.webster@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather, L. Rosentrater, Exhibit HLR-11, at 4, Figure 3, "*Average SAIDI on feeders that have been fully addressed by GMP*."
What is the value in dollars, to the rate payers, for the improvement shown in this figure? Provide all calculations, assumptions, worksheets, and other work completed to develop these estimates. If the DOE's Interruption Cost Estimate model is used, provide all model inputs utilized.

RESPONSE:

Please see the Company's response to PC-DR-112.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/06/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Heather Webster
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 114	TELEPHONE:	(509) 495-8930
		EMAIL:	heather.webster@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 4, Figure 4, "*Average CAIFI on feeders that have been fully addressed by GMP*."
What is the value in dollars, to the rate payers, for the improvement shown in this figure? Provide all calculations, assumptions, worksheets, and other work completed to develop these estimates. If the DOE's Interruption Cost Estimate model is used, provide all model inputs utilized.

RESPONSE:

Please see the Company's response to PC-DR-112.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/06/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 115	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 2–13, and the Distribution Grid Modernization program generally.
Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, or other documentation which indicates that bringing the distribution system up to "**Current Standards**" provides dollar value or increased safety value which justifies the cost.

RESPONSE:

Taking advantage of the opportunity to bring our distribution system up to current standards as part of a Grid Modernization project (or any other rebuild for that matter) is simply a prudent measure that benefits our customers and the Company in the long term. As one simple example, Avista can help reduce the potential cost of litigation for any damages that might occur as the result of historic construction that may not meet newer construction standards. Current standards for clearances and structural integrity, for another example, helps reduce the risk posed to employees, our customers and the general public. Because the Company believes it would be imprudent to construct a new feeder that was clearly out of compliance with more current standards, we do not calculate a cost difference that might be associated with such a decision.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/06/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 116	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 8, regarding feeder prioritization, which states "Once metrics are gathered; individual feeders are evaluated to determine how they rank in comparison to the rest of the electric distribution system."

a) Provide a list of the "metrics" that are gathered. Describe in detail how the metrics are used to evaluate feeders and "determine how they rank in comparison to the rest of the electric distribution system."
b) For each of the metrics listed in response to subpart (a), provide the values for each feeder "modernized" in 2018 for 2015, 2016, and 2017, and for 2019 and 2020.
c) For each of the metrics listed in response to subpart (a), provide the values for each feeder "modernized" in 2019 for 2016, 2017, and 2018, and for 2020.
d) Provide the feeder ranking list for (i) 2018; (ii) 2019; (iii) 2020; and (iv) 2021.
e) If feeders are ranked by a scoring system, provide an explanation of that scoring system, including descriptions of how the scores are calculated.

RESPONSE:

a) Starting in 2018, the Grid Modernization program began using the criteria of reliability, health, and criticality to rank the feeders in Avista's distribution system. These criteria are compiled in the annual Feeder Status Report which scores health, performance, and criticality based on the following:

1. Feeder Health
    a. Age
    b. OH/UG ratio
    c. Pole rejection rate
    d. Reliability Health (CEMI and SAIFI)

2. Performance
    a. Thermal utilization
    b. Voltage regulation
    c. Reliability performance (MAIFI and CAIDI)
    d. Power Factor
    e. FDR imbalance

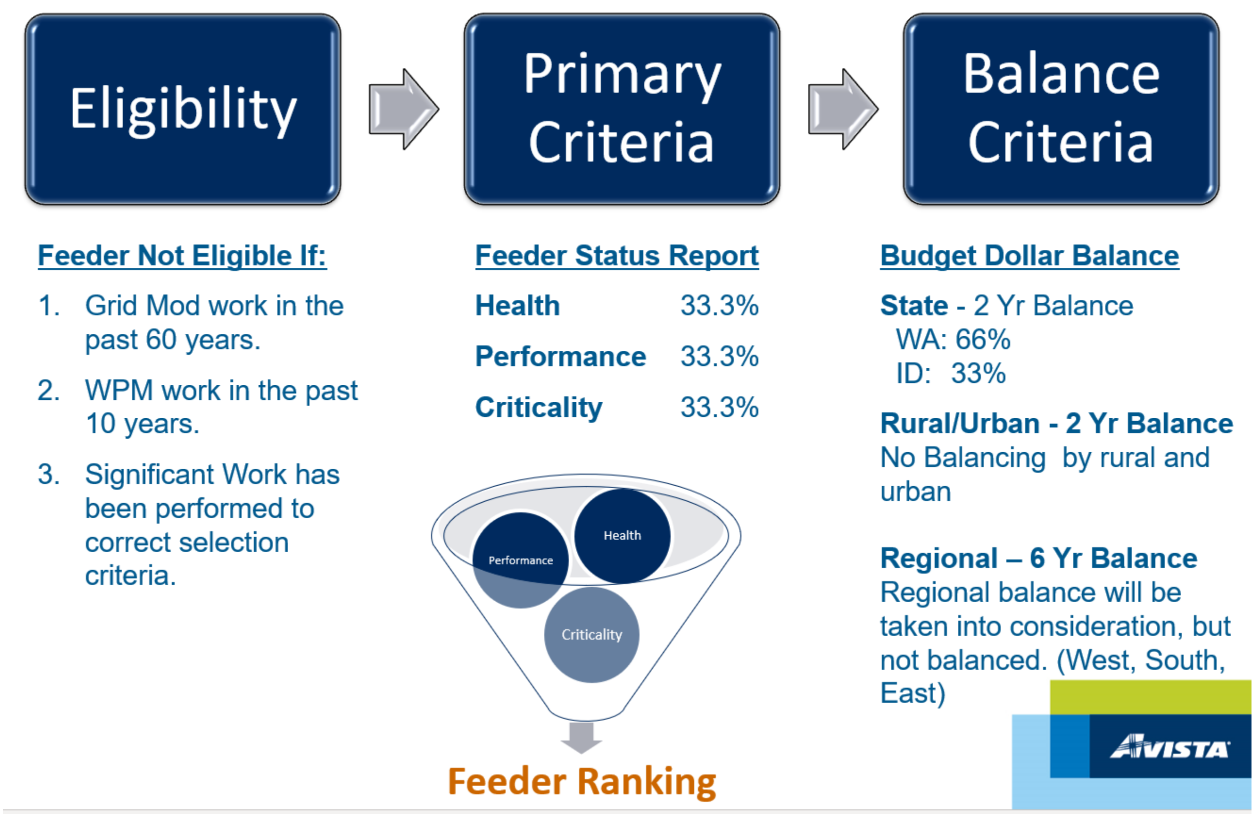
3. Criticality

a. Essential service (Fire, police, EMS, Hospitals, Schools, Water Supply, Sewage treatment, prison, etc.)
b. Commercial account density
c. Customer Density
d. Load Density

The scores from the feeder status report are combined with equal weighting applied to criticality, performance, and health. Feeders with the greatest potential benefit from the Grid Modernization program would be those with the lowest health, poorest performance, and highest criticality. Feeders with the lowest combined score are thus ranked the highest for selection.

Combined score = - Criticality + Health + Performance

A low score, as noted above, indicates a combination of poor asset condition, performance issues, and higher criticality. In addition to the ranked scoring (primary selection criteria), additional eligibility criteria are taken into account, including the balance of work accomplished and planned between our jurisdictions and operating regions, as depicted in the diagram below.



Further, in order for a feeder to be eligible for selection, the following criteria are considered:

- Grid Modernization work has not been performed previously on the feeder.
- Wood Pole Management has not been performed in the past 10 years.
- Significant work that could impact the health, performance, or criticality scores has not been performed recently.

b) Many of the metrics in the feeder status report are based on metrics averaged over multiple years therefore we do not look at the evolution of that score over time when selecting, but look at the score at the time the selection is being performed. Please see a copy of the Company's Feeder Status Report for 2019, provided as PC-DR-116 Attachment A. Avista's Feeder Status Report for 2020 will not be available until later in 2021 due to the time required for analysis and completion.

Also, as the Grid Modernization Program addresses feeders over multiple years through a multiple step process (engineering analysis-> design--> construction), actual construction on feeders selected in a given year may not begin for several years (also dependent on budget and progress of feeders that are currently under construction).

c) Please refer to our response in part (b), above.

d) Prior to 2018, feeder selection was performed based on jurisdictional balance, rural and urban balance, and regional balance. In addition, selection was performed based on performance, avoided costs, and capital offset of future O&M. These metrics depended in forecasting and analysis that were more difficult to quantify, requiring use of several simplifying assumptions. In addition, the balancing among so many areas was difficult to track and maintain with budget variability and the allocation of workload and resources across our service territory. The Company's feeder selection data as organized in 2016 are provided in the file PC-DR-116 Appendix B.

In 2018, the feeder selection process was updated to reduce balancing among every region, and to leverage data created annually in the Feeder Status Report that would not require additional analysis. This updated selection method is the one summarized in part (a) of this response. The feeder ranking list for 2018 is provided as PC-DR-116 Appendix C. The Company's feeder ranking for 2020 is provided as PC-DR-116 Attachment D. The Company is not planning to perform a new ranking for 2021.

As noted above, the Grid Modernization program addresses feeders over multiple years. Once a feeder is selected and undergoes engineering analysis, the feeder is then included in the overall work plan. As there are already multiple feeders in some phase of construction, which were selected in years prior, the number of new feeders that can be selected and placed into the workplan is dependent on the work already in flight and the capital budget anticipated over the next several years. Because of this complexity, the selection process is typically revisited every other year.

e) The scoring process is discussed in part (a) above.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/08/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 117	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Electric Distribution Grid Modernization

REQUEST:

RE: Capital Additions, Test Year (Electric)
Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 9, which states “Future O&M costs are reduced by relocating, removing, or converting sections of Avista facilities that present an opportunity to improve the feeder’s performance.”
For each year from 2018 through 2020, complete a table in the format shown below (2018 example), which identifies the equipment relocated, removed, or converted, as well as the cost of each relocation, removal, or conversion. For each item identified, estimate the annual O&M savings which resulted, and explain each estimate.

2018 Equipment Relocated, Removed or Converted under DGM Program				
Item	**Cost**	**Relocated, Removed, or Converted?**	**Annual O&M Savings Estimate**	**O&M Savings Estimate Explained**
Voltage Reg #2	$8,000	Relocated		
Capacitor #7	$2,000	Removed		
etc	etc	etc	etc.	etc.
Total:	$225,000			

RESPONSE:

2018 Equipment Relocated, Removed, or Converted under DGM Program				
Item	Cost	Relocated, Removed, or Converted?	Annual O&M Saving Estimate	O&M Savings Estimate Explained
ZC435R – Viper Recloser	$48,305.74	Relocated/Converted	In respective feeder baseline report as applicable, please see PC-DR-110 Attachments A-O.	In respective feeder baseline report as applicable, please see PC-DR-110 Attachments A-O.

No devices were relocated, removed, or converted by Grid Modernization in 2019.

2020 Equipment Relocated, Removed, or Converted under DGM Program				
Item	Cost	Relocated, Removed, or Converted?	Annual O&M Saving Estimate	O&M Savings Estimate Explained
ZC448R – Viper Switch	$54,992.10	Converted	In respective feeder baseline report as applicable, please see PC-DR-110 Attachments A-O.	In respective feeder baseline report as applicable, please see PC-DR-110 Attachments A-O

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/06/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 118	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 9, regarding the Distribution Grid Modernization program generally, which states "Replacing equipment upon failure is an alternative to the GMP business case. It would maximize the value of an individual piece of equipment but result in numerous unplanned outages that could arise from and be the cause of unsafe situations to employees and customers. To mitigate the increase of unplanned outages, additional crews would be needed for trouble responses. Aside from a dedicated resource to respond, a variety of equipment and materials would also need to be available to minimize the impact of system failures."
Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, or other documentation which indicates that Avista's Distribution Grid Modernization program is more cost effective in dollars to rate payers than "Replacing equipment upon failure".

RESPONSE:

Please see the Company's response to PC-DR-122 where Avista was asked to estimate the number of outage events for asset failures forecast in year 2030 that would be avoided by the continued current operation of the Company's Asset Maintenance programs, which, like Grid Modernization, focus on replacing end of life assets before they fail in service. In that response the Company projects it would experience a five-fold increase in outage events if it were to adopt a 'Run to Fail' strategy such as posed in this current request of "Replacing Equipment Upon Failure." This evaluation provides a reasonable response to this request because the Grid Modernization program treats all the equipment covered in the Company's Asset Maintenance programs. The increase in outage events as demonstrated in response to PC-DR-122 would result in the consequent rise in annual Risk costs to $181,521,691, which would predominantly be made up of the direct cost to customers for the roughly five-fold increase in service outages they would experience as a result of run to fail. Annual capital costs would also increase from the forecast of our current programs to an annual value in year 2030 of $19,076,602. Clearly, replacing key distribution assets at the end of their useful life, prior to their failure in service (whether performed under the Asset Maintenance, Grid Modernization, or applicable work under the Distribution Minor Rebuild programs, as examples) is much more cost effective for our customers (both in the direct costs they would experience in addition to the increased costs they would pay in their electric rates) than allowing these assets to fail in service.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/06/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 119	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 9, which states "The collaboration that takes place throughout the program improves results upon the completion of each project: an efficient delivery experienced by customers and communities and a reduced risk to Shareholders."
Provide a detailed description of how these projects provide "reduced risk to Shareholders."

RESPONSE:

The subject statement about the Grid Modernization program reflects the Company's view that our efforts to deliver enhanced value to our customers supports the prudence of our decisions in a regulatory context. The enhanced value to customers comes in the form of maintaining a safe and reliable system for their benefit.

As for shareholders, the prudent expenditures to maintain a safe and reliable distribution system helps avoid future costs and risks associated with a poorly maintained system, that would put at risk the shareholders' opportunity to realize a fair return on their investment.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/08/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 120	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: RE: Capital Additions, Test Year (Electric)

REQUEST:
Please refer to the Direct Testimony of Heather L. Rosentrater, Exhibit HLR-1T, at 18:4, regarding the Distribution Grid Modernization program, which states "The purpose of this program is to cyclically rebuild and upgrade every electric feeder in Avista's distribution system, with the objectives of replacing end of life assets, while evaluating improvements in feeder design to bolster service reliability, capture energy efficiency savings, and improve operational ability, code compliance and safety." Please refer also to the Direct Testimony of Heather L. Rosentrater, Exhibit HLR-1T. at 19:10, which states "Further, bundling the work of these individual programs for targeted feeders into one coordinated effort **improves the cost efficiency** by reducing redundant travel costs and capturing labor productivity. In short, customers would experience higher costs for a less robust system absent this program."
Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, or other documentation which indicates that the Distribution Grid Modernization Program "improves the cost efficiency" such that the value to the rate payer is in excess of the cost of the Program to the rate payer.

RESPONSE:

Please see the Company's response to PC-DR-118 for discussion of the types of investments made under the Asset Maintenance and Distribution Grid Modernization Programs that provide a "value to our customers that is in excess of the costs." The subject statement simply recognizes the obvious incremental benefit of the economy of scale achieved through bundling activities into larger aggregated projects. Some of these activities are listed among the examples, below.

- Design efforts invested in aligning existing construction with proposed improvements
- Vegetation management
- Permitting
- Planned outages
- Traffic control
- Material delivery
- Crew mobilization
- Construction audits
- Site restoration

See also PC-DR-110, 121 and 122.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/03/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Larry La Bolle
TYPE:	Data Request	DEPT:	Transm Ops/System Planning
REQUEST NO.:	PC - 121	TELEPHONE:	(509) 495-4710
		EMAIL:	larry.labolle@avistacorp.com

SUBJECT: Forecast of Electric System Outages

REQUEST:

RE: Capital Additions, Test Year (Electric)
Please refer to the Direct Testimony of Heather L. Rosentrater, Exhibit HLR-1T, at 6, Illustration No. 2.1. Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, or other documentation in support of the increase in outages shown in years 2020 through 2030 for:

a) “Plan/Maintenance”,
b) “Outside Forces”, and
c) “Asset Failures”.

RESPONSE:

Avista’s Reliability Strategy Analysis model used to develop these forecasts is attached as PC-DR-121 Attachment A. The forecasts include a Current Case scenario where the Company’s asset maintenance programs and management of our electric distribution generally would be carried out in the same manner as they are today, and a Winning Case, which forecast is based on an optimization of asset maintenance programs in the forecast period. The forecast shown in Illustration 2 is based on the Current Case.

The forecast for <u>Asset Failure</u> outages is performed using Availability Workbench models, which predict equipment failures and vegetation outages based on known failure rates with age (age of equipment in service or time elapsed since last vegetation treatment). The equipment and vegetation modeled include those treated in the Company’s Wood Pole, Transformer and Vegetation Management programs. These outage events are represented in the Reliability Strategy Analysis as “Modeled” outages, such as shown in the second tab labeled “Breakout,” columns C and I, lines 27-35, of the Current Case Forecast.

Forecasts of <u>Outside Forces</u> outages are based on a grouping of outage causes that excludes asset failures and planned / maintenance outages. Avista’s historical outages for these cause types were fit as a group to a failure curve, which was used to forecast expected future outages. The Outside Forces group of outages is represented in the Reliability Strategy Analysis as “Non-Modeled” outages because they were forecast from the failure curve trend noted above, different from the asset failures which were forecast from individual Availability Workbench models for each asset.

Planned / Maintenance outages are those initiated by the Company to safely perform work on the system, which were likewise fit to a failure curve as a group to forecast expected future outages for this category. This group of outages is referred to in the Reliability Strategy Analysis as “Maintenance/Fill-in.”

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/06/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Larry La Bolle
TYPE:	Data Request	DEPT:	Transm Ops/System Planning
REQUEST NO.:	PC - 122	TELEPHONE:	(509) 495-4710
		EMAIL:	larry.labolle@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)
REQUEST:
Please refer to the Direct Testimony of Heather L. Rosentrater, Exhibit HLR-1T, at 7:8, which states "Although the overall forecast shows a likely increasing trend, it is driven primarily by outages beyond our control (outside forces) and those required for maintenance on our system (plan/maintenance). Importantly, outages resulting from asset failures are trending flat over the next decade."

a) Does the statement "outages resulting from asset failures are trending flat over the next decade" assume continuation of the Distribution Grid Modernization (or other) programs, or would the statement be true without continuation of the Distribution Grid Modernization (or other) programs?
b) If the answer to subpart (a) assumes continuation of the programs identified in Avista's response to subpart (a), please re-work Illustration No. 2 on page 6 such that outages avoided by avoided "Asset Failures" and the outages avoided by avoided "Plan/Maintenance" are attributed to each of the programs described in response to subpart (a).

RESPONSE:

a) The forecast for asset failures assumes the broad continuation of current practices, such as electric distribution engineering standards, funding for electric distribution programs, including for examples, Distribution Minor Rebuild and Distribution Grid Modernization, and for continuation of the current practices for the asset maintenance programs, Wood Pole, Transformers, and Distribution Vegetation Management.

b) Please refer to Avista's response to PC-121 and the discussion of current case forecast outages related to Asset Failures. Outages modeled as part of this grouping of outages includes failures of equipment that is evaluated, inspected, repaired or replaced as part of the wood pole and transformer programs and the distribution vegetation management program.

   If Avista were to have terminated its Wood Pole, Transformer, and Vegetation Management Programs in year 2020, the forecast number of outages in year 2030, attributable to Asset Failures, would reach 5,074, up from our current case forecast of 883 outage events. The difference between this number and the current case forecast for year 2030 as shown in Illustration No. 2, represents the "outages avoided by avoided Asset Failures attributable to the current case operation of these asset maintenance programs. Of this total number of outages avoided by avoided Asset Failures, Wood Pole Management accounts for 117 outages, the Transformer Program accounts for 837 outages, and the Vegetation Management Program accounts for 3,237 of the total outages. We were unclear about how this information would be depicted in a revised Illustration No. 2, and further, how the outages represented in the group Plan/Maintenance, where Avista disconnects service to perform work on the system, are related to the outages associated with Asset Failures.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/08/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ken Sweigart
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC - 123	TELEPHONE:	(509) 495-4417
		EMAIL:	ken.sweigart@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to the Direct Testimony of Heather L. Rosentrater, Exhibit HLR-1T. at 9:35, which states, regarding electric transmission infrastructure, "When it comes to the impact for our customers, who must ultimately pay for these requirements and investments, an exacerbating factor is our relatively stagnant load growth due to relatively low increases in population and declining use-per-customer. This translates into nearly flat revenues, which means that new capital investments must be covered by higher customer rates. Historically, annual increases in customer loads produced new revenues that were often sufficient to cover the costs for new investment and inflation without the need to increase rates."

Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, risk assessments, or any other calculations, presentations, requests, standards, or other documentation which indicates that the Transmission Infrastructure Plan is of sufficient value to rate payers to justify rate increases.

RESPONSE:

In response, please refer to Avista's 2018 Electric Transmission Infrastructure Plan, provided as PC-DR-123 Attachment A. On page 7, and beginning on page 58 the report provides a brief and then more detailed definitions, respectively, of the six investment drivers defining the need for Avista's electric transmission infrastructure investments. These include *Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition,* and *Failed Plant & Operations.*

Avista's "relatively stagnant load growth" is an overall assessment. In more specificity, loads are increasing in some areas, reducing in others, and overall, being impacted by a "declining use-per-customer." Areas of load growth typically involve commercial and industrial locations where the incremental increase in load is such that new transformation is often required. This involves substation, transmission, distribution, and communications investments. Similarly, sometimes a large residential development will trigger the need for additional transformation. By our compact, Avista has a responsibility to serve, and to maintain a level of service that is acceptable to our customers and regulators. Projects that meet our requirements to provide adequate system performance and capacity fall under the *Performance & Capacity* driver.

In addition to serving load, Avista is required by Federal Energy Regulatory Commission (FERC) rules to integrate new generation as requested. Avista currently has received over 115 renewable generation project interconnection requests. Few of these projects come to fruition, however, each requires some amount of effort to attend to, and of those that do, a large expenditure of transmission infrastructure may be necessary. The Saddle Mountain and Rattlesnake projects in the Othello area are a prime example of this. These types of projects are somewhat of a bridge of *Customer Requested* and *Mandatory & Compliance* requirements.

Other *Mandatory & Compliance* projects include, but are not limited to, construction or relocation required by franchise agreements, easement requirements, local/state/federal regulatory requirements, code requirements, or other agreements which Avista would violate by not following the prudent route of compliance.

Over the past five years, Avista's electric infrastructure has suffered considerable damage in numerous windstorms and large fires. Some of the resulting outages to transmission infrastructure have left customers without service. Our responses to these events, out of necessity, are generally immediate and expensive. Where possible, Avista will reroute transmission to restore service to our customers, while allowing in some instances, reconstruction to take place in a more systematic and measured approach. Projects of this type are included as part of the *Failed Plant & Operations* investment driver.

Failure to complete projects under the *Customer Requested*, *Performance & Capacity*, *Mandatory & Compliance*, or *Failed Plant & Operations* drivers will ultimately leave customers without service and/or leave Avista financially responsible for legal and/or regulatory penalties and actions. By their very nature these projects are "of sufficient value to rate payers to justify rate increases." As further evidence, Avista System Planning's 2019-2020 System Assessment report categorizes projects under these drivers, which is provided as PC-DR-123 Attachment B.

Projects under the investment driver, *Asset Condition*, include minor rebuilds that arise from the need to comply with the North American Electric Reliability Corporation (NERC) Standard FAC-501-WECC-2, Avista's related Transmission Maintenance and Inspection Program, and air/ground patrol assessments that identify infrastructure nearing failure. The FAC-501-WECC-2, provided as PC-DR-123 Attachment C, drives the need for projects that cross over to the *Mandatory & Compliance* driver. Major rebuilds are related to aging or end-of-life assets and upgrades related to design, safety, or construction standards as well as specific technology upgrades related to interconnected system reliability and cybersecurity as required by NERC. The Company closely monitors outages and replaces equipment that is either impacting customer service or is likely to do so. Some equipment is so critical that it cannot be allowed to fail. When this equipment reaches an age when it is close to or at the end of its useful life, the Company preventively replaces it to maintain reliability and acceptable levels of service. The Company's electric Transmission Maintenance and Inspection Plan is provided at PC-DR-123 Attachment D.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/03/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Amy Jones
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 124	TELEPHONE:	(509) 495-2552
		EMAIL:	amy.jones@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 18, which states "In 2019 2,481 work orders were created with the average cost equaling $4,398." Please refer also to Figure 2 on this page, "Minor Rebuild Historical Spend", which indicates a significant increase over time.
Provide the count of work orders and the average cost per work order by year from 2014 to 2019.

RESPONSE:

Data Note: A correction was made in the data referenced in the business case, which has since been updated as PC-DR-124 Attachment A. Please refer to the chart below for the correct data for 2019. Our work and asset management system does not include data prior to year 2015. Requested information for years 2015-2019 is provided in the table below.

	2015	2016	2017	2018	2019
Count of Work Order #	1,388	1,605	1,408	1,466	1,536
Average $ per WO	$4,790	$4,655	$5,264	$5,512	$7,104

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/03/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Amy Jones
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 125	TELEPHONE:	(509) 495-2552
		EMAIL:	amy.jones@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)
REQUEST:
Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 16, which states "Customer Requested Rebuilds – Work is initiated by an existing customer or property owner, and the costs associated with the work are typically reimbursed by the requesting party. Examples could be a customer requested reroute, overhead to underground line conversion, or customer load increase."

a) Please explain why capital dollars are included in this budget for work which will be paid for by the requesting customer.
b) If the historical spending and forecasted budgets for this item are netted against customer payments, provide the Avista policies and processes for estimating costs of, designing, completing, assigning responsibility for, billing, and accounting for, customer-requested work.

RESPONSE:

a) Capital dollars included in this budget for Customer Requested rebuilds comprise approximately 10% of the overall Minor Rebuild budget. This capital work includes conversions, load increases, service or transformer removal, etc., but does not include Line Extensions, which are covered by Schedule 51. Our customers do pay for work they request, per our tariffs, which provides an offset to the distribution minor rebuild budget. In some instances, however, the requested work may trigger additional system-level work to meet the customer's request. An example is a customer request for a capacity increase to serve new load at their building, and in order to accommodate the additional load, a portion of the feeder needs to be upgraded. The customer pays for the equipment to provide more greater capacity to the building (service from the feeder to the building), but the cost necessary to upgrade the capacity of the feeder is a cost borne by all electric customers. Accordingly, Avista pays for the work to the feeder from the distribution minor rebuild budget. All of this work is classified as Customer Requested because it was triggered by the customer's request for service and would not have otherwise occurred.

b) Avista has multiple documents providing instructions and system requirements for our customer project coordinators (CPC's) who manage field projects for customer requested work. Two of these key documents, include:
    - PC Project Cycle 2019 (Refer to Phases Initiate, Assess & Field Visits, Planning & Design), provided here as PC-DR-125 Attachment A.
    - All About Service Agreements, provided as PC-DR-125 Attachment B. (Refer to page 1)

    Also, the systems we use to design and manage projects automatically create an estimate for the job once the design is completed. All labor and material costs are built into our system.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/06/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Amy Jones
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 126	TELEPHONE:	(509) 495-2552
		EMAIL:	amy.jones@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 16, regarding "Trouble Related Rebuilds", "NESC/Operating Standard Violations", and "Asset Condition" activities.

a) Explain why these activities are spent and budgeted as capital items rather than spent and budgeted as O&M expenses.
b) Provide Avista's Policy regarding the categorization of distribution spending as either capital or O&M expense.
c) Provide the Processes Avista employees are instructed to follow to ensure the Avista Policy regarding the categorization of distribution spending as either capital or O&M expense is followed.

RESPONSE:

a) The activities associated with Trouble Related Rebuilds, NESC/Operating Standard Violations and Asset Conditions meet the criteria outlined in our Capitalization Policy (See section B.) Please see PC-DR-126 Attachment A for the types of activities included in these categories.

b) Project expenditures relating to construction or acquisition of utility property are considered capital if they meet one of the following criteria:
    - Addition of retirement units as identified in the Retirement Unit Catalog that did not previously exist.
    - Replacement of existing retirement units.
    - A portion of the replacement of minor items that substantially betters the related retirement unit by increasing the unit's capacity or significantly extending the unit's useful life.

    For reference to retirement units, please see PC-DR-126 Attachment B.

c) Avista has many resources to assist employees in properly determining what should be charged to capital or O&M. These are available to all employees on our internal intranet on the Projects & Fixed Assets Accounting site, and the Operations Resource Center. For an example of resources available please see the Decision Tree in PC-DR-126 Attachment C.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/08/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Amy Jones
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 127	TELEPHONE:	(509) 495-2552
		EMAIL:	amy.jones@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 17, regarding the Distribution Minor Rebuild program, which states, "Historical spend was used to determine the requested amount. A steady increase in costs for unplanned minor rebuild work has occurred for several reasons. Many assets on the distribution system are past their end of life cycle and contributing to this increase."

a) Confirm that with this statement, Avista is indicating that because "distribution system" assets are "past their end-of-life cycle", that equipment failures are occurring on the system. Confirm further that despite the Distribution Grid Modernization and Minor Rebuild programs, distribution equipment failures are to be expected. If these implications cannot be confirmed, please explain.
b) If the statements listed in subpart (a) can be confirmed, provide a list of the equipment failures that have resulted in the historic spending identified in 2018, 2019, and 2020.
c) Provide detailed "metrics, data, analysis or information" that "was considered when preparing this capital request."
d) If the statements listed in subpart (a) cannot be confirmed, explain in detail the justification for the historic spending and the increases.

RESPONSE:

a) Avista experiences equipment failures across its electric distribution system each year, sometimes among recently installed assets (like a failed newly-installed AMI meter, referred to in asset management parlance as 'infant mortality'), among assets that are in a mid-range of their expected lifecycle (like a 40-year-old cedar pole), and among those that are nearing the end of, or are beyond their useful service life. If the Company were to invest more capital each year than currently planned in programs such as Grid Modernization, or Wood Pole Management, as examples, then the long-term trend in asset failures would be expected to decline somewhat from present forecasts. Alternatively, if Avista were to spend less capital on electric distribution in these and other programs, then the long-term forecast in equipment failures would trend toward increasing. With its current programs and anticipated levels of funding, the Company believes its long-term trend in equipment failures is likely fairly stable.

   It's important to point out, that even with a fairly stable trend in asset failures, it doesn't mean that the level of spending on distribution capital programs will be stable, rather it will continue to increase for the foreseeable future. The need for this increasing capital investment is driven by the age profile of our electric distribution assets, in which a greater number of units each year are nearing, or, are at the end of their useful life. The result of this aging population (just like the retirements of 'baby boomers' we've been experiencing) is that program funding must increase over time to effectively treat these end of life assets each year *in order to keep the number of equipment failures that actually occur fairly stable*. For a detailed description of the phenomenon, please see the discussion found on pages 56-63 of PC-DR-105 Attachment A, Avista's Electric Distribution Infrastructure Plan for 2017. In this section, note especially the discussion of the need for increased investment found on pages 61-63, as well as the expected growth in funding projected for both Grid Modernization and Wood Pole Management, shown in Figure 37, page 63. For more information about the Minor Rebuild Program, please see pages 12 and 13 in Avista's Electric Distribution Infrastructure Plan for 2020, provided as PC-DR_127 Appendix A.

b) In part, for the reasons described above in part (a), the number of equipment failures we experience each year does not necessarily correlate with our investment needs. [The result of this aging population (just like the retirements of 'baby boomers' we've been experiencing) is that program funding must increase over time to effectively treat these end of life assets each year *in order to keep the number of equipment failures that actually occur fairly stable*.] It's the number of end of life assets (including near end of life, as well as beyond) in our system that drives the need for investments. Additionally, for electric distribution infrastructure, we track equipment failures as they relate to service outages for our customers, and many failures do not necessarily result in an outage, even though they must be quickly repaired when they are discovered. That said, please find Avista's equipment failures, which includes the subject years, and which resulted in a service outage for our customers, provided in response to PC-DR-106.

c) Please see PC-DR-127 Appendix B, for the historical investments made under the electric distribution minor rebuild business case.

d) See subpart (a) above.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/03/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Amy Jones
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 128	TELEPHONE:	(509) 495-2552
		EMAIL:	amy.jones@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 19, which states, regarding the Distribution Minor Rebuild program, "Not funding would have a significant impact on business functions and processes as other areas would be responsible for the work and it would also impact the ability to respond to customers' needs for modifications to their electrical service."

If the funding has been reduced in "Other Areas" as funding for "Distribution Minor Rebuilds" has increased, identify the specific areas that have had their funding reduced and the amounts of those reductions. Provide the amounts of these reductions by year, for each "Other Area", from 2014 through 2020.

RESPONSE:

Please see the Company's response to PC-DR-127, part (a) for the explanation of the need for increasing funding for the subject program. The levels of capital funding recommended each year for each program by Avista's capital budget committee represents a complex process of balancing many competing and diverse needs across the enterprise. The committee's recommendations, and indeed the final funding approved for each capital program, is a multivariate endeavor, not a linear, sequential process of specifically taking from one program and allocating to another. There is no possible way to determine in isolation what specific capital programs might have been (if any) funded at a level lower than what was required just because of the increasing needs of the distribution minor rebuild program. For a description of the Company's overall infrastructure plan, please see Exh. MTT-4, and for the high-level objectives of our capital investment planning, we have included an except from Exh. DPV-1T, found on page 37.

> "As discussed in greater detail in Avista's 2020 "Infrastructure Investment Plan" sponsored by Mr. Thies, our process to identify and prioritize capital investment is designed to meet the overall need for investment, in the appropriate time frame, in a manner that best meets the future needs and expectations of our customers, in both the short-term and long-term. The Company's practice has been to constrain the level of capital investment each year, such that not all of the prioritized projects and programs will be funded in a given year at the level requested. Avista believes that holding capital spending below the level requested accomplishes several important objectives, including:
>
> - ***Promotes Innovation*** – Encourages ways to satisfy the identified investment needs in a manner that may identify potential cost savings, defer implementation, or other creative options or solutions.

- ***Balances Cost and Risk*** – Captures the customer benefits of deferring needed investments by prudently managing the cost consequences and risks associated with such deferrals.

- ***Efficiently Allocates Capital*** – Ensures that the highest-priority needs are adequately funded in the most efficient and effective way.

- ***Reduces Variability*** – Moderates the magnitude of year-to-year variability to avoid excessive rate impacts, and more efficiently optimizes the number and cost of personnel necessary to carry out the capital projects."

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/03/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Amy Jones
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 129	TELEPHONE:	(509) 495-2552
		EMAIL:	amy.jones@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)
REQUEST:
Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 19, which states, regarding the Distribution Minor Rebuild program, "The other alternative that was considered is not funding the business case however, the needed work will continue to occur. These costs would be covered under other business cases."

a) Provide the "Other business cases" under which "These costs would be covered", as well as the cost of those items should the business case not be funded.
b) Indicate if these "Other business cases" have ever previously budgeted for this work. If so, provide the justifications used by these "Other business cases" for that spending, and the amounts of that spending by year from 2015 through 2020.

RESPONSE:

a) As a few examples, the capital costs for work needed on the system that would not be charged to the electric distribution minor rebuild budget, would show up as incremental additional capital charges incurred under the Company's Wood Pole Management program (Exh. HLR-11, pages 64-70) and the Distribution Grid Modernization program (Exh. HLR-11, pages 2-13). These costs would also show up in various programs such as 'out-of-budget charges' against customer requested service. The point is that work performed on the system that is charged to the distribution minor rebuild program, is work that must be timely performed to ensure we provide adequate service to our customers and to provide for the safe, reliable and affordable[1] operation of our system. And if not here, it will be required to be charged elsewhere.

   It's impossible to know the ultimate costs for the work that would be charged to other budgets since, in this hypothetical, we don't know by how much the business case funding would be reduced, we don't know decisions that would be made on what work would be charged to this business case, or necessarily, decisions about where the out-of-budget costs would be charged. It's fair to reason, however, that every dollar of capital work not charged to the electric distribution minor rebuild program would be charged against some other capital program, since, as explained above and elsewhere, the needed work would be timely accomplished regardless of the work groups that performed the activities or the ultimate capital budgets to which the charges would be applied.

b) Avista has long budgeted for the type of work accomplished under the electric distribution minor rebuild program as part of this business case and has not formally shifted work activities or budget allocation into other capital business cases.

[1] Replacement of damaged equipment (before it causes an outage) or end of life assets prior to their failure, saves our customers money compared with a scenario where we allow the equipment to fail in service and then replace it on a more costly emergency basis.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/04/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Amy Jones
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 130	TELEPHONE:	(509) 495-2552
		EMAIL:	amy.jones@avistacorp.com

SUBJECT: Electric Distribution Minor Rebuild

REQUEST:

RE: Capital Additions, Test Year (Electric)
Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 20, regarding the Distribution Minor Rebuild program, which states "The Distribution Minor Rebuild business aligns with the company's focus of Our Customers, Our People, and Perform by investing in our infrastructure to achieve optimum life-cycle performance – safely, reliably and affordably. This business case provides a solution to address those small unplanned asset failures and customer driven modifications to the distribution system."

a) Provide a list of the customer complaints that Avista received from 2015 through 2020 that would have been or will be addressed by the proposed Distribution Minor Rebuild spending.
b) Provide a list of the actual safety events that occurred from 2015 through 2020 that would have been or will be addressed by the proposed Distribution Minor Rebuild spending.
c) Provide a list of power quality events that occurred from 2015 through 2020 that would have been or will be addressed by the proposed Distribution Minor Rebuild spending.
d) Provide all cost-benefit analyses which indicate the cost of the proposed work is "affordable" for rate payers.
e) Explain why "customer driven modifications to the distribution system" do not constitute Customer-Requested upgrades, to be paid for by the requesting customer.

RESPONSE:

a) Avista is very attentive to the service and satisfaction of its customers and to carefully addressing issues they have, particularly those that rise to the level of a formal complaint. In its experience, however, the Company has not found individual customer complaints to be a useful metric in helping to guide infrastructure planning or budgeting. Accordingly, the information in this subject request is not among the data used by Avista to support its decision-making related to the electric distribution minor rebuild business case, and consequently, we do not track the information in the form it has been requested.

b) The same can be said for safety incidents, where we carefully evaluate the root cause and take appropriate steps to help ensure risks to our employees and/or customers are effectively reduced and managed. But individual safety incidents typically do not rise to the level of being useful in systematic infrastructure planning or budgeting. Accordingly, the information in this subject request is not among the data used by Avista to support its decision-making related to the electric distribution minor rebuild business case, and consequently, we do not track the information in the form it has been requested.

c) Similarly, power quality issues that arise with our customers are evaluated on a case-by-case basis, are appropriately investigated, and are timely and effectively resolved. Resolving power quality issues naturally requires infrastructure solutions in some cases (typically at the customers' service or feeder section), and they may be at times charged to this program. But power quality issues are a small part of the many different needs, activities and costs included in this business case, and they are not tracked in a form required to provide the information requested.

d) For the many examples of these types of analyses provided in this current case, please see Exhibit HLR-11, which includes, among others, the Company's business cases for its electric energy delivery infrastructure. These business cases provide key information on the need for investments made and the rationale for why these investments are made in the interest of our customers, which includes the affordability of their electric service. As one of many examples, replacing a wood pole at the end of its useful service life, but before it fails, allows us to deliver service to our customers at a lower cost compared with allowing the pole to fail in service and then replacing it. For other specific examples of the analyses Avista performs to ensure the prudent management of our electric infrastructure (which allows us to meet our many service obligations at an affordable price for our customers), please see the following documents.

- Exhibit HLR-11, pages 2-13, 32-38, 49-51, 59-70, 201-227, 265-277.
- Avista's responses to data requests in this current case:
  - i. PC-DR-100
  - ii. PC-DR-101
  - iii. PC-DR-102
  - iv. PC-DR-104
  - v. PC-DR-108
  - vi. PC-DR-109
  - vii. PC-DR-110
  - viii. PC-DR-116
  - ix. PC-DR-117
  - x. PC-DR-120
  - xi. PC-DR-128
  - xii. PC-DR-155
  - xiii. PC-DR-156
  - xiv. PC-DR-157
  - xv. PC-DR-159
  - xvi. PC-DR-160
  - xvii. PC-DR-161
  - xviii. PC-DR-162
  - xix. PC-DR-164
  - xx. PC-DR-166
  - xxi. PC-DR-169
  - xxii. PC-DR-170
  - **xxiii.** PC-DR-172

e) Customer driven modifications and customer requested upgrades are the same. For a description of the types of costs associated with ‘customer requested upgrades’ that are paid for by the requesting customer and those that are borne by all customers, please see the Company’s response to PC-DR-125 subpart (a).

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/12/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ken Sweigart
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC - 155	TELEPHONE:	(509) 495-4417
		EMAIL:	ken.sweigart@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L Rosentrater, Exhibit HLR-11, at 39, regarding the Transmission Construction — Compliance program generally."

Please provide:
a) A copy of NERC Reliability Standard TPL-001-4.
b) Any evidence that Avista compliance with the Standard is mandatory.
c) The Engineering Roundtable Project List.
d) The most recent Avista System Planning Assessment.
e) Actual Transmission Construction — Compliance capital spending by year for the last ten years.
f) An explanation as to how Avista was able to maintain its transmission system in compliance with NERC standards and NESC sections for any years in which no capital was spent on this program.

RESPONSE:

a) Please see PC-DR-155 Attachment A for a copy of TPL-001-4.
b) Please see PC-DR-155 Attachment B, Energy Policy Act of 2005, and refer to Title XII – Electricity, Subtitle A – Reliability Standards.
c) Please see PC-DR-155 Attachment C, 2020 Avista System Plan, and refer to the project list provided starting on page 5.
d) Please see PC-DR-155 Attachment D for the most recent Avista System Planning Assessment.

e) The Transmission Construction – Compliance Business Case was established in 2017. The annual capital spending for the applicable years, under this business case is provided in the table below.
2017: $13,446,203.
2018: $12,271,943
2019: $10,690,960
2020: $4,035,596

f) The Transmission Construction – Compliance business case was formed in response to the company's adoption of Investment Drivers in 2017. Over time, the Company has endeavored to make the timely investments needed to remain in compliance with our applicable requirements, and in prior years, required investments were included among the needs addressed in other business cases, which compliance costs were consolidated in 2017. Specific annual amounts for compliance only are not readily available in prior years, hence, the value of using investment driver categories to help focus the understanding of what factors are driving our need to invest capital on behalf of our customers.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/15/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ken Sweigart
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC - 156	TELEPHONE:	(509) 495-4417
		EMAIL:	ken.sweigart@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L Rosentrater, Exhibit HLR-11, at 39–49, which describes four projects under the Transmission Construction — Compliance program:

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

For each of these projects, provide:

a) The applicable NERC transmission planning standard, NESC section, or other violation and whether the claimed violation is current or Near Term transmission planning horizon.
b) Any evidence that compliance with this standard or section is mandatory.
c) A description of the deficiency the project will rectify, as well as how the deficiency represents a violation of the Standard identified in subpart (a).
d) Any test results, inspection reports, equipment capacity ratings, load forecasts, or other evidence which supports the deficiency.
e) Alternatives Avista considered to address the deficiency, including comparative benefit-cost analyses, comparative risk reduction estimates, technical assessments, or other analyses which indicate the alternatives to the project were inferior.
f) The timing by which the project must be completed per the NERC transmission planning standard for the identified deficiency.
g) The amount added to rate base in 2018.
h) The amount added to rate base in 2019.
i) The amount added to rate base in 2020.
j) The amount projected to be added to rate base from 2021 to 2024 by year.

RESPONSE:

<u>KEC Rimrock Substation</u>

Parts (a-f). The Company provides Network Integration Transmission Service ("NITS") under its Open Access Transmission Tariff ("Tariff") to the Bonneville Power Administration ("BPA") for BPA's service to its various load serving utility customers, including Kootenai Electric Cooperative ("KEC"). The Company is required, pursuant to Sections 31 and 32 of the Tariff and federal law, to study, design and construct new points of interconnection for its NITS transmission customers.

KEC requested a new point of interconnection ("POI") on the Company's Appleway-Rathdrum 115kV Transmission Line, a new station named Rimrock, located in the Coeur d'Alene area. KEC requested that Avista conduct a system impact study to evaluate what facilities are required to interconnect Rimrock station, which study is provided as PC-DR-156 Attachment A (KEC Rimrock System Impact Study Ver0). The Company and KEC entered into the Rimrock Construction Agreement, dated June 30, 2020, which was filed with, and accepted by, the Federal Energy Regulatory Commission in Docket No. ER20-2485-000, which agreement is provided as PC-DR-156 Attachment B (KEC – Rimrock Construction Agmt.pdf). In Q4 2020 the Company completed construction of its required transmission facilities to accommodate the Rimrock Station interconnection.

g) $0
h) $0
i) $329,872
j) Avista objects to this request because it seeks future information this is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

Beacon Ross Park 115kV Rebuild

a) Large percentage of pole structures fail NESC Rule 250B for Medium Loading.
b) The NESC is adopted under the Washington Administrative Code (WAC) via 480-108-999.
c) Project upgrades pole structures in strength to comply with the NESC 250b Medium Load requirement.
d) Please find attached the following report summarizing line structure analysis using industry accepted PLS-CADD design software, provided as PC-DR-156 Attachment C.
e) No other alternatives were considered for alleviating the structural deficiency of the transmission line poles. Replacement is the common and appropriate method utilized for this type of project.
f) The subject standard is not applicable for NESC driven projects.
g) ER 2621 — Beacon-Ross Park 115kV: $0
h) ER 2621 — Beacon-Ross Park 115kV: $47,117 spent but not transferred to plant.
i) ER 2621 — Beacon-Ross Park 115kV: $349,666 spent but not transferred to plant.
j) Please see the Company's response, above, to KEC-Rimrock, part (f).

Beacon-Boulder #1 115kV Rebuild (east of Irvin)

a) Large percentage of pole structures fail NESC Rule 250B for Medium Loading.
b) The NESC is adopted under the Washington Administrative Code (WAC) via 480-108-999.
c) Project upgrades pole structures in strength to comply with the NESC 250b Medium Load requirement.
d) Please find attached the following report summarizing line structure analysis using industry accepted PLS-CADD design software, provided as PC-DR-156 D, and Network Communication Pole Analysis, provided as Attachment E.
e) No other alternatives were considered for alleviating the structural deficiency of the transmission line poles. Replacement is the common and appropriate method utilized for type of project.
f) The subject standard is not applicable for NESC driven projects.
g) ER 2622 — Beacon-Boulder #1 115kV: $0

h) ER 2622 — Beacon-Boulder #1 115kV: $0
i) ER 2622 — Beacon-Boulder #1 115kV: $0
j) Please see the Company's response, above, to KEC-Rimrock, part (f).

Ninth & Central-Sunset 115kV Partial Rebuild (Upgrade to 795 ACSS)

a-j) Because this project is planned for a future period outside this case, please see the Company's response, above, to KEC-Rimrock, part (f).

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/12/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	John Gross
TYPE:	Data Request	DEPT:	System Planning
REQUEST NO.:	PC - 157	TELEPHONE:	(509) 495-4591
		EMAIL:	john.gross@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L Rosentrater, Exhibit HLR-10, at 13, which lists multiple projects Avista claims are required for NERC transmission standard compliance:

- ER 2557 — 9th & Central-Sunset 115kV Transmission Line reconductor and rebuild;
- ER 2576 — Addy-Devils Gap 115kV Transmission Line reconductor and rebuild;
- ER 2457 — Benton-Othello 115kV Transmission Line reconductor and rebuild;
- ER 2556 — CDA-Pine Creek 115kV Transmission Line reconductor and rebuild;
- ER 2564 — Devils Gap-Lind 115kV Transmission Line reconductor and rebuild;
- ER 2310 West Plains transmission reinforcement; and
- ER 2578, the Hatwai-Lolo #2 230kV Transmission.

For each of these projects, provide:

a) The applicable NERC transmission planning standard, and whether the claimed violation is current or Near Term transmission planning horizon.
b) Any evidence that compliance with this standard is mandatory.
c) A description of the deficiency the project will rectify, as well as how the deficiency represents a violation of the Standard identified in subpart (a).
d) Any test results, inspection reports, equipment capacity ratings, load forecasts, or other evidence which supports the deficiency.
e) Alternatives Avista considered to address the deficiency, including comparative benefit-cost analyses, comparative risk reduction estimates, technical assessments, or other analyses which indicate the alternatives to the project were inferior.
f) The timing by which the project must be completed per the NERC transmission planning standard for the identified deficiency.
g) The amount added to rate base in 2018.
h) The amount added to rate base in 2019.
i) The amount added to rate base in 2020.
j) The amount projected to be added to rate base from 2021 to 2024 by year.

RESPONSE:

- ER 2557 — 9th & Central-Sunset 115kV Transmission Line reconductor and rebuild;
- ER 2310 West Plains transmission reinforcement; and
- ER 2578, the Hatwai-Lolo #2 230kV Transmission.

Pertaining to the above subject projects, for which no investments have occurred or are planned until year 2021 and beyond, Avista objects to this request because it seeks future information this is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

- <u>ER 2576 — Addy-Devils Gap 115kV Transmission Line reconductor and rebuild.</u>
  a) TPL-001-4 requirement R2.7. System performance analysis indicates an inability of the System to meet the performance requirements in Table 1 of TPL-001-4 in the current System.
  b) Please see Attachment A, Energy Policy Act of 2005, and refer to Title XII – Electricity, Subtitle A – Reliability Standards.
  c) The Please see PC-DR-157 Attachment B, Section 3 for description of deficiency the project rectified. The exceedance of an applicable facility rating in simulations performed following the Planning Assessment process required in TPL-001-4 is addressed in requirement R2.7 of TPl-001-4.
  d) Please see PC-DR-157 Attachment B documenting the deficiency.
  e) Alternatives considered in the ERT process are stated in Attachment C. The alternatives considered at a high level were not analyzed because they would either have resulted in non-compliance with requirements, or an unacceptable curtailment of Avista's electric generating resources.
  f) 2025
  g) $3,793,657 transferred to plant.
  h) $247,481 - reconciliation from 2018.
  i) $0
  j) Avista objects to this request because it seeks future information this is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

- <u>ER 2457 — Benton-Othello 115kV Transmission Line reconductor and rebuild.</u>
  a) TPL-001-4 requirement R2.7. System performance analysis indicates an inability of the System to meet the performance requirements in Table 1 of TPL-001-4 in the current System.
  b) Please see PC-DR-157 Attachment A, Energy Policy Act of 2005, and refer to Title XII – Electricity, Subtitle A – Reliability Standards.
  c) Please see Attachment D, Section 2 for description of deficiency the project rectified. The exceedance of an applicable facility rating in simulations performed following the Planning Assessment process required in TPL-001-4 is addressed in requirement R2.7 of TPl-001-4.
  d) Please see Attachment D documenting the deficiency.
  e) Alternatives considered in the ERT process are stated in Attachment E. The alternatives did not require in-depth analysis because they would result in either non-compliance with federal transmission standard or undertaking a more complex and expensive project with a lead time that would be unacceptable.
  f) 2018
  g) $564,506 but not transferred to plant.
  h) $3,153,975 transferred to plant.
  i) $0
  j) Please see part (j) above for ER 2576.

- <u>ER 2556 — CDA-Pine Creek 115kV Transmission Line reconductor and rebuild</u>.
  a) TPL-001-4 requirement R2.7. System performance analysis indicates an inability of the System to meet the performance requirements in Table 1 of TPL-001-4 in the current System.
  b) Please see Attachment A, Energy Policy Act of 2005, and refer to Title XII – Electricity, Subtitle A – Reliability Standards.
  c) Please see Attachment F, Section 3 for description of deficiency the project rectified. The exceedance of an applicable facility rating in simulations performed following the Planning Assessment process required in TPL-001-4 is addressed in requirement R2.7 of TPl-001-4.
  d) Please see Attachment F to support the deficiency.
  e) Alternatives considered in the ERT process are stated in Attachment G. A discussion of the five alternatives considered is accompanied by a brief description of why alternatives were not further analyzed.
  f) 2018
  g) $8,195,648 transferred to plant.
  h) $6,126,097 transferred to plant.
  i) 0
  j) Please see part (j) above for ER 2576.

- <u>ER 2564 — Devils Gap-Lind 115kV Transmission Line reconductor and rebuild</u>.
  a) Combined drivers of NERC standard FAC-501-WECC-1, 2010 “NERC Alert” for line ratings, and Asset Management Asset Condition Assessment.
  b) NERC provides for fines for non-compliance with a NERC standard. “NERC Alert” didn’t specify fines, but failure to comply would require Avista to de-rate lines to the point of impacting the Company’s ability to operate.
  c) Repair and replacement structures and structure components to satisfy FAC-501-WECC-1 inspection results, replace (raise) structures to match line ratings, and replace “end of life” aged structures.
  d) Please see the attached documentation, provided as PC-DR-157, Attachments H, I, and J. Sweigart 1-3, Devils Gap-Lind AM Analysis PowerPoint, NERC Line Ratings spreadsheet, FAC-501-WECC-1 wood pole management report.
  e) Please see PC-DR-157 Attachment H.
  f) Not applicable.
  g) $2,617,459 transferred to plant.
  h) $106,214 transferred to plant.
  i) $0
  j) Please see part (j) above for ER 2576.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/14/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	John Gross
TYPE:	Data Request	DEPT:	System Planning
REQUEST NO.:	PC – 158	TELEPHONE:	(509) 495-4591
		EMAIL:	john.gross@avistacorp.com

SUBJECT: Major Maintenance (Electric, Transmission)

REQUEST:

Please refer to Heather L Rosentrater, Exhibit HLR-6, at 8, which describes lists two projects which drive the 2021 and 2024 Transmission "Mandatory and Compliance" capital budgets.

- Saddle Mountain 230/115kV Station (New) Phase 2 ($10.7 M in 2021).
- Ninth & Central Sub — New 230kV Transformation ($9 M in 2024).

Provide, for each of these projects:

a) The NERC Reliability Standard or mandate which prompted the project.
b) Any evidence that compliance with this standard or mandate is required.
c) A description of the Standard or mandate deficiency the project will rectify, as well as how the deficiency represents a violation of the Standard or mandate.
d) Any test results, inspection reports, equipment capacity ratings, load forecasts, or other evidence which supports the deficiency.
e) Alternatives Avista considered to address the deficiency, including comparative benefit-cost analyses, comparative risk reduction estimates, technical assessments, or other analyses which indicate the alternatives to the project were inferior.
f) The timing by which the project must be completed per the NERC transmission planning standard for the identified deficiency.

RESPONSE:

Avista objects to this request because it seeks future information this is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	2/15/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	G. Madden/T. Benjamin
TYPE:	Data Request	DEPT:	Regulatory Affairs
REQUEST NO.:	PC - 159	TELEPHONE:	(509) 495-2225
		EMAIL:	tia.benjamin@avistacorp.com

SUBJECT: Electric Substation Rebuilds Program

REQUEST:

RE: Capital Additions, Test Year (electric)
Please refer to Heather L Rosentrater, Exhibit HLR-10, at 7, which lists eight projects denoted by Expenditure Request Numbers under the Substation Rebuilds program:

- 2112
- 2204
- 2215
- 2278
- 2283
- 2538
- 2569
- 2572

Provide, for each Expenditure Request Number:
a) A name and description of the project.
b) A list of assets replaced.
c) For each asset listed in b for each project, (i) the reason for asset replacement; (ii) the age of the asset upon replacement; and (iii) any test reports and/or inspection reports indicating test or inspection failure.
d) The amount added to rate base in 2018.
e) The amount added to rate base in 2019.
f) The amount added to rate base in 2020.
g) The amount projected to be added to rate base from 2021 to 2024 by year

RESPONSE:

ER 2112

a) Beacon 230 kV Substation - Convert station to Double Breaker Double Bus
b), c), d), e), f) No transactions since 2013.
g) Avista objects to this request because it seeks future information this is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

ER 2204 and ER 2215

a) Substation Rebuilds & Substation – Capital Spares – See Substation Rebuilds Business Case in Exh. HLR-11 for descriptions.

b), c) For a list of all assets replaced, please refer to the spreadsheet provided in response to PC-DR-099 Attachment A.
d) The system total amount added to rate base in 2018 is $14,303,800.
e) The system total amount added to rate base in 2019 is $16,943,484.
f) The system total amount added to rate base in 2020 is $16,143,340.
g) Avista objects to this request because it seeks future information this is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

ER 2278

a) System-Replace Obsolete Reclosers
b), c), d), e), f) No assets replaced or spend as this work is performed under ER 2215.
g) Avista objects to this request because it seeks future information this is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

ER 2283

a) Millwood Sub – Rebuild
b) All assets were installed in 2013 and 2014.
c) All assets were installed in 2013 and 2014.
d) The system total amount added to rate base in 2018 is ($1,673).
e) The system total amount added to rate base in 2019 is ($21).
f) The system total amount added to rate base in 2020 is $0.
g) Avista objects to this request because it seeks future information this is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

ER 2538

a) College & Walnut Substation Yard Expansion
b), c), d), e), f) No transactions since 2017.
g) Avista objects to this request because it seeks future information this is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

ER 2569

a) Gifford 115 kV - Rebuild Substation
b) All assets were installed in 2016 and 2017.
c) All assets were installed in 2016 and 2017.

d) The system total amount added to rate base in 2018 is $68.
e) The system total amount added to rate base in 2019 is $0.
f) The system total amount added to rate base in 2020 is $0.
g) Avista objects to this request because it seeks future information this is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

<u>ER 2572</u>

a) Noxon Construction Sub - Minor Rebuild
b) The system total amount added to rate base in 2018 is $0.
c) The system total amount added to rate base in 2019 is $0.
d) The system total amount added to rate base in 2020 is $0.
g) Avista objects to this request because it seeks future information this is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/12/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ken Sweigart
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC - 160	TELEPHONE:	(509) 495-4417
		EMAIL:	ken.sweigart@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L Rosentrater, Exhibit HLR-10, at 8, which describes multiple projects in the Transmission Major Rebuild program which Avista claims are required due to asset condition, including:

- ER 2550 — Burke-Thompson A&B 115kV Transmission Line rebuild;
- ER 2577 — Benewah-Moscow 230kV Transmission Line structure replacement;
- ER 2597 — Cabinet-Noxon 230kV Transmission Line rebuild; and
- ER 2596 — Lolo-Oxbow 230kV Transmission Line rebuild.

For each of these projects, provide:

a) All business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, or other documentation used by the "Asset Management group" to determine "Probability, Consequence, and Risk Summary." "[W]hich indicates which transmission lines are most in need of replacement due to end-of-life indicators" for each project, as described in Heather L Rosentrater, Exhibit HLR-11, at 49.
b) A list of all "outages related to asset failures" for each of the past five years that were used to justify each project.
c) The amount added to rate base in 2018.
d) The amount added to rate base in 2019.
e) The amount added to rate base in 2020.
f) The amount projected to be added to rate base from 2021 to 2024 by year.

RESPONSE:

<u>ER 2550</u>

a) Please see PC-DR-160 Attachment A (CDA – Rathdrum & Silver Valley Transmission Reinforcement PowerPoint). Burke-Thompson A&B lines of similar condition to Burke-Pine Creek #3 and #4 lines, but with the additional driver of having clearance violations with Winter snowpack, which is a safety issue.

b) The number of outages associated with asset failures occurring each year for each transmission line is not a specific metric used to justify this project, however, equipment failures and outages have been an important part of the analyses used to determine the value of replacing end of life assets, as shown in response to PC-DR-161, part (a). The Company recorded no outages on the Burke-Thompson line that resulted in a loss of service for our customers during the subject period. This should not be a surprise, however, since our transmission system, like that of all utilities, and consistent with the interest and intent of a range of federal regulations governing the bulk electric system, is designed, to the extent reasonable and cost effective, to withstand isolated outages on lines and to have other circuits in the network 'pick up' those customers and shield them from experiencing an outage.[2]

c) -$895,858 reconciliation from 2017.

d) $0

e) $0

f) Avista objects to this request because it seeks future information this is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

<u>ER 2577</u>:

a) Please see the attached BEN-MOS230 rebuild study results, provided as PC-DR-160 Attachment B.

b) The number of outages associated with asset failures occurring each year for each transmission line is not a specific metric used to justify this project, however, equipment failures and outages have been an important part of the analyses used to determine the value of replacing end of life assets, as shown in response to PC-DR-161, part (a). The Company recorded no outages on the Benewah-Moscow line that resulted in a loss of service for our customers during the subject period. This low number should not be a surprise, however, since our transmission system, like that of all utilities, and consistent with the interest and intent of a range of federal regulations governing the bulk electric system, is designed, to the extent reasonable and cost effective, to withstand isolated outages on lines and to have other circuits in the network 'pick up' those customers and shield them from experiencing an outage.

c) $50,026 transferred to plant.

d) $0

e) $0

f) Please see response above for ER 2550, part (f).

<u>ER 2597</u>

a) Please see attached PC-DR-160 Attachment C.

b) The number of outages associated with asset failures occurring each year for each transmission line is not a specific metric used to justify this project, however, equipment failures and outages have been an important part of the analyses used to determine the value of replacing end of life

[2] Avista's customers who are served from radial transmission lines in our system are more likely to experience an outage related to a transmission fault than those who receive network service.

assets, as shown in response to PC-DR-161, part (a). The Company recorded no outages on the Cabinet-Noxon line that resulted in a loss of service for our customers during the subject period. This should not be a surprise, however, since our transmission system, like that of all utilities, and consistent with the interest and intent of a range of federal regulations governing the bulk electric system, is designed, to the extent reasonable and cost effective, to withstand isolated outages on lines and to have other circuits in the network 'pick up' those customers and shield them from experiencing an outage.

c) $0

d) $0

e) $0

f) Please see response above for ER 2550, part (f).

<u>ER 2596</u>

a) Please see attached model assessment provided as PC-DR-160 Attachment D, and the design scoping document provided as PC-DR-160 Attachment E.

b) The number of outages associated with asset failures occurring each year for each transmission line is not a specific metric used to justify this project, however, equipment failures and outages have been an important part of the analyses used to determine the value of replacing end of life assets, as shown in response to PC-DR-161, part (a). The Company recorded three outages on the Lolo-Oxbow line that resulted in a loss of service for our customers during the subject period. This low number should not be a surprise, however, since our transmission system, like that of all utilities, and consistent with the interest and intent of a range of federal regulations governing the bulk electric system, is designed, to the extent reasonable and cost effective, to withstand isolated outages on lines and to have other circuits in the network 'pick up' those customers and shield them from experiencing an outage.

c) $0

d) $24,815 spent but not transferred to plant.

e) $5,758,924 spent but not transferred to plant.

f) Please see response above for ER 2550, part (f).

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/12/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ken Sweigart
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC - 161	TELEPHONE:	(509) 495-4417
		EMAIL:	ken.sweigart@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L Rosentrater, Exhibit HLR-11, at 49, and the Transmission Major Rebuild – Asset Condition program generally.

Please provide:

a) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, or other documentation used by the "Asset Management group" to determine "Probability, Consequence, and Risk Summary." "[W]hich indicates which transmission lines are most in need of replacement due to end-of-life indicators."
b) Provide a list of all "outages related to asset failures" for each of the past five years that were used to justify "Transmission Major Rebuild(s)".

RESPONSE:

a) In addition to the project specific studies included in response to PC-DR-160, please see the attached reports provided as PC-DR-161 Attachments A through F.

b) The number of outages associated with asset failures occurring each year for the transmission system is not a specific metric used to justify this project, however, equipment failures and outages have been an important part of the analyses used to determine the value of replacing end of life assets, as shown in response to PC-DR-161, part (a). We typically experience a small number of transmission outages each year that result in a loss of service for our customers. This low number should not be a surprise, however, since our transmission system, like that of all utilities, and consistent with the interest and intent of a range of federal regulations governing the bulk electric system, is designed, to the extent reasonable and cost effective, to withstand isolated outages on lines and to have other circuits in the network 'pick up' those customers and shield them from experiencing an outage.[3] A list of all transmission outages that have resulted in service outages for our customers during the subject period is provided as PC-DR-161 Attachment G.

[3] Avista's customers who are served from radial transmission lines in our system are more likely to experience an outage related to a transmission fault than those who receive network service.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/08/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ken Sweigart
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC - 162	TELEPHONE:	(509) 495-4417
		EMAIL:	ken.sweigart@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L Rosentrater, Exhibit HLR-11, at 50, which states "The recommended solution is to replace poles, cross-arms, and other assets where the majority of assets have been determined to have reached their end of life" and "There are no expected business impacts (such as staffing, etc.) to continue the program in place as it was split off of an existing business case."

Please provide:

a) The Recommendation (report, presentation, etc.), and support, for the Asset Management Group's "recommended solution" to "replace poles, cross-arms, and other assets where the majority of assets have been determined to have reached their end of life."
b) Actual Transmission Construction — Compliance capital spending by year for the last ten years.
c) An explanation as to how budgets from the "existing business case(s)" that were used to accomplish "Transmission Major Rebuild(s)."
d) An explanation as to why "Transmission Major Rebuild" needed to be "split off of an existing business case."

RESPONSE:

e) For an example of the asset management group's recommendations, please see the excerpt, below, from the Company's 2015 Transmission Asset Management Plan on the prudency of replacing end of life assets through Transmission Major Rebuilds for qualifying lines. A copy of this report is provided as PC-DR-162 Attachment A.

> "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 <u>shown major rebuilds as the optimal rebuild option</u> 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 <u>lowest lifecycle costs</u>, including <u>reduced business risk</u> and <u>lowest consequence costs for the customer</u>." *Underline Added.*

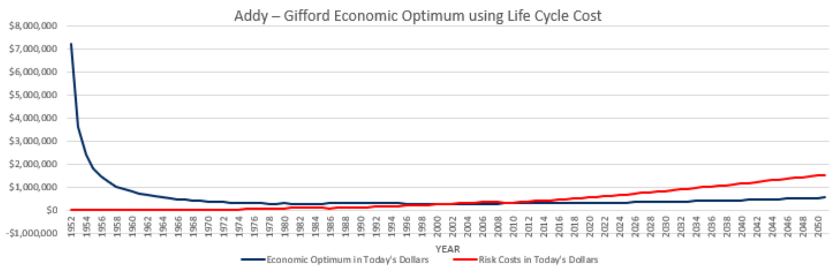
Another example is provided in the analysis performed by the Company's asset management group from a slide presentation illustrating the concept of the lifecycle cost analysis that supports the subject business case, and the concept of the economic optimum, that is, the need to replace assets that have reached the end of useful life.

Methodology for Ranking Lines: Economic Optimum

The economic optimum is the life expectancy of an asset during which time the asset is useful to the owner. The present value of the life cycle costs are plotted and the year where the costs are the lowest is the end of the useful life of the asset and identifies when the asset should be replaced due to rising costs. All the transmission lines are ranked according to the economic optimum year they should be replaced.

Methodology for Ranking Lines: Economic Optimum

As can be seen from Addy – Gifford, the line should have been replaced in 1985 when costs were at their lowest.



	1985
$	262,755.38
$	90,183.61
$	456,398.89

As illustrated in the slide above, assets reach a point (electric transmission in this case) where the cost to customers (which includes risk costs, repair and replacement costs, and customer outage costs) begin to rise above the economic optimum. In the case of the illustration above, and the excerpt and report (PC-DR-162 Attachment A) above that, Avista uses sophisticated asset management analyses to identify end of life assets that are in need of replacement and has developed prioritized lists of transmission lines that should be rebuilt or remediated through minor rebuild. And, as noted in the slide below, the magnitude of the risk and consequence costs are not the same for every asset (line in this case), which allows the need for remediation to be weighted and prioritized.

Methodology for Ranking Lines

Economic optimum for each line was calculated and the year that the line should be replaced is used to rank the lines. In determining what line to rebuild, it is important to look at the risk costs avoided by rebuilding the line. Some costs are so low that you can wait several years past the economic optimum before you rebuild the line.

AVISTA

Examples of the criteria and consequences used in prioritization, as described in the Company's 2015 Asset Management Plan, PC-DR-162 Attachment A, pages 19-22, include the probability index criteria and weightings, which Table 11 shows below, and the consequence index criteria and weightings, which are shown below that in Table 12.

% 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

% 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

These data are integrated in the lifecycle modeling to produce a prioritized list of transmission lines in need of investment based the probability of asset failures and the likely consequence of failure, and the resulting risk score, as shown below in Table 13 from the Company's 2016 Transmission Asset Management Plan, page 23.

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

The ranked risk scores among other factors are then used to develop a list of needed investments (projects) for each of the highest priority projects, as shown below in Table 19 (with brief excerpt language included) for Major Rebuild projects listed in PC-DR-162 Attachment A, page 30.

The most significant major rebuild and reconductor projects currently planned through 2017 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 2018 and 2019 in particular are only partially complete.

Description	BI	Description	2015	2016	2017	2018	2019
Pine Creek-Burke-Thompson Falls	CT101	Rebuild Transmission	$0	$0	$3,500,000	$0	$0
9CE-Sunset 115kV Transmission	ST503	Reconductor/Rebuild	$25,000	$900,000	$0	$0	$0
Garden Springs - Silver Lake 115kV	ST304	Recon/Rebld H&W to S Fairchild Ta	$0	$0	$25,000	$2,000,000	$0
Addy-Devils Gap 115kV	ST306	Reconductor/Rebuild near Ford Sul	$0	$0	$25,000	$2,000,000	$0
Benewah-Moscow 230kV	PT305	Reconductor/Rebuild	$7,815,802	$8,060,576	$8,302,393	$0	$0
Cabinet-Noxon 230kV	AT700	Reconductor/Rebuild	$0	$0	$0	$7,500,000	$7,500,000
Benewah-Pine Creek 230kV	CT908	Reconductor/Rebuild	$0	$0	$0	$0	$0
Lolo-Oxbow 230kV	LT900	Reconductor/Rebuild	$0	$0	$0	$0	$0
Transmission Reconductor/Rebuild	XT703	High Resistance Conductor Replace	$0	$0	$0	$2,000,000	$0
West Plains Trans Reinforcement	ST305	Garden Springs - Sunset	$25,000	$1,000,000	$0	$0	$0
CDA-Pine Creek 115kV Rebuild	CT300	Rebuild Transmission	$0	$0	$4,500,000	$5,000,000	$2,500,000
Devils Gap-Lind 115kV Rebuild	ST302	Rebuild Transmission	$3,947,144	$4,050,558	$0	$0	$0
Chelan-Stratford 115kV	BT304	Rebuild Columbia River Crossing	$400,000	$0	$0	$0	$0
Sys - Rebuild Trans - Condition	AMT81	BRX-CAB & BRX-SCR Rebuild	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,000,000
Ben-Oth SS 115 - ReCond/ReBld	FT130	Ben-Oth SS 115 - ReCond/ReBld	$3,600,000	$3,500,000	$0	$0	$0
		sum	$18,312,946	$20,011,134	$18,852,393	$21,000,000	$12,000,000

Table 19: Major Rebuild Projects, 2015 – 2018

f) Please see the Company's response to PC-DR-155, parts (e) and (f).

g) Prior to 2017 most transmission line projects were captured under the Transmission – Reconductor & Rebuilds Business Cases as indicated in the except above Table 19 from the Company's 2015 Transmission Asset Management Plan.

d) Concurrent with the Company's realignment of Business Cases by Investment Drivers in 2017, it was decided that large and small asset condition transmission line projects should not be funded from the same Business Case. Because of the sometimes-large cost to construct disparity between large and small asset condition projects, any reduction adjustments to requested budget amounts would either significantly reduce the number of smaller asset condition projects that could be completed or impact the efficient prosecution of the larger project component. It was determined that separating the small and large asset condition projects into their own business cases would provide greater visibility to the needs of each.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/10/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ken Sweigart
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC - 163	TELEPHONE:	(509) 495-4417
		EMAIL:	ken.sweigart@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L Rosentrater, Exhibit HLR-11, at 50, which states, regarding Avista's Transmission System Asset Management Plan, "The 30-year replacement period is recommended at $21.1 million per year, split between $11.3 million for 115kV and $9.8 million for 230kV. This policy, when coupled with an ongoing, annual risk assessment and targeting of funds, over the long term will effectively reduce risks and minimize total lifecycle costs".

Confirm that "Avista's Transmission System Asset Management Plan" is the same as the Avista's "Transmission Infrastructure Plan" (Heather L Rosentrater, Exhibit HLR–6). If this is confirmed, identify where in HLR-6 a "30-year replacement period" is recommended. If this cannot be confirmed, provide the Transmission System Asset Management Plan and cite the reference.

RESPONSE:

The subject plan is not the same document as the Exh. HLR-6, but rather, is the Company's Electric Transmission System Asset Management Plan, provided as PC-DR-162 Attachment A. The asset management plan provides the analysis and modeling results used to help the Company identify investment needs based on end-of-life asset replacements and a range of other factors used to support transmission business case investments, such as Electric Transmission Construction – Compliance and Asset Condition. The subject citation comes from an overview of a recommended 30-year spending plan on page 15.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	2/15/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 164	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Major Maintenance

REQUEST:

Please refer to Heather L Rosentrater, Exh. HLR-6 (Transmission Infrastructure Plan) at 4, which states "Thousands of transformers, reactors, capacitors, conductors, poles and structures are well past their expected lifespans. Avista has transmission lines that are over 110 years old. Though the Avista transmission group is replacing these lines as funding is available and changing out wood structures with more resilient steel, the need continues to outpace the ability and funding to complete all the work that must be done."

For each of the six asset types listed (transformers, reactors, capacitors, conductors, poles and structures), provide:

a) The average age (in years) of that type of asset on the Avista system.
b) The age of the youngest asset of that type on the Avista system.
c) The age of the oldest asset of that type on the Avista system.
d) The average age of the assets of that type that have been replaced in the last five years.
e) The age of the youngest asset of that type that has been replaced in the last five years.
f) The age of the oldest asset of that type that has been replaced in the last five years.

RESPONSE:

<u>Substation Power Transformers</u>

a) 33.42 years.
b) 1 year.
c) 74 years.
d) 59 years.
e) 40 years.
f) 79 years.

<u>Transmission Poles and Structures</u>

a) 40.96 years.
b) ≤ 1 year.
c) 113 years.
d) 55.86 years.
e) 4 years.

f) 98 years.

<u>Substation Reactors</u>

a) 4.54 years.
b) 4 years.
c) 5 years.
d) n/a
e) n/a
f) n/a

<u>Substation Capacitor Banks</u>

a) 19.58 years.
b) 4 years.
c) 47 years.
d) 38 years.
e) 38 years.
f) 38 years.

<u>Conductors</u>

a) The Company's transmission lines carry many different types of conductors, composed of different materials, of various segment lengths, installed at different times - related to a wide range of factors. The type of "system-level" information requested for thousands of miles of conductors, composed of many more thousands of miles of individual segments (within lines) of different types of conductors, ages, and dates of installation and retirements (in contrast with the assets listed above) has no practical use, and is therefore not available.
b) 1 month.
c) 113 years.
d) Please see part (a) above.
e) Please see part (a) above.
f) Please see part (a) above.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/11/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ken Sweigart
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC - 165	TELEPHONE:	(509) 495-4417
		EMAIL:	ken.sweigart@avistacorp.com

SUBJECT: Major Maintenance

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-6 (Transmission Infrastructure Plan) generally.

Confirm that the Plan does not state it is necessary to replace assets that are over 30 years old.

RESPONSE:

Please cite to any such reference in question.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	2/12/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	John Gross
TYPE:	Data Request	DEPT:	System Planning
REQUEST NO.:	PC – 166	TELEPHONE:	(509) 495-4591
		EMAIL:	john.gross@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 52–58, regarding the Westside 230/115kV Substation Rebuild project generally.

a) Describe in detail the load growth on this asset that has precipitated this problem, when it first occurred, and the forecast rate of load growth into future years.
b) Explain why "nonconsequential load shedding" cannot be a permanent solution.
c) Provide the details of the "requirements in Table 1 of NERC TPL-001-4."
d) Describe in detail how the "System performance analysis indicates an inability of the system to meet the performance requirements in Table 1 of NERC TPL-001-4 in scenarios representing 2017 Heavy Summer for P1 events."
e) Indicate those parts of this NERC standard which makes this project necessary.
f) Provide evidence that Avista compliance with this NERC standard is mandatory.

RESPONSE:

a) Please see Attachment A, Avista's 2017 Electric Integrated Resource Plan, page 3-22, Figure 3.15 and supporting dialogue within the document for a detailed description of the load growth precipitating the Westside autotransformer overload problem. The problem was projected to first occur in summer peaking conditions of 2017. In 2017, the forecast rate of load growth into future years was 0.42%.

b) Non-consequential load shedding is the act of manually de-energizing portions of the electric system and putting customers in the dark.[4] Intentionally blacking out portions of our system, in particular, when suggested as a permanent solution to avoid overloading a single piece of equipment is generally not a prudent utility practice. In addition to being an imprudent practice in this instance, NERC standard TPL-001-4 Table states non-consequential load loss is not allowed for P1 events, which would put the Company in violation for such a practice. Footnote 12 of Table 1 implies the Washington State Commission would be a stakeholder in approving the use of intentionally dropping service to customers as a prudent alternative.

c) Table 1 of NERC TPL-001-4 states several requirements. With respect to the Westside 230/115kV Station Rebuild, note part (f) is applicable here, stating "Applicable Facility Ratings shall not be exceeded." Conducting the steady state portion of the Planning Assessment required under R3, if simulations show a P1 category contingency from Table 1 does not meet note (f) criteria a correction action plan is necessary according to R2.7

[4] Except when it's light outside, and then they just experience a service outage.

d) Please see details provided in Attachment B on how the System performance analysis indicates an inability of the system to meet the performance requirements in Table 1 of NERC TPL-001-4 in scenarios representing 2017 Heavy Summer for P1 events. Section II starting on page 3 describes the simulated performance issues. In summary, an outage of the Westside #2 230/115kV Transformer (P1 event from Table 1) caused the Westside #1 230/115kV Transformer to exceed its applicable facility ratings to a level of 123.8% in scenarios representing 2018 peak summer conditions.

e) Studies provided in response to part (c) clearly show the inability to meet the requirements of the TPL-001-4 standard. The specific part of the standard driving the project is requirement R2.7, which states "shall include Corrective Action Plan addressing how the performance requirements will be met." Subpart R2.7.1 includes a list of possible associated actions needed to achieve required System performance which includes "installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment."

f) Please refer to Attachment C (Energy Policy Act of 2005), and refer to Title XII – Electricity, Subtitle C – Reliability Standards.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	2/15/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 167	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 179, regarding Protection System Upgrades for PRC-002.
a) How long has the "NERC PRC-002-2 standard requirements of fault recording" been in place?
b) Indicate those parts of this NERC standard which makes these projects necessary.
c) Provide evidence that Avista compliance with this NERC standard is mandatory.
d) How long has Avista been out of compliance with this standard?
e) Does NERC have a grandfather clause that applies to this standard?

RESPONSE:

a) PRC-002-2 became mandatory and enforceable on July 1, 2016.

b) NERC PRC-002-2 is attached as PC-DR-167 Attachment A, which subject requirement R1 1.1 states:

R1. Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]
1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1.

Avista performed the analysis according to the methodology in Attachment 1, which produced the results provided as PC-DR-167 Attachment B, file named "PRC-002 Bus Fault Summary and Analysis 2016.xlsx". From the derived list of BES busses, the capability of the Protection Systems to perform SER and FR was evaluated per PRC-002-2, requirements R2, R3 and R4.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]
3.1 Phase-to-neutral voltage for each phase of each specified BES bus.
3.2 Each phase current and the residual or neutral current for the following BES Elements:
3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

Where deficiencies to perform PRC-002-2 R2, R3 and R4 were identified, a project to upgrade the Protection System was developed.

c) On September 17, 2015, pursuant to Section 215 of the Federal Power Act, FERC issued Order No. 814 [Docket No. RM15-4-000] approving Reliability Standard PRC-002-2. PRC-002-2 applies to NERC-registered Transmission Owners and Generation Owners. Avista is a NERC-registered Transmission Owner and Generator Owner.

References

FERC Order 814
https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/Order%20No%20814%20Approving%20Relaibility%20Standard%20PRC-002-2.pdf

Reliability Standard PRC-002-2: https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-002-2.pdf

NERC Registrations: (see PC-DR-167 Attachment A).

d) Avista is NOT out of compliance with PRC-002-2 as it is currently implementing PRC-002-2 pursuant to the FERC-approved NERC Implementation Plan.

e) NERC does not have a grandfather clause that applies to PRC-002-2.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/15/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ryan Bradeen
TYPE:	Data Request	DEPT:	Downtown Electric Network
REQUEST NO.:	PC - 168	TELEPHONE:	(509) 495-4760
		EMAIL:	ryan.bradeen@avistacorp.com

SUBJECT: Major Maintenance

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 202, regarding the Downtown Network — Asset Condition program generally.

a) Provide the number of customer complaints and reasons for the complaints for each of the last five years associated with the Downtown Network.
b) Provide the number of safety issues that have occurred in each of the last five years associated with the Downtown Network.
c) Provide the number of power quality problems Avista has observed in each of the past five years associated with the Downtown Network.
d) Provide a list of types of equipment on the Downtown Network. For each type of equipment listed provide: (i) the average age of each equipment type; (ii) the youngest age of each equipment type; (iii) the oldest age of each equipment type; (iv) the number of equipment failures for each of the last five years.
e) For transformers and network protectors replaced in the past five years, provide the age of the oldest asset at the time of replacement and the age of the youngest asset at the time of replacement.
f) Provide the number of outages and their causes on the Downtown Network for each of the last five years.

RESPONSE:

As noted below, information in this subject request, parts (a-c), are not among the data used by Avista to support its decision-making related to investments in the Spokane Downtown Network, and consequently, we do not track the information in the form it has been requested.

d) Avista is very attentive to the service and satisfaction of its customers and to carefully addressing issues they have, particularly those that rise to the level of a formal complaint. In its experience, however, the Company has not found individual customer complaints to be a useful metric in helping to guide infrastructure planning or investments.

e) The same can be said for safety incidents, where we carefully evaluate the root cause and take appropriate steps to help ensure risks to our employees and/or customers are effectively reduced and managed. But individual safety incidents typically do not rise to the level of being useful in systematic infrastructure planning.

f) In the same way, power quality issues that arise with our customers are evaluated on a case-by-case basis, are appropriately investigated, and are timely and effectively resolved. Resolving power quality issues naturally requires infrastructure solutions in some cases (typically at the customers' service or feeder section), but they do not rise to the level of being useful in systematic infrastructure planning, such as in the Spokane Downtown Network.

g) Equipment Information

Transformers

i. 20
ii. 1950
iii. 2019
iv. Three

Network Protectors

i. 20
ii. 1962
iii. 2019
iv. None

e) Replacements

i. Transformers – Oldest 1960 / Youngest – 2006
ii. Network Protectors – Oldest 1962 / Youngest – 1992

f) Two: (1) trespass into vault resulted in forced outage; (1) manhole fire resulted in forced outage. It's actually very unusual to have customer outages in the Downtown Network, since like our networked transmission system, it is designed to withstand outages on individual circuits and to have other redundant circuits in the network 'pick up' those customers that would otherwise have experienced an outage. In addition, unlike overhead electrical systems, nearly all of the equipment for the network is located in underground vault and conduits.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/15/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ryan Bradeen/Brian Chain
TYPE:	Data Request	DEPT:	Downtown Electric Network
REQUEST NO.:	PC - 169	TELEPHONE:	(509) 495-4760
		EMAIL:	ryan.bradeen@avistacorp.com

SUBJECT: Major Maintenance

REQUEST:

RE: Major Maintenance
Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 217, regarding the Downtown Network — Performance and Capacity program generally.

a) Provide the present capacity of the network.
b) Provide the present loading of the network.
c) Provide the load growth on the network for the past five years.
d) Explain how Avista addressed capacity issues on the Downtown Network prior to this program.
e) Explain why this new program is superior to the historic approach.

RESPONSE:

a) The Downtown Network is served from two substations, with a total 100 MVA transformer capacity spread among two transformers at each station. Fourteen primary (13.2 kV) feeders serve concentrated loads split into four networks (two networks with four primary feeders and two networks that have only three). Powerflow studies check for contingency loading in the event a substation power transformer or a primary feeder in any given network is out of service. This effectively reduces the 100 MVA transformation capacity to 70 MVA (without one of the 30 MVA units in service). Two 10 MVA non-network feeders are also connected, which further reduces the overall transformation capacity to 50 MVA for the network. The powerflow / contingency requirement also reduces the primary feeder capacities in each network (i.e. the four-feeder networks are required to be able to operate with only three feeders energized under peak load, and the three-feeder networks must operate with only two feeders energized). This combination of requirements results in a hypothetical worst-case contingency state of only ten 5 MVA feeders operating from three transformers with 50 MVA of spare capacity.

b) In a non-contingency state, the eight feeders served from the Post Street substation are averaging nearly 2.25 MVA, while the six feeders served from the Metro substation are averaging approximately 2.75 MVA. During contingency conditions, with primary feeders out of service, these feeders can feasibly peak at 30-50% higher loading. Primary and secondary low voltage circuits downstream can vary widely depending on system topology, with each individual network branch having its own load and corresponding capacity constraints. Capacity is added to the system (usually via cable reconductor projects) when capacity overloads are detected, either under present loading conditions (as shown by AMI metering data fed into the powerflow model), or if capacity overloads are detected given new customer loads notified to Avista. Often, the capacity constraints are detected further down the feeder away from each substation, in sections with smaller conductor size.

c) Peak load demand on the network has been relatively flat, measured as a sum total across all networks. In 2020, however, loads were down as many office buildings sat empty and shops/restaurants were shuttered in response to the pandemic. That said, certain blocks served by the Downtown Network have seen significant re-development, accompanied by increasing loads. Even though these new buildings have often had NEC-calculated peak demands under 500 kVA, they invariably end up stressing elements of the primary or secondary network grid, and additional cable must be installed, or a transformer size increased, in order to ensure that the system as a whole will perform within limits during contingency loading.

d) The Company has introduced new planning tools over the past 15 years, which have been helpful in the planning process with the data historically available. The combination of data now available from AMI and "smart" transformer vault communications, has allowed us to fully realize the usefulness of these planning tools to both anticipate and mitigate problems before they occur, while at the same time, avoiding the installation of capacity that may not be timely utilized.

Prior to receiving this request, Avista was asked to provide several internal documents that were identified by links in Exh. HLR-11, but which were not available to Public Counsel or the other Parties. Two of those papers refer to the Company's Downtown Electric Network and have been provided here as PC-DR-169, Attachments A and B.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/14/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	John Gross
TYPE:	Data Request	DEPT:	System Planning
REQUEST NO.:	PC – 170	TELEPHONE:	(509) 495-4591
		EMAIL:	john.gross@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 294, regarding the New Distribution Station Capacity Program generally.

a) If the spending in this program was due to forecasted or actual substation overloads, identify the transformers, the capacities and the overloads that justified this spending.
b) If the spending was justified based on factors other than overloading, provide those factors and detailed explanation of those factors.
c) If spending was justified based on both loading and other factors, please explain each.
d) The statement "customers can likely continue to receive electric service at a level that they have grown accustom to receiving" would indicate that if this program was not completed in 2020, reliability for customers would deteriorate. Provide data that Avista used to project these decreases in reliability, including reliability metrics and values in dollars.

RESPONSE:

a) Spending in this program for years 2018-2020 was primarily for increasing capacity at the following stations. The list of stations includes reference to the requested information, which is attached.
    a. Boulder - Please refer to PC-DR-170 Attachment A, which provides substation loading including transformers and feeders. The Barker 115/13kV T1 Transformer was projected to be loaded to 92% of its applicable facility rating.
    b. Dalton – Please refer to PC-DR-170 Attachment B, which provides substation loading including transformers and feeders. The Dalton 115/13kV T2 Transformer was shown to have an actual loading of 87% of its applicable facility rating.
    c. Mead – Please refer to PC-DR-170 Attachment C, pages 69-70, which provides historical demand for feeders MEA12F1 and MEA12F2. Actual feeder loading was shown to be 81% and 86% for each feeder, respectively.
    d. Southeast – Please refer to PC-DR-170 Attachment C, pages 95-99, which provide historical demand for feeders SE12F1, SE12F2, SE12F3, SE12F4 and SE12F5. Actual feeder loading on SE12F2 was shown to be 94%.

b) Spending was justified based on overloading factors.

c) Please see responses to parts (a) and (b), above.

d) The statement referenced in the request alluded to the possibility of manually de-energizing portions of the electric system to prevent equipment from exceeding its applicable facility rating. The act of de-energizing portions of the electric system, as explained by the Company in response to PC-

DR166, would cause an outage for customers, which would negatively impact their service reliability. As explained in part (b) above, the subject investments are based on equipment overloading factors. Not properly providing for the capacity necessary to reliably serve our customers could have an impact on the reliability of their service, which would be an added consequence to overloading equipment, however, the prudence of the investments in question, as noted above in response to part (b), is based on equipment overloading factors, and does not include the additional cost customers would experience if we were forced to interrupt their service.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/14/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	John Gross
TYPE:	Data Request	DEPT:	System Planning
REQUEST NO.:	PC – 172	TELEPHONE:	(509) 495-4591
		EMAIL:	john.gross@avistacorp.com

SUBJECT: Major Maintenance (Electric)

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 295, regarding the discussion of "Alternatives considered".

a) Provide list of all "obsolete" and "end-of-life apparatus".
b) Provide the criteria Avista uses to classify each apparatus as "obsolete".
c) Provide the criteria Avista uses to classify each apparatus as "end-of-life".
d) Provide evidence that each apparatus classified as "obsolete" cannot be obtained from any manufacturer.
e) The statement "Extension of distribution feeders from neighboring substations and increased capacity at those substations would be required at a minimum" implies that load forecast or other studies have identified insufficient capacity on the system "neighboring substations." Provide the forecasts and or other studies which shows this lack of system capacity through 2025.
f) Provide the studies calculations that Avista performed which would show the "Increased liability" that "would result" from a lack of this program.

RESPONSE:

a) Please see the Company's response to PC-DR-100 parts (d).

b) Please see the Company's response to PC-DR-100 parts (c).

c) Avista uses a range of typical approaches for determining the end of life of assets, including asset condition based on general and infrared inspections, as described in response to PC-DR-100 part (b), age, obsolescence and lifecycle costs.

d) The fact that an apparatus may be available for purchase, does not obviate the practical need to make asset decisions in the aggregate that allow us to run an efficient, reliable and cost-effective operation.

e) The statement implies nothing about any condition of "insufficient capacity on the system." It simply refers to the fact that if a neighboring substation is tapped to pick up new load, that is, "new load that was not previously in the load forecast for that substation and its feeders," then the capacity at the neighboring station may be insufficient, and regardless, will have to undergo capacity increases earlier in time than was initially forecast. The Company looks for opportunities to tap available capacity from substations, such as those that may have lost a large historic load, to supply feeders from adjacent stations, through the segment reconductor and feeder tie program.

f) The statement simply means that if the Company does not prudently plan for the timely investments in the infrastructure it needs to serve its customers, it will ultimately be held responsible for the consequences of such action or inaction.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 208	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:
Please refer to Attachment A provided by Avista in response to Public Counsel Data Request No. 99, which provides a list of equipment replacements and the reasons for those replacements.
For approximately 306 of the 512 pieces of equipment replaced, the reason for replacement given was "Obsolescence". For each piece of such equipment:

a) Name the piece of equipment replaced.
b) Provide the capital cost.
c) Identify if the equipment was operating safely or not at the time of replacement.
d) For each piece of equipment which was not operating, or not operating safely, provide the length of time the item had not been operating/safe.
e) For each piece of equipment which was not operating, or not operating safely, identify if it failed in service.
f) For each piece of equipment which was not operating, or not operating safely, identify if it failed an objective test or formal inspection.
g) For each piece of equipment replaced, regardless of operation/safety, provide the age upon replacement of the oldest item of that equipment type ever replaced anywhere on Avista's system.
h) For each piece of equipment replaced, regardless of operation/safety, provide the age of the oldest item of that equipment type currently operating anywhere on Avista's system.

RESPONSE:

a) Please Refer to PC-DR-208 Attachment A, which provides additional information to the file originally provided as part of our response to PC-DR-099. The requested information is provided in sheets labeled "2018", "2019" and "2020," under Column C "Equipment Name."

b) Please refer to "PC-DR-208 Attachment A". Sheets "2018", "2019" and "2020." Column D contains "Equipment Costs," which list dollar amounts for purchase cost of the equipment.

c) Equipment replaced in the Substation Rebuilds Program during 2018-2020 for the reason of obsolescence was not specifically designated as being replaced due to safety concerns only. The need to mitigate safety concerns is a consideration among others we have already discussed in replacing equipment determined to be obsolete as part of an entire substation being rebuilt. Please refer to PC-DR-103 for our characterizations of the application of safety in infrastructure planning, and PC-DR-209 for the description and examples of the tools used to identify such equipment.

d) Please see part (c), above.

e) While the information provided in PC-DR-208 A does not indicate whether an obsolete piece of equipment failed in service, Avista endeavors to ensure this is a rare event, given our experience with the emergency replacement times for key pieces of substation equipment, as noted in the table below.

Equipment Type	Estimated Replacement Duration
Voltage Regulator	16 Hours
LV Breaker	2 Days
HV Breaker	1 Week
Power Transformer	1 Week

f) To make the determination whether a piece of equipment is not operating properly, or not operating safely, Avista uses objective tests and/or formal inspections to make that determination. The tests vary depending on the piece of equipment in question.

g) Please Refer to PC-DR-208 Attachment A. Sheet "2018", "2019" and "2020". Column F "Age upon Replacement."

h) Please refer to PC-DR-208 Attachment A, Sheets labeled PC-208, Part h, Equip Type Data.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 210	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to the Direct Testimony of Heather L. Rosentrater, Exhibit HLR-1T, at 33, which states "Rebuilding significant portions of stations may be necessary to accommodate the replacement of failing or obsolete equipment since new standard-use apparatus and equipment is often of higher capacity and newer technology and may need to meet updated equipment spacing and operating standards." Please refer also to Avista's Response to Public Counsel Data Request No. 100, and to Attachment A provided in response. The outages in Attachment A appear to be associated with both substation and feeder outages, though it is Public Counsel's understanding that the Station Rebuild Program was intended to replace failed and/or obsolete equipment within the substation.

a) Identify each outage in Attachment A as either (i) caused by equipment within the substation yard; or (ii) caused by equipment or other factors external to equipment within the substation yard.

b) For each outage in Attachment A identified as caused by equipment or other factors external to equipment within the substation yard, provide justification for replacing equipment within the substation yard.

c) The response to PC-DR-100 states "The table below includes the Company's system values for SAIFI and SAIDI for 2014–2020 (excluding outages associated with major events), and the percentage of these system values attributed to substation outages of all causes, as shown in PC-DR-100 Attachment A." Identify

    (i) the system-wide values for SAIFI and SAIDI for each of the outages in Attachment A that were caused by equipment within the substation yard; and

    (ii) the system-wide SAIFI and SAIDI for each of the outages in Attachment A that were caused by equipment or other factors external to equipment in the substation yard.

RESPONSE:
The subject testimony in the request does not speak to or reference the subject matter of the requests.

a) Please see PC-DR-210 – Attachment A, columns "Outage Reason" and "Reason"/Sub Rsn".

b) Please see PC-DR-210 - Attachment A, columns "Outage Reason," "Reason"/"Sub Rsn" and "Last Remark".

c) While the Company can report out the contribution to annual reliability performance of its transmission and distribution systems, and substations, Avista neither calculates nor tracks IEEE index values, including SAIFI and SAIDI, for the failure of individual pieces of equipment that result in a service outage for our customers.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 211	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Avista's Response to Public Counsel Data Request No. 101, which states "For substation equipment listed in PC-DR-099, Attachment A, with the Reason listed as Overloading, the equipment was considered to be already overloaded by the time that it was replaced. Note that Avista considers anything loaded at or above 80% as being 'overloaded.'"

a) Confirm that equipment loaded to 80 percent can continue to operate safely and reliably for many, many years, including years beyond the depreciable life used for accounting purposes, if it never becomes overloaded. If this cannot be confirmed, please explain.

b) For each item that was replaced, provide the Avista projection of when the item would have been 100 percent overloaded.

c) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, or other documentation or industry publications which indicate that substation equipment loaded in excess of 80 percent should be replaced.

d) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, or other documentation or industry publications which indicate that replacing substation equipment loaded in excess of 80 percent delivers benefits to customers in excess of costs to customers.

RESPONSE:

a) Avista plans, designs, operates, and maintains its transmission system and substations to be capable of supporting loads during peak periods of heavy demand and, and specifically to avoid the next outage, referring to the need for contingency planning. In this regard, contingency planning refers to capacity that may be 'unused' in normal operating conditions, but that is fully utilized during unplanned outage events to maintain the electrical integrity of the system. This common utility philosophy and practice helps ensure customers don't experience major outage events that could occur without such contingency and capacity planning in electric transmission and substations. As such, the question being asked in this request is misleading and irrelevant to the design and operation of the system, for which the Company's standard is appropriate. When determining how to address an overload, Avista considers several alternatives such as increased capacity on existing equipment, adding additional equipment at an existing substation, or building a new substation.

b) Per the explanation in part (a) above, from a transmission and substation contingency planning perspective, for which the subject standard is relevant, Avista considers the subject equipment to be overloaded for contingency operations when it is 80% loaded under normal operating conditions.

c) Please see part (a) above, and the supporting documents provided in PC-DR-211 Attachment A, B and C, which include Standard Operating Procedures (SOP) 19 Transformer Alarms and Short-Term Loading, SOP 34 Transmission Line Five Minute Ratings, and DP-SPP-01 Distribution Substation Planning.

d) Please refer to parts (a) and (c) above.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 212	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Avista's Response to Public Counsel Data Request No. 101 f, g, and h, which states "Equipment replaced in the Substation Rebuilds Program during 2018 - 2020 was not specifically designated as being replaced due to only the 'need to meet updated equipment spacing and operating standards.' The need to meet updated equipment spacing and operating standards is a consideration in replacing equipment as part of an entire substation being rebuilt. Please refer to the Engineering Roundtable (ERT) Engineering Project Request documents for information on specific substation rebuilds, provided as PC-DR-101 Attachments A–J." Confirm that "updated equipment spacing and operating standards", on their own, can never justify replacing equipment. If this cannot be confirmed, please explain.

RESPONSE:

Consistent with its previous statements, including the excerpt in the request above, relying on "updated equipment spacing and operating standards," as might possibly be evaluated as the sole reason for replacing substation equipment, would not typically rise to the level of warranting equipment replacement.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 213	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Avista's Response to Public Counsel Data Request No. 101 i, j, and k, which states "Equipment replaced in the Substation Rebuilds Program during 2018-2020 was not specifically designated as being replaced due to only the "updated design and construction standards." The need to meet updated equipment design and construction standards is a consideration in replacing equipment as part of an entire substation being rebuilt. Please refer to the Engineering Roundtable (ERT) Engineering Project Request documents for information on specific substation rebuilds, provided in PC-DR-101 Attachment A." Confirm that "updated design and construction standards," on their own, can never justify replacing equipment. If this cannot be confirmed, please explain.

RESPONSE:

Consistent with its previous statements, including the excerpt in the request above, relying on "updated design and construction standards," as might possibly be evaluated as the sole reason for replacing substation equipment, would not typically rise to the level of warranting equipment replacement.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 214	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:
Please refer to Avista's Response to Public Counsel Data Request No. 101 and associated Attachment A.
The response states "Avista structures supporting BPA Switch B839 inside Bell Substation have reached danger status and must be removed or replaced. Additionally, under certain heavy summer and winter loading conditions an outage to either the Bell 230/115kV transformer or one of Avista's two 115kV ties to Bell will trigger an operating situation under which the RC may issue an operating instruction to Avista to separate its 115kV ties at Bell (to mitigate the overload of Avista's 115kV facilities under a next contingency) and an operating instruction to BPA to shed load served from its Bell 115kV bus (to mitigate voltage collapse at the Bell 115kV bus under a next contingency)."

a) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, or industry publications which allows Avista engineers and field personnel to classify equipment as having "reached danger status."
b) Provide a detailed definition of "danger status".
c) Provide any and all documentation which indicates that equipment must be replaced when it reaches "danger status".
d) Does the "under certain heavy summer and winter loading conditions" create a situation where the loading of "the structures supporting BPA Switch B839 inside Bell Substation" exceed the emergency ratings of that equipment? If so, provide documentation of the emergency ratings of the equipment in question.
e) Indicate whether the situation described in this response constitutes an N-1 situation or an N-2 situation.

RESPONSE:

a) Please see part (b) below.

b) "Danger Status" is not an official term used by Avista to classify equipment, but is a descriptor used by the Bonneville Power Administration (BPA) for equipment that could fail based on evaluations it conducted. BPA uses "Danger Status" as a way of assigning a level of urgency to certain projects. The specific process that results in a designation of "Danger Status" is not known to Avista in its entirety.

c) Please see parts (a) and (b) above.

d) The electrical loading of equipment is not typically correlated with the structural integrity of transmission line structures. It is possible in certain instances to replace a transmission line structure to achieve a higher equipment rating, but often times the conductor is the most limiting element.

e) The situation described in the response constitutes a "P6 situation" as defined by Table 1 of TPL-001-4. A P6 situation is the outage of a piece of equipment followed by a subsequent outage of another piece of equipment, historically referred to as N-1-1. Operationally, after the first outage occurs, the electrical system must be capable of meeting performance requirements for the next possible outage. If the electrical system does not meet performance requirements for the next possible outage, then action needs be taken as described in the subject citation and response to PC-DR-101.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 215	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Avista's Response to Public Counsel Data Request No. 101 and to Attachment E (Colville Transformer No. 2 Replacement) provided.

a) Provide the cost to replace Colville Transformer No. 2.

b) Provide the age of the oldest transformer currently operating on the Avista system.

c) Provide the age at replacement of the oldest transformer Avista has ever replaced on its system.

d) Provide a count of transformers currently operating on the Avista system for which oil is observable on the outside of the transformer. If this count is not available, estimate the percentage of transformers currently operating on the Avista system for which oil is observable on the outside of the transformer.

e) Provide any internal standard, inspection guide, test, or other document which indicates the amount of observable oil which justifies a transformer replacement.

f) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, or industry publications which indicate that oil observed on the outside of a transformer justifies replacement.

g) Has Avista had transformers operate safely and reliably for many years with oil observed on the outside of that transformer?

h) Explain why Avista would not just change out the under-rated switch gear for Colville Transformer No. 2.

i) Provide the most recent Dissolved Gas Analysis (DGA) for Colville Transformer No. 2 (or, alternatively, the last DGA completed on Colville Transformer # 2 prior to replacement).

j) In the event the Colville Transformer No. 2 fails, describe the actions Avista will take to mitigate customer impact (meaning, the prescribed N-1 action).

RESPONSE:

a) Total cost for the Colville Transformer #2 replacement project was $ 680,524.

b) The oldest transformer (Equipment Type: Power Transformer) currently operating on the Avista system is 75 years.

c) The oldest transformer replaced, using current Asset Management (Maximo) information, was 81 years.

d) Avista estimates the percentage of transformers currently operating for which oil is observable outside of the transformer to be 15%.

e) Avista considers many factors when determining the need to replace a transformer based on asset condition, which include, but are not limited to, asset health data, environmental considerations, age, visual inspection, and operating history. PC-DR-101 Attachment E lists the various drivers for this project.

f) See Part (e).

g) Please see part (d) above.

h) Avista evaluates the issues, needs and ultimate scope for each project, and identifies appropriate actions based on the number, range and severity of problems identified. Had the only problem with the subject transformer been identified as an under-rated circuit switcher, then Avista would have limited the project scope to solve that problem. Clearly, that was not the case.

i) See Pd-DR-215 – Attachment A "CLV T2 5067947 TOA Analysis Report".

j) In the event of a transformer failure Avista would have taken advantage of all available options to pick up load with adjacent equipment and feeders (<u>hence the need for available equipment capacity and loadings as described in PC-DR-211</u>). Once those options were fully optimized Avista would either install a mobile transformer and/or replace the transformer as quickly as possible.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 216	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Avista's Response to Public Counsel Data Request No. 101 and to Attachment "F" (Ford Substation Rebuild) provided.

a) Provide a list of the outages caused by the equipment at this substation over the past five years, as well as the outage report for each such outage.
b) Provide a list of customer complaints related to the outages listed in subpart (a) over the past five years.
c) Provide a list of power quality issues identified at this substation over the past five years.
d) Provide a list of any safety events recorded at this substation over the past five years, as well as the safety event report for each such event.
e) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, or industry publications which justifies the rebuild of this substation.
f) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, or other documentation which indicates the benefits of this substation rebuild to customers exceeded the cost to customers of this substation rebuild.

RESPONSE:

a) Please refer to the data provided in response to PC-DR-210 Attachment A. There were no customer outages on the list that were caused by equipment at this station. This is not uncommon, as we typically experience a small number of substation outages each year that result in a loss of service for our customers. This low number reflects our efforts to avoid equipment failures in our substations, which can have a substantial impact on the service reliability of customers. Such outages can impact service on entire feeders, including all of the feeders associated with a station, which can be thousands of customers, and can require substantial time to repair or remediate, which time could be up to a week, as shown in the table for emergency repairs provided in response to PC-DR-208.

b) Avista is very attentive to the service and satisfaction of its customers and to carefully addressing issues they have, particularly those that rise to the level of a formal complaint. In its experience, however, the Company has not found individual customer complaints to be a useful metric in helping to guide infrastructure planning or budgeting. Accordingly, the information in this subject request is not among the data used by Avista to support its decision-making related to the electric substation rebuilds in general, or this project in particular, and consequently, we do not track the information in the form that has been requested. Please see the problem statement in Staff-DR-101 Attachment F.

c) Power quality issues related to substation equipment may be among the data considered by the Company in determining the need to rebuild a substation. But power quality issues are a small part of the many different needs, activities and costs included in this business case, and they are not tracked by individual pieces of equipment in the Company's system. Please see the problem statement in Staff-DR-101 Attachment F.

d) Avista carefully evaluates the root cause of safety incidents and takes appropriate steps to help ensure risks to our employees and/or customers are effectively managed. But individual safety incidents typically do not rise to the level of being useful in systematic infrastructure planning or budgeting. Accordingly, the information in this subject request is not among the data used by Avista to support its decision-making related to electric substation rebuilds, generally, or this project in particular. Consequently, we do not track the information in the form it has been requested. Please see the problem statement in Staff-DR-101 Attachment F.

e) In addition to PC-DR-101 Attachment F, referenced here, please see the following documents provided in PC-DR-216 Attachment A, titled Brown Glass Survey, Maximo – Work Order History Lists – FOR, and Wood Subs Survey – 2014-01.

f) As part of our regulatory compact Avista is required to take the reasonable and prudent steps necessary to ensure we provide an acceptable level of electric service, both in the eyes of our customers and the Commission. Avista has documented the need to rebuild the subject station and has demonstrated that its actions are reasonable. Because the cost to customers is necessary and reasonable, and because the investment allows us to cost effectively meet our long-term service obligation to our customers, it is prudent and in the interest of our customers.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 217	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:
Please refer to Avista's Response to Public Counsel Data Request No. 101 and Attachment "G" (Kamiah Substation Rebuild) provided.

a) Provide a list of the outages caused by the equipment at this substation over the past five years, as well as the outage report for each such outage.
b) Provide a list of customer complaints related to the outages listed in response to subpart (a).
c) Provide a list of power quality issues identified at this substation over the past five years.
d) Provide a list of any safety events recorded at this substation over the last five years, including issues that have occurred over the past five years.
e) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, or industry publications which justifies the rebuild of this substation.
f) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, or other documentation which indicates the benefits to customers of this substation rebuild exceeded the cost to customers of this substation rebuild.

RESPONSE:

a) Please refer to the data provided in response to PC-DR-210 Attachment A; there were two customer outages on the list that were required to perform work at this station. An outage on October 22, 2015 was required to perform a transformer tap change on Transformer #1, clean the insulators on the circuit switch due to fire and smoke contaminates, and hang switch signs. The outage on November 5, 2015, was required to replace/repair a sudden pressure relay cable on Transformer #1. Each outage impacted service to 1,392 customers. Having no outages, or a small number of them, is not uncommon, as we typically experience few substation outages each year that result in a loss of service for our customers. This low number reflects our efforts to avoid equipment failures in our substations, which can have a substantial impact[5] on the service reliability of customers. We also endeavor to minimize forced outages required to perform maintenance or repairs.

b) Avista is very attentive to the service and satisfaction of its customers and to carefully addressing issues they have, particularly those that rise to the level of a formal complaint. In its experience,

[5] Outages resulting from equipment failures in our substations can impact service on entire feeders, including all of the feeders associated with a station, which could be thousands of customers (as in the example above impacting 1,392 customers), and can require substantial time to repair or remediate, which time could be up to a week, as shown in the table provided in PC-DR-208.

however, the Company has not found individual customer complaints to be a useful metric in helping to guide infrastructure planning or budgeting. Accordingly, the information in this subject request is not among the data used by Avista to support its decision-making related to the electric substation rebuilds in general, or this project in particular, and consequently, we do not track the information in the form that has been requested. Please see the problem statement in PC-DR-101 Attachment G.

c) Power quality issues related to substation equipment may be among the data considered by the Company in determining the need to rebuild a substation. But power quality issues are a small part of the many different needs, activities and costs included in this business case, and they are not tracked by individual pieces of equipment in the Company's system. Please see the problem statement in PC-DR-101 Attachment G.

d) Avista carefully evaluates the root cause of safety incidents and takes appropriate steps to help ensure risks to our employees and/or customers are effectively managed. But individual safety incidents typically do not rise to the level of being useful in systematic infrastructure planning or budgeting. Accordingly, the information in this subject request is not among the data used by Avista to support its decision-making related to electric substation rebuilds, generally, or this project in particular. Consequently, we do not track the information in the form it has been requested. Please see the problem statement in PC-DR-101 Attachment G.

e) In addition to PC-DR-101 Attachment G, referenced here, please see the documents provided in PC-DR-217 Attachment A, titled Brown Glass Survey, Maximo – Work Order History Lists – KAM, and Wood Subs Survey – 2014-01.

f) As part of our regulatory compact Avista is required to take the reasonable and prudent steps necessary to ensure we provide an acceptable level of electric service, both in the eyes of our customers and the Commission. Avista has documented the need to rebuild the subject station and has demonstrated that its actions are reasonable. Because the cost to customers is necessary and reasonable, and because the investment allows us to cost effectively meet our long-term service obligation to our customers, it is prudent and in the interest of our customers.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 217	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:
Please refer to Avista's Response to Public Counsel Data Request No. 101 and Attachment "G" (Kamiah Substation Rebuild) provided.

g) Provide a list of the outages caused by the equipment at this substation over the past five years, as well as the outage report for each such outage.
h) Provide a list of customer complaints related to the outages listed in response to subpart (a).
i) Provide a list of power quality issues identified at this substation over the past five years.
j) Provide a list of any safety events recorded at this substation over the last five years, including issues that have occurred over the past five years.
k) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, or industry publications which justifies the rebuild of this substation.
l) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, or other documentation which indicates the benefits to customers of this substation rebuild exceeded the cost to customers of this substation rebuild.

RESPONSE:

g) Please refer to the data provided in response to PC-DR-210 Attachment A; there were two customer outages on the list that were required to perform work at this station. An outage on October 22, 2015 was required to perform a transformer tap change on Transformer #1, clean the insulators on the circuit switch due to fire and smoke contaminates, and hang switch signs. The outage on November 5, 2015, was required to replace/repair a sudden pressure relay cable on Transformer #1. Each outage impacted service to 1,392 customers. Having no outages, or a small number of them, is not uncommon, as we typically experience few substation outages each year that result in a loss of service for our customers. This low number reflects our efforts to avoid equipment failures in our substations, which can have a substantial impact[6] on the service reliability of customers. We also endeavor to minimize forced outages required to perform maintenance or repairs.

h) Avista is very attentive to the service and satisfaction of its customers and to carefully addressing issues they have, particularly those that rise to the level of a formal complaint. In its experience,

[6] Outages resulting from equipment failures in our substations can impact service on entire feeders, including all of the feeders associated with a station, which could be thousands of customers (as in the example above impacting 1,392 customers), and can require substantial time to repair or remediate, which time could be up to a week, as shown in the table provided in PC-DR-208.

however, the Company has not found individual customer complaints to be a useful metric in helping to guide infrastructure planning or budgeting. Accordingly, the information in this subject request is not among the data used by Avista to support its decision-making related to the electric substation rebuilds in general, or this project in particular, and consequently, we do not track the information in the form that has been requested. Please see the problem statement in PC-DR-101 Attachment G.

i) Power quality issues related to substation equipment may be among the data considered by the Company in determining the need to rebuild a substation. But power quality issues are a small part of the many different needs, activities and costs included in this business case, and they are not tracked by individual pieces of equipment in the Company's system. Please see the problem statement in PC-DR-101 Attachment G.

j) Avista carefully evaluates the root cause of safety incidents and takes appropriate steps to help ensure risks to our employees and/or customers are effectively managed. But individual safety incidents typically do not rise to the level of being useful in systematic infrastructure planning or budgeting. Accordingly, the information in this subject request is not among the data used by Avista to support its decision-making related to electric substation rebuilds, generally, or this project in particular. Consequently, we do not track the information in the form it has been requested. Please see the problem statement in PC-DR-101 Attachment G.

k) In addition to PC-DR-101 Attachment G, referenced here, please see the documents provided in PC-DR-217 Attachment A, titled Brown Glass Survey, Maximo – Work Order History Lists – KAM, and Wood Subs Survey – 2014-01.

l) As part of our regulatory compact Avista is required to take the reasonable and prudent steps necessary to ensure we provide an acceptable level of electric service, both in the eyes of our customers and the Commission. Avista has documented the need to rebuild the subject station and has demonstrated that its actions are reasonable. Because the cost to customers is necessary and reasonable, and because the investment allows us to cost effectively meet our long-term service obligation to our customers, it is prudent and in the interest of our customers.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Lisa La Bolle
TYPE:	Data Request	DEPT:	Wildfire Resiliency
REQUEST NO.:	PC - 219	TELEPHONE:	(509) 495-2612
		EMAIL:	lisa.labolle@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

RE: Capital Additions, Test Year (Electric)
Please refer to Attachment A provided Avista's Response to Public Counsel Data Request No. 105, "Electric Distribution Infrastructure Plan" dated June, 2017.
Figure 3 on page 9 of this Plan provides "Distribution Average Capital Cost per Customer" both nationally and for Avista.

a) Identify the distribution capital accounts on FERC Form 1 used to calculate this data.
b) Identify the utilities included in the "national" figures presented.
c) If Avista did not calculate this data on its own, cite the source of these figures.
d) Provide the national and Avista data for Figure 3 for 2013 through 2019 by year.

RESPONSE:
Figure 3 relies on data through 2016, which was the latest available data from FERC Form 1 when this report was written. FERC uses a database called Microsoft Visual Foxpro which is not available to Avista, has not been updated since 2007, and will not run on current operating systems. However, for several years the University of Texas Energy Institute downloaded FERC Form 1 data and provided it in an Excel format on a public forum, with data starting in 1994. Avista downloaded this data from the referenced source located at: https://openei.org/datasets/dataset/ferc-form-1-electric-utility-cost-energy-sales-peak-demand-and-customer-count-data-1994-2016 This dataset is no longer available online and was not updated after 2016 (no reason is listed on the University's website). The raw data acquired from the University of Texas Energy Institute for years 2013 through 2016, which was used to create Figure 3 is attached as PC-DR-219 Attachment A.

a) The cost categories used to create Figure 3 are specified in PC-DR-219 Attachment A, line 1, columns D through Z.
b) The subject Attachment A lists the utilities included in the "national" figures.
c) Results shown in Figure 3 were calculated by dividing the aggregated Distribution Capital Additions (by year) by the aggregated total number of customers (by year) for all the utilities for which data was collected via FERC Form 1 and included in PC-DR-219 Attachment A. Results for Avista were then segregated from the results for all utilities and the same calculations were performed in order to compare the two. The raw data was converted to 2016 dollars using the Handy Whitman Cost Inflator.
d) Avista has not updated the results used to create Figure 3, in part, because as explained above, the Company does not have access to FERC Form 1 data in a usable electronic format.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas/Heather Webster
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 220	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Electric Distribution Grid Modernization

REQUEST:

Please refer again to the June, 2017 Electric Distribution Plan provided in Avista's Response to Public Counsel Data Request No. 105, at 11, which states "Avista considers electric system reliability in nearly all its investment decisions, however, it does make certain investments solely on the basis of their reliability value. One such effort is the Company's Feeder Automation Program, which is carried out through our Distribution Grid Modernization effort. For this planning period, Avista expects to invest an average of $0.9 million each year to capture reliability benefits through feeder automation."

a) Provide a list of circuits to which automation devices were added by year, and the amount spent annually on feeder Automation by year for each of the past 10 years. Indicate whether or not the amounts provided include the cost of feeder ties and upgrades required to take advantage of the automation.

b) Estimate the number and duration of outages required to install these devices, and a count of customers affected, by year for each of the past 10 years. Provide a list of circuits to which Avista plans to add automation devices in each of the next five years, as well the amount Avista expects to spend annually on feeder Automation by year. Indicate whether or not the amount provided include the cost of feeder ties and upgrades required to take advantage of the automation.

c) Estimate the number and duration of outages Avista expects will be required to install these devices, and a count of customers affected, by year for each of the next five years.

d) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, which indicate that spending "$0.9 million each year to capture reliability benefits through feeder automation" produces a higher dollar value to the rate payer than the cost to the rate payer.

RESPONSE:

a) Costs in the table below include those for planning, design, and construction necessary to add automation devices to the feeders listed. As we have stated in prior responses related to Avista's grid modernization program, in multiple instances, planning and design took place in the year prior to construction. Any work necessary to construct feeder ties and upgrades to take advantage of the automation is included in the costs provided.

Year	Feeder	Annual Cost
2012	N/A	$ -
2013	N/A	$ -
2014	N/A	$ -
2015	RAT233	$ 2,528
	WAK12F2	$ 369,804
	RAT233	$ 172,648

	RAT231/233	$ 164,707
	MIL12F2	$ 103,984
	TUR112	$ 673
	ORO1280	$ 67,440
	PDL1201	$ 7,724
	SPI12F1	$ 1,900
	SPR761	$ 7,695
2017	HOL1205	$ 3,606
	MIL12F2	$ 89,174
	MIS431	$ 207,169
	ORO1280	$ 110,569
	PDL1201	$ 242,387
	RAT231/233	$ 373,970
	SPI12F1	$ 23,581
	SPR761	$ 67,647
	TUR112	$ 82,221
	WAK12F2	$ 94,680
2018	HOL1205	$ 191,308
	MIS431	$ 61,224
	M15514	$ 208,023
	SIP12F4	$ 929
	SPR761	$ 13,756
2019	M15514	$ 254,789
	SIP12F4	$ 2,899
2020	MIS431	$ 132,142
	M15514	$ 121,344
	ORO1282	$ 18,497
	ROS12F4	$ 17,639
	SIP12F4	$ 156,902

b) The number and duration of outages required to install a device would depend on system configuration and options in the area of the device installation and what other work might be planned in the area. In general, one outage is taken for the installation of an automation device. The number of planned outages and the associated outage duration is not tracked by individual pieces of equipment. Avista objects to the request for investments planned in future years because it seeks future information this is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

c) Please see the applicable portion of the response in part (b) above.

d) Subject information has been provided by the Company in response to PC-DR-110, including Attachments P, Q and R.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Mark Gabert
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 221	TELEPHONE:	(509) 495-8747
		EMAIL:	mark.gabert@avistacorp.com

SUBJECT: Electric Distribution Wood Pole Management

REQUEST:

Please refer again to the June, 2017 Electric Distribution Plan provided in Avista's Response to Public Counsel Data Request No. 105, at 13, which states "Avista has 347 overhead electric feeders that are supported by approximately 240,000 wood poles. Poles and equipment comprise the primary infrastructure of the Company's electric distribution system. Avista's wood pole population is inspected on a 20-year cycle interval, which means about 12,000 poles are inspected on average each year. The capital investments made under this program cover the needed repair and replacement of poles and attached equipment that is identified during the inspections. The average annual investment planned for this program is $9.8 million."

a) Provide a table showing the number of poles replaced, and annual cost to replace them, by year for each of the past 10 years.
b) Provide, for each year of the past 10, the average age upon replacement of the wood poles Avista replaced that year.
c) Provide a table showing the number of poles Avista expects to replace, and the anticipated cost to replace them, by year for each of the next five years.
d) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, which shows that spending "The average annual investment" of "$9.8 million" delivers benefits to customers in excess of costs to customers.

RESPONSE:

a) Please see the table below for the subject costs by year. Costs shown are for pole replacements only and do not include the associated costs for replacing cross arms, identified cutouts, stolen grounds, pole reinforcements (stubbing), wildlife guards, leaky or undersized transformers, retirement of idle poles and equipment, removing double wood poles, adding lightning arresters, or adding poles to correct clearance issues.

Year	Number of Poles Replaced in WA	Average of Age of Pole Replaced	Cost
2011	524	55.4	$2,096,000
2012	729	51.1	$2,976,507
2013	659	58.8	$2,759,892
2014	636	61.7	$2,731,620
2015	627	59.3	$2,761,935
2016	651	58.2	$2,941,218
2017	684	55.1	$3,169,656
2018	850	61.7	$4,040,050

2019	809	61.5	$3,743,875
2020	1118	61.2	$5,590,000
Grand Total	7287	58.4	

b) Please see the table provided in part (a), above.

c) Avista objects to this request because it seeks future information this is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

d) Please see the Company's 2017 Wood Pole Management Program Review and Recommendations, and Wood Pole Management business case, provided here as PC-DR-221 Attachments A and B, respectively.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 222	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Electric Distribution Grid Modernization

REQUEST:

Please refer again to the June, 2017 Electric Distribution Plan provided in Avista's Response to Public Counsel Data Request No. 105, at 72, which states, regarding Avista's "grid modernization" program, "This program was designed for a 60-year cycle interval and is dovetailed with the Wood Pole Management program to optimize capital work on our overhead feeders. While replacing assets at the end of their useful life, Grid Modernization delivers a range of benefits that include improved reliability, energy conservation, and reduced operating costs. The planned investments to be made under this program average $13.6 million annually."

a) Provide a table showing the amount spent on Distribution Grid Modernization by year for each of the past 10 years.
b) Provide a table showing the amount Avista expects to spend by year on Distribution Grid Modernization for each of the next five years.
c) Provide a list of feeders addressed by the program in 2018, 2019, and 2020. For each feeder, provide (i) a list of work completed on the feeder; (ii) the cost of the work completed (the total costs should add up to the amounts provided in response to subpart (a); and (iii) the SAIDI and SAIFI statistics for the feeder for each of the three years prior to the year in which the work was completed.
d) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, which shows that spending "The average annual investment" of "$13.6 million" delivers benefits to customers in excess of costs to customers.

RESPONSE:

a) The table below provides the annual spend from the last 10 years for feeder upgrade and automation in the Grid Modernization program.

Year	Grid Mod Spend
2012	$ 7,362,925
2013	$ 7,308,357
2014	$ 10,143,566
2015	$ 12,060,958
2016	$ 10,857,817
2017	$ 16,480,311
2018	$ 15,302,937
2019	$ 10,699,836
2020	$ 7,701,965

b) Avista objects to this request because it seeks future information this is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

c) The list of feeders addressed each year is provided in the table below.

  i. The work planned for each of these feeders is described in PC-DR-110 Attachments A through J.

  ii. Costs for work completed on each feeder in each year have already been provided in response to PC-DR-110. In addition to the costs for each feeder for each year, two other incidental projects were completed under the program, the LOPP removal project and the addition of primary metering points. The LOPP project removes bare poles no longer in service that have already been replaced by new poles, but which were not removed during the initial construction. Installation of new primary metering points provides the Company operational information on parts of our system where we do not currently have SCADA information. The cost includes of $107,647 and $1,697 for primary metering in 2018 and 2019, respectively, and $27,369 for LOPP removals in 2018. Adding these totals to the expenditures by year as provided in PC-DR-110 will match the results provided in part (a) above.

  iii. The Company provided a description of the approach it has used for measuring reliability benefits for feeders treated under the grid modernization program, provided in response PC-DR-111.

d) Avista is required to take the reasonable and prudent steps necessary to ensure we provide an acceptable level of service for our customers and in compliance with Commission and federal guidelines and directives. A utility's need to replace aging infrastructure to achieve these aims is beyond any reasonable debate. The question then, is whether these actions have been conducted in a proven, cost effective and prudent manner. Avista has demonstrated that the individual actions taken in the grid modernization program have been properly evaluated and shown to be cost effective for customers as provided in the examples below.[7]

  e) Avista has documented through asset management analysis and reliability modeling that customers are better off financially if the Company replaces wood poles at the end of their useful life instead of allowing them to fail in service, as explained and supported in the Company's 2017 Wood Pole Management Program Review and Recommendations, and Wood Pole Management business case, provided as PC-DR-221 Attachments A and B, respectively.

  f) Similarly, Avista has documented that our customers are better off financially if we replace certain aging transformers during our wood pole management follow-up work or

[7] This list is not intended to be comprehensive or complete in proving all of the benefits achieved through grid modernization, which more complete explanations are provided in the Company's feeder baseline reports provided in PC-DR-110 Attachments A-O.

through grid modernization, as documented in the Avista's Transformer Changeout Program, provided in PC-DR-232 Attachment A.

g) The Company has demonstrated that our customers are better off financially when we assess and replace undersized conductor during feeder rebuilds (in addition to the savings for upgrading appropriated transformers, noted in part (ii) above), to achieve substantial and cost effective energy conservation savings, as shown in response to PC-DR-110.

h) In addition to these individual programs, the integration of these and multiple other improvement actions undertaken in a grid modernization project allows the Company to deliver additional cost-effective savings to our customers in the following areas. Please see a brief discussion of these areas of improvement provided in response to PC-DR-110, and in the feeder baseline reports provided at PC-DR-110 Attachment A-O:

- ✓ Load balancing
- ✓ Removing high-loss conductors (noted above)
- ✓ Resizing trunk conductors
- ✓ Resizing lateral conductors
- ✓ Improving voltage quality
- ✓ Improve/refine voltage regulation
- ✓ Reduce energy waste through line losses (noted above)
- ✓ Evaluating a correcting power factor

Additionally, because these actions are integrated into one overall program, we are able to perform this wide range of improvements (and many others too numerous to mention here) with fewer service outages, allowing us to minimize the impact we have on our customers. As noted above and as documented in the Company's responses to the data requests cited, including the many others not mentioned here, Avista's actions have been demonstrated to be reasonable, cost effective and in our customers' best interest. Because the cost to customers is necessary and reasonable, and because the investment allows us to meet our short and long-term service obligations to our customers, these investments are deemed to be prudent and in the interest of our customers.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/11/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC – 223 REVISED	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Electric Distribution Grid Modernization

REQUEST:
Please refer again to the June, 2017 Electric Distribution Plan provided in Avista's Response to Public Counsel Data Request No. 105, at 45 which states, regarding Avista's wood pole replacement and "grid modernization" programs, "In addition to repairing and replacing wood poles, these programs, working jointly, also install new equipment including crossarms, transformers, grounding, lightning arresters, and cutouts."

a) Confirm that the statement above is referring to the replacement of existing equipment with new equipment, and not to the installation of equipment which had not previously been in place. If this cannot be confirmed, please explain.
b) For each of the past five years provide the average age at which each type of the equipment listed is replaced: (i) crossarms; (ii) transformers; (iii) grounding; (iv) lightning arrestors; (v) cutouts.
c) In the case of "cutouts", confirm that Figure 23 is showing the actual failure of cutout equipment, and does not include service interruptions of cutouts or fuses that blow in the routine course of operation or for other forms of cutout-related incidents. If this cannot be confirmed, please explain.
d) As shown on Figure 23, confirm that the average reduction in the number of cutout failures per year from 2005 to 2016 is from about 250 per year to about 100 per year, for a reduction of about 150 per year. If this cannot be confirmed, please explain.
e) Provide the number of cutouts preemptively replaced by year since 2005.
f) Provide the number of cutouts Avista plans to preemptively replace by year over the next five years.
g) Provide the average cost to preemptively replace a set of cutouts.
h) As shown on Figure 23, confirm that the average reduction in the number of transformer failures per year from 2005 to 2016 is from about 200 per year to about 100 per year, for a reduction of about 100 per year. If this cannot be confirmed, please explain.
i) Confirm that all transformer related outages shown in Figure 23 are from transformer failures and not from some other transformer related incidents, such as animal contact or transformer internal fuse (CSP). If this cannot be confirmed, please explain.
j) Provide the number of distribution transformers preemptively replaced, by year, for each type of transformer since 2005: (i) Three phase banks; (ii) Two phase banks; and (iii) Single phase banks.
k) Provide the number of transformers Avista plans to preemptively replace by year over the next five years.
l) Provide the average cost to preemptively replace a distribution transformer, by type: (i) three phase bank; (ii) two phase bank; (iii) single phase bank.
m) Provide the number of outages caused by cross arm failures by year since 2005.
n) Provide the number of cross arms replaced preemptively by year since 2005.
o) Provide the number of cross arms (excluding those for the Wildfire Plan) Avista expects to preemptively replace by year for the next five years.

Response:

a) Most often this includes replacing existing equipment with new, however, in some cases, equipment is repaired such as the practice of stubbing wood poles that are determined upon inspection to be appropriate for this treatment. In addition to replacing end of life equipment, certain equipment may be added that was not previously in place, including wildlife guards, avian protection, etc., which is included to bring construction up to current standards. Additional new poles may also be added due to reroute or long span lengths or when overhead equipment is converted to underground. All work is performed to the DFMP standards. Replacement of transformers and cutouts is per specifications outlined in the Company's Distribution Feeder Management Plan (DFMP), previously provided in this case.

b) Crossarms, transformers, grounds, lightning arrestors, and cutouts are replaced per the DFMP standards and are called out during design. Avista has not historically tracked the age of each individual piece of equipment attached to the pole that is listed in the request, and these assets unless known to be otherwise (typically transformers) are assumed to be the age of the pole to which they are attached. For average pole ages of poles replaced please see the Company's response to PC-DR-221. The average age of electric distribution transformers replaced in the last five years is 42.5 years.

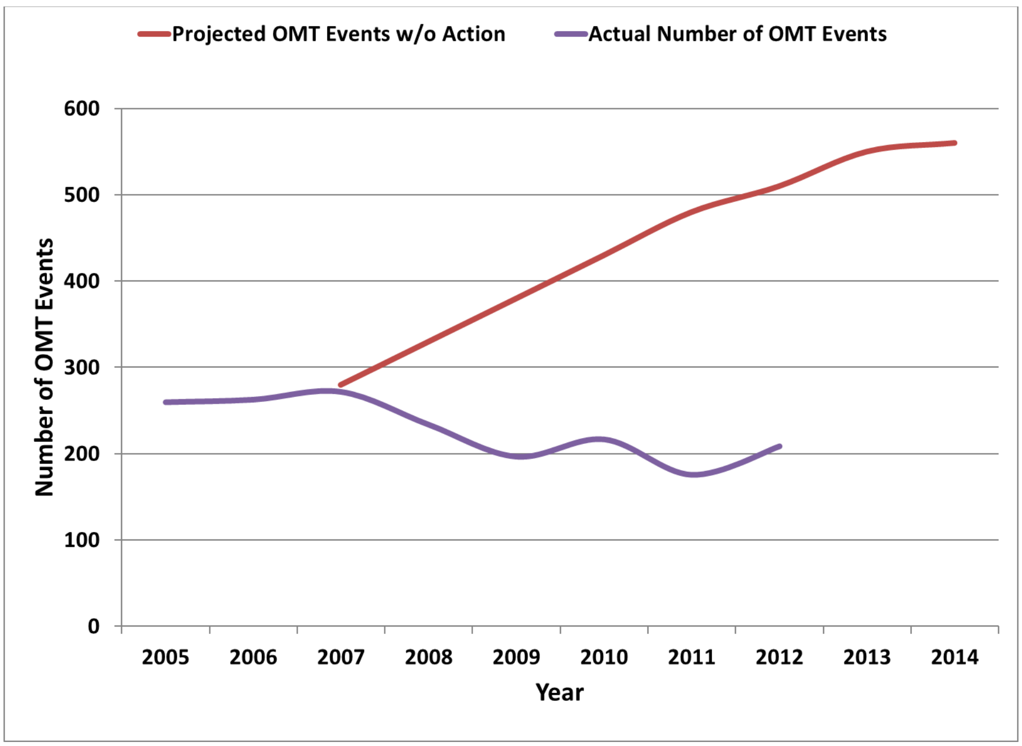
c) Numbers of cutout failures in Figure 23 represent failures of the equipment in service and not a blown cutout fuse resulting from a fault. These failures were typified by older and faulty cutouts, which had been specified by the Company for removal and replacement during Grid Modernization, Wood Pole Management and Distribution Minor Rebuild, and which included Chance, Durabute/V-shaped, Open Fuse Link/Grasshopper, Q-Q, Load Break/Elephant Ear, and Porcelain Box Cutouts). Among these, the predominant cutouts that were targeted for removal were manufactured by A.B. Chance, a problem noted across the industry, as typified by the subject citation footnoted here.[8] The combined benefits of this targeted removal, which included employee and customer safety, avoided customer outage hours, reduced fire risk, and reduced emergency repairs yielded a substantial financial benefit. For the discussion of distinguishing between cutout failures and blown fuses, please see the Company's response to PC-DR-229, including PC-DR-229 Attachment A.

d) Avista notes that Figure 23 represents the annual number of cutout and transformer failures that resulted in a service outage for customers for the period of time 2005 through 2016. It's also important to note that the reliability benefits for customers shown in the figure represent only one of the risk costs associated with these assets.

[8] The Farmington fire was an extreme example of what can happen when a cutout fails. But older cutouts -- especially those made by Chance -- fail more frequently than other types, according to a utility company study, persuading utility companies around the Northeast, including CL&P;, to replace them. Unions representing lineman whose safety depends upon reliable equipment say replacements are not going fast enough. They fear that the older porcelain-insulated cutouts jeopardize public safety. "They're basically a time bomb that should be aggressively pursued," said John Unikas of Local 420 of the International Brotherhood of Electrical Workers, which represents many CL&P; line workers. Unikas said the union complained to CL&P; about A.B. Chance porcelain cutouts. The union also complained to the U.S. Occupational Safety and Health Administration about an April 20, 2004, incident in Goshen, where a Chance ceramic cutout failed. In that incident, like in Farmington, a cross arm burned, causing a high voltage wire to drop, in this case, onto the wire carrying electricity to a house. It damaged the home's electrical system and some appliances. Reports of problems with A.B. Chance cutouts seem to be confined to northern climates, and utility officials suspect the freeze-thaw cycle is to blame. A `TIME BOMB' SITS ATOP 30,000 UTILITY POLES IN STATE - Hartford Courant

More important than the annual number of cutout failures shown in Figure 23 is the modeled forecast of cutout failures <u>that would likely have occurred if not for the systematic replacement of these devices as undertaken by the Company</u>. The figure below shows actual failures that resulted in an outage for customers (Actual OMT Events), and in the red line, the projected number of events, which were forecast to nearly double over the time frame shown, had Avista not undertaken the systematic replacement of these high-risk cutouts through Grid Modernization and Wood Pole Management. Accordingly, the measure of the customer value achieved through the replacement is not the reduction stated in the request above, rather, it's the reduction from approximately 560 annual outage events projected by in the figure below, compared with the number that actually occurred.

Table PC-DR-223 part (d) Outage Forecasts for High-Risk Cutouts without Systematic Replacement, and With Replacement as Conducted by Avista.[9]



Avista does not agree with the oversimplified characterization used by Public Counsel as "preemptive replacement." The Company replaces assets in service at the end of their useful lives. Some assets are allowed to 'run to fail' if the combined risk costs associated with the failure are less than the costs required to systematically replace the equipment before it fails in service. Designation of run to fail for certain assets, however, is not a static determination because it is based on the cost of undertaking an effort to replace the asset prior to failure on a standalone basis – that is, based on the unit cost to canvass the system in an operation to replace only that one type of asset, and nothing else. A good example of this is Avista's subject replacement of cutouts (and distribution transformers). For both these assets, the Company's typical approach is to replace these assets when they fail in service. This makes sense because the failure typically results in an outage for a small

[9] The forecast of outages resulting from cutout failures "projected OMT events w/o action" is based on lifecycle cost modeling using the Isograph Availability Workbench model initially performed in 2007-2008. The figure shows results of the initial model forecasts without action compared with then-current actual outage events through year 2012. Figure 23 in PC-DR-105 Attachment A shows the continuing reduction in cutout failures for the years 2013 through 2016, to the approximate number of annual failures predicted by the modeling.

number of customers, the replacement assets are readily available, and the time required for repair/replacement is not unreasonable. As an alternative, replacing these two assets at end of life but prior to failure, in a standalone replacement effort, would still result in an outage for customers.

That said, it can make sense to replace what would typically qualify as 'run to fail' assets, at the end of their useful lives but prior to failure in service, like cutouts and distribution transformers, if there are additional risk factors that increase the consequence costs[10] of a failure in service to a point beyond the systematic replacement costs as measured by a positive customer internal rate of return. This especially makes sense if the unit cost of replacement can be lowered still by performing the work during another already programmed project, in particular, when that program work may already require a service outage for customers. Such is the case for the Company's prior programs to replace high-risk cutouts and risky and inefficient PCB transformers as part of its ongoing programs for wood pole management and grid modernization. Replacement of these assets as part of these programs has been demonstrated to be cost effective and in the interest of our customers.

e) Avista does not agree with the oversimplified characterization used by Public Counsel as "preemptive replacement." The Company replaces assets in service at the end of their useful lives in the manner deemed to be in our customers' best interest measured both financially and otherwise.[11] Cutouts are replaced per Avista's DFMP standards, which includes the various reasons described above in part (d). Cutouts for distribution grid modernization and distribution minor rebuild, storm damage repair, etc., are included in the order for all material required for the construction of the final design and are not tracked at the level of the individual cutout. Avista has queried its wood pole management data bases and is able to provide the number of end of life cutouts replaced for each of the following years: 2011 (2,884); 2012 (2,340); 2013 (1,650); 2014 (1,418); 2015 (2,150); 2016 (1,439); 2017 (1,365); 2018 (1,685); 2019 (1,771); 2020 (1,196).

f) Avista objects to this request because it seeks future information this is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

g) While as noted above, Avista does not 'preemptively replace' cutouts, a contemporary cost to replace a set of three line cutouts can range as high as $1,918.89, depending on whether the line is energized, whether they are attached to a new pole and crossarm assembly or replaced in place, whether the location is accessible by bucket truck, etc. [12]

h) Avista notes that Figure 23 represents the annual number of cutout and transformer failures that resulted in a service outage for customers for the period of time 2005 through 2016. It's also important to note that the reduction in number of outages shown in the figure represents only one of the risk costs associated with these assets. And, as noted above in part (d), the reliability benefit is not measured by the difference in numbers observed in 2005, for instance, compared with results for 2016, <u>it's measured from the high end of the forecast of the outages (not shown in Figure 23)</u>

[10] Or a corresponding increase in benefits of replacement, such as the energy conservation savings associated with replacing pre-1981 distribution transformers.
[11] The financial value to customers from an avoided outage is measured financially in Avista's analysis, but this does not capture the hardship and difficult experience a customer may have during a service outage.
[12] These represent the cost of replacement today, which costs are greater than Avista's unit cost experience at the time cutout replacements were initially modeled by the Company.

that would have occurred absent the systematic replacement program, such as shown in Figure PC-DR-223 part (d) for high-risk cutouts.

i) Numbers of transformer failures in Figure 23 represent failures of the equipment in service and not a blown cutout fuse, or high or low side connectors, or animals, etc. As noted for cutout failures in part (c), above, and as discussed in PC-DR-229 part (a), transformer failures are determined based on the remarks of field crews performing the repairs associated with the subject outage. A listing of the Company's transformer related outages is provided in PC-DR-229 Attachment B.

j) The number of overhead distribution transformers replaced for all reasons[13] in our Washington service area by the grid modernization and wood pole programs is provided below for each year of the respective program. The total number of transformers installed includes approximately 847 risky and inefficient PCB overhead transformers. Numbers of transformers replaced are recorded and tracked for individual units only, not as configured in construction.

Year	Grid Modernization	Wood Pole Management
2020	310	167
2019	357	210
2018	611	348
2017	627	368
2016	379	351
2015	377	214
2014		349
2013		581
2012		685
2011		533

k) Avista objects to this request because it seeks future information this is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

l) While as noted above, Avista does not 'preemptively replace' transformers, our contemporary cost experience to replace and install a new 25 kVA transformer with no taps ranges as follows: 1-phase transformer is $1,624.01; 2-phase transformer bank is $3,066.59, and 3-phase transformer bank is $4,703.65.[14]

m) Please see the Company's response to PC-DR-229, and Attachment C, which contains the outage reports for the reason of "crossarm" for the period 2001 through 2020. As noted above in part (d) and part (h) the reliability benefit of this cost-effective strategy is not measured as a function of the number of crossarm failures we see in the outage data, but rather, by the difference in numbers observed compared with the failure-related outages that would otherwise have occurred absent the systematic replacement program, as shown for cutouts in Figure PC-DR-223 part (d). As an example

[13] Whether for risky PCB/inefficient units, undersized units, damaged and/or leaking units, or other eligible causes.
[14] These represent the cost of replacement today, which costs are greater than Avista's unit cost experience at the time transformer replacements were initially modeled by the Company.

of the consequence of not replacing distribution wood poles, crossarms, etc., in manner performed by the Company, please see PC-DR-118 and PC-DR-235.

n) As noted in part (e) above, Avista does not agree with the characterization used by Public Counsel as "preemptive replacement," noting the Company replaces equipment in the manner it should be replaced at the end of its useful life. Crossarms are replaced as needed per Avista's DFMP standards, which replacement is called out during project design. Crossarms for distribution grid modernization and distribution minor rebuild, storm damage repair, etc., are included in the order for all material required for the construction of the final design and are not tracked at the level of the individual crossarm. In response to this request, Avista has queried its wood pole management databases and has been able to retrieve cross arm replacements for the following years: 2011 (805); 2012 (791); 2013 (462); 2014 (576); 2015 (631); 2016 (641); 2017 (990); 2018 (955); 2019 (824); 2020 (1,137).

o) Avista objects to this request because it seeks future information that is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/13/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Larry La Bolle
TYPE:	Data Request	DEPT:	Transm Ops/System Planning
REQUEST NO.:	PC – 224 Supplemental	TELEPHONE:	(509) 495-4710
		EMAIL:	larry.labolle@avistacorp.com

SUBJECT: Remote Feeder Operations

REQUEST:

Please refer again to the June, 2017 Electric Distribution Plan provided in Avista's Response to Public Counsel Data Request No. 105, at 46, which states, ". . . equipping a feeder with remote operations capability through feeder automation has also had a positive impact on our overall system reliability" and "Through this remote operation the Company has been able to avoid sustained outages for customers that have totaled an average of over 400,000 minutes per year since 2013."

a) Provide the annual amount spent on the installation of "remote operations capability" by year since 2013.
b) Estimate the average number of outages avoided through remote operations per year since 2013.
c) Provide the count of annual interruptions Avista used to calculate the 0.86 SAIFI figure provide by Avista in response to Public Counsel Data Request No. 138(a) vi.
d) Provide the number customer minutes interrupted Avista used to calculate the 120.93 SAIDI figure provided by Avista in response to PC-DR-138(a)vii.

RESPONSE:

a) Please see PC-DR-110 part (O) for the number of automation devices installed under the Grid Modernization Program, and the annual installation costs provided in the table below.

Grid Modernization Device Installation Costs	
Year	Cost
2020	$446,522
2019	$257,688
2018	$475,239
2017	$1,199,562
2016	$1,407,638
2015	$5,185

b) It appears Avista has not tracked such avoided outage events since the date of the subject citation, however, if it is determined that such data are available, the Company will timely supplement this response.

c) The count of annual interruptions used to derive the average value for SAIFI shown in PC-DR-138 part (a)(vi), and as discussed in greater detail in PC-DR-198 part (a), is provided in the table below.

SAIFI		
Excludes Major Event Days, Fill-In, Forced, and Planned Maint		
Year	Sum of SAIFI Contribution	Number of Outages
2014	1.012086269	4080
2016	0.726530536	3632
2017	1.065542362	4697
2018	0.647314621	3797
2019	0.82391784	4392
Five Year Avg 2014-2019 (excluding 2015)		0.855078325

d) The count of annual customer outage hours used to derive the average value for SAIDI shown in PC-DR-138 part (a)(vii), and as discussed in greater detail in PC-DR-198 part (a), is provided in the table below. Five-year average SAIDI in the table below is expressed in hours.

SAIDI		
Excludes Major Event Days, Fill-In, Forced, and Planned Maint		
Year	Sum of SAIDI Contribution	Hours
2014	2.071252083	15193.4
2016	1.838945227	9361.7
2017	2.651118836	13853.7
2018	1.610098261	10173.0
2019	1.906616701	13542.6
Five Year Avg 2014-2019 (excluding 2015)		2.015606222

<u>SUPPLEMENTAL RESPONSE 04/13/2021</u>

In its initial response in part (b), above, Avista noted that, while responsive data did not appear to be available for the period requested, it would supplement this response in the event such information had been tracked and was available, which additional responsive information is provided here. Avista continued to track outages avoided and the resulting avoided customer outage minutes until year 2018. For the three-year period 2014-2017, Avista's automation devices allowed the Company to avoid 45 outage events, which had a combined total number of customer outage minutes avoided of 1,561,397. The annual average avoided customer outage minutes for this period exceeds 500,000, which is an increase from the annual value of 400,000 minutes cited from Avista in the request above. The Company has no reason to expect this average annual value of 500,000 minutes would have diminished for any reason from 2017 to present, subject of course to the natural variability we experience in outage events on our system year to year. Although the customer financial value of this avoided outage duration is substantial, it represents only one of the many cost savings and safety features provided by automation devices on the Company's electric distribution system.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Larry La Bolle
TYPE:	Data Request	DEPT:	Transm Ops/System Planning
REQUEST NO.:	PC - 225	TELEPHONE:	(509) 495-4710
		EMAIL:	larry.labolle@avistacorp.com

SUBJECT: AMI Enabled Outage Benefits

REQUEST:

Please refer again to the June, 2017 Electric Distribution Plan provided in Avista's Response to Public Counsel Data Request No. 105, at 46, which states "[w]hile these management strategies have a positive impact in reducing the number and duration of outage events we experience on our system, there are other trending factors that are at the same time diminishing the reliability of our system. An example is the number of outage events that result from the Company's need to "de-energize" the system in order to complete maintenance, repairs and upgrades. As Avista has increased the level of its investments in electric distribution infrastructure over the prior decade, as described above, we have experienced a corresponding increase in the number of planned outages required to complete this work, as shown in Figure 25."

a) For each year shown in Figure 25, provide the number of customer minutes of sustained outages that occurred due to planned outages.
b) What is the cost in dollars to customers for these sustained outage minutes?
c) Show how Avista has taken the planned outage cost to customers into account when evaluating or justifying the installation of increasing the "level of its investments in electric distribution infrastructure."

RESPONSE:

a) The table below shows outage events and the associated customer outage hours (outage minutes /60) due to planned/maintenance outages on the Company's system for the subject period.

Planned Work Outages			
Year	Number of Outages	Customer Cost	Total Customer Hours
2005	171		64682.2
2006	210		53985.9
2007	321		41489.1
2008	346		36561.1
2009	507		168250.5
2010	1525		74287.1
2011	3284		98981.2
2012	2566		63223.4
2013	1816		130362.7
2014	1856		89886.6
2015	1774		127942.8
2016	2676	$11,865,220	130044.1

b) As Public Counsel is well aware from the discovery related to Avista's customer outage costs estimated for its AMI business case in 2016, the Company cannot calculate customer costs for the period of time 2005 through 2015. Because we do have an estimate of customer costs for 2016, however, we can generally apply the now very familiar $91.24 to the customer outage hours shown above for 2016, to yield a total customer cost for planned/maintenance outages for that year as shown in the table above in part (a).

c) The investments in electric distribution infrastructure discussed in the subject report need to be timely made in order to provide for the cost-effective continuity of service to our customers. It's not a question of whether the needed investments will be made, it's about how the work is conducted in order to optimize the benefits and costs to our customers. Avista, like every utility, is highly focused on carefully balancing employee (and public) safety,[15] the outage impact to our customers,[16] and the efficiency and ultimate cost[17] for performing the required work. When we decide that interrupting service to perform a specific activity represents the optimized best choice, then we are diligent in notifying customers in advance of the pending outage so they can best prepare for managing the interruption.

[15] Performing 'hot work' increases the potential risk to employees, which could extend to customers and the general public.
[16] Taking facilities out of service can reduce the risks associated with hot work but requires the interruption of service to our customers.
[17] Performing hot work is typically much more expensive than when facilities are deenergized.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Larry La Bolle
TYPE:	Data Request	DEPT:	Transm Ops/System Planning
REQUEST NO.:	PC - 226	TELEPHONE:	(509) 495-4710
		EMAIL:	larry.labolle@avistacorp.com

SUBJECT: Outages by Operating District

REQUEST:

Please refer again to the June, 2017 Electric Distribution Plan provided in Avista's Response to Public Counsel Data Request No. 105, at 48, which states "As expected from the feeder data discussed above, Colville customers on average can expect to see five times the number of outages and eight times the outage duration as the average customer in the Spokane District" and "These 'feeders of concern' are most often rural since it's normal to have a greater number of outages per customer on these often lengthy and extensive systems. For its 'feeders of concern', Avista develops work plans with individual treatments designed for each feeder. These treatments include such improvements, when cost effective."

a) Has Avista set acceptable levels of the number of outages and durations for rural customers. If so, provide those acceptable levels. If not, please explain why not.
b) How does Avista determine if an improvement measure is "cost effective"?
c) Provide examples of cost effectiveness evaluations Avista has completed.
d) Provide an example of a cost effectiveness evaluation Avista completed in 2020 which resulted in the rejection of a proposed capital expenditure.

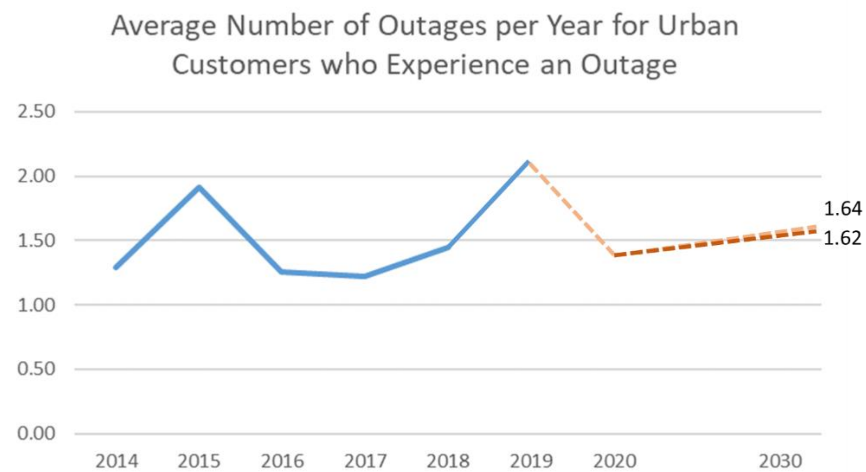
RESPONSE:

a) Avista has not formally adopted reliability metrics for standards of "acceptable service," whether for urban, suburban or rural customers. The reason for this, in part, is that customers receive the best level of service that is possible to provide them given the characteristics of the electric system we have today and the multiple different factors and events that impact that system and their service reliability over time. Avista does have one service quality measure related to outage duration for a single outage event. In that measure, the Company provides the customer with a bill credit in the amount of $50 if they experience an outage greater than 24 hours in duration, and which was not associated with a major event day. The bill credit is not a payment for "unacceptable service," rather it's an acknowledgement of the difficulty and hardship that an outage of that duration can cause. Avista is considering other service-level responses but has not adopted any at this point.

b) Lifecycle cost modeling has been a primary tool. The cost of an investment is measured against the reduction in risk costs, which includes the reduction in outage costs.

c) The reliability strategy analysis tool provided in response to PC-DR-121 is a good example, though there are many that have already been provided to Public Counsel through discovery in this case. The decision analysis tool incorporates 47 different such lifecycle cost models to identify optimized solutions among the programs evaluated.

d) The reliability strategy analysis tool was used, as described in response to PC-DR-121, to forecast long-term reliability trends, and also to evaluate whether different levels of capital and O&M spending in the evaluated programs would produce meaningful improvements in the trend. An example on one such evaluation is represented in the slide below.



In the case represented above, the additional capital and O&M spending required to implement the treatment had only a minor impact on the forecast average number of outages (for urban customers who experience an outage) and was not adopted. Forecast = 1.64; Forecast with Treatment = 1.62.

Similarly, in the Company's Distribution Wood Pole Management program, the lifecycle cost analysis demonstrates slightly improving customer internal rates of return for shorter inspection cycle intervals, however, the up-front costs required to get on the shorter cycle present a barrier when considered against the many other capital funding demands faced by the Company. A shorter cycle interval has not been adopted.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Larry La Bolle
TYPE:	Data Request	DEPT:	Transm Ops/System Planning
REQUEST NO.:	PC - 227	TELEPHONE:	(509) 495-4710
		EMAIL:	larry.labolle@avistacorp.com

SUBJECT: Customers' Reliability Expectations

REQUEST:

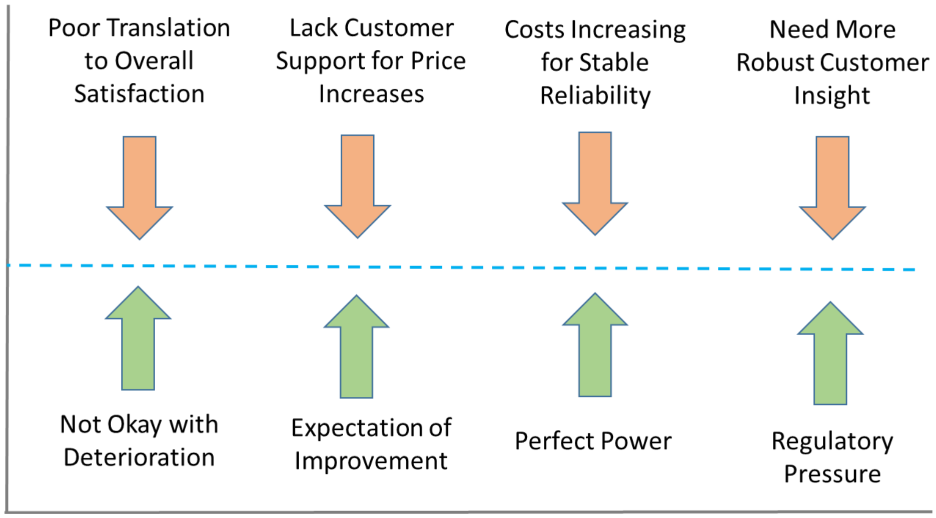
Please refer again to the June, 2017 Electric Distribution Plan provided in Avista's Response to Public Counsel Data Request No. 105, at 48, which states "Avista must be attentive to understanding the evolving expectations of our customers and evaluating our forward capabilities for meeting them" and "we also understand that across the industry, customers' expectations for service reliability are increasing." Describe all survey instruments, satisfaction measurement programs, and other means Avista uses to quantifiably measure customer expectations. From the items described in response to subpart (a), provide all data which indicate the amount and degree to which Avista customers' "expectations for service reliability are increasing." Provide any "willingness to pay" market research Avista has conducted regarding customer interest, in monetary terms, for improving reliability by defined increments (for example, research indicating what rate increase customers on average would be willing to bear for a five percent, or 10 minute, improvement in CAIDI, or for a five percent reduction in SAIFI). If Avista has not conducted such research, please explain why not.

RESPONSE:

Customers' Expectations - Electric customers' expectations for improved service reliability have been and are continuing to increase over time; this fact is evident to every utility that is paying any attention to their customers. For Avista, we have many years' research from JD Power demonstrating this increasing expectation generally, and specifically for our Company. In just one simple example, a decade ago our customers' satisfaction with their service (similar to electric utility customers across the nation) actually increased if they had experienced one outage event, compared with those who had no interruptions in service for the year. In more recent years, however, that pattern has disappeared entirely, with customers now reporting diminished satisfaction with any outage compared with those who experienced no interruptions. While this pattern is interesting, it's hardly worth a debate, for the reasons described below.

Willingness to Pay - While we understand that our customers' service expectations are generally increasing, we also believe it's quite likely that if they were **properly** surveyed, with exceptions of course, they would generally be unwilling to pay more in rates for promises of better service reliability. We say "properly" surveyed because the task of creating survey instruments that truly get at the question of 'willingness to pay,' and that are able to reach a wide range of customers through various channels, is both a complex and expensive effort. Our generalized belief 'that our customers would likely not want to pay more money for better reliability' is based on industry reports generally, our own JD Power survey results, and the detailed results of a proprietary survey on customer willingness to pay, provided to us as a favor by the utility who paid for the research. These proprietary results show very limited customer support for the idea of increased rates to provide better reliability. In short, the research is expensive, and it may not produce sufficient insights to warrant the costs.

The Service Reliability Conundrum – The increasing expectations of customers, combined with a sense they would likely not want to pay for it, presents the utility a conundrum of sorts, represented by the forces shown in the diagram below.



Green arrows on the bottom represent forces we believe are driving an expectation of stable to increasing service reliability, while the **Red arrows** on the top represent forces pushing against the idea of spending more to improve reliability. As we have reasoned through this, our response has been to focus on upholding and maintaining our current level of service reliability because we believe it is generally acceptable to our customers, and as such, represents a cost-effective value.

Future Reliability Trends – Public Counsel has seen the Company's ten-year forecast of service reliability and has noted the potential trend toward increasing numbers of outages and outage duration. As explained in PC-DR-127 part (a), the expected cost to maintain the same level of reliability with respect to outages from asset failures is increasing over time as the number of units reaching end of life continues to grow for the foreseeable future. But, as also shown in the Company's forecast, asset failures are a fairly small percentage of overall outage events and outage hours, which are expected to continue to increase, driving overall reliability impacts upward. The AMI-enabled outage improvements described in the Company's AMI business case represent a cost-effective means, *not to make reliability better than it is today*, but rather, to help reduce a portion of the expected upward trend in customer outage hours. Said differently, Avista expects outage duration to continue to increase by year 2030 (for the reasons described in PC-DR-121), but not as much as it would have without the outage benefits enabled by AMI.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Larry La Bolle
TYPE:	Data Request	DEPT:	Transm Ops/System Planning
REQUEST NO.:	PC - 228	TELEPHONE:	(509) 495-4710
		EMAIL:	larry.labolle@avistacorp.com

SUBJECT: Electric Distribution Plan for 2017

REQUEST:

Please refer to Avista's Response to Public Counsel Data Request No. 106, which provides a count of sustained outage events by cause. Refer also to the June, 2017 Electric Distribution Plan provided in Avista's Response to Public Counsel Data Request No. 105.

a) Admit that the cause "Cutout/Fuse" dose not distinguish between a failed "cutout" and a blown "fuse".
b) Please refer to Avista's indication on page 45 of the June, 2017 Electric Distribution Plan, Figure 23, that Avista is replacing failed cutouts. Explain how Avista determines that cutouts are failing.

RESPONSE:

a) To definitively distinguish between a failed cutout and a blown fuse, Avista relies on the remarks made by the field crew restoring service, where the need to replace a failed cutout is often noted. The data relied upon for reporting outages associated with failed cutouts, as reported in Figure 23 of PC-DR-105 Attachment A, as well as data relied upon for the lifecycle cost modeling for cutouts (see part (b) below), was derived from the remarks section of the outage reports, and as such represent failed cutouts and not a blown fuse. For a list of outages associated with cutouts, please the Company's response to PC-DR-229 part (a) and PC-DR-229 Attachment A.

b) Lineman reports of cutouts failing in service when opening or closing the device, field reports of failures of the equipment when a fuse is blown or failure in the ceramic due to freezing, neighboring utility reports of the same, industry bulletins on the same. These anecdotal reports provide the impetus for collecting field data (including asset management inspection of the actual failed cutouts) on the age at failure and the failure modes for the subject equipment. These failure data provide the basis for the lifecycle cost modeling that establishes the Weibull failure curve for the expected life of such equipment, calculation of the probability of failure and consequences used to establish risk costs. Please see the results of such modeling for A.B. Chance cutout failures (with and without a replacement program) are provided in Table PC-DR-223 part (d). Use of this modeling demonstrated that replacing the high-risk cutouts shown in PC-DR-105 Attachment A, Figure 23, was cost effective in reducing risks when conducted as part of the Company's wood pole management, distribution grid modernization and distribution minor rebuild programs.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/08/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 229	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Attachment A provided by Avista in response to Public Counsel Data Request No. 106.

a) Provide at least 10 randomly chosen outage reports which Avista would consider examples of outages caused by Cutout failures.
b) Provide at least 10 randomly chosen outage reports which Avista would consider examples of outages caused by Distribution transformer failures.
c) Provide at least five randomly chosen outage reports for each additional type of equipment (crossarms, grounding, lightning arrestors, etx.) that Avista deems necessary to preemptively replace because they are “failing”.

RESPONSE:

PC-DR-106 Attachment A contains 30 randomly selected outage reports, provided by Avista at the direction of Public Counsel, from among 20,338 outage events that occurred during the period specified, 2018-2020. Instead of requesting Avista to now select another 25 randomly selected outage reports as requested in PC-DR-229 from the subsample of 30 reports provided in PC-DR-106 Attachment A, the Company assumes the directive is to possibly produce something like the outage reports provided in PC-DR-106 Attachment A. Please see the following files: a) outage records for cutouts provided as PC-DR-229 Attachment A; b) outage reports for transformers provided as PC-DR-229 Attachment B, and c) outage reports for crossarms, arresters, etc., provided as PC-DR-229 Attachment C. These files include all of the Company’s outage reports for the subreason ‘cutout/fuse,’ as well as any notes in the remarks column for each report that mentions ‘cutout.’ The reason for this latter addition is that the need to replace a failed cutout is sometimes mentioned in the remarks section for the event, even though the outage reason and subreason may be categorized by a more predominant cause of the outage. Avista invites Public Counsel to review and inspect these lists of outage reports for the subject failures, and to call to Avista’s attention any specific outages or ‘sample groups of outages’ that might be of interest.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Larry La Bolle
TYPE:	Data Request	DEPT:	Transm Ops/System Planning
REQUEST NO.:	PC - 230	TELEPHONE:	(509) 495-4710
		EMAIL:	larry.labolle@avistacorp.com

SUBJECT: Wood Pole Ages at Replacement

REQUEST:
Please refer to Avista's Response to Public Counsel Data Request No. 108 (f), which states that the oldest wood pole currently operating on Avista's system is 111 years old. Please refer also to Avista's Response to Public Counsel Data Request No. 108 (d), which states that the average age of wood poles on Avista's system is 41 years old. Explain why Avista is prospectively replacing wood poles when, on average, decades and decades of useful life remain.

RESPONSE:
It appears that Public Counsel believes Avista replaces its wood poles when they reach the average age of 41, a point when half of them would still have many years of useful life. In simple mathematical terms if we did replace poles at 41 years, then the average age of the population would be much less than 41 years.

The age distribution of our wood pole population is much like a human population. As an example, the median[18] age of humans in the U.S. population is just less than 40 years. American men and women, however, don't reach the end of their lives on average until the ages of 76.1 and 81.1 years, respectively.[19]

Avista's various programs target the replacement of poles that are nearing the end of their life span and that are not expected to survive until the next inspection interval. As shown in response to PC-DR-221, the average age of poles replaced each year is generally between 55 and 60 years, meaning, that just like a human population, some poles fail and are replaced well before they reach the average age, some fail at the average age, but most fail and are replaced well beyond the average age - many at an age of 70 to 80 years in service. And, as noted in this subject request, some reach an age of 111 years… and counting.

Avista's wood poles are replaced when they should be, when they have reached a practical end of their useful service lives, and for the most part, before they fail in service. The Company's wood pole management program, as it is conducted, is proven by all measures to be prudent, cost effective, and in the best overall interest of our customers.

[18] The median age may be slightly different than the mean age.
[19] Demographics of the United States - Wikipedia

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 232	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Electric Distribution Grid Modernization

REQUEST:
Please refer to Attachments A through J provided by Avista in response to Public Counsel Data Request No. 110.

a) For each feeder analysis report, provide a list of recommended actions.
b) For each recommended action for each feeder provided in response to subpart (a), estimate the cost of the action.
c) Provide a copy of the Transformer Change-Out Program.

RESPONSE:

a) The recommended actions, which are numerous, are described throughout each analysis report provided in the subject attachment, but are summarized in each report as identified by page numbers in the table below.

Attachment	Feeder	Summary Pages
A	BEA12F2	50-52
B	F&C12F1	46-48
C	HOL1205	42
D	M15514	55-56
E	MIS431	40-42
F	ORO1280	31
G	ORO1282	75-77
H	PDL1201	32
I	RAT233	29-30
J	ROS12F5	62-64

b) The costs associated with each individual action recommended, while such actions are proven effective as summarized in response to PC-DR-222 part (d), are neither separated nor tracked individually. Though the individual treatments have been shown to be cost effective and appropriate for each subject feeder, each action is an integrated element of all actions undertaken and are reflected as part of the total project cost.

c) The business case for the Transformer Change-Out Program is provided as PC-DR-232 Attachment A.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 233	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Electric Distribution Grid Modernization
REQUEST:
RE: Capital Additions, Test Year (Electric)
Please refer to Avista's Response to Public Counsel Data Request No. 115, which states "Taking advantage of the opportunity to bring our distribution system up to current standards as part of a Grid Modernization project (or any other rebuild for that matter) is simply a prudent measure that benefits our customers and the Company in the long term. As one simple example, Avista can help reduce the potential cost of litigation for any damages that might occur as the result of historic construction that may not meet newer construction standards. Current standards for clearances and structural integrity, for another example, helps reduce the risk posed to employees, our customers and the general public. Because the Company believes it would be imprudent to construct a new feeder that was clearly out of compliance with more current standards, we do not calculate a cost difference that might be associated with such a decision."

a) Provide a list of the "litigation for any damages" events that have occurred in the past 10 years which the company lost "as the result of historic construction that may not meet newer construction standards."
b) Provide a list of the safety related events that have occurred in the past 10 years due to "clearances and structural integrity" because they did "not meet newer construction standards".

RESPONSE:

a) The subject statement "<u>As one simple example, Avista can help reduce the potential cost of litigation for any damages that might occur as the result of historic construction that may not meet newer construction standards.</u>" is prima facie. Whether we have or have not experienced such litigation,[20] the Company would be foolish to ignore more current standards, <u>including violation of Washington Administrative Code</u>.[21] And because the Company is not including any financial benefits for prudently adopting more current standards, it is not required to prove any financial benefits for an analysis in which none were claimed in support of the customer value of an investment.
b) The subject statement "<u>Current standards for clearances and structural integrity, for another example, helps reduce the risk posed to employees, our customers and the general public.</u>" is also prima facie. Whether we have or have not experienced such safety related events,[22] the Company would be foolish to ignore more current standards, <u>including violation of Washington Administrative Code</u>.[23] And because the Company is not including any financial benefits for prudently adopting more current standards, it is not required to prove any financial benefits for an analysis in which none were claimed in support of the customer value of an investment.

[20] An event made less likely by the prudent adoption of more current standards.
[21] As previously noted by the Company in response to PC-DR-156, the NESC is adopted under the Washington Administrative Code (WAC) 296-45-045, which states: 1) All electric utilities and entities operating transmission and distribution facilities within the state of Washington must design, construct, operate, and maintain their lines and equipment according to the requirements of the 2017 National Electric Safety Code (NESC) (ANSI-C2), parts (1), (2), and (3).
[22] Events made less likely by the prudent adoption of more current standards.
[23] As previously noted by the Company in response to PC-DR-156, and in the response above, the NESC is adopted under the Washington Administrative Code.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 234	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Electric Distribution Grid Modernization

REQUEST:
Please refer to Avista's Response to Public Counsel Data Request No. 117, which lists two items as relocated and/or converted in 2018, including a Viper Recloser and a Viper Switch.

a) Identify the feeders on which a Viper Recloser or a Viper Switch was installed as part of the grid modernization program in 2018, as indicated in Attachments A–J provided in response to Public Counsel Data Request No. 110.

b) For each and every instance identified in response to (a), estimate the annual O&M savings from the relocation and/or conversion. Provide all calculations, assumptions, estimates, worksheets, and other details in support of this answer.

RESPONSE:

a) In response to the subject request PC-DR-117, the only device that was relocated and converted in 2018 was ZC435R on MIS431. The other device, ZC448R, identified in the response to Public Count Data Request No. 110 was also on MIS431.

b) Avista has considerable experience with the successful deployment of reclosers to achieve a range of operational and reliability improvements, including FDIR, remote manual operations to restore service during an outage event, avoiding service dispatches to place hot-line-holds, etc., as also noted in the Company's response to PC-DR-110 part (p). In its response, Avista noted the installation of automation devices provides multiple cost savings to our customers. As an example, in 2019, an analysis was performed on the number of switching events on each device that had been installed (up to that date) by the grid modernization program. The table below, shows the calculated O&M cost savings for each year based on the observed switching events. Utilization of automation devices varies based on outage events and the number of switching orders, so analysis included the total switching operations. Potential savings associated with any single switching action will depend on distance to travel and the time of day (because overtime rates might apply). The analysis used vehicle mileage rates, direct costs associated with labor, tools, and loadings based on average response time of 5 hours.

Year	2017	2018	2019 (through Sept)
Conservative O&M cost savings	$ 139,067	$ 324,252	$ 288,145

As noted above, these are costs represent O&M savings only, <u>not including any customer avoided costs for avoided outage events and reduced outage duration</u>, and as such are not a complete reflection of the customer benefits associated with these devices. Amounts include estimated cost savings for the range of devices deployed under the grid modernization program. The number of operations of the subject recloser/switches listed in part (a) above, is available in the file provided in PC-DR-110 Attachment R, which also includes the incremental O&M savings associated with each such operation.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/08/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Larry La Bolle
TYPE:	Data Request	DEPT:	Transm Ops/System Planning
REQUEST NO.:	PC - 235	TELEPHONE:	(509) 495-4710
		EMAIL:	larry.labolle@avistacorp.com

SUBJECT: Public Counsel Run to Fail Strategy

REQUEST:

Please refer to Avista's Response to Public Counsel Data Request No. 118, which states that a distribution "run to failure" strategy, ". . . would result in the consequent rise in annual risk costs to $181,521,691 . . . " and "the Company projects it would experience a five-fold increase in outage events if it were to adopt a 'run to fail' strategy" and "Wood Pole Management accounts for 117 (avoided) outages, the Transformer Program accounts for 837 (avoided) outages, and the Vegetation Management Program accounts for 3,237 of the total (avoided) outages."

a) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, or industry publications which were used calculate "a five-fold increase in outage events" if Avista were to adopt a 'Run to Fail' strategy.
b) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, or industry publications which were used to calculate the "annual Risk costs" of $181,521,691. Please break out the cost calculations by "Wood Poles", "Transformers" and "Vegetation Management."
c) Explain in detail how vegetation results in asset failures.
d) Explain the difference between asset failures and equipment failures.
e) Provide the number of wood poles Avista changed out to avoid 117 outages.
f) Provide the average cost to change out a wood pole.
g) Provide the number of distribution transformers Avista changed out to avoid 837 outages.
h) Provide the average cost to change out a transformer.
i) Describe in detail the equipment types that are not allowed to run to failure as a result of the vegetation management program.
j) Provide list of all "obsolete" and "end-of-life apparatus".
k) Provide the criteria Avista uses to classify each apparatus as "obsolete".
l) Provide the criteria Avista uses to classify each apparatus as "end-of-life".
m) Provide evidence that each apparatus classified as "obsolete" cannot be obtained from any manufacturer.
n) The statement "Extension of distribution feeders from neighboring substations and increased capacity at those substations would be required at a minimum" implies that load forecast or other studies have identified insufficient capacity on the system "neighboring substations". Provide the forecasts and or other studies which shows this lack of system capacity through 2025.
o) Provide the studies calculations that Avista performed which would show the "Increased liability" that "would result" from a lack of this program.

RESPONSE:

a) All of the worksheets and workbooks have been provided to Public Counsel as Avista's Reliability Strategy Analysis Model provided in response to PC-DR-121 Attachment A. A very general overview of the model is provided in PC-DR-121 and PC-DR-122, and PC-DR-118. As noted in those discussions, the current case forecast assumes a continuation of the asset maintenance program treatments historically and currently conducted. For the response provided in PC-DR-122 part (b) the current case was compared with a scenario where asset maintenance programs were suspended to show the incremental differences in outages for the ten-year horizon ending in year 2030. For a more insightful understanding of the workings of the model, Avista believes it makes the most sense to schedule a working session with Public Counsel to do a walkthrough, and in particular, to show the process for deriving the results provided in PC-DR-118 and PC-DR-122.

   Importantly, the Company's Reliability Strategy Analysis Model, described above, relies on the output from multiple different Availability Workbench Models for the wood pole management program, transformers and vegetation management. A screenshot list of these different models is provided in response to PC-DR-236, parts (a-c), and screenshots of some key outputs of the models are also provided for wood poles, transformers and vegetation management. Unfortunately, the Availability Workbench Models are much too large to easily share, require quite a bit of computing horsepower to run, can only be opened by an entity holding a license for the software, and are complex and somewhat difficult to understand without some training. In the event Public Counsel holds the necessary license for the Availability Workbench application, Avista would be happy to provide such models, as well as provide any tutorial that might be helpful in their review and evaluation. Avista is also happy to schedule a working session with Public Counsel to do a walkthrough of the models and the output that is used in the Reliability Strategy Analysis Model.

b) Risk costs for each subject category forecast as described in PC-DR-118, include 1) $18,960,379 for wood poles; 2) $2,479,649 for transformers, and 3) $160,081,663 for vegetation management. The combined total costs for each group (risk, capital and O&M), include: 1) $35,518,700 for wood poles; 2) $5,500,467 for transformers, and 3) $170,319662 for vegetation management.

   The combined risk, capital and O&M costs from this analysis, representing such a run to fail strategy, total $211,338,829 in year 2030.

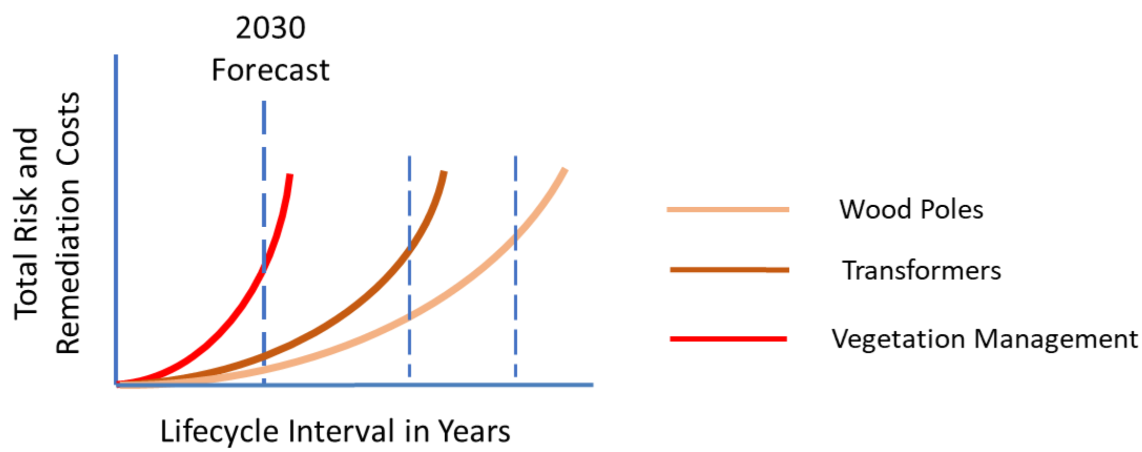
c) What is being measured in response to PC-DR-118 is the impacts associated with moving to a strategy (run to fail) where the Company would only address issues on its feeders when there was an outage or other impact that required a response, compared with results based on managing the system like we do today. The evaluation of Vegetation Management treatment options is similar to the approaches for managing the equipment failures treated by Avista's asset maintenance programs; they are based on inspection and treatment cycle intervals, which include the types and amounts of work performed, including the capital and O&M costs for such work, and that forecast the resulting impact on service outages experienced by our customers (among other risks).

d) Please see part (c), above.

e) The wood pole outages noted in the request represent the number expected in year 2030 in the scenario where the asset maintenance programs were suspended, would be based on prospective replacement of poles and not poles that have already been changed out.[24]

The important point in this discussion, knowing the cessation of asset maintenance programs is only an academic exercise.

For this discussion of the impacts avoided by the Company's asset maintenance programs, the proper evaluation of the impacts and the benefits would need to be made over the lifecycle for each of the three programs. Here, the results for vegetation management are particularly insightful because, as depicted in the figure below, you can begin to see the results for the lifecycle impacts of vegetation management by year 2030.[25] That's why the risk costs (in year 2030) are so much greater, than for wood pole and transformers, for the consequences of ceasing the vegetation management practices we have in place today. Yes, there are incremental increases in wood pole and transformer risks by year 2030, but you don't see the full impact of such a decision to suspend these programs until the point in time where, like vegetation, the risk costs would begin to increase rise dramatically as shown by two dashed lines for transformers and wood poles on the figure.



The request in PC-DR-118 is to compare the current program costs and benefits with the scenario of replacing equipment upon failure, and Avista's response provides incremental effects forecasted in year 2030, including 117 wood pole outages and the 837 transformer outages. While this evaluation is instructive, it does not represent the full impacts and costs associated with a run to failure strategy. As noted above, the full impacts of a sustained run to fail strategy are only evident over a longer period of time, more reflective of the life spans for transformers and wood poles. But just as important, <u>even if the Company were to return to its current practices in year 2031, the impacts of run to fail for the prior decade would still continue to compound in the years to follow</u>, as the maintenance not performed for a decade would show up in the years beyond 2030. So, the real measure of the impact of run to fail through year 2030, using wood poles as the example, would be the incremental number of wood pole failures of 117 at year 2030, plus the ensuing additional failures that would be added to the 117 as a result of the maintenance not performed for a decade.

[24] Clearly, the results are based on a forecast from the Company's wood pole population known today, which condition is based on the wood pole management program described in PC-DR-221.
[25] Avista provides this conceptual figure as a way to help provide context for the request made in PC-DR-118 and the limitations on what can be definitively concluded from the results provided.

f) Avista provides the information for calculating the generalized cost to replace a wood pole through the wood pole management program in response to PC-DR-221.

g) Please see the response provided in part (e) above. The transformer outages noted in the request represent the number expected in year 2030 in the scenario where the asset maintenance programs were suspended, would be based on prospective replacement of transformers and not transformers that have already been changed out.[26]

h) Please see the Company's response to PC-DR-223 part (l).

i) Please see the Company's response to part (c), above.

j) The subject analysis is not based on such any categorization of equipment. Rather, it is based on detailed lifecycle cost modeling that incorporates outage events known to occur over time under different treatment options, combined with the probabilities of occurrence and consequence costs that are required to calculate risk costs and customer internal rates of return for the different treatment options.

k) Please see Avista's response to part (j), above.

l) Please see Avista's response to part (j), above.

m) Please see Avista's response to part (j), above.

n) Avista objects to this request because it seeks future information that is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

o) Please see the Company' response to PC-DR-233 part (a).

[26] Clearly, the results are based on a forecast from the Company's transformer population known today, which condition is based on the transformer changeout program described in PC-DR-223.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Larry La Bolle
TYPE:	Data Request	DEPT:	Transm Ops/System Planning
REQUEST NO.:	PC - 236	TELEPHONE:	(509) 495-4710
		EMAIL:	larry.labolle@avistacorp.com

SUBJECT: Reliability Strategy Analysis Model

REQUEST:
Please refer to Avista's Response to Public Counsel Data Request No. 121, which describes its Reliability Strategy Analysis Model.

a) Provide an example of an Availability Workbench model for wood poles.
b) Provide an example of an Availability Workbench model for transformers.
c) Provide an example of an Availability Workbench model for vegetation management.
d) Provide the "Current Case Forecast".

RESPONSE:

As noted in this request, the Company's Reliability Strategy Analysis Model, described in PC-DR-121, relies on the output from multiple different Availability Workbench Models for the wood pole management, transformers and vegetation management programs. Unfortunately, the Availability Workbench Models are much too large to easily share, require quite a bit of computing horsepower to run, can only be opened using the Availability Workbench application by an entity holding a license for the software, and are complex and somewhat difficult to understand without some guidance. In the event Public Counsel holds the necessary license for the Availability Workbench application, Avista will provide such models, as well as provide any tutorial that might be helpful in their review and evaluation. Avista is also happy to schedule a working session with Public Counsel to do a walkthrough of the models and the output that is used in the Reliability Strategy Analysis Model.

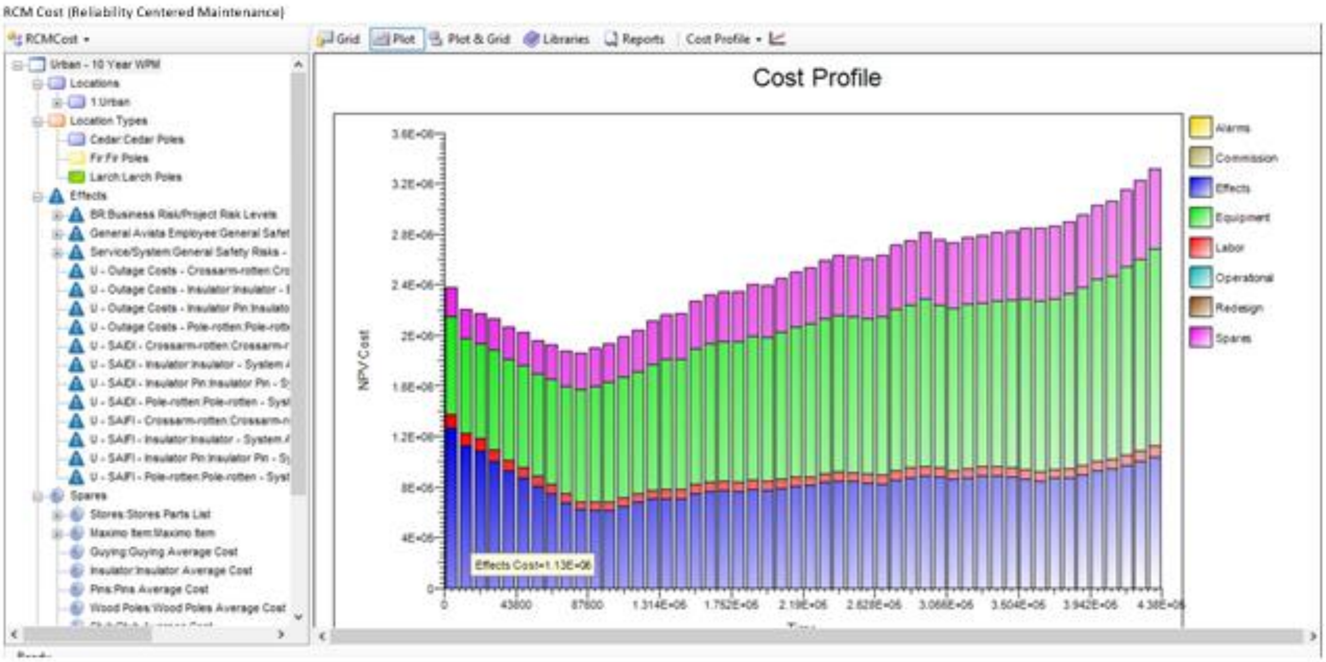
Please see parts (a-c), on the pages that follow. Because, as explained above, we cannot provide the models, we provide a screenshot list of the models for each program and a couple example outputs from a model for each program. Please note, the model icons on the lists appear to be "Adobe PDF" but they are actual models and not PDF documents.

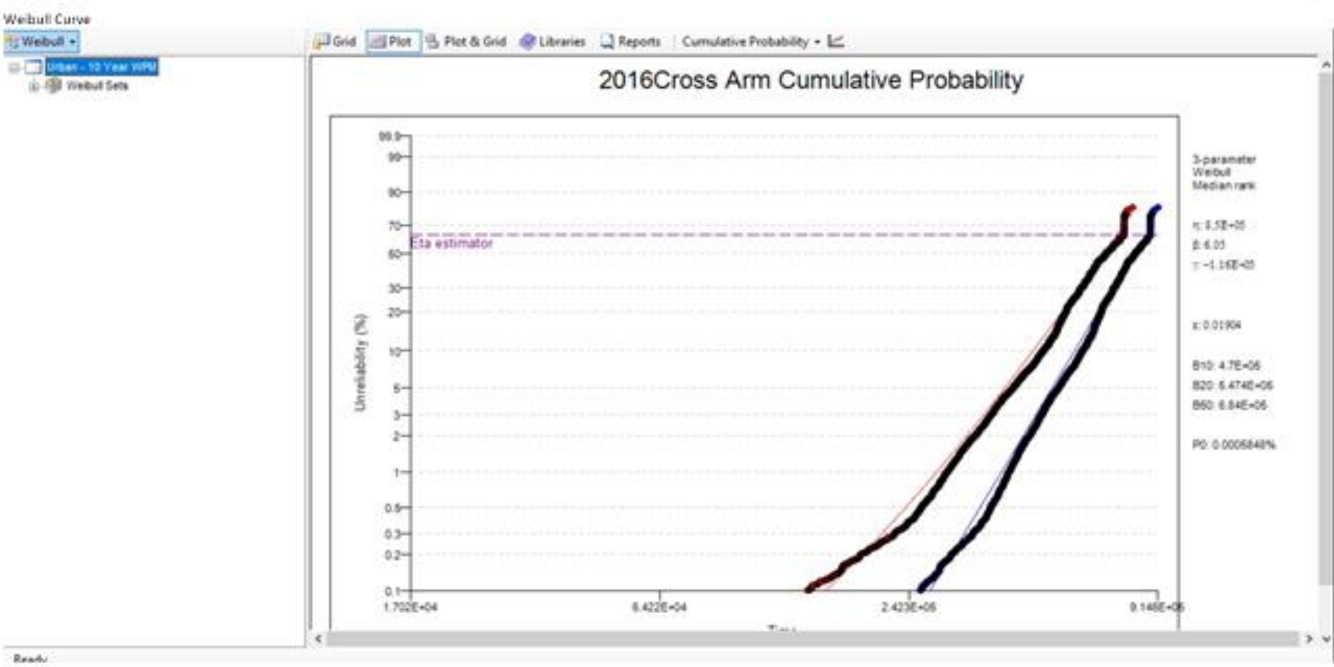
a) A screenshot list of the different wood pole models is provided below. Each item on the list is an individual model. The first one, for example, is for wood pole management based on the current 20-year inspection cycle as applied to rural feeders. As you can see the cycle intervals modeled range from 5 to 20 years.

WPM

2020 Rural Pole Failure Curves - 20 year cycle rev 3-8-2020	3/10/2020 2:43 PM	Adobe Acrobat Docu...	121,431 KB
2020 Rural Pole Failure Curves - 15 year cycle rev 3-9-2020	3/10/2020 2:42 PM	Adobe Acrobat Docu...	121,431 KB
2020 Rural Pole Failure Curves - 10 year cycle rev 3-9-2020	3/10/2020 2:40 PM	Adobe Acrobat Docu...	121,431 KB
2020 Rural Pole Failure Curves - Base Case rev 3-9-2020	3/10/2020 2:39 PM	Adobe Acrobat Docu...	121,431 KB
2020 Suburban Pole Failure Curves - 5 year cycle rev 3-9-2020	3/10/2020 5:04 AM	Adobe Acrobat Docu...	76,734 KB
2020 Suburban Pole Failure Curves - 10 year cycle rev 3-9-2020	3/10/2020 4:57 AM	Adobe Acrobat Docu...	76,734 KB
2020 Suburban Pole Failure Curves - 15 year cycle rev 3-9-2020	3/10/2020 4:55 AM	Adobe Acrobat Docu...	76,734 KB
2020 Suburban Pole Failure Curves - 20 year cycle rev 3-9-2020	3/10/2020 4:52 AM	Adobe Acrobat Docu...	76,734 KB
2020 Suburban Pole Failure Curves - Base Case rev 3-9-2020	3/10/2020 4:48 AM	Adobe Acrobat Docu...	76,734 KB
2020 Urban Pole Failure Curves - 5 year cycle rev 3-9-2020	3/10/2020 3:59 AM	Adobe Acrobat Docu...	43,668 KB
2020 Urban Pole Failure Curves - 20 year cycle rev 3-9-2020	3/10/2020 3:57 AM	Adobe Acrobat Docu...	43,668 KB
2020 Urban Pole Failure Curves - 15 year cycle rev 3-9-2020	3/10/2020 3:56 AM	Adobe Acrobat Docu...	43,668 KB
2020 Urban Pole Failure Curves - 10 year cycle rev 3-9-2020	3/10/2020 3:54 AM	Adobe Acrobat Docu...	43,668 KB
2020 Urban Pole Failure Curves - Base Case rev 3-9-2020	3/10/2020 3:53 AM	Adobe Acrobat Docu...	43,668 KB

The screenshot below shows two key outputs of the models, this one for wood pole management for urban feeders based on a 10-year inspection cycle interval. The top chart represents costs for this scenario, and the bottom is the Weibull failure curve, in this instance, for crossarm failures.



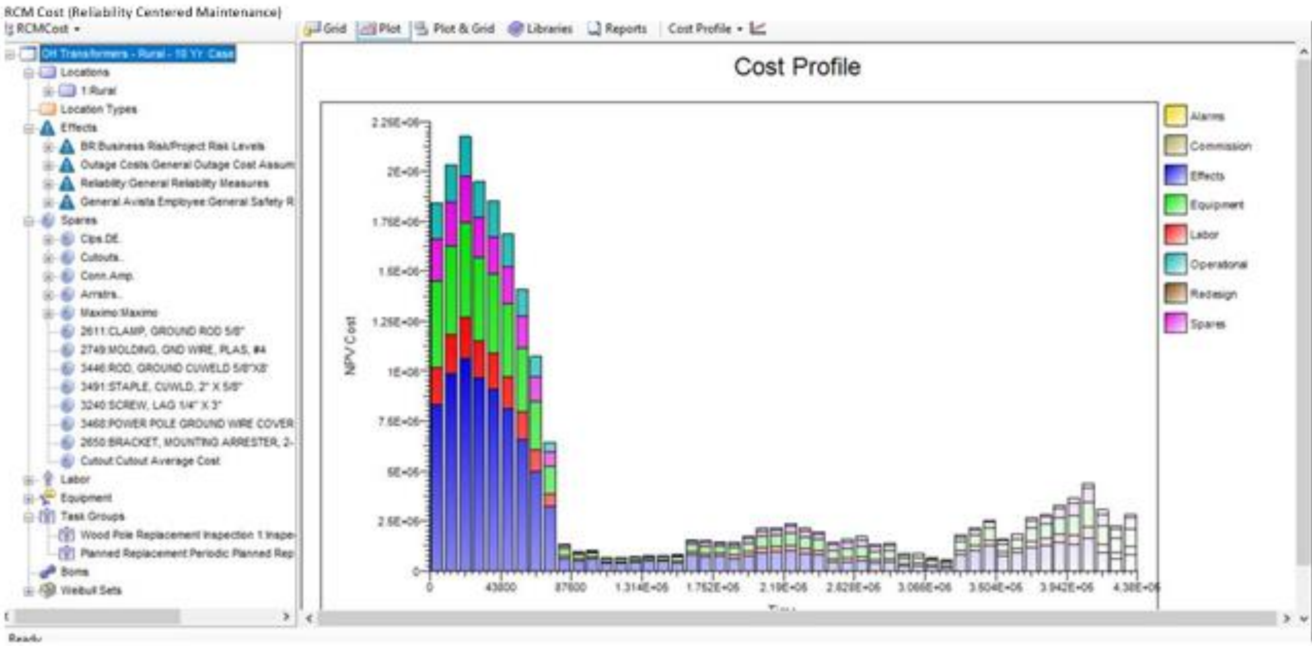


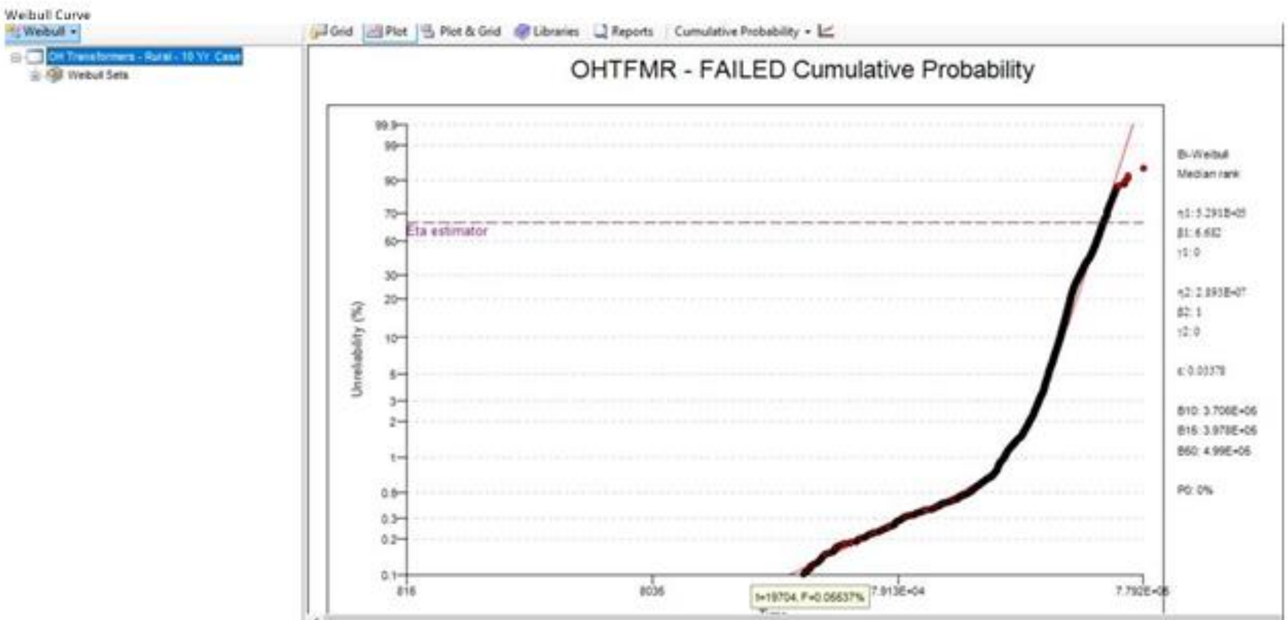
b) A screenshot list of the different transformer models is provided below. Each item on the list is an individual model. The first one, for example, models the impact of not performing any transformer changeout work on urban feeders. Incidentally, in the asset management world the 'base case' is generally applied to the case where no treatment is performed, a compared with Avista's use of the 'current case' as representing the effects of programs as they are conducted today.

TCOP

2020 Urban TCOP Model - Base Case 3-16-2020	3/16/2020 1:01 PM	Adobe Acrobat Docu...	22,298 KB
2020 Rural TCOP Model - 15 Year WPM Cycle Case 3-16-2020	3/16/2020 12:54 PM	Adobe Acrobat Docu...	25,863 KB
2020 Rural TCOP Model - 20 Year WPM Cycle Case 3-16-2020	3/16/2020 12:51 PM	Adobe Acrobat Docu...	25,863 KB
2020 Rural TCOP Model - 10 Year WPM Cycle Case 3-16-2020	3/16/2020 12:50 PM	Adobe Acrobat Docu...	25,863 KB
2020 Rural TCOP Model - 5 Year WPM Cycle Case 3-16-2020	3/16/2020 12:49 PM	Adobe Acrobat Docu...	25,863 KB
2020 Rural TCOP Model - Base Case 3-16-2020	3/16/2020 12:46 PM	Adobe Acrobat Docu...	25,863 KB
2020 Suburban TCOP Model - 10 Year WPM Case 3-16-2020	3/16/2020 12:34 PM	Adobe Acrobat Docu...	24,707 KB
2020 Suburban TCOP Model - 15 Year WPM Case 3-16-2020	3/16/2020 12:29 PM	Adobe Acrobat Docu...	24,707 KB
2020 Suburban TCOP Model - 20 Year WPM Case 3-16-2020	3/16/2020 12:28 PM	Adobe Acrobat Docu...	24,707 KB
2020 Suburban TCOP Model - 5 Year WPM Case 3-16-2020	3/16/2020 12:26 PM	Adobe Acrobat Docu...	24,707 KB
2020 Urban TCOP Model - 5 Yr WPM Case 3-16-2020	3/16/2020 12:12 PM	Adobe Acrobat Docu...	22,298 KB
2020 Urban TCOP Model - 10 Yr WPM Case 3-16-2020	3/16/2020 12:09 PM	Adobe Acrobat Docu...	22,298 KB
2020 Urban TCOP Model - 15 Yr WPM Case 3-16-2020	3/16/2020 12:08 PM	Adobe Acrobat Docu...	22,298 KB
2020 Urban TCOP Model - 20 Yr WPM Case 3-16-2020	3/16/2020 12:04 PM	Adobe Acrobat Docu...	22,298 KB

The screenshot below shows transformer impact costs for rural feeders based on a 10-year inspection cycle interval. The bottom chart is the Weibull failure curve for transformers.





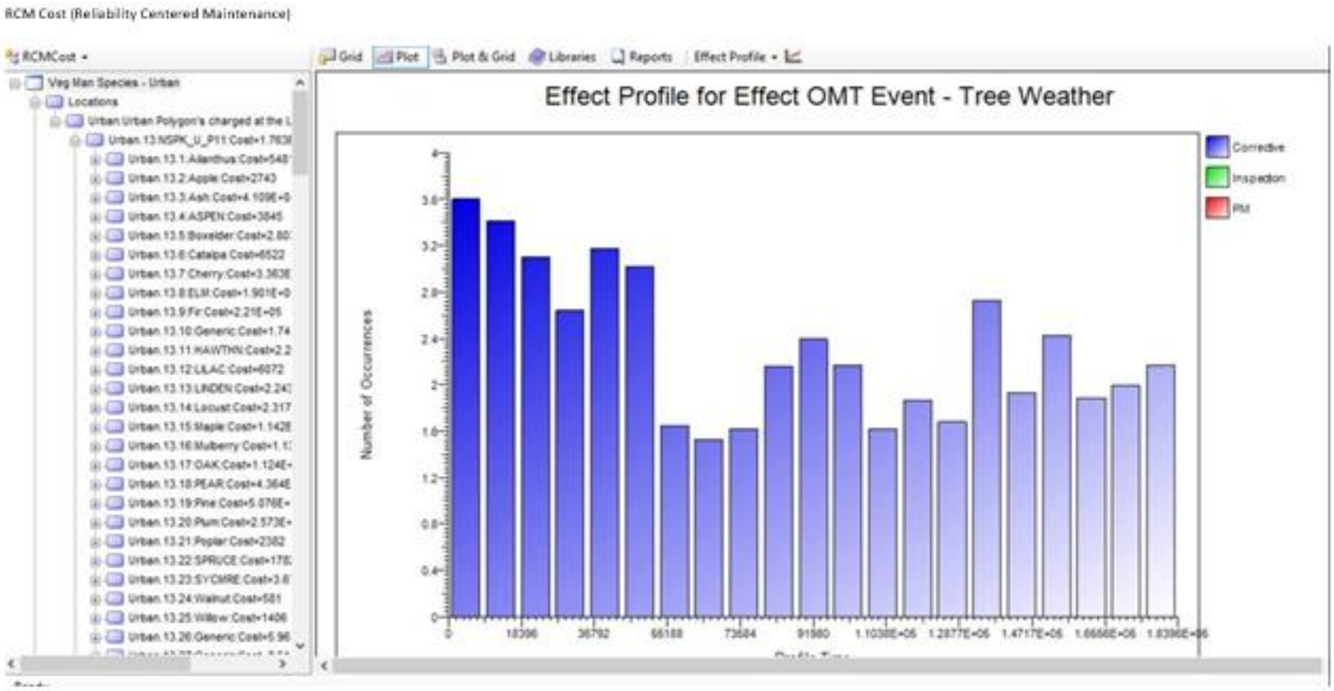
c) A screenshot list of the different vegetation management models is provided below. Each item on the list is an individual model. The first one, for example, models the impact of not conducting any regular cycle trimming (planned work) on rural feeders. The second one, also applied to rural feeders, models the effects of performing risk tree work every other year, and regular cycle trimming every 8 years. One of the models is barely showing at the bottom of the screenshot.

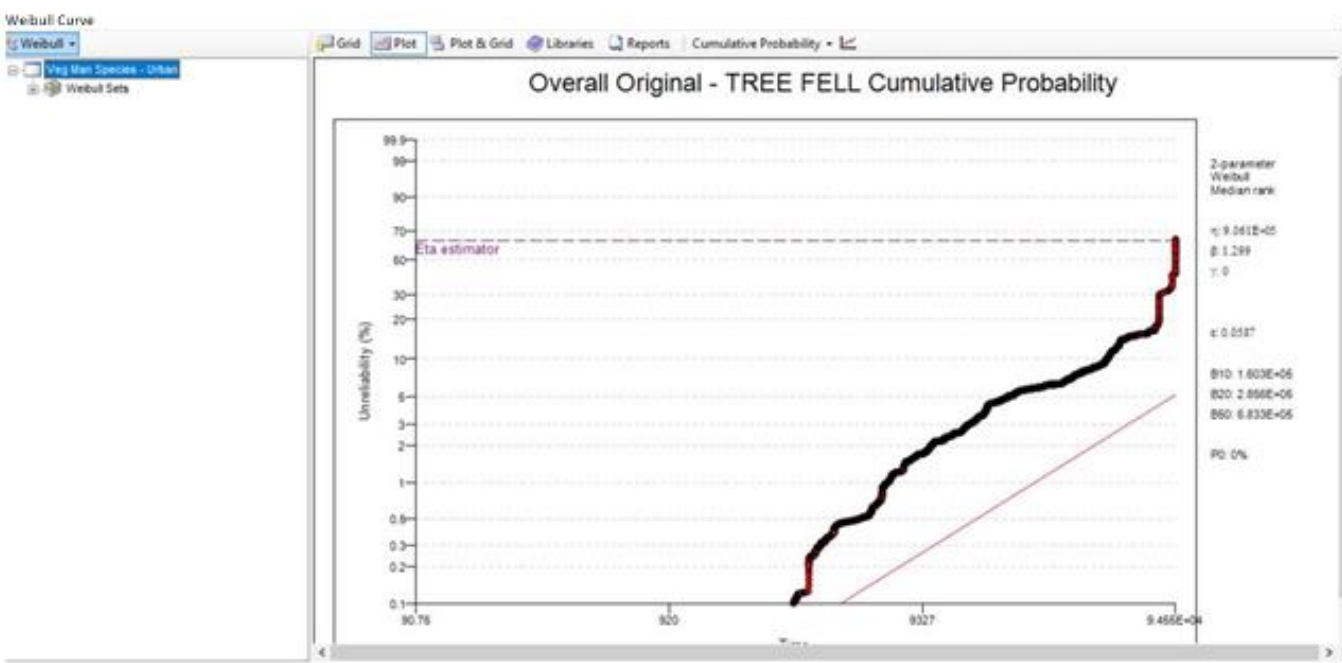
Veg Mgmt.

Feeder Vegetation Management Model Development Polygon - Rural No Planned Work Case 5.24.20	5/24/2020 9:13 PM	Adobe Acrobat Docu...	88,752 KB
Feeder Vegetation Management Model Development Polygon - Rural 2 Year Risk Tree 8 Year Planned Work Case 5.24.20	5/24/2020 9:06 PM	Adobe Acrobat Docu...	88,753 KB
Feeder Vegetation Management Model Development Polygon - Rural 2 Year Risk Tree 6 Year Planned Work Case 5.24.20	5/24/2020 8:57 PM	Adobe Acrobat Docu...	88,753 KB
Feeder Vegetation Management Model Development Polygon - Rural 1 Year Risk Tree 5 Year Planned Work Case 5.24.20	5/24/2020 8:47 PM	Adobe Acrobat Docu...	88,753 KB
Feeder Vegetation Management Model Development Polygon - Rural 6 Year Risk Tree 6 Year Planned Work Case 5.24.20	5/24/2020 8:36 PM	Adobe Acrobat Docu...	88,753 KB
Feeder Vegetation Management Model Development Polygon - Rural 3 Year Risk Tree 6 Year Planned Work Case 5.24.20	5/24/2020 8:05 PM	Adobe Acrobat Docu...	88,753 KB
Feeder Vegetation Management Model Development Polygon - Suburban 1 Year Risk Tree 5 Year Planned Work 5.17.20	5/17/2020 4:27 AM	Adobe Acrobat Docu...	69,393 KB
Feeder Vegetation Management Model Development Polygon - Suburban 2 Year Risk Tree 6 Year Planned Work 5.17.20	5/17/2020 4:24 AM	Adobe Acrobat Docu...	69,393 KB
Feeder Vegetation Management Model Development Polygon - Suburban 2 Year Risk Tree 8 Year Planned Work 5.17.20	5/17/2020 4:17 AM	Adobe Acrobat Docu...	69,393 KB
Feeder Vegetation Management Model Development Polygon - Suburban 3 Year Risk Tree 6 Year Planned Work 5.17.20	5/17/2020 4:15 AM	Adobe Acrobat Docu...	69,393 KB
Feeder Vegetation Management Model Development Polygon - Urban 1 Year Risk Tree 5 Year Planned Work 5.17.20	5/17/2020 4:09 AM	Adobe Acrobat Docu...	57,322 KB
Feeder Vegetation Management Model Development Polygon - Urban 2 Year Risk Tree 6 Year Planned Work 5.17.20	5/17/2020 4:06 AM	Adobe Acrobat Docu...	57,322 KB
Feeder Vegetation Management Model Development Polygon - Urban 2 Year Risk Tree 8 Year Planned Work 5.17.20	5/17/2020 4:02 AM	Adobe Acrobat Docu...	57,322 KB
Feeder Vegetation Management Model Development Polygon - Urban 3 Year Risk Tree 6 Year Planned Work 5.17.20	5/17/2020 3:55 AM	Adobe Acrobat Docu...	57,322 KB
Feeder Vegetation Management Model Development Polygon - Suburban No Planned Work 5.17.20	5/17/2020 2:06 AM	Adobe Acrobat Docu...	69,389 KB
Feeder Vegetation Management Model Development Polygon - Urban 6 Year Risk Tree 6 Year Planned Work 5.17.20	5/17/2020 2:01 AM	Adobe Acrobat Docu...	57,322 KB
Feeder Vegetation Management Model Development Polygon - Urban No Planned Work 5.17.20	5/17/2020 12:59 AM	Adobe Acrobat Docu...	57,319 KB
Feeder Vegetation Management Model Development Polygon - Suburban 6 Year Risk Tree 6 Year Planned Work 5.17.20	5/17/2020 12:41 AM	Adobe Acrobat Docu...	69,392 KB

d) The current case forecast is provided in PC-DR-121 Attachment A, explained in the response.

The screenshot below shows vegetation management impact costs for urban feeders based on a 2-year inspection cycle interval for risk trees (tree fell) and a 6-year cycle for regular trimming work. The bottom chart is the Weibull failure curve for risk trees.





AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ken Sweigart
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC - 237	TELEPHONE:	(509) 495-4417
		EMAIL:	ken.sweigart@avistacorp.com

SUBJECT: Electric Transmission Capital Investment

REQUEST:
Capital Additions, Test Year (Electric)
Please refer to Attachment A provided in response to Public Counsel Data Request No. 123, at 12, which states "All assets have a defined useful service life.

This category provides funding to replace equipment as needed so it can continue to function effectively. It may include replacing parts as they wear out or when items can no longer meet their required purpose, as systems become obsolete and replacement parts are no longer available, to remedy safety or environmental issues, or if the condition of an asset is such that it is no longer optimizing its own performance or customer value. The Company also replaces critical equipment to mitigate the risk of failure."

a) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, risk assessments, or any other calculations, presentations, requests, standards, or other documentation which indicates that the Transmission Infrastructure Plan is of sufficient value to rate payers to justify rate increases.
b) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, or industry publications which were used to determine that a transmission asset "is no longer optimizing its own performance or customer value." Provide example studies.

RESPONSE:

Avista is required to take the reasonable and prudent steps necessary to ensure we provide an acceptable level of service for our customers and in compliance with a broad range of Commission and federal guidelines and directives, as highlighted in the Company's response to PC-DR-123. A utility's need to replace aging infrastructure, as noted in the subject report, to achieve these aims is beyond any reasonable debate. The question then, is whether these actions have been conducted in a proven, cost effective and prudent manner. With respect to this question, Avista has demonstrated, whether though asset management analyses of individual classes of assets or in similar evaluations for individual projects or regional projects, that its actions have been properly evaluated and shown to be cost effective for customers. We have documented this in the many examples already submitted for review, including those provided in this response, below. Because the cost to customers to replace end of life assets is necessary and reasonable, and because the investment allows us to meet our short and long-term service obligations to our customers, and to comply with a range of legal and regulatory requirements, these investments are deemed to be prudent and made in the interest of our customers.

a) In response to this request, as noted above, Avista provides a range of responsive documents that are organized in the following six categories.

1. **General Area-Based Transmission Reinforcement Program Summary Reports,** developed in 2015-2016 for asset management based projects, which following reports are provided in PC-DR-237 Attachment A.
    a. Spokane (West) Transmission Reinforcement Program Summary (2015 Word doc)
    b. Spokane (Central) Transmission Reinforcement Program Summary (2015 Word doc)
    c. Palouse (Pul-Mos) Transmission Reinforcement Program Summary (2016 Word doc)
    d. Palouse (Lew-Clark) Transmission Reinforcement Program Summary (2016 Word doc)
    e. CDA (Silver Valley) Transmission Reinforcement Program Summary (2016 Word doc)
    f. CDA (Sandpoint) Transmission Reinforcement Program Summary (2016 Word doc)
    g. CDA (CDA-Rathdrum) Transmission Reinforcement Program Summary (2016 Word doc)
    h. Big Bend (Othello) Transmission Reinforcement Program Summary (2016 Word doc)
    i. Big Bend (Colville) Transmission Reinforcement Program Summary (2016 Word doc)

2. **Specific Area-Based Asset Management Study Results**, developed in 2015-2016 for Avista transmission lines, which following reports are provided in PC-DR-237 Attachment B.
    a. Spokane (West) Transmission Reinforcement (2015/2016 PowerPoint doc)
    b. Spokane (Central) Transmission Reinforcement (2015/2016 PowerPoint doc)
    c. Palouse (Pul-Mos & Lew-Clark) Transmission Reinforcement (2015/2016 PowerPoint doc)
    d. CDA (CDA-Rat & Silver Valley) Transmission Reinforcement (2015/2016 PowerPoint doc)
    e. CDA (Sandpoint) Transmission Reinforcement (2015/2016 PowerPoint doc)
    f. Big Bend (West) Transmission Reinforcement (2015/2016 PowerPoint doc)

3. **Specific Transmission Line-Based Asset Management Study Results and Prioritization Reports**, developed in 2015-2016, which following reports are provided in PC-DR-237 Attachment C.
    a. Asset Condition Evaluation and Prioritization (2013 Excel doc)
    b. 2013 Devils Gap-Lind Inspection Results (2013 Excel doc)
    c. DG-Lind 115kV Analysis (2013 PowerPoint doc)
    d. 2016 Lolo-Oxbow 230kV Model Asset Management Plan (2016 Word doc)
    e. Rebuild Prioritization (2019 Excel doc)
    f. Lolo-Oxbow Model Results (2015/2016 PowerPoint doc)
    g. Benewah-Moscow 230kV Business Case (2014 Excel doc)
    h. Benewah-Moscow Rebuild Study Results (2014 PowerPoint doc)

4. **General Line-Based Pole Age and Fire Risk Assessments**, which documents are provided in PD-DR-237 Attachment D.
    a. Line Wildfire Risk (2020 Excel doc)
    b. PC-237 Excel Spreadsheet (2021 Excel doc)

5. **NERC Standards-Based Inspection Data**, which documents are provided in PC-DR-237 Attachment E.
    a. FAC-501-WECC Standard (2021 .pdf doc)
    b. Transmission Maintenance and Inspection Program (2021 .pdf doc)
    c. Transmission Inventory WPM Database (2016 Excel doc)
    d. 2020 Aerial Patrol Results (2021 Excel doc)
    e. 2016-2020 Transmission Inspection Data WPM (2021 Excel doc)

6. **Business Case Documents for Asset Condition-Based Major and Minor Rebuild Projects**, which documents are provided in PC-DR-237 Attachment F.
    a. Transmission Major Rebuild Asset Condition BC Justification Narrative (2020 Word doc)
    b. Transmission Minor Rebuild BC Justification Narrative (2020 Word doc)

b) Please see the documents listed below, provided in PC-DR-237 Attachment G, accompanied by the following narrative description.

    a. 2013 Devils Gap-Lind Inspection Results (2013 Excel doc)
    b. DG-Lind 115kV Analysis (2013 PowerPoint doc)
    c. 2016-2020 Transmission Inspection Data WPM (2021 Excel doc)

Review of the 2013 wood pole inspection results for the Devils Gap-Lind line showed an unusual number of wood poles needing full replacement. These results prompted a request for Avista's Asset Management Group to perform an evaluation on the entire line and to develop an optimized replacement recommendation. The solution resulted in a multi-phase structure replacement project that addressed poles in need of replacement (based on age, type, and location) that were most likely to fail in the near term. This option was shown to provide the most efficient (optimized) use of our customers' money.

A similar situation is developing on the 8FA-LAT 115kV line where several structures are asset condition deficient. This situation is coupled with several structures needing to be replaced to ensure line ratings capabilities, combined with the need for Avista to locate network communications from its northern to southern service areas. When all these conditions are considered, it may be determined that this transmission asset "is no longer optimizing its own performance or customer value," and is in need of remediation.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	John Gross
TYPE:	Data Request	DEPT:	System Planning
REQUEST NO.:	PC - 238	TELEPHONE:	(509) 495-4951
		EMAIL:	john.gross@avistacorp.com

SUBJECT: Electric Transmission Construction - Compliance

REQUEST:
Please refer to Attachment A provided by Avista in response to Public Counsel Data Request No. 123, at 69, Table 4, as well as the statement "Investments made under this program support the addition of new substations due to load growth in a particular area or to reinforce existing substations with new transmission required for increased performance."

a) Identify the specific projects which are driving the dramatic increase in spending in the years 2021 and 2022 in the Investment Driver "Performance and Capacity."
b) For each project identify the specific performance or capacity issues driving the need for these projects.
c) Identify each project as being required because of "load growth" or "required for increased performance".
d) For each project identified in subpart (c) as "required for increased performance", provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, or industry publications which justify the project and the associated risk reduction/performance increase need.

RESPONSE:

Avista objects to this request because it seeks future information this is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ken Sweigart
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC - 239	TELEPHONE:	(509) 495-4417
		EMAIL:	ken.sweigart@avistacorp.com

SUBJECT: Electric Transmission

REQUEST:
Capital Additions, Test Year (Electric)
Please refer to Attachment A provided by Avista in response to Public Counsel Data Request No. 123, at 45, Figure 22.

c) Provide a random sample of 10 outage reports related to conductor of the approximately 60 shown on Figure 22.
d) Provide a random sample of 10 outage reports related to transformers of the approximately 20 shown on figure 22.

RESPONSE:

a) There are very few outages of this type on the transmission system that actually result in a service outage for our electric customers, as is indicated by only 35 such outages since 2002. This small number of outages should be of no surprise to our regulators, however, since our transmission system, like that of all utilities, and consistent with the interest and intent of a range of federal regulations governing the bulk electric system, is designed, to the extent reasonable and cost effective, to withstand isolated outages on lines and to have other circuits in the network 'pick up' those customers and shield them from experiencing an outage.[27] As such, transmission outages resulting from equipment failures, which actually result in service outages for our customers, under-represent the actual equipment failures experienced on our system (because the great majority of failures, by design, do not result in customer outages). A list of all the transmission outages caused by conductor failures that have resulted in service outages for our customers, which are represented in outage reports for the subject Figure 22, are provided in PC-DR-259 Attachment A. Avista invites Public Counsel to review and inspect the list of outage reports for conductor failures, and to call to Avista's attention any specific outages or 'sample groups' of outages that might be of interest.

b) There are very few outages of this type on the transmission system that actually result in a service outage for our electric customers, as is indicated by only 17 such outages since 2002. This small number of outages should be of no surprise to our Commission, however, since our transmission system, like that of all utilities, and consistent with the interest and intent of a range of federal regulations governing the bulk electric system, is designed, to the extent reasonable and cost effective, to withstand isolated outages on lines and to have other circuits

[27] Avista's customers who are served from radial transmission lines in our system are more likely to experience an outage related to a transmission fault than those who receive network service.

in the network 'pick up' those customers and shield them from experiencing an outage.[28] As such, transmission outages resulting from equipment failures, which actually result in service outages for our customers, under-represent the actual equipment failures experienced on our system (because the great majority of failures, by design, do not result in customer outages). A list of all the transmission outages caused by transformer failures that have resulted in service outages for our customers, which are represented in outage reports for the subject Figure 22, are provided in PC-DR-239 Attachment A. Avista invites Public Counsel to review and inspect the list of outage reports for transformer failures, and to call to Avista's attention any specific outages or 'sample groups' of outages that might be of interest.

[28] Avista's customers who are served from radial transmission lines in our system are more likely to experience an outage related to a transmission fault than those who receive network service.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/15/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Amy Jones
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 240	TELEPHONE:	(509) 495-2552
		EMAIL:	amy.jones@avistacorp.com

SUBJECT: Electric Distribution Minor Rebuild

REQUEST:
Please refer to Attachment A provided by Avista in their response to Public Counsel Data Request No. 124, and to their response to Public Counsel Data Request No. 124, regarding the Distribution Minor Rebuild program.

a) What year did Avista start spending on this "Distribution Minor Rebuild" program?
b) Identify any and all "larger projects with an identified need and short timeframe" that were accomplished under this program for each year since the program was started.
c) Refer to the statement "Not funding would have a significant impact on business functions and processes as other areas would be responsible for the work" Please estimate the amount spent by Avista in each of the five years prior to the start of this program by "other areas" or any areas of Avista.
d) Identify the "other areas" that will be "impact(ed)" and the amount of that impact, if the program is "Not funded".
e) The statement "Minor Rebuild work occurs regularly due to the nature of the utility business" would indicate that Avista has always had to deal with minor rebuild work. If Avista has always had to accomplish minor rebuilds on its system, how were these projects funded prior to the implementation of the "Distribution Minor Rebuilds" program.
f) Please explain why "customers' needs for modifications to their electrical service" are not paid for by the customer.

RESPONSE:

a) The Company has been making investments under this program for many decades.

b) Such projects identified for the last five years 2016 – 2020 are listed in the table below.

Distribution Minor Rebuild Identified Large Projects by Year							
Prj Num	Project Name	2016	2017	2018	2019	2020	Grand Total
5012	FAIRFIELD CARE CENTER REBUILD		$ 27,461.76	$ 1,981.78	$ 1,082.85	$ 4,196.58	**$ 34,722.97**
5052	ZH609R Recloser Repl-Othello	$ 29,135.11					**$ 29,135.11**
5064	SOT522 Hwy 24 Midline Regs				$ 63,332.55		**$ 63,332.55**
5201	Orin 12F1 Midline Regs					$ 32,733.82	**$ 32,733.82**
5212	STANLEY FARMS UG PRIMARY			$114,439.60			**$ 114,439.60**
5245	ZP1101R - Viper Replacement					$ 39,181.32	**$ 39,181.32**
5844	SUN 12F4 - Add Line Regulators	$126,631.03					**$ 126,631.03**
5884	727 E Sharp Ave Rebuild	$ 38,463.63	$ (736.96)				**$ 37,726.67**
5885	Maplewood RV Park Re-route	$ 30,410.19					**$ 30,410.19**
5925	3HT 12F2 Recond-Pepsi Grow-D	$ 162,465.69	$ 736.72				**$ 163,202.41**
5982	INT 12F1 TIE (Barnes &Phoebe)		$ 49,572.05	$ (4,618.39)			**$ 44,953.66**
6100	Z977 Scadamate Replacement			$ 1,865.53	$ 60,467.30		**$ 62,332.83**
6135	3HT12F1-S.Landing 200ABackbone				$ 120,481.59		**$ 120,481.59**
6136	H&W12F3 Z1310V LineReg Replace				$ 26,404.10	$ 49,137.74	**$ 75,541.84**
6151	SLK12F2 - VMC OH Line Upgrade				$ 215,428.11	$ 240.54	**$ 215,668.65**
6210	WAK12F1 & 12F2 Exit Reconfig					$ 56,016.80	**$ 56,016.80**
6231	MINOR REBUILD - E ALKI AVE					$ 98,743.53	**$ 98,743.53**
6483	RR009 Replacement WIL12F2		$ 66,953.02				**$ 66,953.02**
6643	SR23 Clear Zone Issues - MB			$ 39,481.01		$ 152.93	**$ 39,633.94**
6755	328 Regs Lee E of Billington				$ 52,022.47	$ 26,873.07	**$ 78,895.54**
		$387,105.65	$ 143,986.59	$ 153,149.53	$ 539,218.97	$ 307,276.33	**$ 1,530,737.07**

c) Please see part (a), above.

d) Since the investments funded under the distribution minor rebuild program are not discretionary, then, hypothetically speaking, the amount of the impact on operating budgets elsewhere in the Company would correspond with the amount not funded in this program, which would be allocated to budgets based on the type of work required and the geographic location.

e) Please see part (a), above.

f) This request, as previously answered in response to PC-DR-125 part (a), pertains to work on our electric system, which need is initiated by a customer's request for service, but which costs are not included among the costs the requesting customer pays under the Company’s Commission-Approved Tariffs for Line Extensions. Under our Commission Authorized tariffs, the customer pays for the investments required to provide the capacity requested from the feeder to the customer’s service entrance. But if the feeder itself lacks the capacity to serve the customer’s incremental load, then the feeder upgrades needed to adequately serve the loads of all customers on the feeder are funded under this program as a cost borne by all customers.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/15/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater/K. Schultz
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden/ K. Schultz
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 241	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Substation Rebuilds Program

REQUEST:
Please refer to Attachments A–J provided by Avista in their response to Public Counsel Data Request No. 101.

a) For each Attachment/project, provide the amount added to the rate base since the last rate case.

b) For each Attachment/project, provide the amount of accumulated depreciation associated with the amounts provided in response to subpart (a) as of the end of the test period in this rate case.

c) Provide the amount estimated for the Colville Transformer No. 2 replacement (not provided on Attachment E).

d) Some Attachments do not identify any alternative to the work proposed. For each such Attachment, explain why the project was approved without a consideration of available alternatives.

e) Some Attachments identify alternatives to the work proposed. For each such alternative identified, provide the estimated benefits and costs of the approved project, and the estimated benefits and costs of the identified alternatives, along with all associated business cases, worksheets, workbooks, models, cost-benefit analysis, or any other calculations used to calculate these benefit and cost estimates.

f) For each attachment, provide any and all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, or industry publications which show that the value in dollars of the proposed work to customers exceeds the cost of the proposed work to customers.

g) Provide any substation rebuild Engineering Project Request forms submitted by Avista engineers which were not approved for implementation from 2016 to 2020.

RESPONSE:

a) Please see PC-DR-241 Attachment A, in the tab labeled “TPP Detail” for the monthly transfers to plant for the projects represented in PC-DR-101 Attachments A-J. The Company’s historical test period in its prior Washington general rate case ended December 31, 2018. Accordingly, plant additions for these projects (less A/D and ADFIT) are provided for the period January 1, 2019 through December 31, 2020.

b) For the monthly accumulated depreciation associated with the amounts provided in part (a) please see PC-DR-241 Attachment A, in the tab labeled “Summary Cost E.” Accumulated depreciation for the end of the Company's test period was through December 31, 2019, however, included in the rate base calculation for part (a), above, is the accumulated depreciation for the period ending December 31, 2020.

c) Please see the Capital Project Request Form for the estimated cost provided as PC-DR-241 Attachment B.

d) Alternatives to the work proposed are considered but may not be included in the request if they are determined to be not viable (as compared with the lowest lifecycle cost of the solution implemented).

e) Please see the response to part (d), above.

f) Avista is required to take the reasonable and prudent steps necessary to ensure we provide an acceptable level of service to our customers. The Attachments to Public Counsel request PC-DR-101 document the need for such investments in order to meet our service obligations, and these actions are reasonable. Because the cost to customers is necessary and reasonable, and because the investment allows us to meet our short and long-term service obligation to our customers, these costs are deemed to be prudent and in the interest of our customers.

g) Proposed projects for the Substation Capacity Business Case are not discretionary in the long run (i.e. they are not rejected for implementation). As the demand for capital forces a reprioritization of company-wide projects, however, some substation capacity projects may be moved to future years depending on the risks associated with such a move.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	3/16/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Randy Gnaedinger
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC - 242	TELEPHONE:	(509) 495-2047
		EMAIL:	randy.gnaedinger@avistacorp.com

SUBJECT: Electric Transmission Construction - Compliance

REQUEST:
Please refer to Attachment C provided by Avista in response to Public Counsel Data Request No. 101.
This project appears to be work requested by PacifiCorp (PAC).

a) Provide any invoices to PacifiCorp for this work. If invoices have yet to be provided to PacifiCorp, please explain why not.
b) If Avista does not plan to invoice PacifiCorp for this work, please explain why not.
c) If the amounts estimated for this work as provided in Attachment C are net of any amounts billed to PacifiCorp, or if the amounts estimated for this work will not be billed to PacifiCorp as explained in response to subparts (a) and/or (b), please explain why any unbilled amounts are Avista customers' responsibility to pay.

RESPONSE:

a) PC-DR-242 Attachment A, provided, is invoice 128598 for the subject work, which PacifiCorp has paid.

b) Please see response to part (a).

c) There are no outstanding unbilled amounts to PacifiCorp.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/14/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	John Gross
TYPE:	Data Request	DEPT:	System Planning
REQUEST NO.:	PC - 243	TELEPHONE:	(509) 495-4591
		EMAIL:	john.gross@avistacorp.com

SUBJECT: Electric Substations Rebuilds

REQUEST:

Please refer to Attachment I provided by Avista in response to Public Counsel Data Request No. 101. The Problem Statement on this Engineering Project Request states "Othello is home to 2 of our largest customers — McCain's and Simplot. Both peak over 10MVA, and have no viable backup. In addition, loading has grown in the area with a new hospital, school, and agricultural loads. The L&R transformer is currently a 20MVA unit with 4 feeders, and is near the limit at summer peak."

a) Confirm that customers are responsible for their own "backup". If this cannot be confirmed, please explain.

b) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, load forecasts, equipment capacity ratings, net overload limits, or any other calculations, presentations, requests, standards, other documentation, which shows that the "The L&R transformer" is forecasted to be actually overloaded at some point in the future. In these materials, be sure to provide evidence which indicates the year in which the projected overloads will (i) exceed emergency equipment ratings; and (ii) exceed N-1 requirements.

RESPONSE:

a) Avista is responsible to plan, design and construct its electrical system to cost effectively and reliably serve the needs of its customers. Customers are not expected or required to install onsite generation or storage to augment the basic service the Company is required to provide. Some customers do install their own "backup" generation, however, to carry critical load in their facilities during an outage event or other emergency. But customers' emergency backup generation is not a substitute for the service provided by Avista. The "viable backup" referenced in Attachment I of PC-DR-101 is noting that Avista's electrical system should be reasonably expected to have the ability to take certain equipment out of service for maintenance, or due to unplanned conditions, and still maintain service to customers. This redundancy built into the system cannot reasonably be implemented for every customer and should not be taken out of context.

b) Please reference PC-DR-243 Attachment A, which provides context for this project, including present transformer loadings and specific customer load increases to be served by the Lee & Reynolds Station. With the given existing loading of the station and the customer load increases planned for 2021, the projected overload of the Lee & Reynolds #1 115/13.2kV Transformer would have occurred in 2022. The N-1 requirements would not have been satisfied prior to the station rebuild project.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/15/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	John Gross
TYPE:	Data Request	DEPT:	System Planning
REQUEST NO.:	PC - 244	TELEPHONE:	(509) 495-4591
		EMAIL:	john.gross@avistacorp.com

SUBJECT: Westside Substation Rebuild - Revisited

REQUEST:

RE: Capital Additions, Test Year (Electric)
Please refer to Attachment J provided by Avista in response to PC-DR-101.
The Problem Statement on this Engineering Project Request states "The existing Westside #1 230/115 kV Transformer exceeds it applicable facility rating for the P1 event of Westside #2 230/115 kV Transformer. System performance analysis indicates an inability of the System to meet the performance requirements in Table 1 of NERC TPL-001-4 in scenarios representing 2017 Heavy Summer Scenarios for the P1 events. An Operating Procedure to shed non-consequential load can be used until 2021 to mitigate system deficiencies (non-consequential load shedding is considered acceptable through the 84 month implementation of TPL-001-4)."

a) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, load forecasts, equipment capacity ratings, net overload limits, or any other calculations, presentations, requests, standards, other documentation, which "indicates an inability of the System to meet the performance requirements in Table 1 of NERC TPL-001-4 in scenarios representing 2017 Heavy Summer Scenarios for the P1 events." In these materials, be sure to provide evidence which indicates the year in which the projected overloads will (i) exceed emergency equipment ratings; and (ii) exceed N-1 requirement, both with and without the "Operating Procedure to shed non-consequential load".
b) Indicate whether or not the "Operating Procedure to shed non-consequential load" can be used "to mitigate system deficiencies" beyond 2021. If not, please explain why not, and/or why such an option cannot be used to comply with Table 1 of NERC TPL-001-4.

RESPONSE:

a) In its response to PC-DR-166, Avista provided sufficient documentation describing the need for, and the appropriateness of the solution taken by the Company to resolve the subject issues. We also provided documentation responsive to the nearly identical questions above. Please refer to PC-DR-166 and Attachments.

b) Similarly, the Company has already provided an explanation of why "nonconsequential load shedding" 'is not a permanent solution' to problems being resolved by the Westside Project, and why such a practice would be considered imprudent, objectionable to customers and the Commission, and would place Avista in clear violation of NERC standards, which excerpt from PC-DR-166 part (b) explains, below.

PC-DR-166 part (b) - Non-consequential load shedding is the act of manually de-energizing portions of the electric system and putting customers in the dark.[29] Intentionally blacking out portions of our system, in particular, when suggested as a permanent solution to avoid overloading a single piece of equipment is generally not a prudent utility practice. In addition to being an imprudent practice in this instance, NERC standard TPL-001-4 Table states non-consequential load loss is not allowed for P1 events, which would put the Company in violation for such a practice. Footnote 12 of Table 1 implies the Washington State Commission would be a stakeholder in approving the use of intentionally dropping service to customers as a prudent alternative.

Further, the Company went on to explain why such a practice is not a viable option for complying with the subject standard as described in the excepts below from Avista's response to PC-DR-166, parts (c-f).

PC-DR-166 part (c) - Table 1 of NERC TPL-001-4 states several requirements. With respect to the Westside 230/115kV Station Rebuild, note part (f) is applicable here, stating "Applicable Facility Ratings shall not be exceeded." Conducting the steady state portion of the Planning Assessment required under R3, if simulations show a P1 category contingency from Table 1 does not meet note (f) criteria a correction action plan is necessary according to R2.7

PC-DR-166 part (d) - Please see details provided in Attachment B on how the System performance analysis indicates an inability of the system to meet the performance requirements in Table 1 of NERC TPL-001-4 in scenarios representing 2017 Heavy Summer for P1 events. Section II starting on page 3 describes the simulated performance issues. In summary, an outage of the Westside #2 230/115kV Transformer (P1 event from Table 1) caused the Westside #1 230/115kV Transformer to exceed its applicable facility ratings to a level of 123.8% in scenarios representing 2018 peak summer conditions.

PC-DR-166 part (d) - Studies provided in response to part (c) clearly show the inability to meet the requirements of the TPL-001-4 standard. The specific part of the standard driving the project is requirement R2.7, which states "shall include Corrective Action Plan addressing how the performance requirements will be met." Subpart R2.7.1 includes a list of possible associated actions needed to achieve required System performance which includes "installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment."

PC-DR-166 part (d) - Please refer to Attachment C (Energy Policy Act of 2005), and refer to Title XII – Electricity, Subtitle C – Reliability Standards.

[29] Except when it's light outside, and then they just experience a service outage.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/15/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 245	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Electric Distribution Grid Modernization

REQUEST:
Please refer to Attachments A–O provided by Avista in response to Public Counsel Data Request No. 110.

a) For each Attachment/Feeder, provide a range for the likely O&M and capital costs to execute the recommended additional investigations and implement additional solutions. For each Attachment/Feeder, provide these ranges for the work required by intended outcome, such as (i) reliability-related work; (ii) work to avoid energy costs; and (iii) capital to offset of future O&M.
b) Each Attachment/Feeder indicates that some amount of reliability improvement is anticipated from the work. Provide this reliability improvement estimate, and all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, or industry publications which show how this estimate was determined.
c) Each Attachment/Feeder indicates that some amount of avoided energy costs is anticipated from the work. Provide this avoided energy cost estimate, and all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, or industry publications which show how this estimate was determined.
d) Each Attachment/Feeder indicates that some amount of future O&M costs is anticipated from the work. Provide this avoided future O&M cost estimate, and all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, or industry publications which show how this estimate was determined.

RESPONSE:

a) To the degree that any recommended additional investigations and/or actions are undertaken in the final design and construction, they would adhere to the lifecycle cost and benefit analyses described in parts (b-d), below for reliability, energy conservation, and future O&M savings.

b) While the predominant reason for these projects is to replace end of life assets, because they are comprehensive and offer an integrated approach to enhancing feeder performance and value, they provide the opportunity to capture benefits not accessible through an approach that replaces assets ‘in kind’ and ‘in place.’ As an end of life asset replacement program, it’s important to remember that the reliability benefit that comes from having new equipment replacing the old is just one of the many benefits captured. The proven, cost-effective reliability benefit achieved through a grid modernization feeder rebuild is the product of the combination of treatments applied in each project, which predominant treatments are briefly noted below.

    i. The cost-effective reliability benefit that comes from replacing end of life wood poles has been described and documented in the Company’s responses to several data requests, including PC-DR-221 among others. This benefit, as explained in multiple responses, including Avista’s response to PC-DR-118, has been proven through repeated lifecycle cost analyses where program costs, benefits and risk reduction have been demonstrated to be in the financial best interest of our customers. For further description of results of this lifecycle cost modeling, please see the Company's response to PC-DR-235 in general, and part (i) in particular.

ii. The cost-effective reliability benefit that comes from systematically replacing end of life distribution transformers, when performed as part of a broader program like wood pole management or grid modernization, has been described and documented in the Company's responses, noting PC-DR-232. The reliability benefit among others has been proven through lifecycle cost analyses where program costs, benefits and risk reduction have been demonstrated to be in the financial best interest of our customers.

iii. Similarly, the Company has documented, though lifecycle cost analyses, the reliability benefit of replacing aging conductor when completed as part of a systematic replacement project.

iv. Similarly, the Company has documented the cost-effective reliability benefit that comes from systematically replacing end of life distribution cutouts, crossarms, and other attached equipment, when performed as part of a broader program like wood pole management or grid modernization, which has been described and documented in the Company's responses, noting PC-DR-223. These reliability benefits among others have been proven through lifecycle cost analyses where program costs, benefits and risk reduction have been demonstrated to be in the financial best interest of our customers.

Avista has described the limitations of presenting year-to-year reliability data in an attempt to attribute annual performance to any single factor, as described response to PC-DR-111, and as excerpted below.

> *From PC-DR-111* – Outages vary substantially from year to year and area to area across the Company's service territory, based on the interaction of a wide range of factors (wind, equipment failure, major events, wind, vegetation, etc.). Because of this significant annual variability, the reliability improvement provided by an investment must generally be evaluated over several years, against several years' data on the historic reliability performance. As Grid Modernization is a relatively new program, there is not enough data available to make outages on a per feeder basis meaningful at this point. Because of this, Avista has evaluated reliability indices before and after Grid Modernization by looking at the average across all feeders addressed by the program to date. This helps to normalize the impact of year to year and local variability as well as the number of years' data available for each feeder. As was discussed in the business case, there has been a reduction in the average CEMI3 post Grid Modernization (with and without major event days included in the analysis). In the future, when more outage data is available post treatment, the Company will be able to generate more meaningful reliability data on a feeder-by-feeder basis.

The approach used by the Avista Grid Modernization program for demonstrating the integrated reliability benefit has been described in response to PC-DR-111, including Attachment A.

c) Similar to the reliability benefit described in part (a) above, Avista has demonstrated that replacing end of life transformers saves customers money through reduced energy consumption and is a cost-effective portion of the other benefits demonstrated through the lifecycle cost analyses described in part (a) above. Additionally, the Company has demonstrated that our customers are better off financially when we assess and replace undersized conductor during feeder rebuilds, to achieve substantial and cost-effective energy conservation savings, as shown in response to PC-DR-110.

d) Lifecycle O&M costs are included as an integral part of the lifecycle cost analyses described in part (a) above, and described in greater detail in response to PC-DR-223 and PC-DR-235, among others. The approach taken by the Company, as noted in part (a), above, to replace end of life assets through the subject program is proven to provide cost-effective O&M savings.

Additionally, because the actions described above are integrated into one overall program we are able to perform this wide range of improvements (and many others too numerous to mention) with fewer service outages, allowing us to minimize the impact we have on our customers. As noted above and as documented in the Company's responses to the data requests cited, including the many others not mentioned here, Avista's actions have been demonstrated to be reasonable, cost effective and in our customers' best interest. Because the cost to customers is necessary and reasonable, and because the investment allows us to meet our short and long-term service obligations to our customers, these investments are prudent and in the interest of our customers.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	3/15/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 246	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Electric Distribution Grid Modernization

REQUEST:

Please refer to Avista's Responses to Public Counsel Data Request No. 110 regarding the grid modernization program generally.

Public Counsel is aware that many utilities maintain a worst performing feeder program. In such programs, the two to three percent of feeders exhibiting the worst reliability over a three to five year period are examined for recurring issues, which are then prioritized and addressed in a manner which maximizes risk reduction per dollar of capital.

a) Does Avista maintain a worst performing feeder program?
b) If Avista does not maintain a worst performing feeder program, please explain why not. Please include in this explanation the degree to which the grid modernization program serves as a substitute for a worst performing feeder program.
c) If Avista does maintain a worst performing feeder program, please describe this program. Please include in this description the manner in which the worst performing feeder program and the grid modernization program work together.
d) Has Avista ever had a worst performing feeder program? If so, explain the origins and, if applicable, the discontinuation of this program. If Avista has never had a worst performing feeder program, please explain why not.
e) If Avista had a worst performing feeder program at one time, and if the grid modernization program serves as a substitute for this program to any extent, provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, or industry publications which indicate that the benefit-to-cost ratio of the grid modernization program is greater than the benefit-to-cost ratio of the former worst performing feeder program.
f) Explain the extent to which activities which might take place under a worst performing feeder program are undertaken in the Distribution Minor Rebuild program.

RESPONSE:

a) Avista has at times in the past had a capital business case known as the Worst Feeders program, which was discontinued in 2017.

b) A portion of the funding previously budgeted under the worst feeders business case was allocated to the grid modernization program. As the Company experienced growing infrastructure demands, as explained in PC-DR-105 Attachment A, the limited level of funding allocated to worst feeders did not justify a standalone business case.

c) Please see part (a), above.

d) Please see parts (a) and (b), above.

e) The programs are not directly comparable because, as explained by the Company in previous responses, grid modernization evaluates multiple opportunities for creating value in a holistic approach to analyzing performance, health, and criticality of feeders that are candidates for rebuild under the program. Service reliability is of course one of the many types of improvements targeted in a grid modernization feeder rebuild. By contrast, the worst feeders program enabled targeted reliability improvements on feeders experiencing the greatest outage frequency and duration. That said, the investments made under both programs rely(ied) on the same asset lifecycle cost modeling in the evaluation of opportunities for reliability improvement, as described in response to PC-DR-245 part (b). In this respect, delivering cost effective reliability improvements for our customers, both programs were likely equally effective, though improvements in grid modernization are likely delivered more efficiently due to the integrated nature of the work.

f) The activities previously undertaken in worst feeders projects would likely have little overlap with investments made under the distribution minor rebuild program. The minor rebuild program, as explained in PC-DR-105 Attachment A, and in the Company's several responses to requests in this case, predominantly addresses repair of failed assets and provides for system investments needed to meet customers' requests for service, as explained in Avista's response to PC-DR-125 part (a), which are not part of the tariffed costs paid for directly by our customers. The worst feeders program funded targeted reliability improvements on circuits with high numbers of outages and was not directed at the repair of failed assets or system capacity issues related to meeting our customers' requests for service.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/15/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater/K. Schultz
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas / K. Schultz
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 247	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Electric Distribution Grid Modernization

REQUEST:
Please refer to Table k-1 provided by Avista in response to Public Counsel Data Request No. 110 (k).

a) Provide, for each feeder listed in Table k-1, the amount of accumulated depreciation associated with the amounts provided as of the end of the test period in this rate case.
b) Provide, for each feeder listed in Table k-1, the amounts added to rate base since the last rate case associated with the installation of distribution automation equipment of the types listed in tab "Grid Mod Device List" of Attachment R provided in response to PC-DR-110 (r).
c) Provide, for each amount provided in response to subpart (b), the amount of accumulated depreciation associated with the amounts provided as of the end of the test period in this rate case.

Response:

a) Below are the projects and project numbers for the feeders listed in Table k-1. No construction has been performed on five of the feeders in the table.

Table k-1 Feeders (ER #2470)	
Feeder	Project Number
BEA1242	95605981
F&C12F1	02806408
HOL1205	93205098
M15514	93305069
MIS431	90705107
NE12F4*	95606217
ORO1280	03805531
ORO1282*	91305012
PDL1201	92205117
RAT233	03805513
ROS12F4*	95606153
ROS12F5*	95606152
SPI12F1	02805932
SPR761	02806174
TUR112	02806176

*Construction has not taken place.

Please refer to PC-DR-247 Attachment A for accumulated depreciation (A/D) balances related to the feeders listed in Table k-1, which is included herein for ease of reference. As shown in Table k-

1 there are five feeders where construction has not taken place. Thus, no balances have transferred to plant yet. Of note, A/D as of the end of the Company's test period would be December 31, 2019. However, included in the rate base (plant, less A/D and ADFIT) calculation for subpart (b) below would be A/D as of December 31, 2020.

b) Automation devices listed for each feeder are provided in the table below, from the Company's response to PC-DR-110 Attachment R.

Feeder	Viper Switch	Viper Recloser	Switched Cap Bank	Fixed Capacitor	Smart Midline Regulators
BEA 12F2	0	0	0	0	0
F&C 12F1	0	0	0	0	0
HOL 1205	1	1	1	1	0
M15 514	5	1	1	3	0
MIS 431	1	4	0	0	0
ORO 1280	1	1	1	1	0
ORO 1282	0	0	0	0	0
PDL 1201	3	1	1	1	0
RAT 233	2	4	0	1	0
ROS 12F4	0	0	0	0	0
ROS 12F5	0	0	0	0	0
SIP 12F4	1	1	0	0	0
SPI 12F1	0	3	1	0	0
SPR 761	0	1	1	1	0
TUR 112	0	1	1	1	1

Note: Not all devices listed were installed between the years 2018 and 2020.

The Company's historical test period in its prior rate case was the twelve months ended December 31, 2018; thus, the Company has included plant additions for the projects contained on the "TTP Detail" tab in PC-DR-247 Attachment A for the period of January 1, 2019 through December 31, 2020. Please refer to PC-DR-247 Attachment A for the associated rate base (plant additions, less A/D and ADFIT) as of December 31, 2020 EOP.

c) Please refer to subpart (a) above. PC-DR-247 Attachment A includes A/D balances related to the feeders listed in Table k-1 above. A/D as of the end of the Company's test period would be December 31, 2019. However, included in the rate base (plant, less A/D and ADFIT) calculation for subpart (b) above is A/D as of December 31, 2020.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/15/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 248	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Electric Distribution Grid Modernization

REQUEST:
Please refer to Attachment R provided by Avista in response to Public Counsel Data Request No. 110(r).

a) Tab "Analysis" provides a count of instances in which each device was "used". For each year, provide the number of recloser "uses" included in these counts of instances.
b) Of the amounts provided in response to subpart (a), provide a count of recloser "uses" in which the recloser eventually locked out.
c) In calculating the cost savings of "uses" in Tab "Analysis", each instance of device "use" appears to assume five hours of avoided labor saved. Provide support for the estimate that each "use" of a device avoided five hours of labor.
d) Refer again to Tab "Analysis". As of 2019, Avista indicates that these devices are reducing O&M costs of approximately $300,000 annually. Provide the headcount reductions Avista has been able to secure in distribution operations resulting from the installation of these devices.

RESPONSE:

a) Please see the tables of operations provided below.

Count of Action (2017) Row Labels	Column Labels 43I DISABLE / ENABLE	43R NON-RECLOSING / RECLO	HLH	HLH REMOVE / APPLY	OPE	OPEN / CLOSE	Grand Total
BEA_12F1_Z 1086R				4			4
BEA_12F1_Z 516R				4			4
M23_621_ZP 6213R	1	2				2	5
M23_621_ZP 6216R						1	1
MIL_12F2_Z1 095R			2				2
MIS_431_ZC 434R	5	5	2	12		6	30
MIS_431_ZC 439R			41	20	1	5	67
ORO_1280_Z L1540R				46			46
PDL_1201_ZL 1387R				4		6	10
PDL_1201_ZL 1388R	4	5		10		4	23
PDL_1201_ZL 1516R						2	2
RAT_231_ZC 247R				2		1	3
RAT_231_ZC 323R						2	2
RAT_233_ZC 201R	2	2	2				6
RAT_233_ZC 202R	2	2	4	18			26
RAT_233_ZC 265R	2	2		6			10
RAT_233_ZC 326R				2		2	4
RAT_233_ZC 335R	4			6		1	11
SPI_12F1_ZE 171R	4	4		6		6	20
SPI_12F1_ZE 172R	4	5		5		5	19
SPI_12F1_ZE 173R	4	5		4		4	17
TUR_112_ZP 1803R			36	32	1		69
WAK_12F2_Z 1090R				2			2

Grand Total	32	32	87	183	7	48	389

Count of Action (2018) Row Labels	Column Labels 43I DISABLE / ENABLE	43R NON-RECLOSING / R	43R NON-RECLOSING / RECLO	43R NON-RECLOSING /RECLO	HLH	HLH APPLY / REMOVE	HLH REMOVE / APPLY	OPEN	OPEN / CLOSE	Grand Total
BEA_12F1_Z1086R							17			17
BEA_12F1_Z320R							2			2
M23_621_ZP6213R		1		1						2
M23_621_ZP6216R		1		1			2			4
MIL_12F2_Z584R						2	2			4
MIS_431_ZC434R	2	1		1		8	44		2	58
MIS_431_ZC439R			1			27	113		4	145
ORO_1280_ZL1540R							62		1	63
PDL_1201_ZL1387R			3				8		9	20
PDL_1201_ZL1388R						30	98		3	131
PDL_1201_ZL1397R							4		10	14
PDL_1201_ZL1516R						2			2	4
RAT_231_ZC285R							2			2
RAT_231_ZC323R									2	2

RAT_233_ZC201R	6	1	5	1	1	19	229	1	5	268
RAT_233_ZC202R	2	1		1						4
RAT_233_ZC265R	2	1		1			2		2	8
RAT_233_ZC282R							6		4	10
RAT_233_ZC326R	1						2			3
RAT_233_ZC335R	4						6		1	11
SPI_12F1_ZE171R	2	1		1		8	4		1	17
SPI_12F1_ZE172R						2		2		4
TUR_112_ZP1803R						4	72	1		77
WAK_12F2_Z1089R							2			2
WAK_12F2_Z168R									4	4
WAK_12F2_Z251R								2		2

Grand Total	**19**	**7**	**9**	**7**	**1**	**102**	**677**	**6**	**79**	**907**

Count of Action (2019)	**Column Labels**							
Row Labels	**43I DISABLE / ENAB**	**43I DISABLE / ENABLE**	**43R NON-RECLOSING**	**43R NON-RECLOSING / REC**	**43R NON-RECLOSING / RECLO**	**HLH REMOVE / APPLY**	**OPEN / CLOSE**	**Grand Total**
BEA_12F1_Z1086R						17	2	19
M23_621_ZP6213R	1		1		1			3
M23_621_ZP6216R	1		1		1			3
MIS_431_ZC434R	1	2	1	1			1	6
MIS_431_ZC439R						6	4	10
ORO_1280_ZL1541R			2			11	4	17
PDL_1201_ZL1388R							2	2
PDL_1201_ZL1397R							2	2
RAT_231_ZC247R		2						2
RAT_231_ZC285R						4	3	7
RAT_231_ZC323R						2	6	8
RAT_233_ZC201R	1	1	1	1		91		95
RAT_233_ZC202R	1	1	1	1				4
RAT_233_ZC265R	1	1	1	1		5		9
RAT_233_ZC282R						51		51
RAT_233_ZC326R						4	2	6
RAT_233_ZC335R	2	35				69		106
SPI_12F1_ZE171R			1	1		6		8
SPR_761_ZH645R	1	6	1	1	5	12	4	30
TUR_112_ZP1803R	1	1	1		1	6		10
WAK_12F2_Z1089R						2		2
Grand Total	**10**	**49**	**11**	**6**	**8**	**286**	**33**	**403**

b) Counts of lockouts are not tracked among the results of device operations.

c) Five hours is the average response time reported across the Company's operating areas, which varies, of course with local staffing and the proximity of the device to each local operations office.

d) Avista's staffing requirements for operating its integrated electric transmission, substation and distribution systems is a function of the amalgam of many different business needs, which naturally vary over time, including the need for contract resources to help fulfill the same. As such, the number of employees retained by the Company in each of its operating areas is right sized to the work required to perform these duties. The subject automation devices produce efficiencies and financial savings that are ultimately reflected in a cost to customers that is lower than it would otherwise have been, regardless of the employee roster required to efficiently and cost effectively provide them service.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/12/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	UTC Staff	RESPONDER:	Ken Sweigart
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC-249	TELEPHONE:	(509) 495-4417
		EMAIL:	ken.sweigart@avistacorp.com

SUBJECT: Transmission Major Rebuild

REQUEST:
Please refer to Attachments A through F provided by Avista in response to Public Counsel Data Request No. 161.

a) Each of the attachments has a "Probability Index - Criteria and Weighting". Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, or industry publications which show how these numbers were determined.
b) Each of the attachments has a "Consequence Index - Criteria and Weighting". Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, or industry publications which show how these numbers were determined.
c) Each of the attachments has a "Risk Index - Criteria and Weighting". Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, or industry publications which show how these numbers were determined.
d) Each of the attachments has a "Probability Index Summary". Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, or industry publications which show how these numbers were determined.
e) Each of the attachments has a "Recommendations" sheet. Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, or industry publications which show how the Risk Index numbers were used to justify the Recommendations.
f) Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, or industry publications which show that the value in dollars of the proposed work to customers exceeds the cost of the proposed work to customers.

RESPONSE:

a) - d) The probability, consequence, and risk indices were developed in 2016 through a series of engineering meetings held with System Planning, System Operations, Transmission Engineering, Protection Engineering, Substation Engineering Technology, and Communications representatives who discussed each element they determined as the group to be relevant criteria.

For the line health index, the factors considered were unplanned outages and associated spending, remaining service life based on Company experience, and general utility expectations, the time since the infrastructure had been maintained, rebuilt, or identified as needing work, the number of miles of the circuit, any noted system stability, voltage control, or thermal problems, and voltage and configuration. For each criterion identified, the group determined based primarily on experience and knowledge what would comprise the good to poor health of a line. For example, if the line experienced over 10 outages per year, these outages impacted over 5,000 customers, and caused over $50,000 in unplanned spending, on a scale of 1 (good) to 5 (poor) it would be considered a 5.

For the criticality index, the group determined that primary elements should include power delivery, potential damage with a failure, access, system stability, voltage control and thermal problems, and voltage and configuration. Again, these elements were ranked 1 (good) to 5 (poor) based on the prior year's PI data results.

The Risk index was calculated based on the probability x the criticality index results.

A stakeholder index was developed based on each groups' (those identified above) concerns and priorities. This was done by allocating each group a total of 100 points for each line. They used these points to score their weighting of each line and to "vote" on which ones, based on their knowledge and experience, should be prioritized.

The capital replacement index was calculated by adding the risk index to the stakeholder index.

A summary of these indices is provided in the spreadsheet PC-DR-249 Attachment A.

e) The recommendations and rationale for selection of the lines is detailed in each of the attached reports provided in response to PC-DR-161. Included in those recommendations are results of the evaluations described in parts (a-d), above. This information helps support the identification of priority projects, for which lines treatment options and recommendations are developed as has already been described in the Company's Engineering Roundtable process. Among factors considered in that process are the requirements of meeting load growth, pole age and condition, providing upgrades for adding renewable energy projects to the grid, etc. Please see the recommendations provided in attachments. PC-DR-161 Attachment A, PC-DR-161 Attachment B, PC-DR-161 Attachment C, PC-DR-161 Attachment D, PC-DR-161 Attachment E, PC-DR-161 Attachment F.

f) Avista is required to take the reasonable and prudent steps necessary to ensure we provide an acceptable level of service, both in the eyes of our customers and the Commission. Avista has documented the need to rebuild the subject station and has demonstrated that its actions are reasonable. Because the cost to customers is necessary and reasonable, and because the investment allows us to meet our short and long-term service obligation to our customers, it is deemed to be prudent and in the interest of our customers. For additional supporting analyses, please see the 34 reports provided in support of the Company's response to PC-DR-237.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	3/16/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	John Gross
TYPE:	Data Request	DEPT:	System Planning
REQUEST NO.:	PC - 250	TELEPHONE:	(509) 495-4591
		EMAIL:	john.gross@avistacorp.com

SUBJECT: NERC Mandatory & Compliance Projects

REQUEST:

RE: Capital Additions, Test Year (Electric)
Please refer to Exhibit HLR-7, at 9, which states, regarding the Mandatory & Compliance program: "Projects in this category are primarily driven by external requirements that are largely beyond the Company's control, such as building the Saddle Mountain Substation, required to meet NERC grid stability requirements, as well as construction of the West Plains Substation and the reinforcement of the Ninth and Central and Westside Substations, again required by NERC related to remediating system reliability issues."

a) Please indicate if Saddle Mountain, West Plains, Ninth and Central and Westside Substations, are transmission substations or distribution substations.
b) If any of these substations are distribution substations, please explain how "NERC grid stability requirements" apply, and/or how they are "required by NERC to remediating system reliability issues".
c) Please explain in detail how "NERC grid stability requirements" and or "NERC related to remediating system reliability issues." have or will be violated and how these substation projects remedy those violations.

RESPONSE:

a) The Saddle Mountain and Westside substations are transmission substations. The projects associated with the West Plains and Ninth and Central substations are planned for years 2021 and beyond and are therefore outside the scope of this case.

b) Saddle Mountain and Westside substations are transmission substations. Please see part (a) above.

c) Regarding the Saddle Mountain Station, please refer to PC-DR-250 Attachment A at page 6. Through the planning assessment process required in part by NERC Standard TPL-001-4, performance issues were identified in the area in proximity to the Saddle Mountain Substation. Specifically, Category P6 events as defined in Table 1 of TPL-001-4 caused transmission lines to exceed their applicable facility ratings, therefore not meeting the performance requirements of Table 1. The studies associated with Attachment A were performed in 2014 with system models configured to represent the near-term planning horizon. At the time of the studies, the performance issues represented a future violation of the criteria. If the Saddle Mountain Substation project had not been completed, the criteria violations would now (in year 2021) be an existing issue. Please refer to PC-DR-250 Attachment A at page 43 for "how [the] substation project remedies those violations." Specifically, the new Saddle Mountain Substation adds an additional electrical path for power to flow from generation to load during normal system configurations and during outage scenarios. The additional electrical path provides for reduced loading of existing infrastructure, thereby remedying demonstrated performance issues related to TPl-001-4.

Regarding the Westside Substation, please refer to the Company's response to PC-DR-166 along with the supporting Attachments A-C. Avista's response in PC-DR-166, as reaffirmed in response to PC-DR-244, addresses the applicability of NERC Standard TPL-001-4 and how the substation project remedies the violations.

As stated above in part (a), the West Plains and Ninth and Central substation projects, currently scheduled for years 2021 and beyond are not at issue in this proceeding.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 286	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Refer to Avista's response to PC DR 211, which states "Avista plans, designs, operates, and maintains its transmission system and substations to be capable of supporting loads during peak periods of heavy demand and, and specifically to avoid the next outage, referring to the need for contingency planning."

a) Provide a list of all outages on the Avista system, 2014 through 2020, which were a result of substations being loaded in excess of 80 percent. An example might be a substation transformer failure, which resulted in load not being able to be picked up because a backup bank was loaded in excess of 80 percent.

b) Provide a list of substation banks presently loaded at peak in excess of 80 percent.

c) For each of the substation banks listed in response to subpart (b), provide a list of alarms by type that have occurred over each of the years since each bank has been loaded to over 80 percent.

RESPONSE:

a) The example provided in this part of the request presumes that a contingency load won't be picked up in the event the transformer intended to carry the switched load is already above 80 percent loading. The 80 percent planning standard referred to in this example does not govern the loadings applied during contingency in realtime operations, as described by the Company in response to PC-DR-289, part (a). We have not, by design, planning and operation, experienced customer outages as a result of such loadings on our substation equipment because our planning standards have provided the contingency reserve needed to pick up and carry customer loads as intended. As noted elsewhere in our responses, we typically experience a small number of transmission and substation outages each year that result in a loss of service for our customers. This low number is of no surprise, however, since our transmission and substations systems, like that of all utilities, and consistent with the interest and intent of a range of federal regulations governing the bulk electric system, are designed, to the extent reasonable and cost effective, to withstand isolated outages and to have other equipment and circuits in the network 'pick up' and carry those additional loads safely, reliably, and without failure due to overloading.

b) In PC-DR-286 Attachment A, Avista provides records of alarms indicating when the transformer banks listed in PC-DR-099 Attachment A, with the Reason listed as Overloading, were loaded in excess of 80 percent for the period 2016 to the time of replacement.[30] Although the Westside #2 230-115kV transformer did not experience any in-service overloading in the subject period, the need for its replacement based on overloading in contingency events is documented and described in response to PC-DR-166 Attachment B, Westside Transformer Replacement, and in response to PC-DR-289 parts (c) and (d).

c) Please refer to PC-DR-286 Attachment B for the list of Transformer Major and Minor Alarms for the transformer banks listed in PC-DR-099, Attachment A, with the Reason listed as Overloading.

[30] Alarms for Lee & Reynolds #2 115/13.8kV transformer are not presented because it was a new install and not a replacement for the existing unit.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 287	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Substation Transformers

REQUEST:
Refer to Attachment A provided by Avista in response to Public Counsel Data Request 215. Confirm that none of the test results shown, in and of themselves, would justify the replacement of this transformer. If this cannot be confirmed, explain how the test results do justify the replacement of this transformer. If this can be confirmed, explain how Avista justifies transformer replacement without test results, which justify replacement.

RESPONSE:

As stated in response to PC-DR-215 part (e), Avista considers many factors when determining the need to replace a transformer based on asset condition, which include, but are not limited to, asset health data, environmental considerations, age, visual inspection, and operating history. Factors are not limited to parameters that have Dissolved Gas Analysis, fluid quality, infrared or electrical test results. The parameters without test results include, but are not limited to age, leaks, and condition of accessories: temperature gauges, fans, pumps, and oil preservation system.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/15/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Larry La Bolle
TYPE:	Data Request	DEPT:	Transm Ops/System Planning
REQUEST NO.:	PC – 288 Revised	TELEPHONE:	(509) 495-4710
		EMAIL:	larry.labolle@avistacorp.com

SUBJECT: Customers' Reliability Expectations

REQUEST:
Refer to Avista's response to Public Counsel Data Request 227, regarding "willingness to pay" research on reliability improvements.

a) Provide the "detailed results of a proprietary survey on customer willingness to pay (provided to us as a favor by the utility who paid for the research)".

b) Given that Avista's reliability performance, particularly as measured by SAIFI, is already strong, and given Avista's belief that "customers are unwilling to pay more in rates for promises of better service reliability", explain the rationale for Avista's use of "standing budgets" for grid modernization, substation rebuild, and any other programs, which involve the prospective replacement of equipment outside of standard industry practices (including "run to failure" for distribution equipment; routine testing for substation equipment; and routine pole inspection programs, to name a few).

RESPONSE:

a) The referenced study was conducted in 2016, at the behest of HydroOne for their purposes, and was not relied upon by Avista for purposes of this case.

b) Please see Avista's responses in the subparts below to the statements made in part (b) of this request.

   i. Pertaining to the initial part of the statement in this request, Avista is unable to assign any meaning or interpretation to Public Counsel's attribution to the Company's SAIFI as "already strong."

   ii. Pertaining to the reference to "standing budgets" for programs: The Company has responded to numerous data requests on its many infrastructure programs that are intended to have the integrated long-term impact of generally maintaining and upholding the overall reliability performance of our electric infrastructure.[31] Programs for which we have provided very detailed information include, among others, grid modernization, wood pole management, vegetation management, wildfire resiliency, transmission minor rebuilds, transmission major rebuilds, investments to meet transmission code compliance, substation rebuilds, new distribution substations, distribution minor rebuilds, Avista's overall electric system planning and assessment, and a wide range of electric infrastructure and asset management plans, system reliability modeling, and a wide range of data, analyses, failure modeling and lifecycle cost

[31] Service reliability, is of course, only one of the many objectives, risks costs and benefits that are optimized in our infrastructure investments, including our overall intent to meet our many legal and compliance obligations and to generally provide our customers service at the lowest reasonable lifecycle cost. Please see the Company's responses to PC-DR-297 through PC-DR-305.

modeling. In Avista's view, to not have standing infrastructure programs to address the many issues and objectives we have already identified and discussed in detail, would be imprudent and in conflict with our obligation to meet the service standards required by the Commission.[32] Further, the Company has identified in numerous instances why its program budgets are not static, and in particular, why some budgets have had to increase over time just to maintain and uphold our current compliance requirements, lifecycle cost value, and the overall reliability performance of our infrastructure.

iii. Regarding the statement referring to "prospective replacement," the Company has at every instance noted its disagreement with Public Counsel's use of that phrase, including the use of "preemptive replacement," to describe how Avista replaces any equipment before it fails in service. The reason for our strong disagreement is that use of these phrases seeks to establish a premise that the default (and proper) strategy for replacement of assets is only when they fail in service. As we have stated in response to numerous requests, the Company replaces electric system assets when they are deemed to have reached the end of useful life. Further, we have explained and demonstrated that 'end of useful life' is determined through asset failure analysis, and evaluation of costs, benefits and risks in both simple analyses and very complex lifecycle cost modeling – all to identify the replacement strategy (and the ultimate designation of end of life) that allows us to deliver service to our customers at the lowest reasonable optimized cost. Therefore, Avista does not preemptively or prospectively replace equipment, rather, we replace assets at a point in time and in a manner that delivers our customers the greatest overall value. Accordingly, there is no 'one size fits all' definition of what constitutes the end of useful life for an asset. It's defined by the specific context and application for each asset, based on analysis of those specific risks, consequences and costs associated with that equipment failing in service, the unique costs of replacement, in that particular application and context.

iv. Regarding the statement "outside of industry practices," Avista is not aware of any accepted electric utility practice that seeks to achieve a different outcome than the prudent practices adopted by the Company, described in part (iv), above.

[32] Please see Avista's responses to PC-DR-297 through 305.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	John Gross
TYPE:	Data Request	DEPT:	System Planning
REQUEST NO.:	PC – 289	TELEPHONE:	(509) 495-4591
		EMAIL:	john.gross@avistacorp.com

SUBJECT: Electric Equipment Loading

REQUEST:

RE: Capital Additions, Test Year - Electric
Refer to Attachment A provided by Avista in response to Public Counsel Data Request 211.

a) Confirm that this response indicates that transformers need not be replaced at 80% loading. If this cannot be confirmed, please explain.
b) Provide a list of Major Alarms activated by year from 2016 through 2020 for each of the substation transformers Avista plans to replace.
c) Provide, for each transformer Avista plans to replace, the load forecast, which indicates if and when each transformer will exceed 90 percent of loading.
d) Provide, for each transformer Avista plans to replace, the load forecast, which indicates if and when each transformer will exceed 100 percent of loading.

RESPONSE:

a) Avista suggests this request may be confusing the difference between the Company's planning standards, which include a threshold requirement that has been discussed for replacing applicable electrical equipment when loadings reach 80 percent, and our real-time operating procedures, which latter document for transformer alarms and short-term loadings was provided as PC-DR-211 Attachment A. The subject Attachment A includes operating procedures, which among them include a requirement for transformers to be operated below 90% of their continuous rating to allow for the use of their short-term rating.

The Company's planning standard of 80 percent loading, as stated in response to PC-DR-211 part (a), pertains to how Avista plans, designs and maintains its transmission system and substations to be capable of supporting loads during peak periods of heavy demand, and specifically to avoid the next outage, referring to the need for contingency planning. In this regard, contingency planning refers to capacity that may be 'unused' in normal operating conditions, but that is fully utilized during unplanned outage events to maintain the electrical integrity of the system. This common utility philosophy and practice helps ensure customers don't experience major outage events that could occur without such contingency and capacity planning margin in electric transmission and substations.

Accordingly, as explained in the foregoing, the statement seeking confirmation in part (a), above, is erroneous and is rejected by the Company.

b), c) and d) In the period of review for this case, the Company is seeking recovery of costs for replacement of three transformers based on loading, as previously described in response to PC-DR-286.

Lee & Reynolds 115/13.8kV transformer

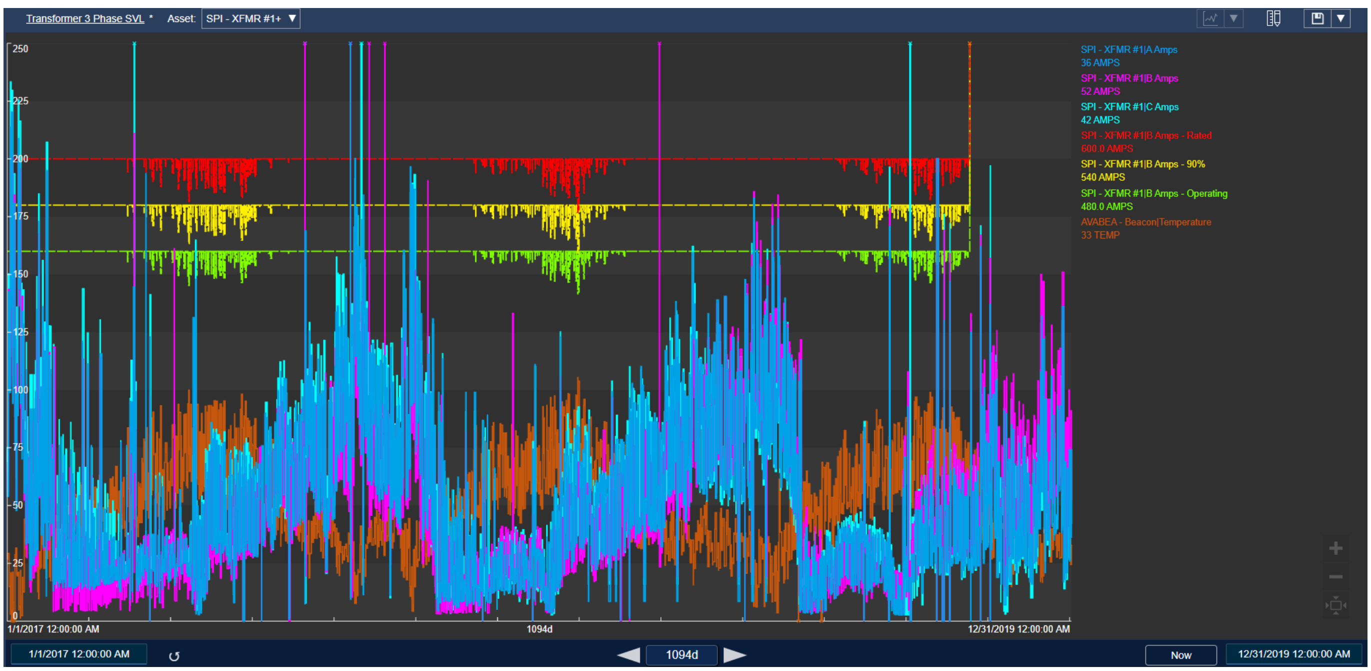
Transformer Alarms – Please see PC-DR-286 Attachment B.

Transformer Loading – Avista did not have a distribution system load forecast established when the project to replace the Lee & Reynolds 115/13.8kV transformer was established. Please refer to PC-DR-243 Attachment A which states the subject transformer loading of 17.8MVA in 2020, which combined with the expected customer load growth in 2021, would have exceeded the existing 20MVA transformer capacity.

Spirit 115/13.8kV Transformer

Transformer Alarms – Please see PC-DR-286 Attachment B.

Transformer Loading – Avista did not have a distribution system load forecast established when the project to replace the Spirit 115/13.8kV Transformer was established. Please see below figure showing transformer loading for years 2017 through 2019.



Westside #2 230/115kV Transformer

Transformer Alarms – Please see PC-DR-286 Attachment B.

Transformer Loading – In response to PC-DR-166 Attachment B, Westside Transformer Replacement, Avista provided results for Westside #2 230/115kV Transformer loading for the 20-year planning horizon in Table 2. We have noted in part (a) above and elsewhere the need to account for equipment loading during contingency events, as provided in Table 2. Westside #2 230/115kV

Transformer loads to 111% in planning scenarios for next year (2022) with the outage of Westside #1 230/115 kV Transformer. Table 2 does not identify in what year the 90% and 100% loading levels are exceeded.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	John Gross
TYPE:	Data Request	DEPT:	System Planning
REQUEST NO.:	PC - 290	TELEPHONE:	(509) 495-4591
		EMAIL:	john.gross@avistacorp.com

SUBJECT: Ratings for Transmission Lines

REQUEST:
Refer to Attachment B provided by Avista in response to Public Counsel Data Request 211. Confirm that the 80 percent rating limits in this document only pertain to transmission conductors, and not to substation transformers or other substation equipment. If this cannot be confirmed, please explain.

RESPONSE:

Avista applies a rating of 80 percent loading as a planning standard to a range of equipment, which has been described in the Company's response to prior data requests. Attachment B, provided by Avista in response to Public Counsel Data Request 211, is applied solely to transmission lines and was provided as an example of how the Company approaches the 80 percent rating limit for that infrastructure. Transmission "conductors" as stated in the data request are a component of transmission lines.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	John Gross
TYPE:	Data Request	DEPT:	System Planning
REQUEST NO.:	PC - 291	TELEPHONE:	(509) 495-4591
		EMAIL:	john.gross@avistacorp.com

SUBJECT: Substation Equipment Loading

REQUEST:
Refer to Attachment C provided by Avista in response to Public Counsel Data Request 211. Confirm that nothing in this document states that substation transformers or other substation equipment must be replaced when 80 percent of rated capacity is reached. If this cannot be confirmed, please explain.

RESPONSE:

Attachment C, provided by Avista in response to PC-DR-211, contains distribution system performance criteria for the planning horizon in Table 1, found on page 4. These performance criteria are used to evaluate system performance. This documentation does not state a required method for mitigation of performance criteria violations <u>because such mitigation is not necessarily limited to the replacement of equipment</u>. As an example, Table 1 states the expected thermal performance of equipment shall be less than 67% of the equipment continuous rating during a normal system configuration. Footnote 6 explains the 67% limit was selected with consideration to contingency events and having the system capacity needed to restore service to customers without severely overloading equipment in realtime operations. As stated in response to PC-DR-211 part (a), Avista plans, designs, operates, and maintains its transmission system and substations to be capable of supporting loads during peak periods of heavy demand, and specifically to avoid the next outage, referring to the need for contingency planning. In this regard, contingency planning refers to capacity that may be 'unused' in normal operating conditions, but that is fully utilized during unplanned outage events to maintain the electrical integrity of the system. This common utility philosophy and practice helps ensure customers don't experience major outage events that could occur without such contingency and capacity planning in electric transmission and substations. Projects are developed according to this philosophy. The replacement of equipment with larger capacity equipment is an acceptable approach to mitigate performance criteria issues.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC – 292	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Electric Distribution Grid Modernization

REQUEST:
Refer to Avista's revised response to Public Counsel Data Request 223, and in particular to footnote 1 on page 2. Refer also to Figure 23 in the June, 2017 Electric Distribution Plan provided by Avista in response to Public Counsel Data Request 105.

a) Provide a count of A.B. Chance cutouts referenced in this footnote that Avista currently has in operation on its system.
b) Of the cutouts shown to have failed in Figure 23 in the June, 2017 Electric Distribution Plan, provide the number which are A.B. Chance cutouts of the type referenced in footnote 1.
c) Provide a count of cutouts Avista has prospectively replaced by year from 2016 through 2020.
d) Provide a count of A.B. Chance cutouts of the type referenced in footnote 1 Avista has replaced by year from 2016 through 2020.

RESPONSE:

a) Although the number remaining is very small, there are a few noted as failing in service and being replaced in recent years. This small number remaining is the result of not all electric distribution infrastructure having been systematically inspected, storm damaged, rebuilt, or otherwise 'touched' by field crews during the period of time when the Company has focused on removing Chance cutouts from service. The cutouts failing in service now still demonstrate their tendency for premature failures compared with the expected life of replacement equipment.

b) From the total cutout failures represented the subject Chance cutouts represent approximately 97.6% of those failures.

c) Please see the Company's response in PC-DR-288, and elsewhere, regarding Public Counsel's misleading use of the phrase 'prospectively replaced,' and the available subject information already provided in response to PC-DR-223 Revised.

d) Please see the cutout failure data already provided in response to PC-DR-229 Attachment A.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC – 293	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Electric Distribution Grid Modernization

REQUEST:
Refer to Avista's Revised response to Public Counsel Data Request 223, and in particular, the Table provided in response to part (d), "Outage Forecasts for High-Risk Cutouts". This table shows a notable increase in the number of OMT events in the years 2007 through 2014. This does not appear to be consistent with the trend indicated in years 2005 through 2007. Provide the rationale behind and data and calculations used to project the increase from 2007 through 2014.

Response:

The forecast of high-risk cutouts, which as noted in response to PC-DR-292 are nearly all Chance cutouts, was developed from actual failures of these cutouts, based on known failures experienced by Avista, modes of failure and service life. The forecasts were performed using the Availability Workbench modeling to develop failure curves (and subsequent lifecycle cost modeling), which process has been described by the Company in numerous data requests, including PC-DR-118, PC-DR-121, PC-DR-122, PC-DR-223 Revised, PC-DR-221, PC-235, and notably in PC-DR-236 where Avista offered to provide the subject models and/or an online working session, PC-DR-294, PC-DR-295 PC-DR-296, and by reference in responses to PC-DR-298 through 305. The forecast failures shown for 2007-2014 for high-risk cutouts is a mathematically sound representation of expected failures based on known failure data and expected remaining units in service at the time the forecast was performed. Of interest in the forecast is the predicted 'flattening out' of the failure curve in years 2012-1014, which would be as expected for the population of Chance cutouts that was being depleted in the model via the rapidly increasing number of annual failures. Finally, the fit of the failure forecast appears to be more consistent with the prior years' actual failures when a longer period (such as 2001 – 2007) is used to show the history instead of just two years. The purpose of the illustration was not to show history, but rather, to forecast failures reasonably expected to occur without systematic replacement of the clearly end of life assets.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC – 294	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Electric Distribution Grid Modernization

REQUEST:
Refer again to Avista's Revised response to Public Counsel Data Request 223, which states "Avista does not agree with the oversimplified characterization used by Public Counsel as "preemptive replacement." The Company replaces assets in service at the end of their useful lives. Some assets are allowed to 'run to fail' if the combined risk costs associated with the failure are less than the costs required to systematically replace the equipment before it fails in service." This indicates that Avista only replaces cutouts and non-PCB transformers when the "risk costs associated with failure" exceed "the costs required to systematically replace the equipment before it fails in service".

a) For the cutout originally placed into service most recently on the Avista system, which was replaced as part of the cutout replacement program, provide the analysis Avista completed which indicates the "risk costs associated with failure" exceed "the costs required to systematically replace the equipment before it fails in service".

b) For the non-PCB transformer originally placed into service most recently on the Avista system, which was replaced as part of the transformer replacement or grid modernization program, provide the analysis Avista completed which indicates the "risk costs associated with failure" exceed "the costs required to systematically replace the equipment before it fails in service".

Response:

a) Currently, the Company replaces cutouts as they fail in service and as end of life replacements when part of a systematic program. We have described and documented the analyses we have performed for cutouts and a range of other assets, in which the Company develops mathematical failure curves for each asset based on failures of known age assets Avista has experienced, and based on detailed lifecycle cost modeling that uses the probability of failure with age and condition, with the probability of the failure resulting in a specific consequence, and the known risk costs associated with the consequence. These analyses, both generally, and specifically in the case of cutouts, shows that the manner in which the Company replaces these end of life assets results in the lowest optimized lifecycle cost of ownership for our customers.

   For an illustration of how the Availability Workbench model calculates the optimized lifecycle cost for replacement of a cutout as part of the wood pole management program, please see the Company's response to PC-DR-295 and PC-DR-296. Similarly, in response to PC-DR-121 in Attachment A, replacement of end of life transformers is selected by the model as providing the greatest lifecycle benefit for customers when performed as part of the wood pole management program. Replacement of the end of life cutout is included as part of the analysis for transformer replacements.[33] As one would expect, with Chance cutouts largely removed from our system, the risk cost of a cutout failure is much lower today; what makes their end of life replacement prior to failure in service the best financial value for customers is the fact that replacement costs are lower when conducted as part of a systematic program like wood pole management. For results of the analyses historically performed, supporting the program to systematically replace Chance cutouts, please see the table, below, which customer rate of return based on lifecycle cost modeling was 19.1% for systematic replacement, compared with a customer rate of return of 0.7% for letting these cutouts fail in service.

Option Comparison – 10 Year Outlook

Model	Today's Case	Planned Replacements
Cutout Failure Rate	400 per year	46 per year
Customer Cost	$2.2 million	$0.26 million
Minor Safety	0.8 events	1.3 events
SAIFI Impact	0.05 added	0.006 added
Avg Annual Capital Budget	$475,000	$192,000
Avg Annual O & M Budget	$268,000	$32,000
IRR (Lifecycle Cost)	0.7%	19.1%
Levelized ROE	$92,000	$44,000
Expected Value to Implement	$6.2 million	$4.6 million

b) Results of the lifecycle cost modeling supporting Avista's decisions to replace end of life transformers has already been presented and discussed in detail, not the least of which is demonstrated in our response to PC-DR-121, in Attachment A, where replacement of end of life transformers is selected by the model as providing the greatest lifecycle benefit for customers when performed as part of the wood pole management program. Avista has already provided results of analyses demonstrating customers are better off financially[34] when we replace end of life transformers as part of a systematic program like wood pole management. As one would expect, with risky PCB transformers largely removed from our system, the risk cost for a distribution transformer failure is lower today and is relatively stable; what makes the end of life replacement prior to failure in service the best financial value for customers is the fact that replacement costs are lower when conducted as part of a systematic program like wood pole management.

[33] The lifecycle cost analysis for replacing end of life transformers as part of a systematic program like wood pole management includes not only the cost, benefits and risks associated with the transformer, but also includes the high and low-side connectors, lightning arrester, cutout, and wildlife guard. Each of these pieces of replaced equipment has its own unique failure curve and lifecycle cost modeled, which results are integrated in determining the optimized end of life for that group of equipment based on replacement in a systematic program. Please see PC-DR-295 and PC-DR-296 for helpful illustrations.
[34] As measured by a lower lifecycle cost of ownership, lower total risk cost, higher benefit to cost ratio, and higher risk reduction ratio, compared with replacing transformers when they would otherwise fail in service.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Larry La Bolle
TYPE:	Data Request	DEPT:	Transm Ops/System Planning
REQUEST NO.:	PC - 295	TELEPHONE:	(509) 495-4710
		EMAIL:	larry.labolle@avistacorp.com

SUBJECT: Lifecycle Cost Modeling

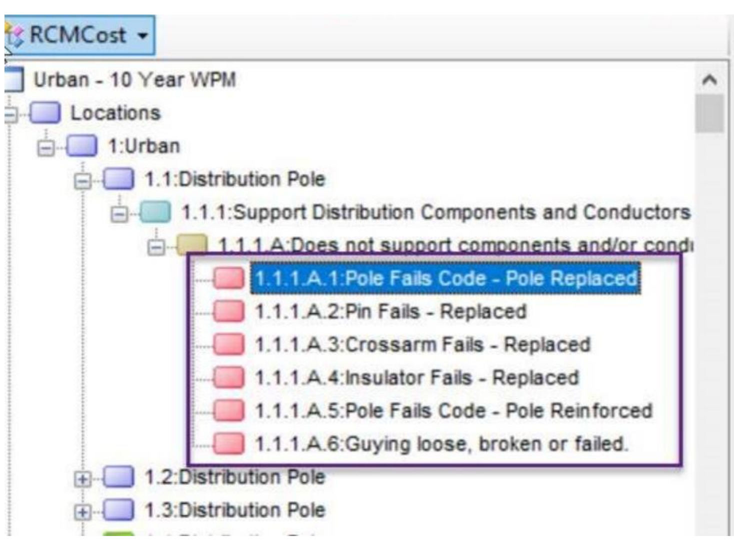
REQUEST:
Refer to Avista's response to Public Counsel Data Request 236, and to the "cost charts" in particular.

a) Provide an explanation and an example of how the "effects" costs were calculated.
b) Provide an explanation and an example of how the "spares" costs were calculated. Include in your explanation the number of spares assumed per installation.

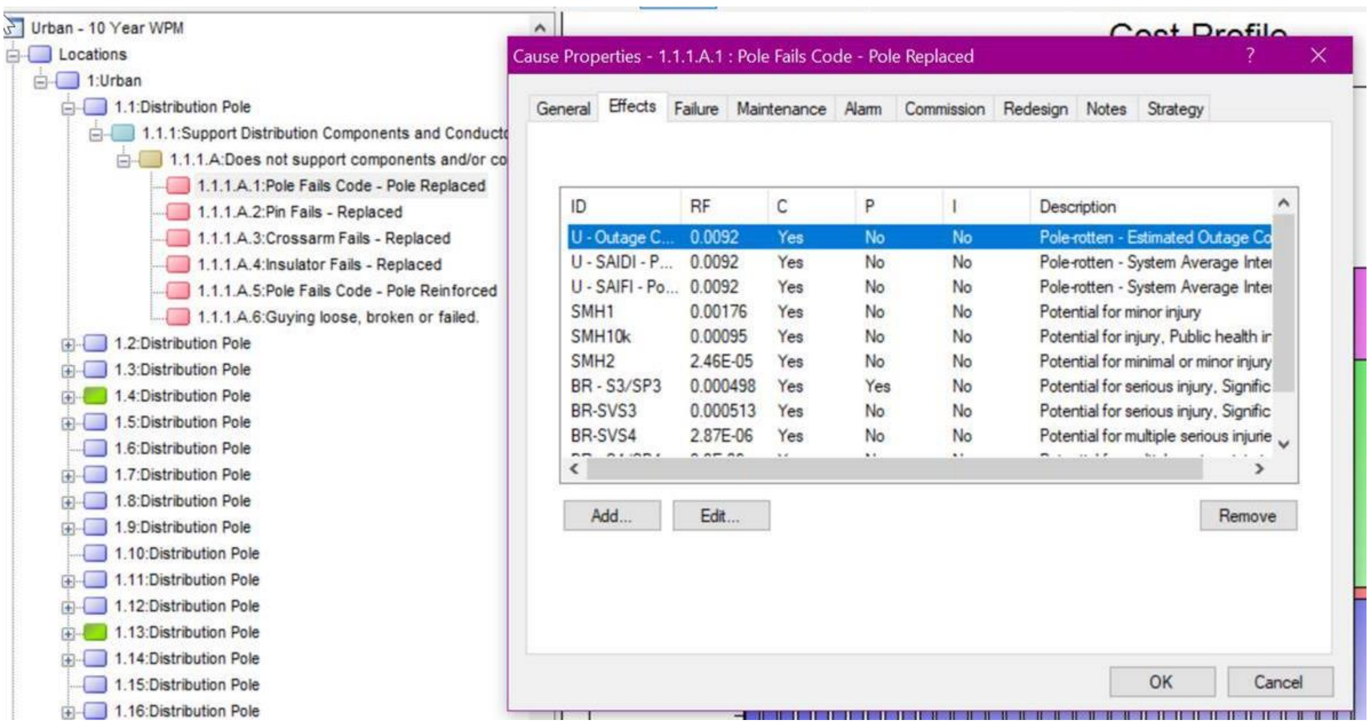
RESPONSE:

a) Following is a high-level overview of how effects costs are calculated in the Availability Workbench model, using the example of the Company's wood pole management program, based on a 10-year inspection cycle interval for our urban feeders.

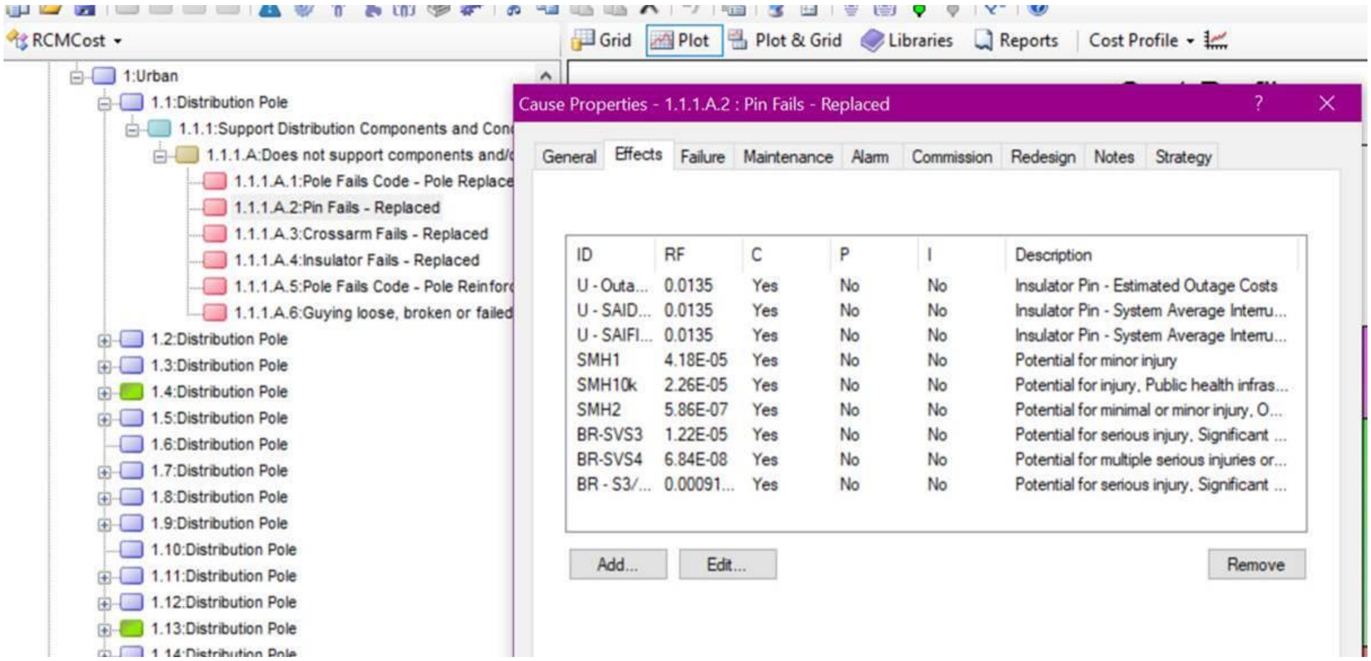
i. The distribution pole has multiple failure modes (indicated by the red boxes in the image below). As you can see, these failure modes are made up of different pieces of equipment attached to the pole, such as the crossarm. As explained in response to PC-DR-294, individual failure curves (models) are developed for each piece of equipment (crossarm, insulator, pin, etc.). The output of the failure modeling for each piece of equipment is the Weibull curve that describes the failure probability of each asset based on known failures and age, which Avista has experienced. Accordingly, the 'Crossarm Fails' failure curve has a different shape and statistics than that for 'Insulator Fails,' and so on.

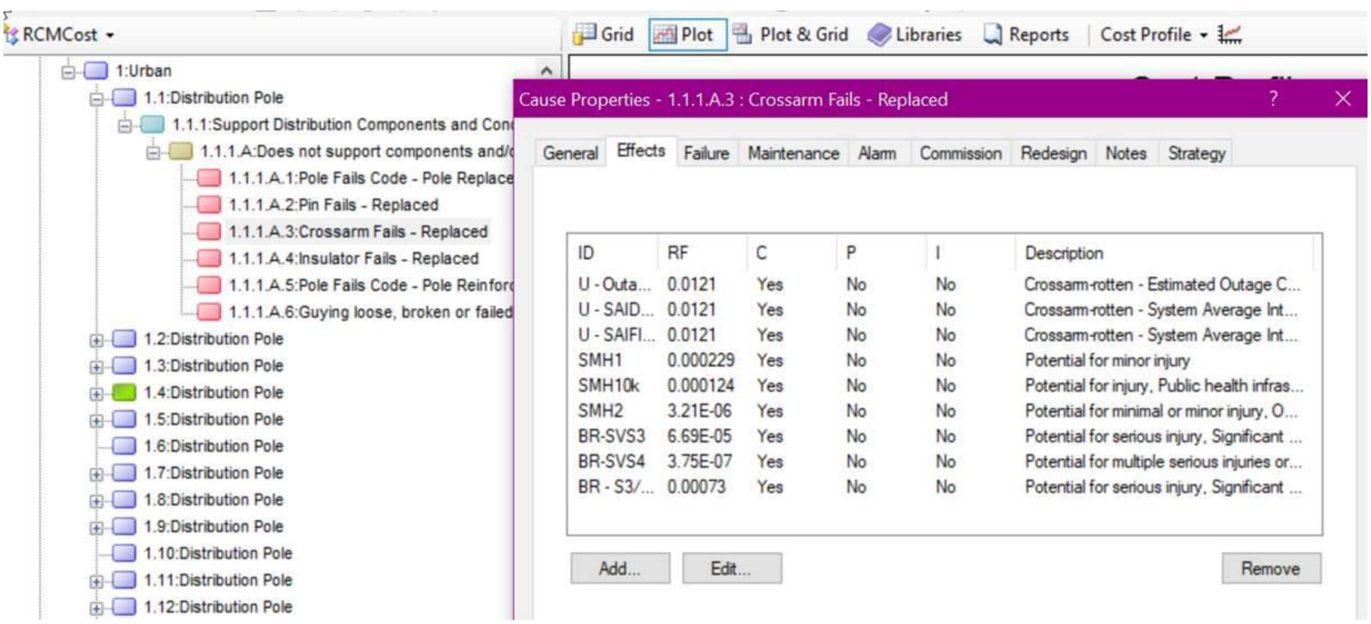


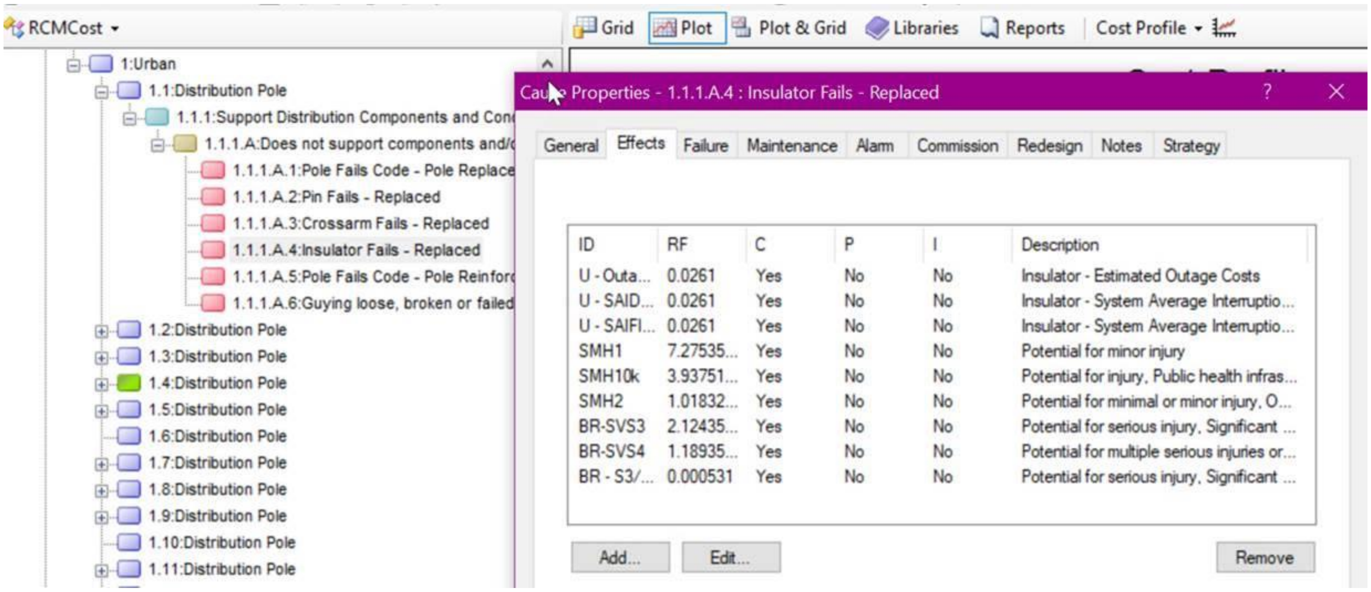
ii. Each of these failure modes (failure curve for each piece of equipment) has its own list of effects (consequences) and redundancy factors (probabilities). The point of the latter probabilities is to represent the fact that an asset failure does not always result in the same consequences (e.g. a pole failure does not always result in a customer outage). The image below provides additional detail on the failure mode 'pole fails code' and shows the initial frame of the list of effects for that failure mode. Each effect, as noted in column C indicates whether that effect triggers corrective maintenance, preventative maintenance and/or inspections. In these examples, each failure mode may have multiple tiers of effects based on severity of the consequences. For instance, a SMH10k 'Safety' event carries a higher risk cost than an SMH1 event, but is less likely to occur, as evidenced by a lower probability of occurrence, represented in the RF (Redundancy Factor) score. Therefore, the overall risk cost is the probability an asset fails, multiplied by the probability of a consequence occurring, multiplied by the risk cost (if that consequence occurs).



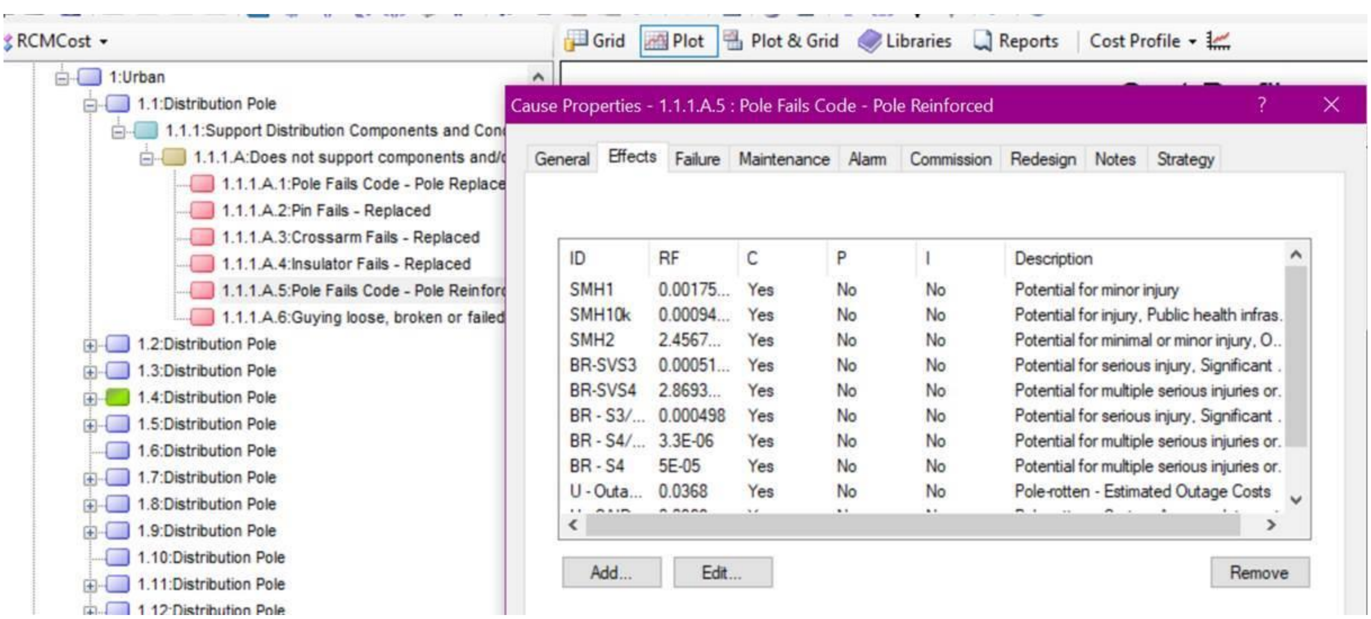
iii. The images below highlight a portion of the consequence scores (RF) for the effects shown for each of the 6 failure modes represented in the image at top (failure modes 1.1.1.A.1 through1.1.1.A.6).



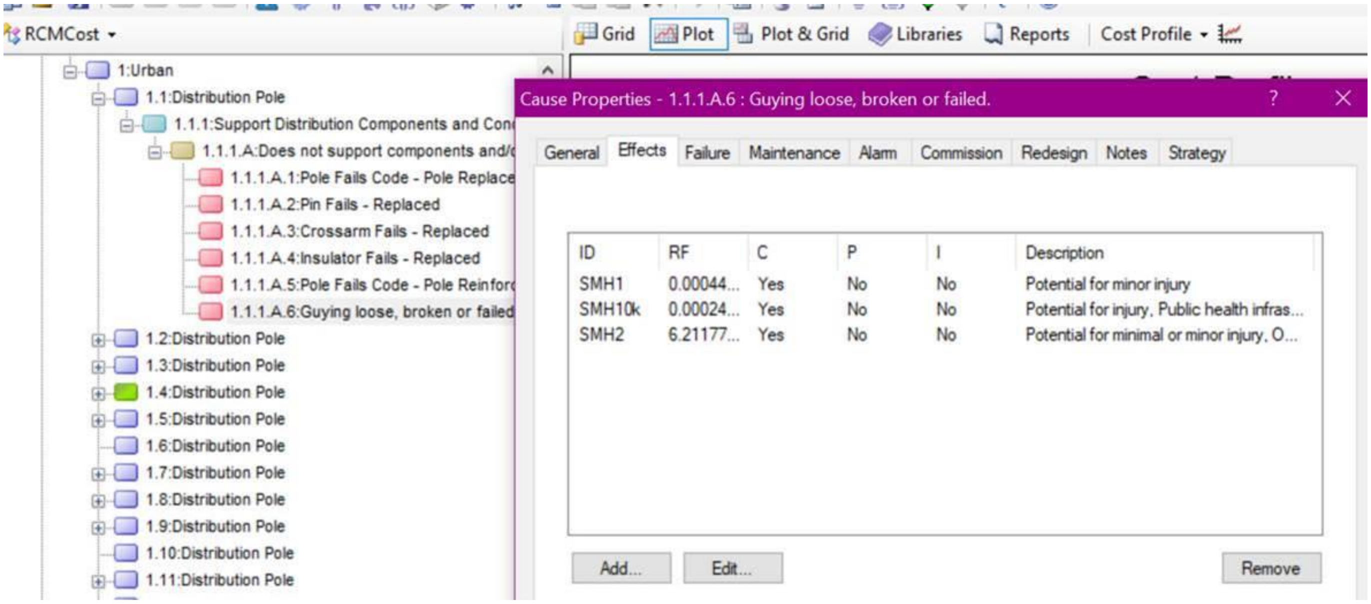




ID	RF	C	P	I	Description
U - Outa...	0.0261	Yes	No	No	Insulator - Estimated Outage Costs
U - SAID...	0.0261	Yes	No	No	Insulator - System Average Interruptio...
U - SAIFI...	0.0261	Yes	No	No	Insulator - System Average Interruptio...
SMH1	7.27535...	Yes	No	No	Potential for minor injury
SMH10k	3.93751...	Yes	No	No	Potential for injury, Public health infras...
SMH2	1.01832...	Yes	No	No	Potential for minimal or minor injury, O...
BR-SVS3	2.12435...	Yes	No	No	Potential for serious injury, Significant ...
BR-SVS4	1.18935...	Yes	No	No	Potential for multiple serious injuries or...
BR - S3/...	0.000531	Yes	No	No	Potential for serious injury, Significant ...



ID	RF	C	P	I	Description
SMH1	0.00175...	Yes	No	No	Potential for minor injury
SMH10k	0.00094...	Yes	No	No	Potential for injury, Public health infras.
SMH2	2.4567...	Yes	No	No	Potential for minimal or minor injury, O..
BR-SVS3	0.00051...	Yes	No	No	Potential for serious injury, Significant .
BR-SVS4	2.8693...	Yes	No	No	Potential for multiple serious injuries or.
BR - S3/...	0.000498	Yes	No	No	Potential for serious injury, Significant .
BR - S4/...	3.3E-06	Yes	No	No	Potential for multiple serious injuries or.
BR - S4	5E-05	Yes	No	No	Potential for multiple serious injuries or.
U - Outa...	0.0368	Yes	No	No	Pole-rotten - Estimated Outage Costs



iv. The image below provides more insight from the Availability Workbench model on the calculation of the risk costs described above.

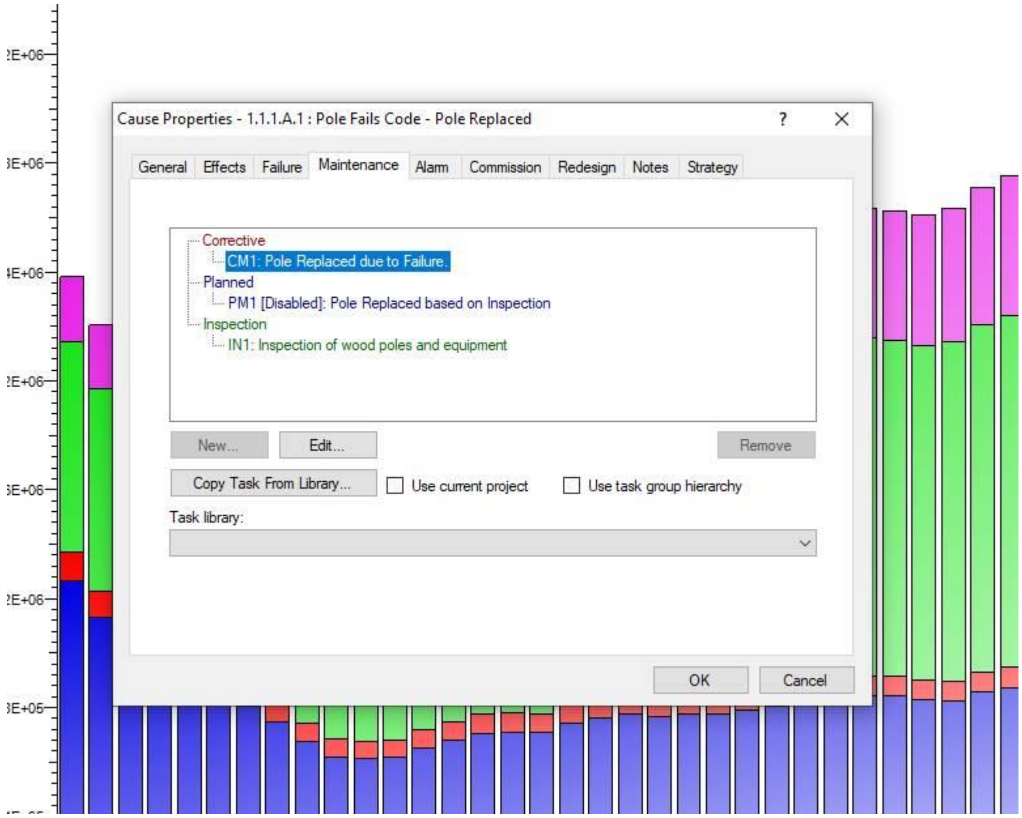
Effect costs are computed by summating the costs originating from all effects. Effects costs are determined from the following expressions:

$$C = C_R T + C_O N$$

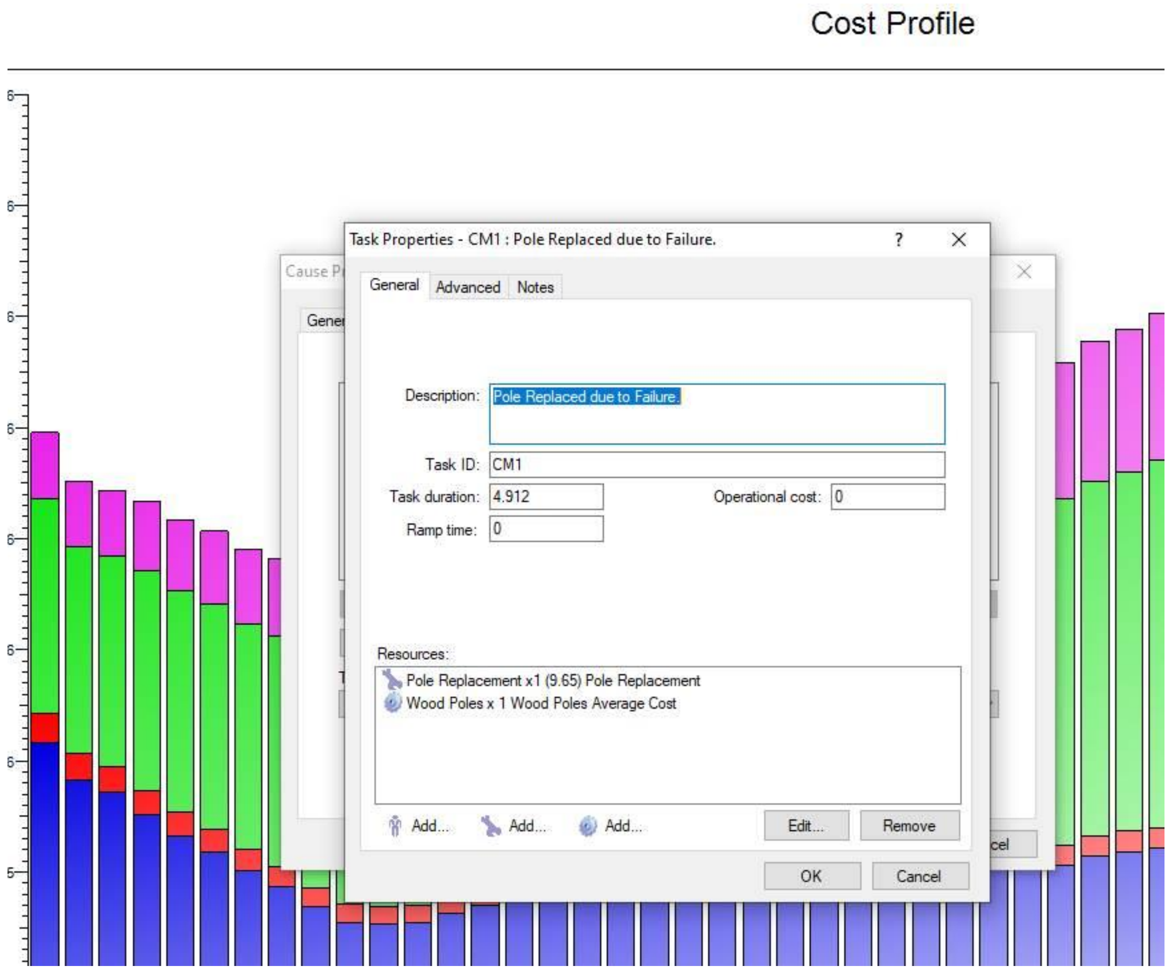
where C = effect cost over lifetime
C_R = effect cost rate
C_O = effect cost per occurrence
T = total effect duration over lifetime
N = expected number of occurrences for effect over the lifetime

v. As you can see in the first image in section (ii), above, the above examples represent <u>only one of the failure modes</u> for Distribution Poles (1.1), <u>of the 16 different failure mode</u> classifications that are shown in image for Distribution Poles (1.1 through 1.16). Similarly, the images showing effects in parts (ii) and (iii), above, are not necessarily showing all of the effects categories modeled.

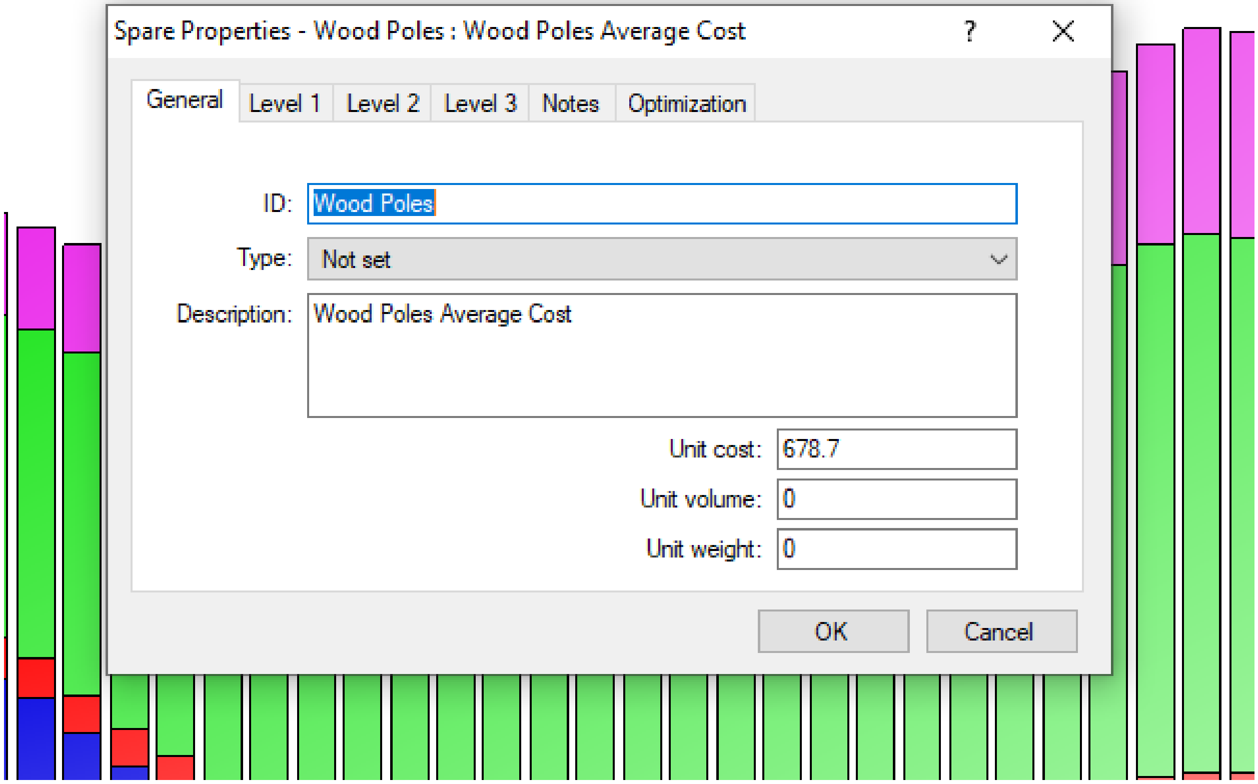
b) Spares are the pieces of equipment identified in the model that are required to replace failed assets, called for when the subject failure mode triggers the corrective action of replacement, as indicated in part (ii), above. As an example, if we experience the 'Pole Fails Code – Pole Replaced' failure mode (1.1.1.A.1), the system will look to 'Corrective Maintenance' for replacement of that pole, as shown in the image below.



i. The Corrective Maintenance (CM1: Pole Replaced due to Failure) is represented in the image below, showing the cost of the replacement pole (spare) identified as Wood Poles X 1 Wood Poles Average Cost. Pole Replacement is the cost to replace the pole and includes the labor and equipment needed to replace the pole.



ii. To further highlight the spares cost, you can query the 'Spares' tab, which image is shown below, indicating the cost for only the replacement pole as $678.70. This cost does not include the labor and equipment costs to install the pole, since in the query shown, the cost represents the status of "not set." As noted above, the ultimate spares costs include the material and all the costs of installation, including labor resources, time required (shown above 4.92 hours) and equipment required and those costs.



iii. In this Availability Workbench model we are simulating results for the entire distribution system, and calculating the total spares costs for all of the modeled equipment. As this model is currently configured, we have focused on the <u>total cost of spares (units expected to be replaced in the simulation including all costs of replacement)</u>. This total cost is fundamental to the lifecycle cost analysis, and which costs are shown in the image above behind the open dialog box (and as illustrated in the images provided in PC-DR-236). In this form, the model reports total spares costs (material, labor, equipment) but does not provide a report on the numbers of units expected to be replaced in the simulation.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Larry La Bolle
TYPE:	Data Request	DEPT:	Transm Ops/System Planning
REQUEST NO.:	PC - 296	TELEPHONE:	(509) 495-4710
		EMAIL:	larry.labolle@avistacorp.com

SUBJECT: Avista Lifecycle Cost Modeling

REQUEST:
Refer to Avista's response to Public Counsel Data Request 236, and to the Weibull failure curves specifically.

a) Confirm that the ETA estimator line represents the point at which Avista has determined it is cost-effective to prospectively replace a piece of equipment. If this cannot be confirmed, please explain.
b) For each equipment type for which a Weibull failure curve is provided, provide the analysis Avista completed, which indicates prospective replacement is cost-effective relative to continuing to failure.
c) It appears that the horizontal axis is a time axis. Provide the time in years for each Weibull failure chart provided.
d) Provide the data, and identify the sources of each, used to develop each of the Weibull failure charts provided.

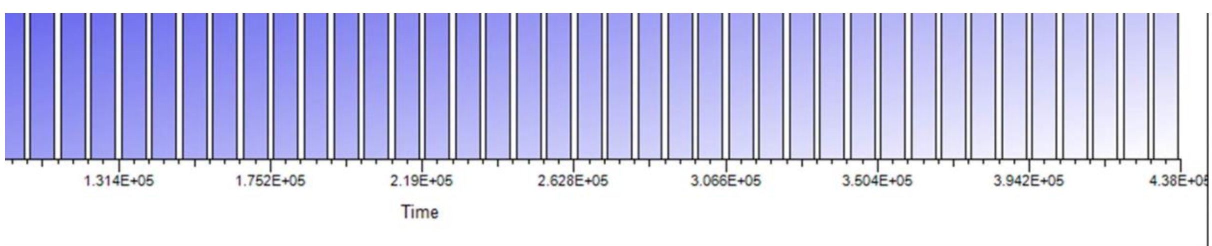
RESPONSE:

a) The ETA estimate line represents the point in time when 63.2% of the assets of that age are expected to have failed in service. Avista does not 'prospectively' replace equipment, rather, as previously stated, we replace equipment at the end of its useful service life, which is based on achieving the lowest optimized total lifecycle cost of ownership for our customers. The ETA line neither represents the optimized end of life for an asset, nor is it relied upon by Avista solely to determine such. As explained in response to PC-DR-295, Avista determines end of life for an asset based on its failure characteristics (Weibull curve) and the probabilities and consequences of asset failures. On a systematic basis, end of life is the point where either the asset fails in service by intention or, alternatively, the point during the life of the asset still in service where the consequence costs of a failure in service exceed the replacement costs.

   As we have noted before, these designations of run to fail or not run to fail, are not necessarily static for each asset. This is because the consequences of a failure in service for an asset may be dramatically different depending on its application and location in our system. Likewise, the costs of replacement are not static. As an example of the latter, it would not be cost effective to send crews across our system solely to locate and replace distribution transformers based on a given age of the units. But it is cost effective to replace transformers based on a given age (and condition) of the units when a crew is already performing work on the pole where such a transformer is located. Furthermore, replacing a transformer based on age and condition, during a systematic program like wood pole management, is more financially viable because, as part of the transformer replacement, we're also inspecting and replacing as needed the cutout, lightning arrester, high and low-side connectors and wildlife guard, and capturing the energy efficiency savings provided by a new replacement transformer. The lifecycle costs analyzed in the Availability Workbench model take all of this into account in calculating the financial value associated with the transformer changeout program (avoidance of the risk costs associated with a failure in service for the transformer, cutout, arrester, high and low-side connectors, etc.; combined with the gain in energy efficiency; combined with the lower cost to install when other capital work is already being performed on that pole). As explained in response to PC-DR-295 and elsewhere, results of our lifecycle cost modeling demonstrate that replacement of a transformer and the attached equipment in the manner just described provides our customers a lower total cost of ownership, when financially compared with the alternative of allowing the transformer (and attached equipment) to fail in service.

b) Results of analyses completed, among the many other examples provided, which validate the efficacy and cost effectiveness of Avista's end of life designation for the subject assets have been provided in response to PC-DR-118, for example. This analysis presents results of the Availability Workbench modeling (described at length, including in PC-DR-121, PC-DR-122, PC-DR-235, PC-DR-236, and PC-DR-295, among many others), which conclusively shows the dramatic increase in customers costs, which analysis was performed at the request of Public Counsel, which would result from the Company abandoning its designation of end of life for these subject assets in favor of a blanket run to fail strategy.

c) Below is an enlarged image of the x (time) axis showing in the Availability Workbench log scale the elapse hours in the failure analysis for the asset. The middle value of 2.628E+05, represents an interval of 262,000 hours in the asset life, or an equivalent period of 30 years.



d) Please see PC-DR-295 for the example discussion of the failure mode for wood poles. In that discussion, we explain some of the assets (pieces of equipment) represented by failure modes for the wood pole model. A very brief description of the data relied upon for such modeling is provided below.

- ✓ **Wood poles** – A data set of approximately 12,000 (and growing) known age and known species wood poles in the Company's system. For each pole, the data used in the modeling includes all of the inspection data and the failures identified during the inspection, supplemented with failures of known age poles reported as they occur in the system. Also included is the information for each of the failures about whether or not the failed pole resulted in a customer outage (including the number of customers affected in the outage, and the duration of the outage), and the remediation action that was taken in each instance, such as repairing the pole by stubbing or replacement of the pole.
- ✓ **Crossarms** – Same information as above for crossarms on the wood poles that include a crossarm in the construction. For each crossarm, the data used in the modeling includes all of the inspection data and the failures identified during the inspections, supplemented by reports of failures as they otherwise occur. Also included is the associated information about whether or not the failed crossarm resulted in a customer outage, as well as the remediation action taken in each instance.

- ✓ **Transformers** – Same type of information as above, including energy efficiency data for transformers replaced, and updated and supplemented by failure data from transformers of known age that have failed in service across our system.
- ✓ **Cutouts** – As applicable, same as above.
- ✓ **Lightning Arresters** – As applicable, same as above.
- ✓ **Grounds, Guying, High-Side Connectors, Low-Side Connectors, Wildlife Guard** – As applicable, same as above.
- ✓ **Vegetation** – A data set of over 300,000 individual trees, by individual species, and by health status, located in and near our distribution line rights of way that have the potential to either grow into our lines or to fall into the conductor based on storm, disease or other conditions. The Availability Workbench models includes a Weibull failure curve for each species of tree on our system, which allows Avista to predict when each individual tree is likely to cause an outage event based on the last time the tree was 'trimmed' and the kind of trimming work that was performed at that time. The Availability Workbench model, as described in PC-DR-295, also includes the probabilities that a tree 'grow-in' or 'tree fell' will result in a customer outage, how many customers are expected to be impacted, and the expected duration of the outage, as well as a range of other risk costs (e.g. capital and O&M repair costs for damage to the feeder) associated with these events. The models also include the costs associated with different regimens for inspections, cycle trimming and risk tree removal, allowing the Company to identify the lowest lifecycle cost strategies for managing the vegetation associated with its facilities, as shown in PC-DR-121 Attachment A.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ken Sweigart/John Gross
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC - 297	TELEPHONE:	(509) 495-4417
		EMAIL:	ken.sweigart@avistacorp.com

SUBJECT: Electric Transmission Investments

REQUEST:
Refer to Attachment B provided by Avista in response to Public Counsel Data Request123, and to Table 1, "Avista Ten-Year Project List Summary". For each and every project in Table 1, provide the analysis Avista completed which indicates the benefits of the project exceed the cost of the project to customers.

RESPONSE:

For pertinent information on the subject investments for projects listed in Table 1, please see PC-DR-297 Attachment A, which comments shaded in light green pertain to projects for which the Company is seeking recovery in this case. The comments for each project identify documents supporting the need, analysis, benefits and the overall prudence of these transmission investments. For the projects listed in Appendix A, which comments are shaded light red, Avista objects to this request because it seeks future information that is neither within the scope of this proceeding nor is it reasonably calculated to lead to the discovery of admissible evidence. The information requested pertains to future investments that have not yet been made, that are not subject to a prudence review in this current case, and for which the Company is not seeking any cost recovery at this time. The only capital projects included in this case for the period 2021 and beyond, relate to Wildfire, Colstrip, EIM and AMI.

Avista's approach for determining the customer value of electric transmission and distribution investments is multi-faceted and is best understood in the context of the overall electric system that is required to effectively meet the needs of our customers.

Avista Must Meet Required Standards of Service – As a service provider under Washington law, the Company is required to govern its conduct to achieve the public good and to provide facilities and services that are deemed to be safe, adequate and efficient, and in all respects just and reasonable.[35]

Avista Must Meet the Service Demands of Our Customers - Further, Avista is required, upon reasonable notice, to provide to any customer (or service to a potential new customer) the amount of electricity requested, delivered over suitable facilities that are necessary for providing such services.[36] Our Commission established tariffs for service, which have already been discussed at some length in previous discovery, dictate which costs are paid directly by the requesting customer, and which additional investments required to provide the requested service are the responsibility of the Company, and indeed, all other customers receiving electric service.

[35] RCW 80.28.010 sections (1) (2).
[36] RCW 80.28.110.

Avista Determines Infrastructure Needs by Comprehensive System Planning - So, in meeting these and other standards of service, and in compliance with a wide range of federal[37] and state requirements,[38] how does Avista decide what safe, adequate and efficient facilities it reasonably needs to have in place and to plan for in the future? It begins with comprehensive electric system planning conducted by the Company to determine what capabilities it must have in order to timely serve the current and future needs of our customers, delivered in a manner that satisfies our service obligations and compliance requirements. This planning assessment is based on the electric system we have in place today, which by definition, establishes all of the Company's existing transmission and related substation facilities as fundamental and necessary to the provision of adequate and efficient electric service to our customers. The Company has provided results of its 2019-2020 Avista System Assessment in response to PC-DR-123 Attachment B, which Table 1 referred to in this request, lists projects the Company has identified as necessary to meet the service needs to our customers. The high-level justification for each project listed in the table includes condition-based asset replacements necessary to meet performance requirements, customer growth, and projects necessary to meet performance requirements categorized as Corrective Action Plans. Corrective Action Plans address how performance requirements will be met where the technical studies have indicated an inability of the System to meet the performance requirements of TPL-001. The subject projects in this request are thus identified as necessary for providing safe, adequate and efficient electric service. As appropriate, system planning analyses also evaluate alternatives for meeting our service obligations. Do we upgrade and reinforce a line to meet a demonstrated need, or do we construct some new segment of line that allows us to meet the need (and possibly others) in a more cost-effective fashion. At this highest level, Avista demonstrates its prudence in effectively identifying and evaluating its electric system needs, appropriately identifying and evaluating alternatives, and selecting the best optimized solutions for meeting our service obligations to our customers.

The Subject Transmission Lines are Fundamental and Necessary – As noted above, the electric transmission lines that are the subject of this request have been determined through this comprehensive system planning to be a fundamental and necessary part of the integrated electric system that is required to provide safe, adequate and efficient service to our customers, and in a manner that is just and reasonable.

Avista Maintains its Necessary Facilities in a Prudent Manner - How does the Company then manage these facilities to ensure our customers receive the benefits they provide at a cost that is just and reasonable? We identify investments needed to properly maintain these facilities to ensure their long-term reliable service, as noted for the subject projects in Table 1. We also identify solutions and related investments required to meet our compliance and other legal obligations, again, as noted in Table 1. As part of this effort, and as described in responses to numerous data requests, including PC-DR-298, 299, 300, 301, 302, 303 and 304, we prudently replace assets at the end of their useful life, as determined by detailed engineering experience, expertise and evaluation, by analysis of historic failure data and modeling, through detailed and comprehensive lifecycle cost modeling, and by understanding the risks and consequences of failures of equipment in service. Accordingly, the need for the projects subject to review in this case, listed in Appendix A, and the prudence of these investments is documented in the above responses, and in documents identified in the comments of PC-DR-297 Attachment A, and in PC-DR-297 Attachments B through E. Both generally, as described in PC-DR-298, 299, 300, 301, 302, 303 and 304, and specifically, with respect to the subject projects in Table 1, Avista has demonstrated that it delivers necessary electric system investments to serve our customers in a prudent and cost-effective manner.

Benefits to Customers Exceed the Costs Included in Rates – Avista has clearly demonstrated and explained in the responses above how we assess the need and measure the customer value of our

[37] As an example, Avista has responded to numerous requests from Public Counsel regarding our requirement to comply with a range of NERC standards.
[38] Avista has previously noted its obligation to meet updated standards under the NESC, which, as noted by the Company, has been adopted as law by the State of Washington.

transmission investments, how such investments are necessary and prudently incurred, how these investments allow Avista to meet its standards of service to our customers, and how these investments deliver benefits to our customers that are just and reasonable. Because, in doing so, we regularly meet the standards of service to which we are held, our investments are deemed to provide service benefits to our customers in a manner that exceed the just and reasonable costs they pay in their electric rates for service established by the Commission.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ken Sweigart
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC - 298	TELEPHONE:	(509) 495-4417
		EMAIL:	ken.sweigart@avistacorp.com

SUBJECT: Electric Transmission Investments

REQUEST:
Refer to Attachment A provided by Avista in response to Public Counsel Data Request 237, part (a). Confirm that Attachment A provides a spending plan but fails to indicate that the Transmission Infrastructure Plan is of sufficient value to ratepayers to justify rate increases. If this cannot be confirmed, please indicate where in Attachment A an indication that benefits to rate payers in excess of rate payer costs can be found.

RESPONSE:

In response to PC-DR-297, Avista presents its approach for determining the value of electric transmission and distribution investments for our customers, provided in the context of the overall electric system that is required to effectively meet their needs. Because the subject investments in this request have been identified as necessary for providing safe, adequate and efficient service to our customers, they are fundamentally necessary for delivering them the benefits of electric service. And, as noted in our response below, because the Company is attentive to properly maintaining its system, has carefully evaluated the identified needs in an effort to deliver them at a reasonable cost, the ultimate cost borne by our customers meets the test of being prudently incurred, and in all respects just and reasonable. Because, in doing so, we regularly meet the standards of service to which we are held, our investments are deemed to provide service benefits to our customers in a manner that exceed the just and reasonable costs they pay in their electric rates for service established by the Commission.

The documents provided in response to PC-DR 237, contained in Attachments A through G, have been submitted together as providing the information and analyses necessary to conclude that the Company's transmission investments deliver benefits to our customers that are fundamental and necessary to providing them service and that are delivered at a cost that is prudent, just and reasonable. Documents provided in response to PC-DR-237, demonstrate the Company has an orderly infrastructure plan for identifying and delivering needed investments (Attachment A and Others), that it maintains necessary systematic inspections of its transmission facilities and carefully notes remediation actions resulting from such inspections (Attachment E and Others), that it properly uses actual data to develop asset failure models to better determine asset life expectancy, and that it uses multiple other relevant data on benefits, costs and risks to develop appropriate lifecycle cost analyses of actions and alternatives (Attachments B, C and Others), and that it properly relies on the above information and analyses, and the expertise, experience and judgement of its professional engineers to carry out a prudent plan of investment.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ken Sweigart
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC - 299	TELEPHONE:	(509) 495-4417
		EMAIL:	ken.sweigart@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Refer to Attachment B provided by Avista in response to Public Counsel Data Request 237, part (a).

a) Confirm that "Asset Management info and recommendations" do not employ historical actual equipment failure data to assess risk, but rather a subjective approach to risk assessment based on opinion. If this cannot be confirmed, please indicate where historical actual equipment failure data was employed to assess risk.
b) Confirm that Attachment B fails to indicate that the transmission reinforcements are of sufficient value to rate payers to justify rate increases. If this cannot be confirmed, please indicate where in Attachment B an indication that benefits to rate payers in excess of rate payer costs can be found.

RESPONSE:

a) The subject documents provided in Appendix B, asset management information and recommendations, are based on a range of evaluations, which among others, includes the use of historical actual equipment failure data to statistically determine expected asset life for transmission structures. This historic actual failure data was integrated with other cost, benefit and risk data to conduct lifecycle cost modeling to evaluate the customer financial benefits of systematic vs unplanned replacements of end of life assets.

b) The documents provided in response to PC-DR 237, contained in Attachments A through G, have been submitted together as providing the information and analyses necessary to conclude that the Company's transmission investments deliver benefits to our customers that are fundamental and necessary to providing them service and that are delivered at a cost that is prudent, just and reasonable. Documents provided in response to PC-DR-237, demonstrate the Company has an orderly infrastructure plan for identifying and delivering needed investments (Attachment A and Others), that it maintains necessary systematic inspections of its transmission facilities and carefully notes remediation actions resulting from such inspections (Attachment E and Others), that it properly uses actual data to develop asset failure models to better determine asset life expectancy, and that it uses multiple other relevant data on benefits, costs and risks to develop appropriate lifecycle cost analyses of actions and alternatives (Attachments B, C and Others), and that it properly relies on the above information and analyses, and the expertise, experience and judgement of its professional engineers to carry out a prudent plan of investment.

In response to PC-DR-297, Avista presents its approach for determining the value of electric transmission and distribution investments for our customers, provided in the context of the overall electric system that is required to effectively meet their needs. Because the subject investments in this request have been identified as necessary for providing safe, adequate and efficient service to our customers, they are fundamentally necessary for delivering them the benefits of electric service. And, as noted in our response above, because the Company is attentive to properly maintaining its system, has carefully evaluated the identified needs in an effort to deliver them at a reasonable cost, the ultimate cost borne by our customers meets the test of being necessary, prudently incurred, and in all respects just and reasonable. Because, in doing so, we regularly meet the standards of service to which we are held, our investments are deemed to provide service benefits to our customers in a manner that exceed the just and reasonable costs they pay in their electric rates for service established by the Commission.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ken Sweigart
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC - 300	TELEPHONE:	(509) 495-4417
		EMAIL:	ken.sweigart@avistacorp.com

SUBJECT: Electric Transmission Investments
REQUEST:
Refer to Attachment C provided by Avista in response to Public Counsel Data Request 237, part (a). Confirm that Attachment C provides an alternatives analysis, including "Earnings per Share" analyses, but does not indicate that the selected alternatives are of sufficient value to rate payers to justify rate increases. If this cannot be confirmed, please reference where in Attachment C an indication that selected alternatives deliver benefits to rate payers in excess of rate payer costs can be found.

RESPONSE:
The subject Attachment C to PC-DR 237 provides a comprehensive overview of how the Company used actual historical equipment failures and other quantitative risk data in lifecycle cost simulation modeling to evaluate and compare the financial benefit to customers associated with different transmission line rebuild strategies. Among other quantitative analyses of the benefit to customers provided in the documents (as appropriate) is the stated "Customer IRR" (customer internal rate of return) scores calculated for the subject projects. These evaluations demonstrate the financial benefit for customers and show the Company's prudence in conducting such evaluations when appropriate.

Further, the documents provided in response to PC-DR 237, contained in Attachments A through G, have been submitted together as providing the information and analyses necessary to conclude that the Company's transmission investments deliver benefits to our customers that are fundamental and necessary to providing them service and that are delivered at a cost that is prudent, just and reasonable. Documents provided in response to PC-DR-237, demonstrate the Company has an orderly infrastructure plan for identifying and delivering needed investments (Attachment A and Others), that it maintains necessary systematic inspections of its transmission facilities and carefully notes remediation actions resulting from such inspections (Attachment E and Others), that it properly uses actual data to develop asset failure models to better determine asset life expectancy, and that it uses multiple other relevant data on benefits, costs and risks to develop appropriate lifecycle cost analyses of actions and alternatives (Attachments B, C and Others), and that it properly relies on the above information and analyses, and the expertise, experience and judgement of its professional engineers to carry out a prudent plan of investment.

In response to PC-DR-297, Avista presents its approach for determining the value of electric transmission and distribution investments for our customers, provided in the context of the overall electric system that is required to effectively meet their needs. Because the subject investments in this request have been identified as necessary for providing safe, adequate and efficient service to our customers, they are fundamentally necessary for delivering them the benefits of electric service. And, as noted in our response above, because the Company is attentive to properly maintaining its system, has carefully evaluated the identified needs in an effort to deliver them at a reasonable cost, the ultimate cost borne by our customers meets the test of being necessary, prudently incurred, and in all respects just and reasonable – clearly meeting the standards of service to which the Company is held by the Commission.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ken Sweigart
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC - 301	TELEPHONE:	(509) 495-4417
		EMAIL:	ken.sweigart@avistacorp.com

SUBJECT: Electric Transmission Investments

REQUEST:
Refer to Attachment D provided by Avista in response to Public Counsel Data Request 237, part (a).

a) Confirm that pole life expectancies do not employ historical actual failure data to assess risk, but rather subjective assessments. If this cannot be confirmed, please indicate where historical actual failure data was employed to determine pole life expectancies.
b) Confirm that Attachment B fails to indicate that the transmission reinforcements are of sufficient value to rate payers to justify rate increases. If this cannot be confirmed, please indicate where in Attachment B an indication that benefits to rate payers in excess of rate payer costs can be found.

RESPONSE:

a) The documents provided in response to PC-DR 237, contained in Attachments A through G, have been submitted together as providing the information and analyses necessary to conclude that the Company's transmission investments deliver benefits to our customers that are fundamental and necessary to providing them service and that are delivered at a cost that is prudent, just and reasonable. Avista has provided several documents in response to PC-DR-237 that demonstrate the Company's use of historical actual failure data to determine the expected asset life of the Company's transmission poles, including multiple examples in documents provided in Attachments B, C and G. For example, in the document titled "CDA-Rathdrum & Silver Valley," in the key considerations listed on page 6, the ETA values for cedar and larch poles are determined from Availability Workbench modeling of historical actual failure data. The ETA values appear repeatedly in the evaluations discussed for each of the sub-projects. As another example, in the document title "CDA (Sandpoint) Transmission Reinforcement" the Planned vs. Unplanned Tx Spending chart shown on page 3 was developed from lifecycle cost modeling of the customer benefits related to systematic vs unplanned replacement of end of life assets, which relied in part on the historical actual failure data described just above.

b) The documents provided in response to PC-DR 237, contained in Attachments A through G, have been submitted together as providing the information and analyses necessary to conclude that the Company's transmission investments deliver benefits to our customers that are fundamental and necessary to providing them service and that are delivered at a cost that is prudent, just and reasonable. Documents provided in response to PC-DR-237, demonstrate the Company has an orderly infrastructure plan for identifying and delivering needed investments (Attachment A and Others), that it maintains necessary systematic inspections of its transmission facilities and carefully notes remediation actions resulting from such inspections (Attachment E and Others), that it properly uses actual data to develop asset failure models to better determine asset life expectancy, and that it uses multiple other relevant data on benefits, costs and risks to develop appropriate lifecycle cost analyses of actions and alternatives (Attachments B, C and Others), and that it properly relies on the above information and analyses, and the expertise, experience and judgement of its professional engineers to carry out a prudent plan of investment.

In response to PC-DR-297, Avista presents its approach for determining the value of electric transmission and distribution investments for our customers, provided in the context of the overall electric system that is required to effectively meet their needs. Because the subject investments in this request have been identified as necessary for providing safe, adequate and efficient service to our customers, they are fundamentally necessary for delivering them the benefits of electric service. And, as noted in our response above, because the Company is attentive to properly maintaining its system, has carefully evaluated the identified needs in an effort to deliver them at a reasonable cost, the ultimate cost borne by our customers meets the test of being necessary, prudently incurred, and in all respects just and reasonable. Because, in doing so, we regularly meet the standards of service to which we are held, our investments are deemed to provide service benefits to our customers in a manner that exceed the just and reasonable costs they pay in their electric rates for service established by the Commission.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ken Sweigart
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC - 302	TELEPHONE:	(509) 495-4417
		EMAIL:	ken.sweigart@avistacorp.com

SUBJECT: Electric Transmission Investments

REQUEST:
Refer to Attachment E provided by Avista in response to Public Counsel Data Request 237, part (a). Confirm that Attachment E provides transmission line inspection information, but does not indicate that the Transmission Infrastructure Plan is of sufficient value to rate payers to justify rate increases. If this cannot be confirmed, please reference where in Attachment E an indication that the Transmission Infrastructure Plan delivers benefits to rate payers in excess of rate payer costs can be found.

RESPONSE:

Please see the Company's responses to PC-DR-297, 298, 299, 300, and 301. The documents provided in response to PC-DR 237, contained in Attachments A through G, have been submitted together as providing the information and analyses necessary to conclude that the Company's transmission investments deliver benefits to our customers that are fundamental and necessary to providing them service and that are delivered at a cost that is prudent, just and reasonable. Documents provided in response to PC-DR-237, demonstrate the Company has an orderly infrastructure plan for identifying and delivering needed investments (Attachment A and Others), that it maintains necessary systematic inspections of its transmission facilities and carefully notes remediation actions resulting from such inspections (Attachment E and Others), that it properly uses actual data to develop asset failure models to better determine asset life expectancy, and that it uses multiple other relevant data on benefits, costs and risks to develop appropriate lifecycle cost analyses of actions and alternatives (Attachments B, C and Others), and that it properly relies on the above information and analyses, and the expertise, experience and judgement of its professional engineers to carry out a prudent plan of investment.

In response to PC-DR-297, Avista presents its approach for determining the value of electric transmission and distribution investments for our customers, provided in the context of the overall electric system that is required to effectively meet their needs. Because the subject investments in this request have been identified as necessary for providing safe, adequate and efficient service to our customers, they are fundamentally necessary for delivering them the benefits of electric service. And, as noted in our response above, because the Company is attentive to properly maintaining its system, has carefully evaluated the identified needs in an effort to deliver them at a reasonable cost, the ultimate cost borne by our customers meets the test of being necessary, prudently incurred, and in all respects just and reasonable. Because, in doing so, we regularly meet the standards of service to which we are held, our investments are deemed to provide service benefits to our customers in a manner that exceed the just and reasonable costs they pay in their electric rates for service established by the Commission.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ken Sweigart
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC - 303	TELEPHONE:	(509) 495-4417
		EMAIL:	ken.sweigart@avistacorp.com

SUBJECT: Electric Transmission Investments

REQUEST:
Refer to Attachment F provided by Avista in response to Public Counsel Data Request 237 (a). Confirm that Attachment F provides asset condition information and an analysis of alternatives, but does not indicate that the Transmission Infrastructure Plan is of sufficient value to rate payers to justify rate increases. If this cannot be confirmed, please reference where in Attachment F an indication that the Transmission Infrastructure Plan delivers benefits to rate payers in excess of rate payer costs can be found.

RESPONSE:

Please see the Company's responses to PC-DR-297, 298, 299, 300, 301 and 302. The documents provided in response to PC-DR 237, contained in Attachments A through G, have been submitted together as providing the information and analyses necessary to conclude that the Company's transmission investments deliver benefits to our customers that are fundamental and necessary to providing them service and that are delivered at a cost that is prudent, just and reasonable. Documents provided in response to PC-DR-237, demonstrate the Company has an orderly infrastructure plan for identifying and delivering needed investments (Attachment A and Others), that it maintains necessary systematic inspections of its transmission facilities and carefully notes remediation actions resulting from such inspections (Attachment E and Others), that it properly uses actual data to develop asset failure models to better determine asset life expectancy, and that it uses multiple other relevant data on benefits, costs and risks to develop appropriate lifecycle cost analyses of actions and alternatives (Attachments B, C and Others), and that it properly relies on the above information and analyses, and the expertise, experience and judgement of its professional engineers to carry out a prudent plan of investment.

In response to PC-DR-297, Avista presents its approach for determining the value of electric transmission and distribution investments for our customers, provided in the context of the overall electric system that is required to effectively meet their needs. Because the subject investments in this request have been identified as necessary for providing safe, adequate and efficient service to our customers, they are fundamentally necessary for delivering them the benefits of electric service. And, as noted in our response above, because the Company is attentive to properly maintaining its system, has carefully evaluated the identified needs in an effort to deliver them at a reasonable cost, the ultimate cost borne by our customers meets the test of being necessary, prudently incurred, and in all respects just and reasonable. Because, in doing so, we regularly meet the standards of service to which we are held, our investments are deemed to provide service benefits to our customers in a manner that exceed the just and reasonable costs they pay in their electric rates for service established by the Commission.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ken Sweigart
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC - 304	TELEPHONE:	(509) 495-4417
		EMAIL:	ken.sweigart@avistacorp.com

SUBJECT: Electric Transmission Investments

REQUEST:
Refer to Attachment G provided by Avista in response to Public Counsel Data Request 237, part (b).

a) Confirm that Attachment G provides inspection reports and alternatives considered, but does not provide a basis for an objective determination that a transmission asset "is no longer optimizing its own performance or customer value." If this cannot be confirmed, please indicate where in Attachment G the basis for an objective determination that a transmission asset "is no longer optimizing its own performance or customer value" can be found.
b) Provide the definition for "no longer optimizing its (an asset's) own performance" Avista uses to determine that a transmission asset should be replaced.
c) Provide Avista's definition of "customer value".

RESPONSE:

a) The documents provided in response to PC-DR 237, contained in Attachments A through G, have been submitted together as providing the information and analyses necessary to conclude that the Company's transmission investments deliver benefits to our customers that are fundamental and necessary to providing them service and that are delivered at a cost that is prudent, just and reasonable. Documents provided in response to PC-DR-237, demonstrate the Company has an orderly infrastructure plan for identifying and delivering needed investments (Attachment A and Others), that it maintains necessary systematic inspections of its transmission facilities and carefully notes remediation actions resulting from such inspections (Attachment E and Others), that it properly uses actual data to develop asset failure models to better determine asset life expectancy, and that it uses multiple other relevant data on benefits, costs and risks to develop appropriate lifecycle cost analyses of actions and alternatives (Attachments B, C and Others), and that it properly relies on the above information and analyses, and the expertise, experience and judgement of its professional engineers to carry out a prudent plan of investment.

   As one example provided in Attachment G that a transmission asset "is no longer optimizing its own performance or customer value," please see page 15 of the document titled "Devil's Gap Lind 115 kV Rebuild Analysis." In the financial analysis table, because the "Do Nothing" alternative has a lower customer internal rate of return than three of the other alternatives analyzed, that line, at the time it was evaluated, was no longer achieving "optimized performance or customer value." Similarly, the transmission wood pole inspection data, provided in Attachment G, indicates individual assets that are beyond their useful service life, and as a result, are no longer achieving optimized performance or customer value.

b) Avista has provided numerous examples of such conditions in the documents provided in response to PC-DR-237, and elsewhere. It can be defined in a variety of ways, such as not meeting a NERC compliance standard, or the Company planning standard for equipment loading, or simply, when the cost to customers of keeping an asset in service is greater than the cost of an alternative treatment.

c) Avista's approach for determining the "customer value" of electric transmission and distribution investments for our customers is multi-faceted and is best understood in the context of the overall electric system that is required to effectively meet the needs of our customers.

Avista Must Meet Required Standards of Service – As a service provider under Washington law, the Company is required to govern its conduct to achieve the public good and to provide facilities and services that are deemed to be safe, adequate and efficient, and in all respects just and reasonable.[39]

Avista Must Meet the Service Demands of Our Customers - Further, Avista is required, upon reasonable notice, to provide to any customer (or service to a potential new customer) the amount of electricity requested, delivered over suitable facilities that are necessary for providing such services.[40] Our Commission established tariffs for service, which have already been discussed at some length in previous discovery, dictate which costs are paid directly by the requesting customer, and which additional investments required to provide the requested service are the responsibility of the Company, and indeed, all other customers receiving electric service.

Avista Determines Infrastructure Needs by Comprehensive System Planning - So, in meeting these and other standards of service, and in compliance with a wide range of federal[41] and state requirements,[42] how does Avista decide what safe, adequate and efficient facilities it reasonably needs to have in place and to plan for in the future? It begins with comprehensive electric system planning conducted by the Company to determine what capabilities it must have in order to timely serve the current and future needs of our customers, delivered in a manner that satisfies our service obligations and compliance requirements. The projects listed in such comprehensive assessments, as noted for example in our response to PC-DR-297, are thus identified as necessary for providing safe, adequate and efficient electric service. As appropriate, system planning analyses also evaluate alternatives for meeting our service obligations. Do we upgrade and reinforce a line to meet a demonstrated need, or do we construct some new segment of line that allows us to meet the need (and possibly others) in a more cost-effective fashion. At this highest level, Avista demonstrates its prudence in effectively identifying and evaluating its electric system needs, appropriately identifying and evaluating alternatives, and selecting the best optimized solutions for meeting the service obligations we have to our customers.

The Subject Transmission Lines are Fundamental and Necessary – As noted above, the electric transmission lines that are the subject of this request have been determined through this comprehensive system planning to be a fundamental and necessary part of the integrated electric system that is required to provide safe, adequate and efficient service to our customers, and in a manner that is just and reasonable. More simply put, Avista cannot deliver "benefits to its customers" without these lines in service.

Avista Maintains its Necessary Facilities in a Prudent Manner - How does the Company then manage these facilities to ensure our customers receive the benefits they provide at a cost that is just and reasonable? We identify investments needed to properly maintain these facilities to ensure their

[39] RCW 80.28.010 sections (1) (2).
[40] RCW 80.28.110.
[41] As an example, Avista has responded to numerous requests from Public Counsel regarding our requirement to comply with a range of NERC standards.
[42] Avista has previously noted its obligation to meet updated standards under the NESC, which, as noted by the Company, has been adopted as law by the State of Washington.

long-term reliable service, as noted in our responses to PC-DR-289, 299, 300, 301, 302, and 303, As demonstrated in the documents noted in these responses, Avista identifies solutions and related investments required to meet our compliance and other legal obligations, to prudently replace assets at the end of their useful life, as determined by detailed engineering experience, expertise and evaluation, by analysis of historic failure data and modeling, through detailed and comprehensive lifecycle cost modeling, and by understanding the risks and consequences of failures of equipment in service. Through these processes Avista has demonstrated it delivers the electric system investments necessary to serve our customers in a prudent and cost-effective manner.

Benefits to Customers Exceed the Costs Included in Rates - In the foregoing description, including our responses to the data requests noted above, as well as in other responses provided in this case, Avista has clearly documented and explained how we assess the need and measure the customer value of our transmission investments, how such investments are necessary and prudently incurred, how these investments allow Avista to meet its standards of service to our customers, and how these investments deliver benefits to our customers that are just and reasonable. Because, in doing so, we regularly meet the standards of service to which we are held, our investments are deemed to provide service benefits to our customers in a manner that exceed the just and reasonable costs they pay in their electric rates for service established by the Commission.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Ken Sweigart
TYPE:	Data Request	DEPT:	Transmission Engineering
REQUEST NO.:	PC - 305	TELEPHONE:	(509) 495-4417
		EMAIL:	ken.sweigart@avistacorp.com

SUBJECT: Electric Transmission Investments

REQUEST:
Refer to Attachments A-G provided by Avista in response to Public Counsel Data Request 237, parts (a) and (b).

a) Identify any information in any of these attachments, which indicates that the benefits of Avista's Transmission Infrastructure Plan delivers benefits to rate payers in excess of rate payer costs.
b) Provide any business cases, worksheets, workbooks, models, cost-benefit analyses, risk assessments, or any other calculations, presentations, requests, standards, or other documentation, which indicates that Avista's Transmission Infrastructure Plan delivers benefits to customers in excess of costs to customers.

RESPONSE:

a) Avista has clearly documented and explained in numerous instances, including our responses to PC-DR-297, 298, 299, 300, 301, 302, 303 and 304, and others, how we assess the need and measure the customer value of our transmission investments, how such investments are necessary and prudently incurred, how these investments allow Avista to meet its standards of service to our customers, and how these investments deliver benefits to our customers that are just and reasonable. Because, in doing so, we regularly meet the standards of service to which we are held, our investments are deemed to provide service benefits to our customers in a manner that exceed the just and reasonable costs they pay in their electric rates for service established by the Commission.

b) Please see part (a), above.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	John Gross
TYPE:	Data Request	DEPT:	System Planning
REQUEST NO.:	PC - 306	TELEPHONE:	(509) 495-4591
		EMAIL:	john.gross@avistacorp.com

SUBJECT: Electric Transmission Investments

REQUEST:
Refer to Attachment A provided by Avista in response to Public Counsel Data Request 250, “Othello Area Transmission Feasibility Study”. Page 58, “Conclusion”, is blank, consisting only of the statement “Tracy – only the two Saddle Mountains alternatives are going forward. Given we are about to play with Grid on this, how should this conclusion read?” Provide a summary of the conclusions of this study including:

a) The recommended proposal description including all cost estimates.
b) The reason for rejecting each alternative.
c) The cost estimates for each alternative.

RESPONSE:

Avista appreciates Public Counsel’s request to provide clarification on PC-DR-250 Attachment A, which inadvertently did not include a completed “Conclusion” section. Please refer to the following sub-parts for a summary of the conclusions of this study.

a) The recommended proposal description is provided below. Cost estimates which were established at the time the study was conducted are provided in part (c), below.

   - The alternatives considered in this study were:
   - Big Bend Closed In closes two of Avista’s currently open 115 kV transmission lines in the Big Bend Area
   - Warden Generation adds generation at Warden Station
   - Lind – Odessa constructs a new 115 kV line between Odessa and Lind stations
   - Saddle Mountains loops the Walla Walla – Wanapum 230 kV Transmission Line into a new station south of Othello
   - Saddle Mountains x2 includes the Saddle Mountains alternative with a second 115 kV path toward Othello
   - Grant Open opens ties between Grant and Avista systems at Warden Station

   The study determined two alternatives should be carried forward: the Saddle Mountains project and the Saddle Mountains x2 project.

b) The reasons for rejecting the alternatives not recommended are provided in the body of PC-DR-250 Attachment A, starting on page 25.

c) Cost estimates for each alternative are listed below. Please refer to Exhibit HLR-11 page 29, which provides the business case justification for the Saddle Mountain Project as originally requested in part by PC-DR-250.

- Big Bend Closed - $75 million
- Warden Generation - $35 million
- Lind – Odessa - $15 million
- Saddle Mountains - Cost estimates which were established at the time the study was conducted
- Saddle Mountains x2 - Cost estimates which were established at the time the study was conducted
- Grant Open – alternative rejected based on study results

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/07/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 307	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Substation Equipment

REQUEST:

Please refer to Attachment A, "LVCB Oil LCA transmittal 022719.pdf", provided by Avista in response to Public Counsel Data Request No. 209.

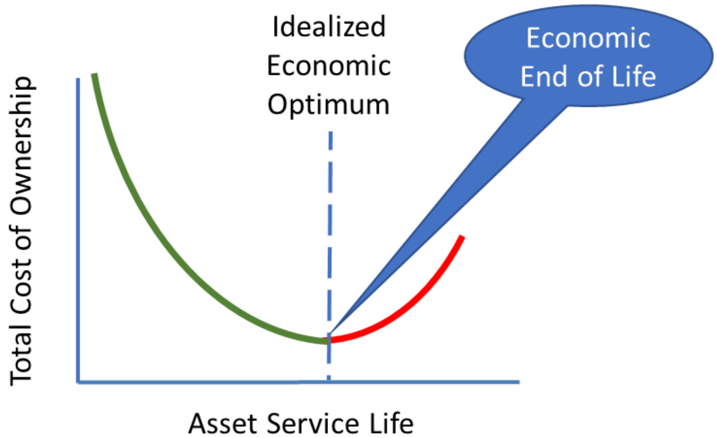
Please refer to the box in the right-hand column on page 1, which references three different equipment age measures: (1) "Economic Optimum" (38 years); "RTF" (30 years); and "ETA" (52.3 years).

a) Provide a definition for each of these three types of equipment age measures. In each definition, describe what each age measure is intended to represent.

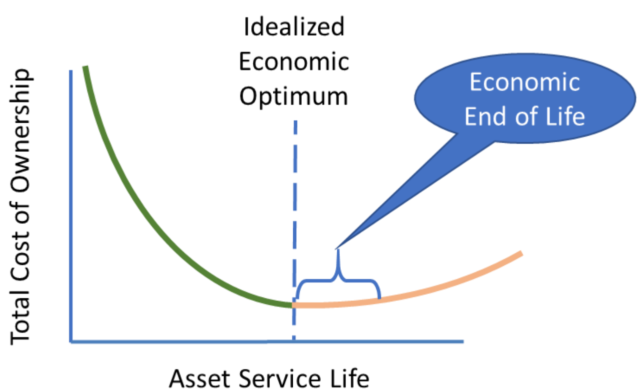
b) Identify which age measure Avista considers to be representative of the age at which the equipment in question should be replaced such that the benefits to customers of preemptive replacement exceed the cost to customers of preemptive replacement.

RESPONSE:

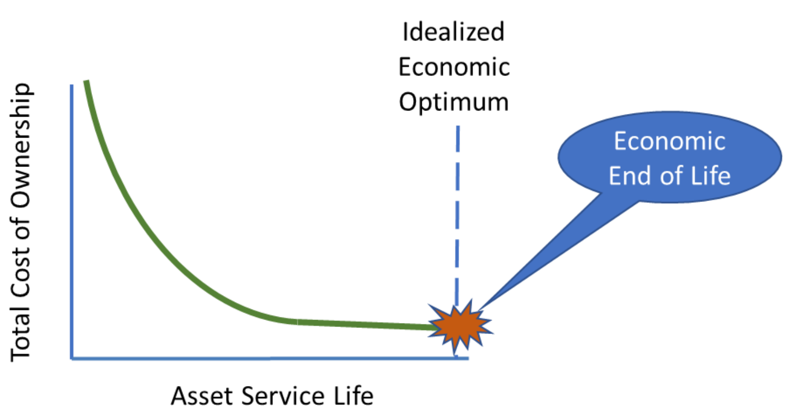
a) **Economic Optimum** is the idealized point of the lowest total cost of ownership for an asset. Total cost of ownership includes the initial investment, maintenance and replacement costs, as well as risk costs associated with operation and failure in service (e.g. outage risk, safety risk, environmental risk, among others). In the illustrative example, below, replacing the asset much prior to the economic optimum will not capture the full value of the initial investment, while replacing it much beyond the economic optimum will result in the encumbrance of uneconomic costs for maintenance or failure, as noted above. Replacement either too early or too late in this idealized example costs customers more money than targeting the economic optimum. Because the costs beyond the optimum are substantial, and the optimum is fairly narrow, this illustration might represent an asset that you target for replacement at the end of its useful life, which is defined by its Economic end of Life, but while the asset is in service.



In the next illustration, below, while there is still an idealized economic optimum, the more-moderate accumulation of costs and risks beyond the optimum (compared with the illustration, above) provides the financial opportunity to keep the asset in service beyond the economic optimum. In this case, the financial consequences of capturing a few more years' service, including its possible failure in service, may not add substantially to the total cost of ownership.



Finally, the illustration, below, represents the lifecycle costs for an asset whose end of useful life would be defined by 'when it fails in service.' The failure in service for such an asset represents the economic optimum because the consequence costs for keeping the equipment in service are generally lower than the cost of replacing it while still in service.



ETA - The point referred to as the "Eta" value or line, which was described by Avista in response to PC-DR-296 part (a), is a Weibull Curve function that represents the point in time at which 63.2% of an asset population of the same age will have failed. This value is derived as the point in which the probability of failure for the population has reached 50%. As noted in response to PC-DR-308, the Eta value, considered in isolation, is not particularly useful for understanding the ultimate failure characteristics for an asset.

30 years - RTF – The Availability Workbench model calculated 5% band in total cost of ownership centered on the economic optimum in this case of 38 years. This function represents the flatness (or steepness) of the total cost curve. In this case, while there is an economic optimum time of replacement at 38 years, the asset could be replaced, as appropriate, anytime between 30 and 50 years at a potential incremental cost of 5 percent beyond the economic optimum.

b) Avista, as noted elsewhere, does not 'preemptively' replace equipment; rather, as we have explained and supported, we replace equipment when it should be replaced - at the end of its useful service life - defined typically as the "Economic End of Life" – depicted in the illustrations provided in part (a), above. Accordingly, Avista replaces some assets well before they might fail in service, some around an optimum age or based on condition (which may have broad discretion or leeway depending on factors noted above), and many others, typically, when they fail in service. In each of these instances, the assets are replaced at a time, and in a manner that delivers our customers the reasonably optimized lowest cost of ownership.

Importantly, as noted in the Company's response to PC-DR-296 part (a), and in PC-DR-308, these designations of run to fail or not run to fail, are not necessarily static for each asset. This is because the consequences of a failure in service for an asset may be different depending on its application and location in our system. Using substation equipment as an example discussed in PC-DR-308, the outage consequences of the failure of certain equipment are often minimal in urban substations, because service to customers can be quickly restored by switching among interconnected substations and feeders. By contrast, for our radial rural substations, the failure of the same equipment will result in an outage for a large number of customers, and often a lengthy one, because there are no other facilities to pick them up. Likewise, the costs of replacement are not static. As an example of the latter, it would not be cost effective to send crews across our system solely to locate and replace distribution transformers based on a given age or condition of the units. But it is cost effective to replace transformers based on a given age (and condition) of the units when a crew is already performing work on the pole where such a transformer is located.

The other perspective that is distorted and lost in the discussion focused on each single asset in isolation, is the simple fact that most of our individual assets function together with other assets in assemblies or units of construction, which significantly blurs the lines of the differing asset lives, lifecycle costs, economic optima, and install dates and ages. This can be a particular issue for substations where the notion of being able to replace each single piece of equipment, at its unique economic optimum, reaches a point where the overall customer value is lost by the multiple mobilizations and outages required to perform such work. As demonstrated in the example of power transformers in PC-DR-308, it makes greater financial sense for customers to inspect, refurbish or replace related equipment at one time, even though that time may represent the economic optimum for only a portion of the assets treated. In a related example, Avista has found that replacing a transformer based on age and condition, as part of its wood pole management program, is financially viable, in part, because as part of the transformer replacement, we're also inspecting and replacing as needed the cutout, lightning arrester, high and low-side connectors and wildlife guard, and capturing the energy efficiency savings provided by a new replacement transformer. The lifecycle costs analyzed in the Availability Workbench model take all of this into account in calculating the financial value associated with the transformer replacement (avoidance of the risk costs associated with a failure in service for the transformer, cutout, arrester, high and low-side connectors, etc.; combined with the gain in energy efficiency; combined with the lower cost to install when other capital work is already being performed on that pole). In this instance, and as explained in PC-DR-295 and elsewhere, results of our lifecycle cost modeling demonstrate that replacement of a transformer and the attached equipment in the manner just described provides our customers a lower total cost of ownership, when compared financially with the alternative of allowing the transformer (and attached equipment) to fail in service. <u>None of this financial value for customers can be captured if the individual assets are analyzed and managed in isolation from the other closely allied assets that are part of the assembly</u>.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/07/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 308	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Electric Substation Rebuilds

REQUEST:

Please refer to Avista's response to Public Counsel Data Request No. 100, which states "The equipment types Avista typically replaces in the Substation Rebuilds program are: Air Switches, Batteries, Battery Chargers, Breaker Reclosers, Capacity Banks, Circuit Switchers, Current Transformers, Distribution Transformers, High Voltage Circuit Breakers, High Voltage Bushings, Low Voltage Bushings, Auxiliary Equipment, Perimeter Security items, Power Transformers, Potential Transformers, Substation- Generation Meters, Surge Arresters, Timber Structures, and Voltage Regulators." Please refer also to Attachment A, "LVCB Oil LCA transmittal 022719.pdf", provided by Avista in response to Public Counsel Data Request No. 209. Please refer to the box in the right-hand column on page one, which references three different equipment age measures: (1) "Economic Optimum" (38 years); "RTF" (30 years); and "ETA" (52.3 years).

a) For each of the 19 equipment types listed above, provide the total number of each type that are presently in service on the Avista system.

b) For each of the 19 equipment types listed above, provide (i) the "Economic Optimum" age; (ii) the "RTF" age; (iii) the "ETA" age; and (iv) the age at which Avista believes that the benefits to customers of preemptive replacement exceed the costs to customers of preemptive replacement.

c) For each of the 19 equipment types listed above, provide the average annual rate of failure in service (not including test failures).

RESPONSE:

a) The current total number of units in service for each of the subject equipment types is provided in the table below, extracted from information available in Avista's work and asset management system.

Equipment Type	In-Service Count
Air Switches	2119
Batteries	131
Battery Chargers	135
Breaker Reclosers	373
Capacitor Banks	33
Circuit Switchers	122
Current Transformers	*
Distribution Transformers	*

HV Circuit Breakers	339
High Voltage Bushings	*
Low Voltage Bushings	*
Auxiliary Equipment	*
Perimeter Security Items	*
Power Transformers	228
Potential Transformers	279
Substation-Generation Meters	*
Surge Arresters	*
Timber Structures (Substation, not individual pole structure)	39
Voltage Regulators	1026

* Equipment not currently available as a complete inventory from the work and asset management system.

b) As explained by the Company in response to PC-DR-307, while the statistics noted in the request for the subject equipment listed in part (a), above, represent some of the important outputs from the analysis of failure data, development of failure curves, and the lifecycle cost analysis, focusing on each piece of equipment in isolation can distort the understanding of how this equipment ought to be prudently managed. In Avista's experience, and in its analysis of substation equipment, and entire substations, and even groups of substations, the Company has determined that it is not in our customers' best financial interest to manage, maintain and replace individual pieces of substation equipment based only on the economic optima for every piece of equipment, as noted in response to PC-CR-307. This is true even when considering the differences in economic optima for the same piece of equipment deployed in different substations across the Company's system, as explained further below.

Through Availability Workbench modeling, Avista has determined groups of maintenance activities that optimize the lifecycle cost of major equipment in the substation, which list of maintenance activities is provided for power transformers, as an example, which includes: rewind transformer, replace cooling pumps, replace high and low voltage bushings, replace gaskets, process transformer oil, replace all cooling fans and fan motors, replace or calibrate gauges, and replace lightning arresters. This analysis is based on the following failure curve statistics for each type of equipment refurbished or replaced during such maintenance activities.

Component	ETA	Beta	Gamma
Transformer	75	3.764	0
Transformer Oil	75	3.764	0
Cooling Pump and Motor	123	1.705	0
High and Low Voltage Bushings	6,364	0.3201	0
Repair / Replace Gauges*	9,747 / 122	0.8 / 2.9	0 / 0
Gaskets	30	3	0
Cooling Fans and Motors	143.7	2.538	0
Lightning Arresters	325	1.064	0

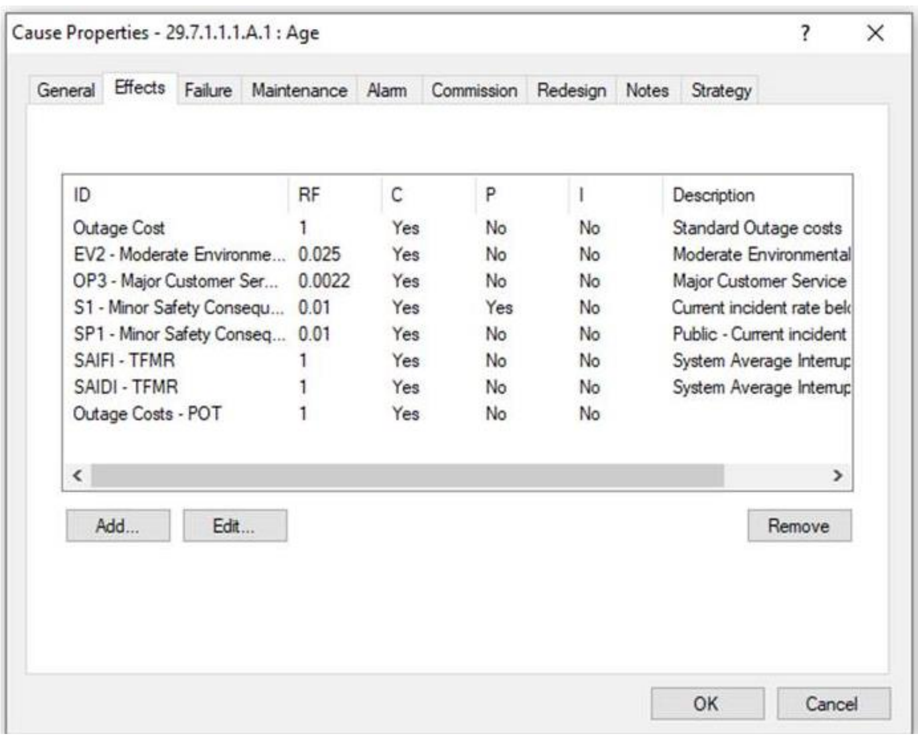
*Results best fit by use of a Bi-Weibull failure curve.

In the table above, we have included the failure curve statistics for Beta and Gamma, which in addition to the Eta value, define the useful failure characteristics of the equipment in question. The Eta value, considered in isolation, has little value in determining the implications of the failure characteristics of the asset. Based on results of the above analyses, and based on the variability in economic end of life for transformers across the Company's system, the lowest optimized lifecycle costs for power transformers is achieved when the maintenance is performed within the time interval of 21 to 54 years, or in the alternative, when no maintenance is performed and the transformer is run to failure. Likewise, the optimized range in age for transformer replacement is 40 to 67 years, or in the alternative, upon failure of the unit in service. As explained above, and in response to PC-DR-307, the reason our analysis results in alternatives for the replacement of a transformer is because of the differing consequence costs associated with transformer failure in substations across the Company's electric system, as illustrated in the example provided below.

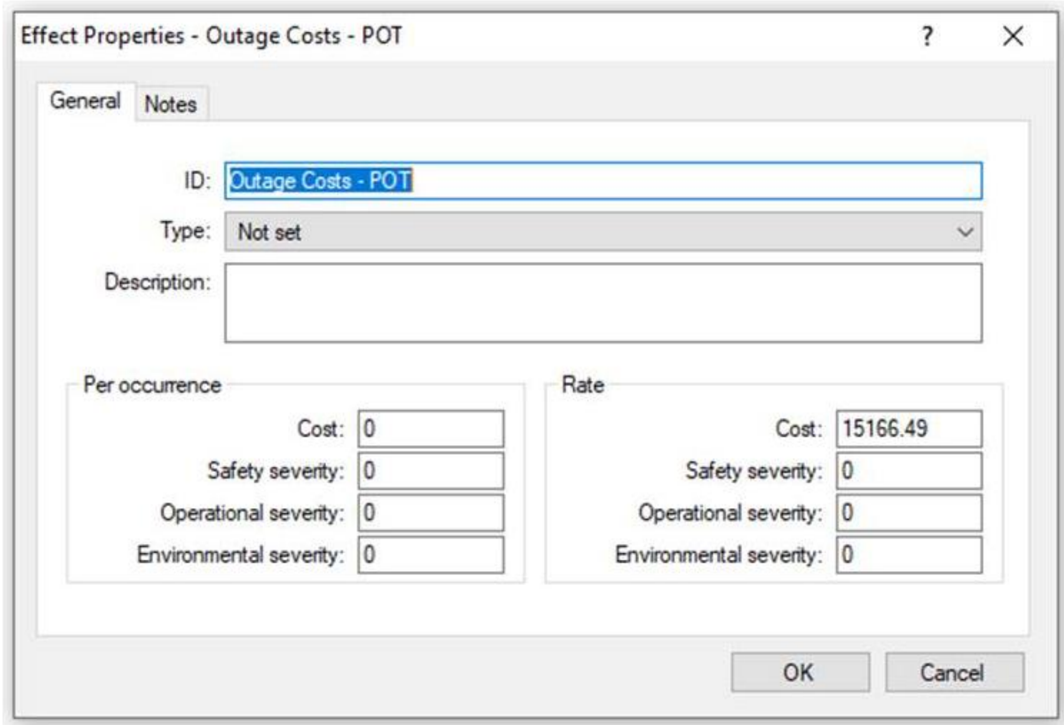
As noted elsewhere, the Company does not 'preemptively' replace equipment, rather, we replace assets when they should be, at the end of useful life, which, as explained in part, above, and in response to numerous other requests, including PC-DR-307, is at the time and in a manner that delivers our customers the best financial value for their investment. As we have also explained and supported with results of lifecycle cost modeling, including the transformer example, above, there is typically no static age for an asset that necessarily defines its end of useful life. As one example, for which we have provided considerable data, background information, failure results and results of lifecycle costs modeling, consider the cutout. When work is already being performed on a feeder, and on a particular pole or transformer being inspected, if the cutout is of an identified age or condition (which age and condition has been determined by evaluation of inspection and failure data, analysis of failure modes, Weibull failure analysis, and lifecycle cost modeling) <u>then it has economically reached the end of its useful life, because replacing the cutout at the time of inspection and work on the pole, even though the cutout is still functional, represents on average the best financial value for customers – the lowest lifecycle cost – compared with the alternative of sending a crew to that pole later in time to replace that cutout when it does fail in service.</u> For the cutout in service that is not qualified for replacement based on age or condition during work on a feeder, or the cutout in service on a feeder that has not been systematically inspected, upgraded, or otherwise been worked on by the Company, then end of life for that cutout is at the point it fails in service.

Again, going beyond the example for a single piece of equipment, and as explained in the discussion above, and in our numerous other responses, the identification of a specific age for replacement of an asset gets more complicated when you consider the impact of multiple assets in a common assembly that may have been installed at different times, that have different failure characteristics and expected service lives, and different lifecycle cost characteristics. Depending on the complexity of designing the job, mobilizing crews, and taking the outages required to perform the work, it can be impossible to define any optimum time once the lifecycle costs for multiple pieces of equipment has declined to a somewhat static state. These factors were part of the analyses, discussed above, performed by the Company in identifying the optimum groups and times for maintenance activities for power transformers.

Further, as explained above, and in response to PC-DR-307 part (b), the consequences of a failure in service for a given piece of equipment can vary substantially based on where that equipment is installed in our system. The notion of having a static age of replacement, as posed by Public Counsel in this request, assumes the economic optimum for a particular type of equipment is based on a fixed set of consequence and replacement costs, which is not the case. Using a couple examples to illustrate this are the Company's Ninth & Central Substation, in a suburban location, and the Potlatch Substation, which is in a rural location. The Ninth & Central substation has redundancy and interconnections to other substations, which enables operating flexibility that can be used to minimize customer outages in the event of the failure of a piece of equipment in the station. The Potlatch substation does not have the same redundancy and interconnections, which makes it more likely that an equipment failure will result in a customer outage. While some equipment failures at these two substations have the same potential to result in a customer outage, the consequence costs may be different based on the situations described above. As an illustration, Avista used the Availability Workbench model to compare the difference in consequence costs at these two stations for the same event. Using the example of a transformer trip due to high side protection, the consequence costs at Ninth and Central were near zero because of the flexibility at that location to quickly pick up those customers, avoiding a sustained outage. At the Potlatch Substation, however, as noted in the image below for "Outage Costs – POT," such a failure will result in customer outages100% of the time (RF=1).



Because there is no opportunity to alternatively pick up those customers served from the Potlatch substation, the customer outage cost is shown in the image below as $15,166.49. This simple example demonstrates why one type of equipment may have a different economic optima depending on were in the system it is deployed.



c) The Company has previously provided such failure data in response to PC-DR-100, part (d), Attachment A.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/07/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 311	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:
Please refer to Attachment A provided by Avista in response to Public Counsel Data Request No. 108, "Distribution Feeder Management Plan".
Page four references "Avista's Existing Facilities Replacement Modifications Guidelines" document. Please provide this document.

RESPONSE:

Please see the subject document, provided as PC-DR-311 Attachment A.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/07/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Amy Jones
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 312	TELEPHONE:	(509) 495-2552
		EMAIL:	amy.jones@avistacorp.com

SUBJECT: Electric Distribution Minor Rebuild

REQUEST:
Please refer to Avista's response to Public Counsel Data Request No. 246, regarding the worst performing feeders program, which was apparently discontinued in 2017.
Provide the capital spent by year on the worst performing feeder program from 2013-2017.

RESPONSE:

Worst Feeders Program Capital Spend by Year	2013	2014	2015	2016	2017
Worst Feeders Program	$ 2,043,036	$ 1,906,993	$ 1,131,378	$ 1,348,071	$ 17,653

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/07/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 313	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:
Please refer to Attachment A provided by Avista in response to Public Counsel Data Request No. 108, "Distribution Feeder Management Plan".
Page nine states "Replace all primary wood cross arms with the appropriate fiberglass cross arm if any of the following apply: (i) Visible moss covers some area of the cross arm which indicates that the wood treatment has leached out; (ii) Contains wood pins that are floating or sinking." Please provide all data and calculations that justify replacement of wood cross arms that have "Visible moss covers some area of the cross arm", such as an increasing rate of cross-arm failure when moss is visible.

RESPONSE:

Avista regularly inspects wood crossarms as part of its wood pole management, distribution minor rebuild and grid modernization programs, and has regularly used such inspection, condition and failure mode data on wood crossarms in its Availability Workbench modeling to identify failure curves and perform lifecycle cost analysis, used to identify the modes of end of useful life for crossarms. Avista has described how the models operate, has provided data used in modeling, has provided failure curves for various assets, including cost results, and has provided examples of how risk and replacement (spares) costs are calculated in the models. An explanation of how effects costs are calculated for crossarms, as one example, was provided in response to PC-DR-295, and in PC-DR-296, the Company described the data associated with crossarms relied upon for these models. Such models, including results requested by Public Counsel, have been explained, described and supported by the Company in responses to numerous data requests in this case. Because the presence of moss on a crossarm has been identified, based on inspection and failure data and analysis, as a useful indicator of its age, condition and likelihood of failure, Avista has properly identified this as an indicator of end of life for a crossarm that is attached to a pole being reinforced, replaced or otherwise worked on as part of a systematic program such as grid modernization and wood pole management, or repair or other work performed on the system intended to meet other objectives, such as individual projects under the electric distribution minor rebuild program.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/07/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 314	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT:

REQUEST:
Please refer to Attachment A provided by Avista in response to Public Counsel Data Request No. 108, "Distribution Feeder Management Plan".
Page nine states "Replace all double wood cross arms (dead-end, tangent, etc.) with the appropriate fiberglass cross arm if either of the following apply: (i) The arms and insulators are NOT in good operating condition; (ii) Raptor nests are a known problem in the area." Please provide the process field personnel follow to determine that "The arms and insulators are not in good operating condition".

RESPONSE:

Avista's professional linemen and inspectors are trained to assess insulators for cracks or deformation and other anomalies that indicate a replacement is warranted during systematic inspections or work on the individual pole or feeder. Our employees are also trained in the Company's electric distribution line construction standards, so they can readily spot missing or damaged hardware, and other indicators of potential failure. As explained in response to PC-DR-313, Company employees are trained in identifying factors indicating when a crossarm should be replaced as part of work being performed on a pole. As noted in PC-DR-313, and elsewhere, the Company has analyzed inspection and failure data, has modeled the expected life of a crossarm (and has done the same for pins, insulators, etc., etc.), and identified end of life modes for a crossarm using Availability Workbench lifecycle costs analysis. Replacement of damaged or otherwise end of life crossarms, insulators and pins, while performing work on the pole, has been demonstrated by the Company to represent the best financial value for our customers, compared with the alternative of coming back later to replace them - one at time - once they have failed.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/19/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 316	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Substation Rebuilds
REQUEST:

Please refer to Attachment A provided by Avista in response to Public Counsel Data Request No. 286(b).

a) Confirm that there are only 15 items in all of the 519 pieces of equipment shown over the years 2018 to 2020 that are marked with the "reason (use for PC-101)" as Overloading. If this cannot be confirmed, please explain.

b) The column labeled as "Reason (use for PC-101)" appears to have been added to this report to respond to PC-099 and PC-101. Please confirm. If this cannot be confirmed, please explain.

c) Please explain what the reasons in the column with the heading "AVA Reason" are intended to represent.

d) Given Avista's response to subpart (c), explain why the column with the heading "AVA Reason" is different reasons than the column "Reason (use for PC-101)".

RESPONSE:

a) Avista notes that of the 519 pieces of equipment listed in the subject table, 49 pieces of equipment, as designated in the column labeled "use for PC-101," were replaced for the stated Reason of Overloading.

b) Avista responded to the contemporaneous data requests, as part of the group PC-DR-098 through PC-DR-130, which specific requests for information were often intertwined and at times overlapping. The subject table, PC-DR-099 Attachment A, was created by Avista specifically under the direction of Public Counsel. In PC-DR-101, the Company was directed to provide information related to 'Reasons for Replacement' categories that were stated by Public Counsel. The column heading noted in the request, labeled "Reason (use for PC-101)," simply referred to the stated reasons listed by Public Counsel, as designated by Avista under the direction of Public Counsel, that we referred to in responding to the information requested in PC-DR-101.

c) The column "AVA Reason" contains miscellaneous comments and notes included by the analyst at the time Avista was creating the table under the direction of Public Counsel, and which were inadvertently and unintentionally left in the table. Avista therefore directs Public Council to refer to the replacement reasons listed in the column labeled "Reason (use for PC-101)".

d) The column "AVA Reason" contains miscellaneous comments and notes included by the analyst at the time Avista was creating the table under the direction of Public Counsel, and which were inadvertently and unintentionally left in the table. Avista therefore directs Public Council to refer to the replacement reasons listed in the column labeled "Reason (use for PC-101)".

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/19/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	John Gross
TYPE:	Data Request	DEPT:	System Planning
REQUEST NO.:	PC – 317	TELEPHONE:	(509) 495-4591
		EMAIL:	john.gross@avistacorp.com

SUBJECT: Westside Transformer Replacement

REQUEST:
Capital Additions, Test Year (Electric) Please refer to Attachment B provided by Avista in response to Public Counsel Data Request No. 166.
Confirm that this analysis, of possible overloading of the transformers at Westside substation, takes into account all breaker bus ties and field tie reliefs when considering contingency relief at this substation. If this cannot be confirmed, please explain.

RESPONSE:

The Westside substation transformers referenced in the data request are specifically the Westside #1 & #2 230/115kV transformers. The Westside #1 & #2 230/115kV transformers are components of the electrical transmission system. The electrical transmission system is operated, in general, as a networked system where "breaker bus ties and field tie reliefs" are operated in a normally closed state. The studies performed as described in PC-DR-166 Attachment B utilized a model of the electrical transmission system which represents the projected System conditions following the NERC Standard TPL-001-4 R1. Utilization of system reconfiguration was considered for "contingency relief" for analysis of the Westside #1 & #2 230/115kV transformers.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/19/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Larry La Bolle
TYPE:	Data Request	DEPT:	Transm Ops/System Planning
REQUEST NO.:	PC - 318	TELEPHONE:	(509) 495-4710
		EMAIL:	larry.labolle@avistacorp.com

SUBJECT: Lifecycle Cost Modeling

REQUEST:

Please refer to Avista's response to Public Counsel Data Request No. 295(a)(i), which states "The output of the failure modeling for each piece of equipment is the Weibull curve that describes the failure probability of each asset based on known failures and age, which Avista has experienced."

a) For each type of equipment, i.e. Poles, distribution transformers, cross arms, arrestors, cutouts, or any other type of equipment that Avista in replacing in advance of failure, provide "the Weibull curve that describes the failure probability of each asset based on known failures and age which Avista has experienced."
b) Provide all the supporting data for each curve provided in response to subpart (a), including age of assets and failure rates, including failures by age group,
c) For the curves provided in response to subpart (a), provide these curves and supporting data for any asset subtype, such as by manufacturer, or any other subtype that Avista has used to categorize these assets.

RESPONSE:

a) Avista performs failure analysis and lifecycle cost modeling to determine the effective end of life of assets in our system. End of life is typically defined as the economic end of life, such as illustrated and described in response to PC-DR-307, and as discussed in numerous other responses. As such, while we target replacement of assets at their economic end of life, the designation of circumstances that constitute end of life for many assets is not fixed or static. In multiple examples provided by the Company, economic end of life for an asset may be run to fail in the event a particular piece of equipment has not been inspected or evaluated as part of a systematic inspection, repair, replace, rebuild program. In this case, the economic end of life, or the lowest lifecycle cost to customers, is when that piece of equipment has failed. But the same lifecycle cost modeling also identifies age or condition criteria for that same type of equipment that warrants its replacement while still in service, when it is conducted as part of a systematic program where work is already being performed on that feeder or pole. In this case, the economic end of life for that type of equipment is defined by age or condition, because if that equipment qualifies, it's less expensive for our customers to replace it then, as part of other work already being performed, than it is to let the equipment fail in service, take the customer outage, and send a crew out again to replace it. As we have also explained and supported in PC-DR-308 and PC-DR-309, among others, the economic end of life for an individual piece of equipment will also vary based on its location in our system and/or the integration of the varying asset lives, dates of install, failure characteristics and lifecycle costs of other types of equipment with which it is installed in a common assembly.

   Weibull curves supporting the subject lifecycle cost modeling have been extracted from our Availability Workbench models and are provided in the attachments referenced below:

i. Individual Weibull curves for the assets listed below are provided in PC-DR-318 Attachment A. Though the images in the attachment appear to be relatively small in size, zooming in on the curves allows one to see all the legible details.

- Wood Pole Reinforcement
- Wood Poles
- Insulator Pins
- Insulators
- Guying
- Crossarms

ii. Individual Weibull curves for the assets listed below are provided in PC-DR-318 Attachment B.

- Overhead Transformers
- Cutouts
- High and Low-Side Connectors
- Grounds
- Lightning Arresters

iii. As noted in Avista's response to PC-DR-296 part (d), our models include failure characteristics for predominant species of tree and failure modes in the Company's electric distribution system. As such, the individual Weibull Curves (approximately 77 individual curves) for each species of tree modeled were too numerous to easily extract in graphic form from Avista's Availability Workbench models, however, we have extracted the key Weibull curve failure statistics for each species and failure mode, provided here as PC-DR-318 Attachment C. Headings in this report table are described below.

- ✓ Type – Used to organize the failure curves but not always used.
- ✓ ID – Weibull Curve unique identifier.
- ✓ Description – Description of the component associated with the failure curve.
- ✓ Eta-1, Beta-1, and Gamma-1 – Weibull Curve parameters, previously discussed by Avista, that describe the failure characteristics and the resulting failure curve.
- ✓ Eta-2, Beta-2, and Gamma-2 – Weibull Curve parameters determined to describe the failure curve, used only for bi-Weibull, tri-Weibull, and 2 or 3 phased Weibull Curves.
- ✓ Eta-3, Beta-3, and Gamma-3 – Weibull Curve parameters determined to describe the failure curve, only used for tri-Weibull and 3 phased Weibull Curves.
- ✓ Mean Time to Failure – Only used for Normal Distribution failure curves.
- ✓ Standard Deviation – Only used for Normal Distribution failure curves.
- ✓ Fit Distribution – Identifies the type of failure curve distribution used for the failure curve (i.e. Weibull, Bi-Weibull, Normal, and etc.).

b) Supporting data, extracted from Avista's Availability Workbench models, for the subject Weibull curves listed above in part (a) are provided in the attachments listed below.

i. Supporting data for the six Weibull curves provided in PC-DR-318 Appendix A, Wood Pole Reinforcement, for Wood Poles, Insulator Pins, Insulators, Guying and Crossarms are provided in PC-DR-318 Appendix D. The dataset is in the form of a table that includes nearly 679,000 individual entries. Headings in the table for each entry are defined as follows: "Weibull Set" is the specific equipment type modeled; "Time" is the duration of hours in service for the individual piece of equipment listed in each entry; "Suspended" is the status of that specific piece of equipment: True – the equipment was still in service / False – that piece of equipment had failed at the age shown in the "Time" column for that individual piece of equipment; "Disabled" notes whether or not that data point is used in the failure curve determination: True – the data point is an outlier and is excluded from the Weibull analysis / False – the data point is included in the failure analysis; "Quantity" is the number of identical pieces of equipment that are included as part of that data point; "Reference ID" is an identifier sometimes used to tie that piece of equipment to a specific pole number.

ii. Supporting data, extracted from Avista's Availability Workbench models, for the five Weibull curves provided in PC-DR-318 Appendix B, for Overhead Transformers, Cutouts, High and Low-Side Connectors, Grounds and Lightning Arresters are provided in the table PC-DR-318 Appendix E. For the description of the table headings, please see part (b)(i), above.

iii. Supporting data, extracted from Avista's Availability Workbench models, for the vegetation management Weibull failure analyses provided in PC-DR-318 Attachment C, above, is provided in PC-DR-318 Appendix F. As noted in Avista's response to PC-DR-296 part (d), this data set is quite voluminous, and includes over 1.1 million individual entries. For the description of the table headings, please see part (b)(i), above.

c) Weibull curves, and the underlying data supporting the failure analyses, for the subject lifecycle cost modeling for the applicable subsets of the assets listed above, have been extracted from our Availability Workbench models and are provided in the attachments referenced below:

i. The Weibull curve for Chance Cutouts is provided in PC-DR-318 Attachment G.

ii. Data supporting the Weibull curve for Chance Cutouts is provided in PC-DR-318 Attachment H, beginning on line 24.

iii. The Weibull curve for Risky PCB Transformers is provided in PC-DR-318 Attachment I.

iv. Data supporting the Weibull curve for Risky PCB Transformers is provided in PC-DR-318 Attachment J.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/19/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 319	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Avista Distribution Feeder Management Plan
REQUEST:
Please refer to Attachment A provided in response to Public Counsel Data Request No. 108 (Avista's Distribution Feeder Management plan).

a) Provide the percent of poles replaced each year that did not fail a viability test such as that performed by Osmose.
b) Provide the percent of distribution transformers replaced each year which were not transformers with PCBs.

RESPONSE:

a) The Company's Distribution Feeder Management Plan identifies a threshold replacement age for cedar poles, to be applied in the instance when a feeder is being rebuilt by the Company, such as feeders rebuilt as part of Avista's Grid Modernization Program. As described and supported by the Company in responses to numerous data requests, Avista has determined this age of replacement based on failure analysis, such as described and supported in response to PC-DR-318, and integrated lifecycle cost analyses, such as described in responses to PC-DR-221, PC-DR-222, PC-DR-223, PC-DR-294, PC-DR-295, PC-DR-296, among others. As such, <u>during a feeder rebuild, a cedar pole aged 60 years or greater has been determined to have reached its economic end of life, because replacing it during the rebuild project provides customers a lower lifecycle cost for that pole compared with the alternative of sending a crew later to replace it once it has failed in service.</u> As part of a feeder rebuild, using the example of a grid modernization project, poles younger in age than 60 years are routinely tested to determine their suitability for remaining in service, and a portion of these poles fail such tests and are replaced as part of the rebuild project. As also discussed by the Company, and as noted in the Distribution Feeder Management Plan, poles are replaced for a variety of other reasons during a feeder rebuild, as a result of strength or class issues, to address clearance issues, for re-alignment as required, and for corrected span lengths, etc., per standards in the Company's Distribution Feeder Management Plan.

   As noted elsewhere in the Company's responses to numerous requests, Avista also determines end of life for wood poles through inspection and testing only, <u>when the work performed is not part of a feeder rebuild project</u>. Such is the case for the Company's Wood Pole Management program where individual poles in a feeder are evaluated to determine whether they are likely to remain serviceable until the next inspection cycle when they will again be evaluated for service. This program falls short of a feeder rebuild because existing equipment is evaluated and repaired or replaced in its original configuration, location, existing alignment, with its existing conductor, etc., etc. Because it is known when in time the feeder will be inspected again, the Company determines end of life based on condition of the pole and years in service until the next inspection. Avista's testing and remediation approach in the wood pole management program produces the lowest reasonable lifecycle cost for customers in this application, as different from the testing and aged-based identification of economic end of life for wood poles in a feeder rebuild project, which produces the lowest reasonable lifecycle cost for customers in this application, as identified in the Distribution Feeder Management Plan.

The table below refers to PC-DR-110 Attachments A through N, which pages listed for each attachment under 'Pole Pages' describe the analyses on poles performed for each feeder. Later baseline analyses have the breakdown of poles added to the report (this data was not included in baseline reports in earlier years).

PC-DR-110 Attachment	Feeder	Pole Pages
A	BEA12F2**	47*
B	F&C12F1***	43*
C	HOL1205	39*
D	M15514***	52*
E	MIS431***	38
F	ORO1280	29
G	ORO1282**	72*
H	PDL1201	32
I	RAT233***	28
J	ROS12F5*	58*
K	SIP12F4**	59*
L	SPI12F1	19
M	SPR761	25
N	TUR112	38

* Pages that contain pole data in later baseline reports.
** No construction date.
*** Feeder only partially constructed.

In total, 3,875 poles have been replaced in the above grid modernization feeder projects based on inspection and testing, pole age, and replacements required as a result of strength or class issues, to address clearance issues, for re-alignment as required, and for corrected span lengths, etc., per standards in the Company's Distribution Feeder Management Plan. In response to PC-DR-221, Avista provided the number of wood poles replaced each year as part of the Company's wood pole management program in Washington, which total replaced was 7,287, based on inspection and testing only. The table below shows the total number of end of life poles replaced in the Company's wood pole management and grid modernization programs in Washington for the period 2011 – 2020, indicating the totals for end of life based on inspection and testing, and the totals for end of life based on age and the other requirements noted above for feeder rebuild projects.

End of Life Poles Replaced Based on Inspection and Testing in Grid Modernization and Wood Pole Management	End of Life Poles Replaced Based on Age and Other Feeder Rebuild Requirements	Total End of Life Poles Replaced
8,392	2,770	11,162

b) Avista has provided such data in response to PC-DR-223 part (j), which shows the overhead transformers replaced each year for the Company's wood pole management and grid modernization programs for the period 2011 - 2020. The total number of risky PCB transformers replaced during this period, which is included in the total number of transformers replaced, is also provided in that response.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/28/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 322	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Lifecycle Cost Modeling

REQUEST:

Please refer to the Company's response to Public Counsel Data Request No. 307(a), which states "**Economic Optimum** is the idealized point of the lowest total cost of ownership for an asset. Total cost of ownership includes the initial investment, maintenance and replacement costs, as well as risk costs associated with operation and failure in service (e.g. outage risk, safety risk, environmental risk, among others)." Please refer also to the first chart provided in the response to Public Counsel Data Request No. 307(a), and specifically the total cost of ownership curve. In responses to this data request, please do not provide screen shots of the Availability Workbench software. Public Counsel is interested in the data, inputs, processes, and calculations, not software.

a) Provide inputs, equations, calculations, workpapers, descriptions, and/or other means to explain how "initial investment" is determined and incorporated into the total cost of ownership curve.
b) In response to subpart (a), please identify whether or not each of the following potential components are included in the "initial investment" part of the cost curve, including (i) initial equipment and installation costs; (ii) depreciation; (iii) book value; (iv) carrying charges customers must pay on the initial investment (authorized return, federal income taxes, interest expense, property taxes, and Washington utility tax).
c) Provide inputs, equations, calculations, workpapers, descriptions, and/or other means to explain how "maintenance" costs are determined and incorporated into the total cost of ownership curve.
d) Provide inputs, equations, calculations, workpapers, descriptions, and/or other means to explain how "replacement" costs are determined and incorporated into the total cost of ownership curve.
e) In response to subpart (d), please identify whether or not each of the following potential components are included in the "replacement" cost part of the cost curve, including (i) initial equipment and installation costs; (ii) depreciation; (iii) book value; (iv) carrying charges customers must pay on the initial investment (authorized return, federal income taxes, interest expense, property taxes, and Washington utility tax).
f) Provide inputs, equations, calculations, workpapers, descriptions, and/or other means to explain how "operation and failure in service" costs are determined and incorporated into the total cost of ownership curve. Please include separate inputs, equations, calculations, workpapers, descriptions, and/or other means to explain each of the components listed as part of these costs, including (i) outage risk; (ii) safety risk; (iii) environmental risk; (iv) any and all "other" components of these costs.

RESPONSE:

a) The initial investment includes the cost of the asset, the cost to install the asset, the costs of any outage required for the installation, and any safety or other installation-related risk costs. These costs are included in year one of the analysis and they carry through the period of the lifecycle cost analysis. For example, an asset that has a combined initial cost of $10,000 in year one, has a Total Cost of Ownership of $10,000 in that year. In year two, assuming there we no maintenance or other incremental costs during the year, the Total Cost of Ownership is $5,000, derived by dividing the initial cost of $10,000 by two (for the number of years in service). For year three, again, assuming no incremental costs, the Total Cost of Ownership is $3,333 ($10,000/3 years).

b) The subject cost components are meaningful if the purpose of a particular analysis is to forecast the actual additions to revenue requirement for an investment. Typically, because the need for the investment is demonstrated and prudent, the Company is held to a standard of demonstrating it has selected the optimized least-cost alternative. Predicting the actual impact on revenue requirement is often unnecessary, unless the respective alternatives have widely differing capital and expense components and timing, or other factors that warrant such evaluation. The subject cost components are not included in the Availability Workbench model because their inclusion serves to distort the fundamental lifecycle cost analysis. When Avista believes the inclusion of these cost components is appropriate for an analysis, however, we use the Availability Workbench model to identify a likely set of alternatives. The financial results of these simulations are imported into Avista's Revenue Resource Requirements model, which calculates and includes the subject cost components, to compare the revenue requirement impact of the alternatives.

c) Maintenance costs are included as annual costs in the year(s) in which they are expected to occur in the Total Cost of Ownership model. Two general types of maintenance costs are included in the Availability Workbench models, which are maintenance actions based on time interval and maintenance actions based on inspection and condition. Time-based maintenance costs are input, as noted above, in the years corresponding with the planned interval, and inspection/condition maintenance costs are input by calculating the likelihood in each year of such maintenance costs occurring (annual maintenance costs = probability of occurrence x cost of the maintenance action). Using the example in part (a), above, if $200 in maintenance costs were expected in each year, then the Total Cost of Ownership for year one is now $10,200, ($10,000 + $200)/1 (years). For year two, the Total Cost of Ownership is $5,200, ($10,200 + $200)/2 (years). For year three, the Total Cost of Ownership is $3,533, ($10,400 + $200)/3 (years). In this fashion, the Total Cost of Ownership includes the prior years' cumulative costs plus current year costs divided by time in service.

d) Replacement costs, as explained above in part (a) for initial investment costs, include the expected cost of the asset, the installation cost, and any associated risk costs. Replacement costs are included in the Total Cost of Ownership as an annual cost, which is calculated by multiplying the replacement cost by the probability that the replacement will occur in that year (annual replacement cost = total replacement cost x probability the replacement will occur in that year), as shown in the table below. If the consequences of a failure in service are significant, then the replacement cost, with its significant risk costs, can be much greater than the amount of the initial investment (essentially the planned replacement costs). Conversely, for example, when the replacement of the asset can be performed as part of other work being conducted, then the replacement cost can be lower than the initial cost.

Age	**Initial Investment**	**Annual Maintenance**	**Replacement Cost**[43]	**Failure Probability** (Replacement)	**Total Cost** (Cumulative)	**Total Cost of Ownership** (Cumulative Cost/Age[44])
0	$10,000		$10,000			
1		$200		1%	$10,300	$10,300
2		$200		3%	$10,800	$5,400
3		$200		5%	$11,500	$3,833

e) Please see part (b), above.

f) Please see Avista's response to PC-DR-295 part (a), where we provide a very detailed explanation with examples, images and the formula explaining how such "operation and failure in service" costs, which are also "risk costs," "effects costs" and "consequence costs," are calculated in the Availability Workbench model and included in the Total Cost of Ownership.

[43] As noted in the narrative, the magnitude of the replacement cost will vary with the magnitude of the risk costs (emergency vs. planned replacement), the manner of replacement (whether the replacement is performed in combination with other work already being done), among other factors.
[44] For example, year 3 Cumulative Cost/Age is $4,000. This is based on prior year Total Cost, ($10,800 + $200 (Annual Maintenance) + $500 (5% failure * $10,000, replacement cost)) / Age, 3 years. (10,800+200+500)/3 = $3,833. As year 3 has a lower Cumulative Cost/Age, you would not consider replacing asset before year 3.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	04/28/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 323	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Lifecycle Cost Modeling

REQUEST:

Please refer to the first chart provided in the response to Public Counsel Data Request No. 307(a), and specifically the charts presenting the total cost of ownership curves. Select any substation power transformer Avista has recently replaced. Provide, for that particular substation power transformer selected:

a) The actual total cost of ownership curve for that substation power transformer.
b) The actual inputs used to develop the total cost of ownership curve for that power transformer provided in response to subpart (a), including (i) "initial investment"; (ii) "maintenance" costs; (iii) "replacement" costs; and (iv) "operation and failure in service" costs, including all components (outage risk, safety risk; environmental risk; and "others").
c) The actual formulas, with calculations, which translate the inputs into the values represented in the total cost of ownership curve for that power transformer.
d) Provide any and all Weibull curves that were used to develop the equipment failure rates used in the development of that power transformer's total cost of ownership curve. Please do not provide unavailability curves or outage data, only failure rate data that shows failure relative to the age of the equipment. Further, in any Weibull curves provided, please ensure the horizontal axis is denominated in years.
e) For any and all Weibull curves provided in response to subpart (c), provide the historical actual data for asset type "power transformers" used to develop those Weibull curves.
f) Provide any and all actual historical data used to justify any inputs into the total cost of ownership curve for power transformers, including (i) "initial investment"; (ii) "maintenance" costs; (iii) "replacement" costs; and (iv) "operation and failure in service" costs, including all components (outage risk, safety risk; environmental risk; and "others").

RESPONSE:

A Total Cost of Ownership curve does not exist for a single piece of equipment, because both the Weibull failure curve and the accompanying lifecycle cost curve (which together comprise the Total Cost of Ownership) are defined by the performance of a "population of individual assets of a given type," such as substation power transformers. An example of these individual data points in a Weibull failure curve for power transformers is shown on page 10 (right hand side) of Exh. PADS-19, provided in support of Exh. PADS-1T. Accordingly, one transformer represents only a data point in the Total Cost of Ownership curve for power transformers.

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RESPONSE TO REQUEST FOR INFORMATION

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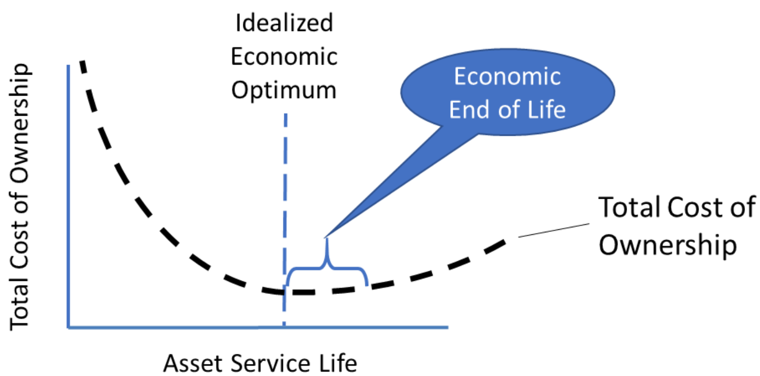
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 324	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Lifecycle Cost Modeling

REQUEST:
Please refer again to the Company's response to Public Counsel Data Request No. 307(a), which states "**Economic Optimum** is the idealized point of the lowest total cost of ownership for an asset. Total cost of ownership includes the initial investment, maintenance and replacement costs, as well as risk costs associated with operation and failure in service (e.g. outage risk, safety risk, environmental risk, among others)." Please refer also to the charts with the total cost of ownership curves presented in response to PC-DR-307 (a). Presumably, the total cost of ownership for a new asset is represented by the upper left part of the green line. If the total cost of ownership curve includes all costs and risks, as described in the statement referenced, explain why the "Economic Optimum" time of replacement would be anything other than the point at which the upper right point of the curve reaches as high up on the vertical axis as the upper left point of the curve.

RESPONSE:
In the illustrative examples provided in response to PC-DR-307, the descending limb of the curve in each example, represented by the color green, includes, as explained in PC-DR-322, the initial cost of the asset, any inspection or maintenance costs, risk costs, and the replacement cost for each year of service during the period of time where the ultimate cost customers are paying for the asset is declining. For the illustration that shows the Economic Optimum as the end of life for the asset (failure in service), the total cost customers pay for the asset continues to decline until the point at which the equipment fails. In the two other illustrations, which represent an Economic Optimum replacement period prior to a failure in service, the red or orange ascending limb of the curve includes the identical cost components, as explained in PC-DR-322, as those in the descending green line, however, that limb shows the Total Cost of Ownership increasing as a result of increasing inspection, maintenance, repair and risk costs associated with keeping the asset in service past its economic optimum. The green and red colors in the illustrations are simply intended to represent when the Total Cost to customers is decreasing (green) and when the Total Cost to customers is increasing (red), however, both colors are part of the single Total Cost of Ownership curve, represented by the dashed line in the illustration below.



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RESPONSE TO REQUEST FOR INFORMATION

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REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 325	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Lifecycle Cost Modeling

REQUEST:

Please refer to the Company's response to Public Counsel Data Request No. 308(b), which states "focusing on each piece of equipment in isolation can distort the understanding of how this equipment ought to be prudently managed. In Avista's experience, and in its analysis of substation equipment, and entire substations, and even groups of substations, the Company has determined that it is not in our customers' best financial interest to manage, maintain and replace individual pieces of substation equipment based only on the economic optima for every piece of equipment."

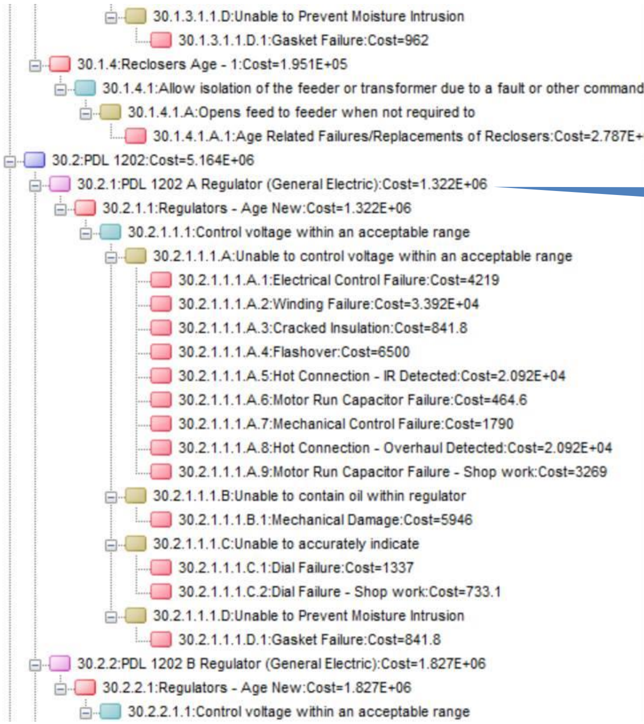
a) Provide example calculations which indicate that "it is not in our customers' best financial interest to manage, maintain and replace individual pieces of substation equipment based only on the economic optimum for every piece of equipment".

b) Provide example calculations which indicates that it is more costly for customers to maintain a piece of equipment than it is to replace it.

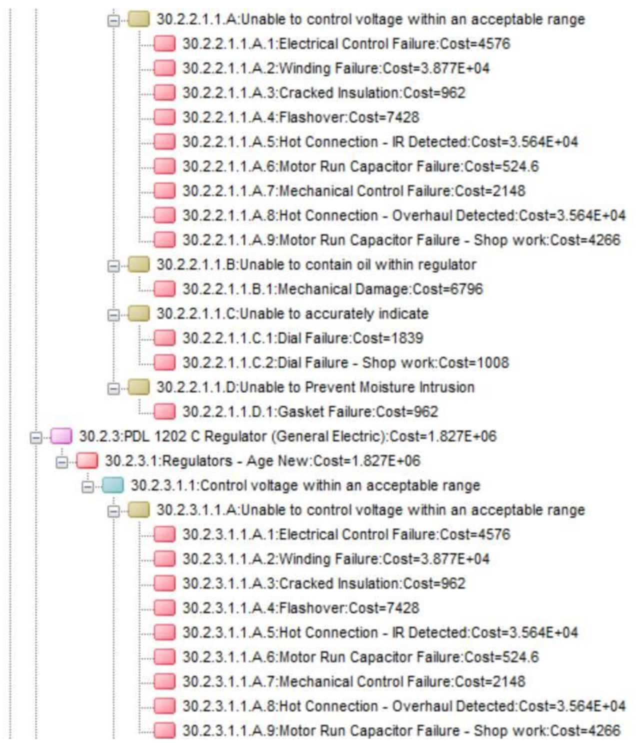
RESPONSE:

a) In the subject example provided by Avista, derived from the failure characteristics of the listed transformer components, and combined with the initial installation, maintenance, replacement and lifecycle risk costs, the model selected an optimized group of maintenance activities and produced results for the optimized lowest lifecycle cost, including a bimodal Economic End of Life. These results reflect the integrated analysis of components with different failure characteristics, expected service lives, differing times of installation, and differing maintenance and risk costs associated with maintenance and failure. In this analysis, the model evaluates the alternative of maintaining, refurbishing or replacing each component at the point in time of its unique lowest lifecycle cost. If that alternative had produced the lowest integrated lifecycle cost, then the model would have selected that alternative instead of the solution recommended.

   Following, are some illustrations we believe are helpful for understanding some of the detail included in the Availability Workbench model used to derive the example solutions discussed above. Below, is a model directory for a portion of the equipment in one substation on our system, Pound Lane.



Regulator, Phase A, Feeder 1202



The numerical designation, 30, identifies the Pound Lane Substation in the Availability Workbench model. Further drop downs, 30.2.1, 30.2.2, and 30.2.3, represent the three regulators (on Feeder 1202) at Pound Lane (phases A, B, C). From this breakout, different failure modes represented (in gold). 30.2.1.1.1.A, for example, cites the inability to control voltage in an acceptable range. The resulting 9 drop down items (in red) look at the possible causes for that failure mode. These failure modes are repeated for like assets (e.g. regulators B, C). 30.2.2.1.1.A, for instance, is the same failure mode, but represents Regulator B (on feeder 1202). Differences in costs shown in the model for the failure modes (e.g. Flashover Cost is higher for B than it is for A, 7428 v. 6500) is a function in this case of the different ages of each component. Assuming long-term wear out, an older component carries a higher risk cost than a newer asset (due to higher failure probabilities associated with the older asset). Each failure mode (red) can have its own Weibull Curve, and therefore unique failure probability, associated with that asset.

- 30.2.3.1.1.B:Unable to contain oil within regulator
  - 30.2.3.1.1.B.1:Mechanical Damage:Cost=6796
- 30.2.3.1.1.C:Unable to accurately indicate
  - 30.2.3.1.1.C.1:Dial Failure:Cost=1839
  - 30.2.3.1.1.C.2:Dial Failure - Shop work:Cost=1008
- 30.2.3.1.1.D:Unable to Prevent Moisture Intrusion
  - 30.2.3.1.1.D.1:Gasket Failure:Cost=962
- 30.2.4:Reclosers Age - 1:Cost=1.874E+05
  - 30.2.4.1:Allow isolation of the feeder or transformer due to a fault or other command
    - 30.2.4.1.A:Opens feed to feeder when not required to
      - 30.2.4.1.A.1:Age Related Failures/Replacements of Reclosers:Cost=2.677E+
- 30.3:PDL 1203:Cost=5.634E+06
  - 30.3.1:PDL 1203 A Regulator (General Electric):Cost=1.827E+06
    - 30.3.1.1:Regulators - Age New:Cost=1.827E+06
      - 30.3.1.1.1:Control voltage within an acceptable range
        - 30.3.1.1.1.A:Unable to control voltage within an acceptable range
          - 30.3.1.1.1.A.1:Electrical Control Failure:Cost=4576
          - 30.3.1.1.1.A.2:Winding Failure:Cost=3.877E+04
          - 30.3.1.1.1.A.3:Cracked Insulation:Cost=962
          - 30.3.1.1.1.A.4:Flashover:Cost=7428
          - 30.3.1.1.1.A.5:Hot Connection - IR Detected:Cost=3.564E+04
          - 30.3.1.1.1.A.6:Motor Run Capacitor Failure:Cost=524.6
          - 30.3.1.1.1.A.7:Mechanical Control Failure:Cost=2148
          - 30.3.1.1.1.A.8:Hot Connection - Overhaul Detected:Cost=3.564E+04
          - 30.3.1.1.1.A.9:Motor Run Capacitor Failure - Shop work:Cost=4266
        - 30.3.1.1.1.B:Unable to contain oil within regulator
          - 30.3.1.1.1.B.1:Mechanical Damage:Cost=6796
        - 30.3.1.1.1.C:Unable to accurately indicate
          - 30.3.1.1.1.C.1:Dial Failure:Cost=1839
          - 30.3.1.1.1.C.2:Dial Failure - Shop work:Cost=1008

Regulator, Phase A, Feeder 1203

Similar to the notes above, for feeder 1202, this illustration shows regulators A, B, and C for feeder 1203 (Pound Lane Substation). While the information listed here is similar to that shown for 1202, the model recognizes the assets as being separate, unique, and specific to a location. The following page shows a similar regulator listing for feeder 1204.

- 30.3.1.1.1.D:Unable to Prevent Moisture Intrusion
  - 30.3.1.1.1.D.1:Gasket Failure:Cost=962
- 30.3.2:PDL 1203 B Regulator (General Electric):Cost=1.785E+06
  - 30.3.2.1:Regulators - Age New:Cost=1.785E+06
    - 30.3.2.1.1:Control voltage within an acceptable range
      - 30.3.2.1.1.A:Unable to control voltage within an acceptable range
        - 30.3.2.1.1.A.1:Electrical Control Failure:Cost=4505
        - 30.3.2.1.1.A.2:Winding Failure:Cost=3.877E+04
        - 30.3.2.1.1.A.3:Cracked Insulation:Cost=962
        - 30.3.2.1.1.A.4:Flashover:Cost=7428
        - 30.3.2.1.1.A.5:Hot Connection - IR Detected:Cost=3.409E+04
        - 30.3.2.1.1.A.6:Motor Run Capacitor Failure:Cost=514.6
        - 30.3.2.1.1.A.7:Mechanical Control Failure:Cost=1926
        - 30.3.2.1.1.A.8:Hot Connection - Overhaul Detected:Cost=3.409E+04
        - 30.3.2.1.1.A.9:Motor Run Capacitor Failure - Shop work:Cost=4381
      - 30.3.2.1.1.B:Unable to contain oil within regulator
        - 30.3.2.1.1.B.1:Mechanical Damage:Cost=6796
      - 30.3.2.1.1.C:Unable to accurately indicate
        - 30.3.2.1.1.C.1:Dial Failure:Cost=1839
        - 30.3.2.1.1.C.2:Dial Failure - Shop work:Cost=1008
      - 30.3.2.1.1.D:Unable to Prevent Moisture Intrusion
        - 30.3.2.1.1.D.1:Gasket Failure:Cost=962
- 30.3.3:PDL 1203 C Regulator (General Electric):Cost=1.827E+06
  - 30.3.3.1:Regulators - Age New:Cost=1.827E+06
    - 30.3.3.1.1:Control voltage within an acceptable range
      - 30.3.3.1.1.A:Unable to control voltage within an acceptable range
        - 30.3.3.1.1.A.1:Electrical Control Failure:Cost=4576
        - 30.3.3.1.1.A.2:Winding Failure:Cost=3.877E+04
        - 30.3.3.1.1.A.3:Cracked Insulation:Cost=962
        - 30.3.3.1.1.A.4:Flashover:Cost=7428

- 30.3.1.1.1.D:Unable to Prevent Moisture Intrusion
  - 30.3.1.1.1.D.1:Gasket Failure:Cost=962
- 30.3.2:PDL 1203 B Regulator (General Electric):Cost=1.785E+06
  - 30.3.2.1:Regulators - Age New:Cost=1.785E+06
    - 30.3.2.1.1:Control voltage within an acceptable range
      - 30.3.2.1.1.A:Unable to control voltage within an acceptable range
        - 30.3.2.1.1.A.1:Electrical Control Failure:Cost=4505
        - 30.3.2.1.1.A.2:Winding Failure:Cost=3.877E+04
        - 30.3.2.1.1.A.3:Cracked Insulation:Cost=962
        - 30.3.2.1.1.A.4:Flashover:Cost=7428
        - 30.3.2.1.1.A.5:Hot Connection - IR Detected:Cost=3.409E+04
        - 30.3.2.1.1.A.6:Motor Run Capacitor Failure:Cost=514.6
        - 30.3.2.1.1.A.7:Mechanical Control Failure:Cost=1926
        - 30.3.2.1.1.A.8:Hot Connection - Overhaul Detected:Cost=3.409E+04
        - 30.3.2.1.1.A.9:Motor Run Capacitor Failure - Shop work:Cost=4381
      - 30.3.2.1.1.B:Unable to contain oil within regulator
        - 30.3.2.1.1.B.1:Mechanical Damage:Cost=6796
      - 30.3.2.1.1.C:Unable to accurately indicate
        - 30.3.2.1.1.C.1:Dial Failure:Cost=1839
        - 30.3.2.1.1.C.2:Dial Failure - Shop work:Cost=1008
      - 30.3.2.1.1.D:Unable to Prevent Moisture Intrusion
        - 30.3.2.1.1.D.1:Gasket Failure:Cost=962
- 30.3.3:PDL 1203 C Regulator (General Electric):Cost=1.827E+06
  - 30.3.3.1:Regulators - Age New:Cost=1.827E+06
    - 30.3.3.1.1:Control voltage within an acceptable range
      - 30.3.3.1.1.A:Unable to control voltage within an acceptable range
        - 30.3.3.1.1.A.1:Electrical Control Failure:Cost=4576
        - 30.3.3.1.1.A.2:Winding Failure:Cost=3.877E+04
        - 30.3.3.1.1.A.3:Cracked Insulation:Cost=962
        - 30.3.3.1.1.A.4:Flashover:Cost=7428

- 30.4.1.1.1.B:Unable to contain oil within regulator
  - 30.4.1.1.1.B.1:Mechanical Damage:Cost=6796
- 30.4.1.1.1.C:Unable to accurately indicate
  - 30.4.1.1.1.C.1:Dial Failure:Cost=1839
  - 30.4.1.1.1.C.2:Dial Failure - Shop work:Cost=1008
- 30.4.1.1.1.D:Unable to Prevent Moisture Intrusion
  - 30.4.1.1.1.D.1:Gasket Failure:Cost=962
- 30.4.2:PDL 1204 B Regulator (General Electric):Cost=1.74E+06

  Regulator, Phase B, Feeder 1204
  - 30.4.2.1:Regulators - Age New:Cost=1.74E+06
    - 30.4.2.1.1:Control voltage within an acceptable range
      - 30.4.2.1.1.A:Unable to control voltage within an acceptable range
        - 30.4.2.1.1.A.1:Electrical Control Failure:Cost=4362
        - 30.4.2.1.1.A.2:Winding Failure:Cost=3.716E+04
        - 30.4.2.1.1.A.3:Cracked Insulation:Cost=921.9
        - 30.4.2.1.1.A.4:Flashover:Cost=7119
        - 30.4.2.1.1.A.5:Hot Connection - IR Detected:Cost=3.409E+04
        - 30.4.2.1.1.A.6:Motor Run Capacitor Failure:Cost=489.6
        - 30.4.2.1.1.A.7:Mechanical Control Failure:Cost=1812
        - 30.4.2.1.1.A.8:Hot Connection - Overhaul Detected:Cost=3.409E+04
        - 30.4.2.1.1.A.9:Motor Run Capacitor Failure - Shop work:Cost=3720
      - 30.4.2.1.1.B:Unable to contain oil within regulator
        - 30.4.2.1.1.B.1:Mechanical Damage:Cost=6513
      - 30.4.2.1.1.C:Unable to accurately indicate
        - 30.4.2.1.1.C.1:Dial Failure:Cost=1713
        - 30.4.2.1.1.C.2:Dial Failure - Shop work:Cost=939.3
      - 30.4.2.1.1.D:Unable to Prevent Moisture Intrusion
        - 30.4.2.1.1.D.1:Gasket Failure:Cost=921.9
- 30.4.3:PDL 1204 C Regulator (General Electric):Cost=1.827E+06
  - 30.4.3.1:Regulators - Age New:Cost=1.827E+06
    - 30.4.3.1.1:Control voltage within an acceptable range

30.4.3.1.1.A:Unable to control voltage within an acceptable range
30.4.3.1.1.A.1:Electrical Control Failure:Cost=4576
30.4.3.1.1.A.2:Winding Failure:Cost=3.877E+04
30.4.3.1.1.A.3:Cracked Insulation:Cost=962
30.4.3.1.1.A.4:Flashover:Cost=7428
30.4.3.1.1.A.5:Hot Connection - IR Detected:Cost=3.564E+04
30.4.3.1.1.A.6:Motor Run Capacitor Failure:Cost=524.6
30.4.3.1.1.A.7:Mechanical Control Failure:Cost=2148
30.4.3.1.1.A.8:Hot Connection - Overhaul Detected:Cost=3.564E+04
30.4.3.1.1.A.9:Motor Run Capacitor Failure - Shop work:Cost=4266
30.4.3.1.1.B:Unable to contain oil within regulator
30.4.3.1.1.B.1:Mechanical Damage:Cost=6796
30.4.3.1.1.C:Unable to accurately indicate
30.4.3.1.1.C.1:Dial Failure:Cost=1839
30.4.3.1.1.C.2:Dial Failure - Shop work:Cost=1008
30.4.3.1.1.D:Unable to Prevent Moisture Intrusion
30.4.3.1.1.D.1:Gasket Failure:Cost=962
30.4.4:Reclosers Age - 1:Cost=1.874E+05
30.4.4.1:Allow isolation of the feeder or transformer due to a fault or other command
30.4.4.1.A:Opens feed to feeder when not required to
30.4.4.1.A.1:Age Related Failures/Replacements of Reclosers:Cost=2.677E+
30.5:EM DISTR LINE, UND 5 YRS:Cost=4.636E+04
30.5.1:system protection
30.5.1.A:Partial failure, found thru maintenance
30.5.1.A.1:EM adjustment, out of calibration:Cost=938.2
30.5.1.A.2:EM internal component failure, replace component:Cost=77.14
30.5.1.B:Total failure, multiple components, found thru maintenance
30.5.1.B.1:EM unrepairable, age/unavailability:Cost=6034
30.5.1.C:Relay fails to operate
30.5.1.C.1:relay fails to operate, backup protection operates:Cost=2690
30.5.1.D:Relay misoperates
30.5.1.D.1:relay misoperates, unnecessary outage.:Cost=1851
30.6:EM DISTR XFMR, 10-15 YRS:Cost=4.181E+04
30.6.1:system protection
30.6.1.A:Partial failure, found thru maintenance
30.6.1.A.1:EM adjustment, out of calibration:Cost=79.48
30.6.1.A.2:EM internal component failure, replace component:Cost=146.1
30.6.1.B:Total failure, multiple components, found thru maintenance
30.6.1.B.1:EM unrepairable, age/unavailability:Cost=1.828E+04
30.6.1.C:Relay fails to operate
30.6.1.C.1:relay fails to operate, backup protection operates:Cost=1203
30.6.1.D:Relay misoperates
30.6.1.D.1:relay misoperates, unnecessary outage.:Cost=1192
30.7:EM 115KV LINE, 5-10 YRS:Cost=1.534E+05
30.7.1:system protection
30.7.1.A:Partial failure, found thru maintenance
30.7.1.A.1:EM adjustment, out of calibration:Cost=1569
30.7.1.A.2:EM internal component failure, replace component:Cost=99.48
30.7.1.B:Total failure, multiple components, found thru maintenance
30.7.1.B.1:EM unrepairable, age/unavailability:Cost=7.347E+04
30.7.1.C:Relay fails to operate
30.7.1.C.1:relay fails to operate, backup protection operates:Cost=1528
30.7.1.D:Relay misoperates
30.7.1.D.1:relay misoperates, unnecessary outage.:Cost=49.13
30.8:PDL - Pound Lane 115kV:Cost=8.457E+06
30.8.1:Transformer #1 System:Cost=2.82E+06
30.8.1.1:PDL - Transformer #1:Cost=2.305E+05
30.8.1.1.1:Change Voltage levels from Transmission voltages to Distribution Volt
30.8.1.1.1.A:Fails to conduct power
30.8.1.1.1.A.1:Age:Cost=1.515E+05

Pound Lane Substation Transformers #1 and #2 are shown in this portion of the directory. The Availability Workbench model directory is similar in appearance to that shown above for regulators, however, the transformers include different purpose statements and have unique characteristics for the equipment type ages, failure modes and costs.

Pound Lane Transformer #1

Bushings – Insulation Deterioration

Deteriorated Gasket

- 30.8.1.1.1.A.2:Oil Degradation:Cost=6.708E+04
- 30.8.1.1.1.A.3:Internal component failure:Cost=340.7
- 30.8.1.1.2:Remove heat to maintain transformer rating
  - 30.8.1.1.2.A:Fails to remove heat
    - 30.8.1.1.2.A.1:Transformer Cooling System Failure:Cost=1.159E+04
- 30.8.1.2:Support Equipment:Cost=2.59E+06
  - 30.8.1.2.1:High and Low Voltage Bushings:Cost=6.541E+05
    - 30.8.1.2.1.1:Insulating case for external connections to internal windings
      - 30.8.1.2.1.1.A:Out of Specification measurements
        - 30.8.1.2.1.1.A.1:Insulation deterioration:Cost=9.344E+04
  - 30.8.1.2.2:Power Transformer Gages:Cost=1.935E+06
    - 30.8.1.2.2.1:Provide local indication of measure parameter
      - 30.8.1.2.2.1.A:Fail to indicate properly
        - 30.8.1.2.2.1.A.1:Gage is broken or damaged:Cost=3.225E+05
      - 30.8.1.2.2.1.B:Indication out of calibration
        - 30.8.1.2.2.1.B.1:Gage calibration drift:Cost=0
  - 30.8.1.2.3:Various Gaskets:Cost=0
    - 30.8.1.2.3.1:Provide a seal at connections
      - 30.8.1.2.3.1.A:Develops a leak
        - 30.8.1.2.3.1.A.1:Deteriorated Gasket - Age related:Cost=0
  - 30.8.1.2.4:Cooling Fan:Cost=157.3
    - 30.8.1.2.4.1:Force cooling air across cooling fins for forced air cooling
      - 30.8.1.2.4.1.A:Fails to drive air across cooling fins
        - 30.8.1.2.4.1.A.1:Motor Failure:Cost=26.22
  - 30.8.1.2.5:Lightning Arresters:Cost=341.1
    - 30.8.1.2.5.1:Supress Over-Voltage spikes
      - 30.8.1.2.5.1.A:Fails to suppress voltage spike
        - 30.8.1.2.5.1.A.1:Lightning Arrester Failure:Cost=341.1
- 30.8.2:Transformer #2 System:Cost=5.637E+06
  - 30.8.2.1:PDL - Transformer #2:Cost=2.576E+05
    - 30.8.2.1.1:Change Voltage levels from Transmission voltages to Distribution Volt
      - 30.8.2.1.1.A:Fails to conduct power
        - 30.8.2.1.1.A.1:Age:Cost=1.502E+05
        - 30.8.2.1.1.A.2:Oil Degradation:Cost=6.873E+04
        - 30.8.2.1.1.A.3:Internal component failure:Cost=2.706E+04
    - 30.8.2.1.2:Remove heat to maintain transformer rating
      - 30.8.2.1.2.A:Fails to remove heat
        - 30.8.2.1.2.A.1:Transformer Cooling System Failure:Cost=1.159E+04
  - 30.8.2.2:Support Equipment:Cost=5.379E+06
    - 30.8.2.2.1:High and Low Voltage Bushings:Cost=5.121E+05
      - 30.8.2.2.1.1:Insulating case for external connections to internal windings
        - 30.8.2.2.1.1.A:Out of Specification measurements
          - 30.8.2.2.1.1.A.1:Insulation deterioration:Cost=7.315E+04
    - 30.8.2.2.2:Power Transformer Gages:Cost=4.856E+06
      - 30.8.2.2.2.1:Provide local indication of measure parameter
        - 30.8.2.2.2.1.A:Fail to indicate properly
          - 30.8.2.2.2.1.A.1:Gage is broken or damaged:Cost=7.936E+05
        - 30.8.2.2.2.1.B:Indication out of calibration
          - 30.8.2.2.2.1.B.1:Gage calibration drift:Cost=1.579E+04
    - 30.8.2.2.3:Various Gaskets:Cost=1.055E+04
      - 30.8.2.2.3.1:Provide a seal at connections
        - 30.8.2.2.3.1.A:Develops a leak
          - 30.8.2.2.3.1.A.1:Deteriorated Gasket - Age related:Cost=1.055E+04
    - 30.8.2.2.4:Cooling Fan:Cost=348.2
      - 30.8.2.2.4.1:Force cooling air across cooling fins for forced air cooling
        - 30.8.2.2.4.1.A:Fails to drive air across cooling fins
          - 30.8.2.2.4.1.A.1:Motor Failure:Cost=58.04
    - 30.8.2.2.5:Lightning Arresters:Cost=341.1
      - 30.8.2.2.5.1:Supress Over-Voltage spikes
        - 30.8.2.2.5.1.A:Fails to suppress voltage spike
          - 30.8.2.2.5.1.A.1:Lightning Arrester Failure:Cost=341.1

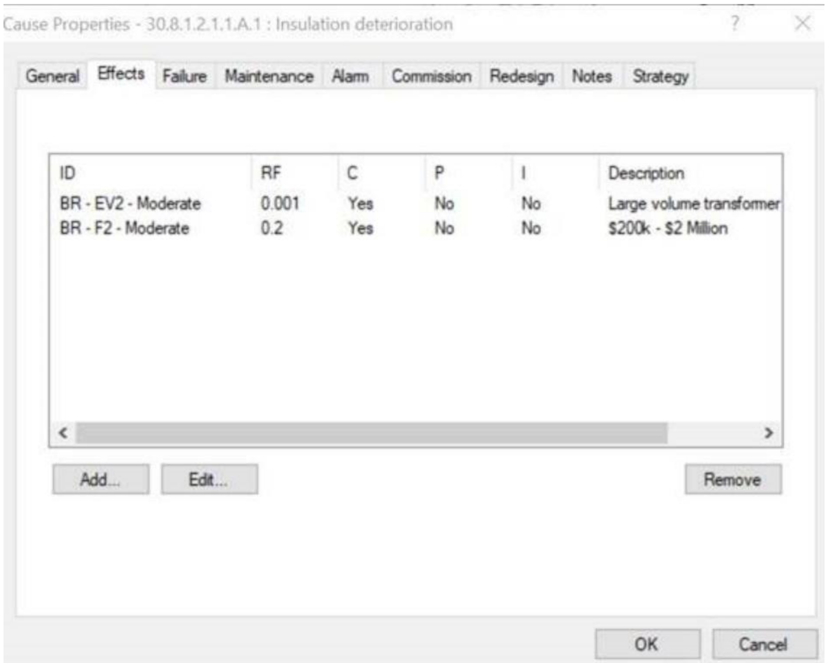
The image below shows the list of planned activities performed on equipment at the substation. 30.8.1 identifies Transformer #1 while Transformer #2 is 30.8.2 (Pound Lane Substation). Descriptions like 'Rewind' are listed in duplicate because those items are specific to each of the two transformers.

Cause	Task ID	Type	Enabled	Description	Interval	Fixed maintenance interval	Interval offset	Task duration	Std duratio
30.8.1.1.1.A.1	PM171	Planned	☐	Rewind (capital funding)	8760	☐	0	0	0
30.8.1.1.1.A.2	PM166	Planned	☐	Process existing oil (not new ...	8760	☐	0	168	0
30.8.1.1.2.A.1	PM158	Planned	☐	Replace Cooling Pump	8760	☐	[illegible]	[illegible]	[illegible]
30.8.1.2.1.1.A.1	PM159	Planned	☐	Replace Bushing	8760	☐	0	96	0
30.8.1.2.2.1.A.1	PM162	Planned	☐	Repair or replace gage	8760	☐	0	0	0
30.8.1.2.2.1.B.1	PM160	Planned	☐	Calibrate Gage	8760	☐	0	0	0
30.8.1.2.3.1.A.1	PM161	Planned	☐	Planned Re-gasket	8760	☐	0	216	0
30.8.1.2.4.1.A.1	PM163	Planned	☐	Replace Fan motor and Fan	8760	☐	0	2	0
30.8.1.2.5.1.A.1	PM165	Planned	☐	Replace Lightning Arrester S...	8760	☐	0	8	0
30.8.2.1.1.A.1	PM171	Planned	☐	Rewind (capital funding)	8760	☐	0	0	0
30.8.2.1.1.A.2	PM166	Planned	☐	Process existing oil (not new ...	8760	☐	0	168	0
30.8.2.1.2.A.1	PM158	Planned	☐	Replace Cooling Pump	8760	☐	[illegible]	[illegible]	[illegible]
30.8.2.2.1.1.A.1	PM159	Planned	☐	Replace Bushing	8760	☐	0	96	0
30.8.2.2.2.1.A.1	PM162	Planned	☐	Repair or replace gage	8760	☐	0	0	0
30.8.2.2.2.1.B.1	PM160	Planned	☐	Calibrate Gage	8760	☐	0	0	0
30.8.2.2.3.1.A.1	PM161	Planned	☐	Planned Re-gasket	8760	☐	0	216	0
30.8.2.2.4.1.A.1	PM163	Planned	☐	Replace Fan motor and Fan	8760	☐	0	2	0
30.8.2.2.5.1.A.1	PM165	Planned	☐	Replace Lightning Arrester S...	8760	☐	0	8	0

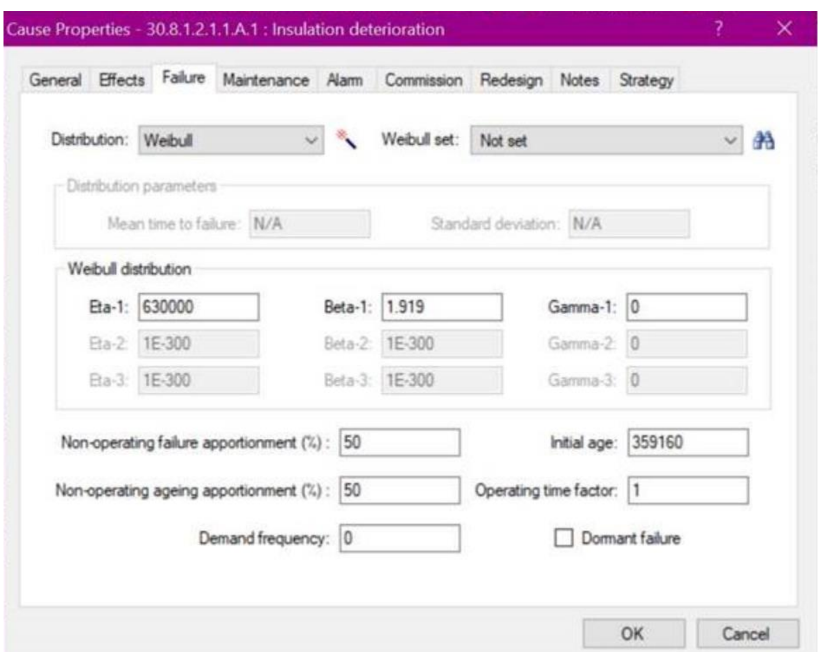
Bushings, Transformer #1

Re-Gasket, Transformer #2

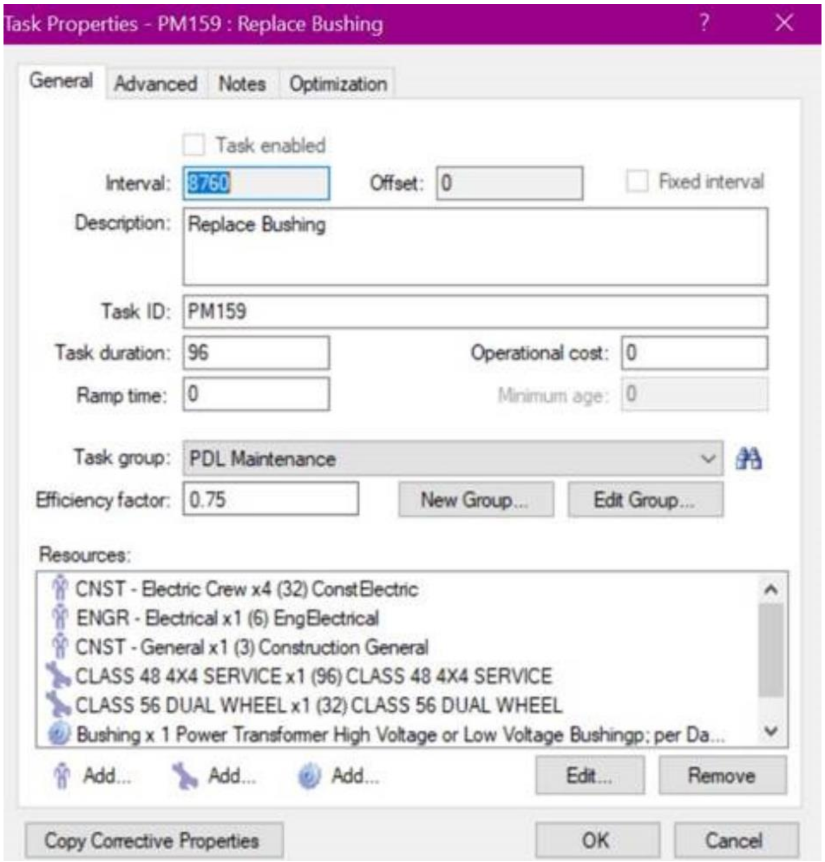
The image below from the Availability Workbench model shows inputs for calculation of effects costs (in this case, for bushings). The effects assume a failure mode and then calculate the expected consequences associated with that unique failure mode. An EV2 – Moderate is an Environmental Event is expected to occur one time in every 1000 failures (RF = Redundancy Factor, or likelihood of occurrence). An F2 is a Moderate financial event likely to occur one time in every five failure events. Therefore, its cost is the Probability of Failure (identified by the unique failure characteristics represented in the Weibull Curve) * RF (Redundancy Factor) * Consequence Cost. 'C, P, and I' represent corrective maintenance, planned maintenance and inspection. 'Yes' or 'No' indicates whether the event is active. In this example, the consequences from an EV2 and F2 event will only occur under corrective maintenance (for this example only). In other words, these events are possible during an unexpected failure (corrective maintenance) but unlikely to occur from planned maintenance or from an inspection.



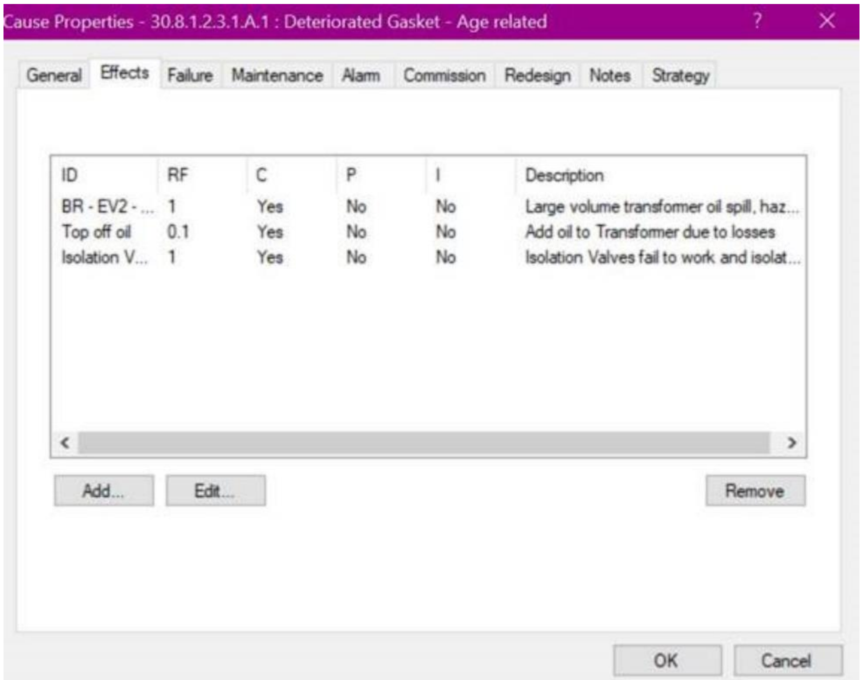
The image below shows the Weibull Distribution statistics for Bushings: Eta = 630,000 (hours). As we have noted in other similar descriptions, this value indicates that approximately 63.2% of the bushings will be unreliable (will have failed) at just under 72 years. The Beta value of 1.919, suggests long-term wear out where the Beta is essentially the slope of the failure curve. (Beta < 1, Infant Mortality, Beta = 1, Random Failure, Beta > 1, Long-term Wear Out). Initial Age is the age of the bushings (in hours). These particular bushings are 41 years old and the Availability Workbench model calculates their probability of failure, combined with inspection results, and lifecycle consequence costs to determine the optimized lowest lifecycle cost for this equipment along with the other equipment in the station.



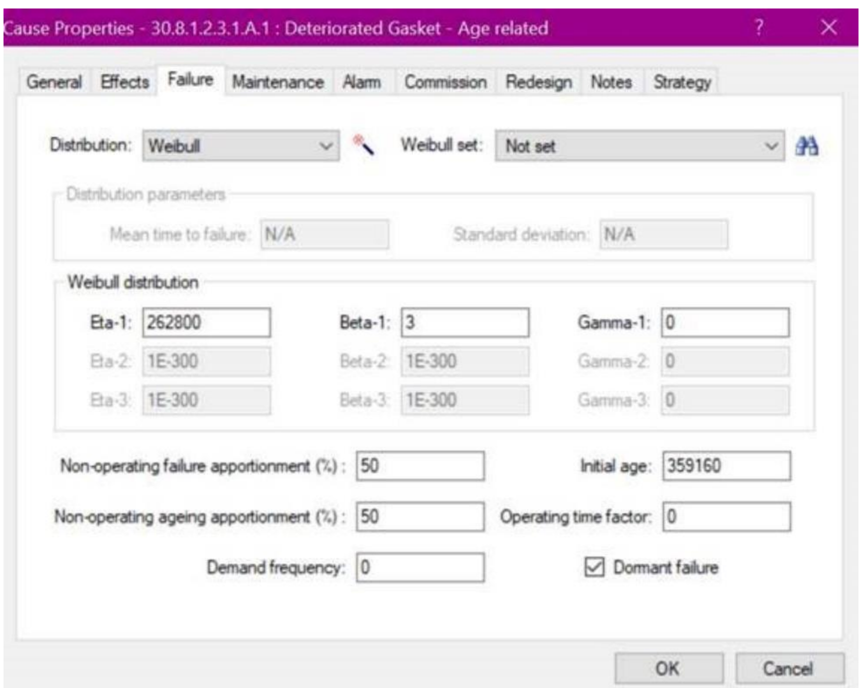
The image below includes the labor and equipment resources required to replace bushings in the instance that option is selected. The Task ID, PM 159 lists planned maintenance activities for both Transformers #1 and #2 at the Pound Lane Substation. It shows the task duration, in hours, as well as the resources needed for the job. The Efficiency Factor indicates the fractional reduction in task time applicable only when activities can be grouped. Therefore, performing this function as part of a scheduled planned maintenance cycle reduces the overall cost by 25%. When performed as stand-alone tasks, the Efficiency Factor does not apply. In this manner, the Availability Workbench model evaluates different maintenance strategies and determines whether or not it makes sense to repair or replace additional assets as part of a routine maintenance cycle.



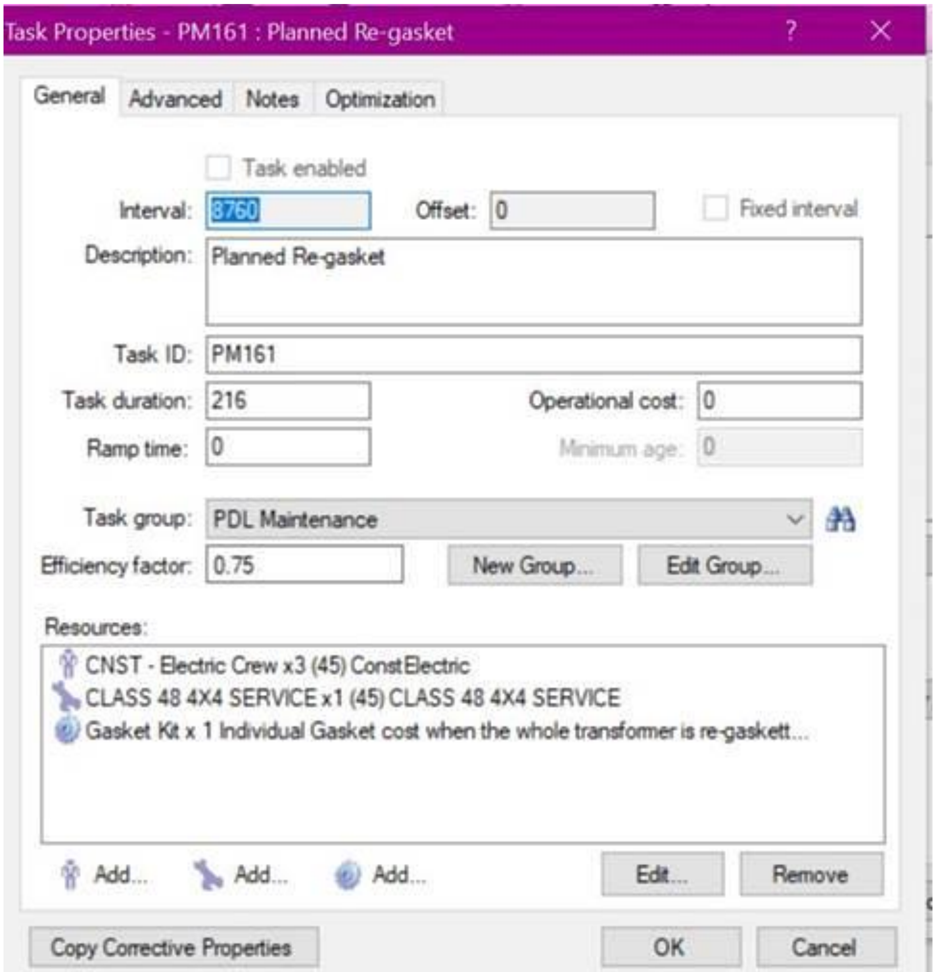
Another example, similar to the bushings discussion, above, is replacing a deteriorated gasket. The image below shows the modeling for effects calculations for a deteriorated gasket. Similar to the bushings example, this only occurs under corrective maintenance (e.g. unexpected failure) with two of the events having a redundancy factor of 1, or 100% chance of occurring with a failure.



The image below contains the Weibull Distribution statistics for a deteriorated gasket, including Eta, and Beta, which definitions are briefly described above, and the Initial Age (in hours).



The image below shows the resources required to perform the task, Planned Re-gasket. It also includes an efficiency factor which represents any possible savings in the event the Company were to make the decision to perform other activities as part of the PDL maintenance task group along with replacing the gasket.



b) The Availability Workbench model optimizes asset maintenance activities, costs and benefits along with the alternative of replacement to generally achieve the lowest reasonable lifecycle cost, as provided in the example in part (a), above.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	05/03/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Larry La Bolle
TYPE:	Data Request	DEPT:	Transm Ops/System Planning
REQUEST NO.:	PC - 328	TELEPHONE:	(509) 495-4710
		EMAIL:	larry.labolle@avistacorp.com

SUBJECT: Lifecycle Cost Modeling

REQUEST:
RE: Capital Additions, Test Year (Electric)
Please refer to the Company's response to Public Counsel (PC) Data Request No. 318(d), which states "Weibull curves, and the underlying data supporting the failure analyses, for the subject lifecycle cost modeling for the applicable subsets of the assets listed above, have been extracted from our Availability Workbench models."

a) For each subset of assets listed, identify all sources of data used to populate the "Availability Workbench models."
b) For each data source identified in response to subpart (a), identify if the data source is Avista's own experience, or from outside sources. For those data sources identified as "outside," identify and describe each source.
c) For each data source identified in response to subpart (a) which is from Avista's own experience, identify the Avista software system or processes used to supply and/or generate the data.
d) For each Avista software system or process identified in response to subpart (c), explain how the data is collected for input into each software system or process.
e) For each Avista software system or process identified in response to subpart (c), describe the process employed to extract the data for delivery to the "Availability Workbench models."

RESPONSE:

a) Avista has previously described the type of information used in such analyses, and has also included a substantial portion of the data used in the lifecycle cost modeling for these assets. The type of data we have collected is described in our response to PC-DR-296, excerpted below.

> For each (piece of equipment),[45] the data used in the modeling includes all of the inspection data and the failures identified during the inspection, supplemented with failures of known age (equipment) reported as they occur in the system. Also included is the information for each of the failures about whether or not the failed (equipment) resulted in a customer outage (including the number of customers affected in the outage, and the duration of the outage), and the remediation action that was taken in each instance, such as repairing the (piece of equipment) or replacement of (the equipment).

We also explained in response to PC-DR-228 the analysis of failure modes for actual failed equipment, including transformers and cutouts, as excerpted below.

[45] This portion of the response written for wood poles was noted by Avista in that response as being the same ('same as above') for all of the subsequent equipment described in this response, which included cutouts and transformers.

> Lineman reports of cutouts failing in service when opening or closing the device, field reports of failures of the equipment when a fuse is blown or failure in the ceramic due to freezing, neighboring utility reports of the same, industry bulletins on the same. These anecdotal reports provide the impetus for collecting field data (including asset management inspection of the actual failed cutouts) on the age at failure and the failure modes for the subject equipment.

The Company has also provided much of this actual data in response to Public Counsel's request PC-DR-229, which applicable section is excerpted below.[46]

> Please see the following files: a) outage records for cutouts provided as PC-DR-229 Attachment A; b) outage reports for transformers provided as PC-DR-229 Attachment B, and c) outage reports for crossarms, arresters, etc., provided as PC-DR-229 Attachment C. These files include all of the Company's outage reports for the subreason 'cutout/fuse,' as well as any notes in the remarks column for each report that mentions 'cutout.' The reason for this latter addition is that the need to replace a failed cutout is sometimes mentioned in the remarks section for the event, even though the outage reason and subreason may be categorized by a more predominant cause of the outage.

We have also explained how lifecycle costs are used in the models, including Avista's own costs for inspection, remediation, repair and replacement, such as illustrated in response to PC-DR-295, and PC-DR-325, as examples.

b) The data described was developed by Avista.

c) Outage data for cutouts and transformers, such as provided in response to PC-DR-229 Attachments A and B, is collected by dispatchers and automation in the ESRI application supporting the Company's Outage Management System (which was built by Avista), and is downloaded into Excel format, as provided in the subject attachments. Wood pole inspection data, which includes inspection results for all the attached equipment, including cutouts and transformers, as explained in response to PC-DR-296 and elsewhere, is collected by field inspectors in an Access Database. Failure mode analyses are typically stored in Excel files. Vegetation management data are collected in the application Field Note, used by the Company's contract inspectors. These data, which we have described and illustrated in response to numerous data requests, are loaded into the Availability Workbench application in order to perform the failure analysis and lifecycle cost modeling.

d) Please refer to part (c), above.

e) The data is made available directly from the applications described in part (c), above.

[46] With underlines added for emphasis.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	05/03/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Kyle Jonas
TYPE:	Data Request	DEPT:	Transm Ops/System Planning
REQUEST NO.:	PC - 330	TELEPHONE:	(509) 495-2695
		EMAIL:	kyle.jonas@avistacorp.com

SUBJECT: Lifecycle Cost Modeling

REQUEST:

Please refer to the Company's response to Public Counsel Data Request No. 319, which states "As such, during a feeder rebuild, a cedar pole aged 60 years or greater has been determined to have reached its economic end of life, because replacing it during the rebuild project provides customers a lower lifecycle cost for that pole compared with the alternative of sending a crew later to replace it once it has failed in service."

a) Avista is indicating that it is cost effective to replace equipment as part of a "feeder rebuild project" For each feeder rebuild project initiated by Avista in the last two years, provide all worksheets and other analysis which indicates that the reliability, energy efficiency, and O&M savings reductions from the feeder rebuild project were greater than the cost to customers of the feeder rebuild project.

b) PC understands that the cost of replacing a transformer at the same time that a pole is replaced might be less than having to return to replace the transformer at some other time. However, this does not necessarily mean that the cost reduction is sufficient to justify transformer replacement during pole replacement. i) Confirm that the cost reduction associated with replacing a transformer at the same time that a pole is replaced does not necessarily justify transformer replacement.
   ii) If this cannot be confirmed, please explain, and provide any benefit-cost analyses which indicate that the cost reduction associated with replacing a transformer at the same time a pole is replaced is large enough to justify such replacement.
   iii) If Avista believes that the cost reduction associated with replacing a transformer at the same time that a pole is replaced justifies transformer replacement, please provide all benefit-cost analyses, end of life analyses, and replacement schedules to support this conclusion.

RESPONSE:

a) The Company has previously responded to this request in various forms such as in PC-DR-222 part (d), where we explained that the individual actions (like replacing a wood pole or a transformer) have been properly evaluated in lifecycle cost analyses and have been shown to be cost effective for customers, as described briefly in the examples below.[47]

   i. Avista has documented through asset management analysis and reliability modeling that customers are better off financially if the Company replaces wood poles at the end of their useful life instead of allowing them to fail in service, as explained and supported in the Company's 2017 Wood Pole Management Program Review and Recommendations, and Wood Pole Management business case, provided as PC-DR-221 Attachments A and B, respectively.

   ii. As demonstrated above, Avista has documented that our customers are better off financially if we replace certain aging transformers during our wood pole management follow-up work

[47] This list is not intended to be comprehensive or complete in proving all of the benefits achieved through grid modernization, which more complete explanations are provided in the Company's feeder baseline reports provided in PC-DR-110 Attachments A-O.

or through grid modernization, as documented in the Avista's Transformer Changeout Program, provided in PC-DR-232 Attachment A.

iii. The Company has demonstrated that our customers are better off financially when we assess and replace undersized conductor during feeder rebuilds (in addition to the savings for upgrading appropriated transformers, noted in part (ii) above), to achieve substantial and cost effective energy conservation savings, as shown in response to PC-DR-221.

iv. In addition to these individual actions, which have been demonstrated to be cost effective for a feeder rebuild, the Grid Modernization project allows the Company to deliver many additional benefits to our customers that cannot be captured in a traditional inspection and maintenance program like wood pole management. A brief discussion of these additional areas of improvement is provided in response to PC-DR-110, and in the feeder baseline reports provided at PC-DR-110 Attachment A-O:

- ✓ Load balancing
- ✓ Removing high-loss conductors (noted above)
- ✓ Resizing trunk conductors
- ✓ Resizing lateral conductors
- ✓ Improving voltage quality
- ✓ Improve/refine voltage regulation
- ✓ Evaluate and correct power factor
- ✓ Modify existing alignment of lines to avoid outage prone areas.
- ✓ Modify existing alignment to improve access to lines during an outage event
- ✓ Reconfigure lines to create feeder ties to improve flexibility and reliability
- ✓ Bring facilities more in line with applicable standards
- ✓ Add remote operations to reduce operating costs and improve reliability

Additionally, because these actions are integrated into one overall program, we are able to perform this wide range of improvements (and many others too numerous to mention here) with fewer service outages, allowing us to minimize the impact we have on our customers. As noted above and as documented in the Company's responses to the data requests cited, including the many others not mentioned here, Avista's actions have been demonstrated to be reasonable, cost effective and in our customers' best interest. Because the cost to customers is necessary and reasonable, and because the investment allows us to meet our short and long-term service obligations to our customers, these investments are deemed to be prudent and made in the interest of our customers.

As for the analysis that proves the cost effectiveness of the feeder rebuild, Avista has provided to Public Counsel in response to PC-DR-121 working analytical models in the Company's Reliability Strategy Analysis Tool. This tool incorporates results from 47 different lifecycle models used to identify optimized solutions among the programs evaluated, which include the wood poles and attached equipment, transformers, and vegetation management strategies discussed above in parts (a)(i)(ii). The reliability strategy analysis model generates forecasts of capital and O&M spending related to different strategies for these programs and reports the customer internal rates of return on the investment for different strategies. The tool was used to demonstrate to Public Counsel in response to PC-DR-118 (which portion is excerpted below), the analytical and financial cost effectiveness of these programs for our customers.

Subject request in PC-DR-118…………………

> Provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, or other documentation which indicates that Avista's Distribution Grid Modernization program is more cost effective in dollars to rate payers than "Replacing equipment upon failure".

Avista used the reliability strategy analysis tool to analyze and forecast the ultimate cost to customers if Avista were to adopt a run-to-fail strategy for our wood pole management, transformers and vegetation management programs. In that response the Company projects it would experience a five-fold increase in outage events if it were to adopt a 'Run to Fail' strategy such as posed in subject request of "Replacing Equipment Upon Failure." This evaluation provides a reasonable response to this request because the Grid Modernization program treats all the equipment covered in the Company's Asset Maintenance programs. The increase in outage events as demonstrated in response to PC-DR-122 would result in the consequent rise in annual Risk costs to $181,521,691, which would predominantly be made up of the direct cost to customers for the roughly five-fold increase in service outages they would experience as a result of run to fail. Annual capital costs would also increase from the forecast of our current programs to an annual value in year 2030 of $19,076,602. Clearly, replacing key distribution assets at the end of their useful life, prior to their failure in service (whether performed under the Wood Pole Management, Grid Modernization, or applicable work under the Distribution Minor Rebuild programs, as examples) is more cost effective for our customers (both in the direct costs they would experience in addition to the increased costs they would pay in their electric rates) than allowing these assets to otherwise fail in service.

b) As a reminder, when Avista inspects and replaces a transformer as part of a systematic program like wood pole management or grid modernization, we are also inspecting and replacing as needed the cutout, lightning arrester, high and low-side connectors, grounds and wildlife guard. As we have already noted in prior requests, the analyses demonstrating this approach as prudent and in the financial interest of our customers is based on the integrated lifecycle costs for this 'assembly of equipment' and not just the transformer alone.

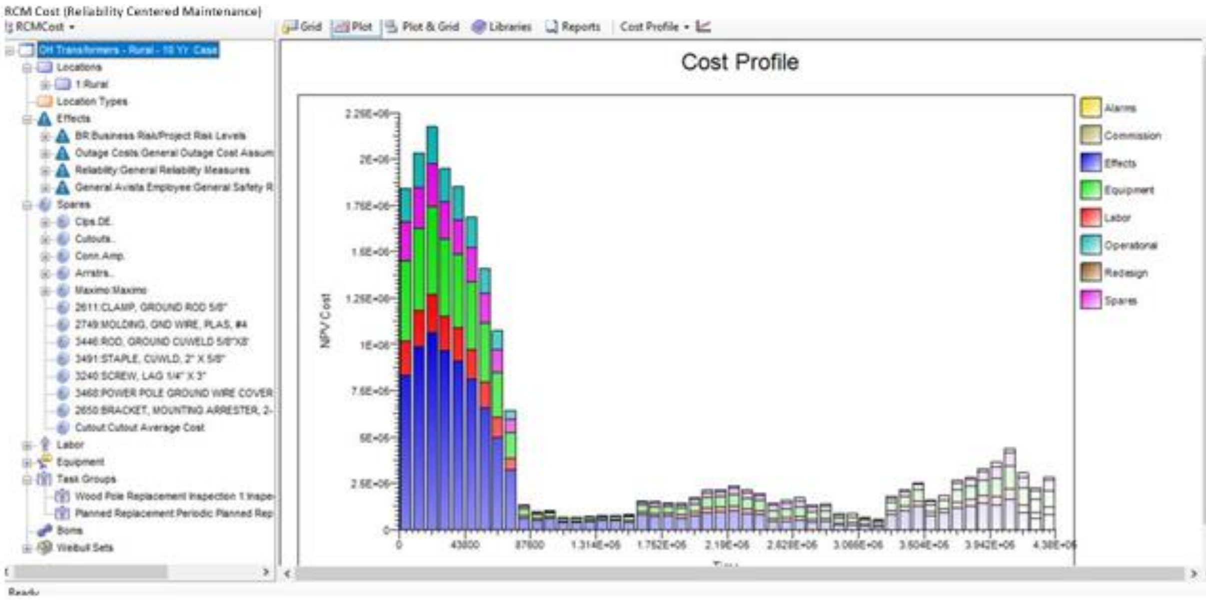
As we have noted before, these designations of run to fail or not run to fail, are not necessarily static for each asset. This is because the consequences of a failure in service for an asset may be dramatically different depending on its application and location in our system. Likewise, the costs of replacement are not static. As an example of the latter, Avista has already stated that its analyses demonstrate it would not be cost effective to send crews across our system solely to locate and replace distribution transformers based on a given age of the units. Neither have we claimed that it is cost effective for customers to replace any transformer of any age or condition just because a pole is being reinforced or replaced. But our lifecycle cost analyses, provided in response to the requests of Public Counsel, proves that it is cost effective to replace transformers based on a threshold age (or condition) of the units when a crew is already performing work on the pole where such a transformer is located. Furthermore, results of our analyses provided in response to the requests of Public Counsel, prove that replacing a transformer based on age and condition, during a systematic program like wood pole management or grid modernization, is made more financially viable because, as part of the transformer replacement, we're also inspecting and replacing as needed the cutout, lightning arrester, high and low-side connectors, grounds and wildlife guard, and capturing the energy efficiency savings provided by a new replacement transformer. The lifecycle costs analyzed in the Availability Workbench model take all of this into account in calculating the financial value associated with the transformer changeout program (avoidance of the risk costs associated with a failure in service for the transformer, cutout, arrester, high and low-side connectors, etc.; combined with the gain in energy efficiency; combined with the lower cost to install when other capital work is already being performed on that pole). As explained in response to PC-DR-295 and elsewhere, results of our lifecycle cost modeling demonstrate that replacement of a transformer and the attached equipment in the manner just described provides our customers a lower total cost of ownership, when financially compared with the alternative of allowing the transformer (and attached equipment) to later fail in service.

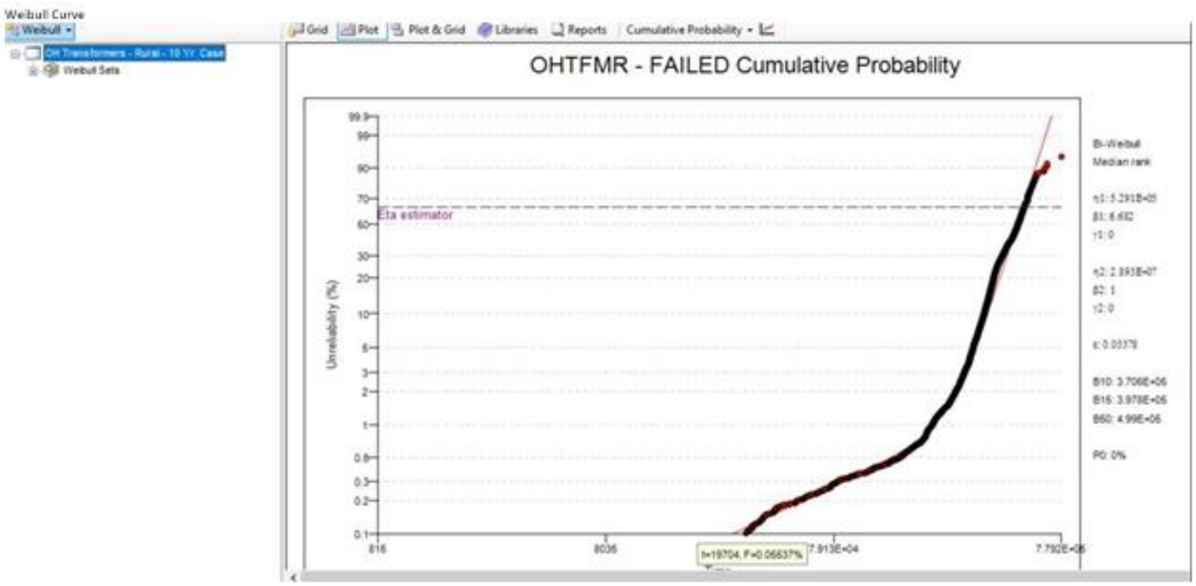
Results of the lifecycle cost modeling supporting Avista's decisions to replace end of life transformers have already been presented and discussed in detail, not the least of which is demonstrated in our response to PC-DR-121, in Attachment A, where replacement of end of life transformers is selected by the model as providing the greatest lifecycle benefit for customers when performed as part of the wood pole management program. Avista has already provided results of analyses demonstrating customers are better off financially[48] when we replace end of life transformers as part of a systematic program like wood pole management or grid modernization. In response to PC-DR-236, we provided Public Counsel examples of the Availability Workbench models we use to analyze replacement of overhead transformers. A screenshot list of the different transformer models is provided below. Each line item on the list is an individual Availability Workbench model for overhead transformers. The first one, for example, labeled 'base case' models the impact of not performing any transformer changeout work on urban feeders. The model compares this base case, which is essentially 'run to fail' with Avista's 'current case,' which represents the total and effect costs of programs as they are conducted today, under different inspection cycle intervals.

TCOP
- 2020 Urban TCOP Model - Base Case 3-16-2020
- 2020 Rural TCOP Model - 15 Year WPM Cycle Case 3-16-2020
- 2020 Rural TCOP Model - 20 Year WPM Cycle Case 3-16-2020
- 2020 Rural TCOP Model - 10 Year WPM Cycle Case 3-16-2020
- 2020 Rural TCOP Model - 5 Year WPM Cycle Case 3-16-2020
- 2020 Rural TCOP Model - Base Case 3-16-2020
- 2020 Suburban TCOP Model - 10 Year WPM Case 3-16-2020
- 2020 Suburban TCOP Model - 15 Year WPM Case 3-16-2020
- 2020 Suburban TCOP Model - 20 Year WPM Case 3-16-2020
- 2020 Suburban TCOP Model - 5 Year WPM Case 3-16-2020
- 2020 Urban TCOP Model - 5 Yr WPM Case 3-16-2020
- 2020 Urban TCOP Model - 10 Yr WPM Case 3-16-2020
- 2020 Urban TCOP Model - 15 Yr WPM Case 3-16-2020
- 2020 Urban TCOP Model - 20 Yr WPM Case 3-16-2020

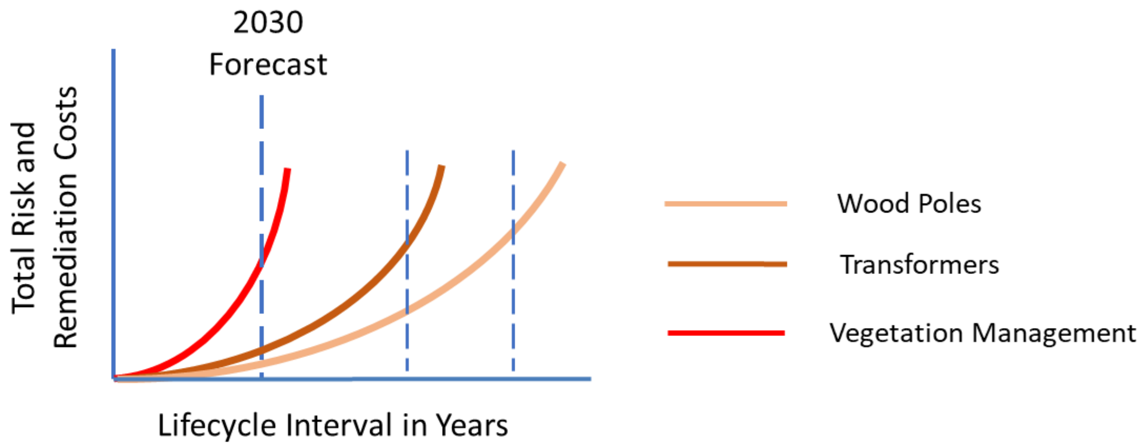
The screenshot below shows transformer lifecycle costs for rural feeders based on a 10-year inspection cycle interval. The bottom chart is the Weibull failure curve for transformers, and the cost profile represents the lifecycle Total Cost of Ownership for overhead transformers under this replacement scenario.

[48] As measured by a lower lifecycle cost of ownership, lower total risk cost, higher benefit to cost ratio, and higher risk reduction ratio, compared with replacing transformers when they would otherwise fail in service.





Results of this modeling for overhead transformers, presented in response to PC-DR-235 part (b) demonstrate from a proven financial lifecycle cost analysis the prudence of Avista's practice of selectively replacing overhead transformers of a specified age and condition. <u>Results of this analysis show that the total cost to customers (Capital, O&M and Risk Costs) associated with a run to fail strategy for overhead transformers would increase by $5,500,467 by year 2030.</u> Avista also provided a helpful illustration to help demonstrate the greater long-term impact of adopting such a run-to-fail strategy for overhead transformers, which is provided below.



The request in PC-DR-118, to compare the current program costs and benefits with the scenario of replacing equipment upon failure, and Avista's response provides incremental effects forecasted in year 2030, including an increase in 117 wood pole outages and 837 transformer outages. While this evaluation is instructive, it does not represent the full impacts and costs associated with a run to failure strategy. As noted in the illustration above, the full impacts of a sustained run to fail strategy are only evident over a longer period of time, more reflective of the life spans for transformers and wood poles. But just as important, even if the Company were to return to its current practices in year 2031, the impacts of run to fail for the prior decade would still continue to compound for transformers in the years to follow, as the maintenance not performed for a decade would show up in the years beyond 2030. So, the real measure of the impact of run to fail through year 2030, using transformers as the example, would be the incremental number of transformer failures of 837 at year 2030, plus the ensuing additional failures that would be added to the 837 as a result of end of life replacements not performed for a decade. In addition to the evidence already provided in response to the requests of Public Counsel, Avista points to the additional analysis of our approach for determining the economic end of life for distribution transformers in the analysis provided in the Company's 2016 Asset Management Distribution Program Review, where the initial analysis for Avista's approach for determining the economic end of life for distribution transformers reflected a an internal rate of return on the investment of between five and nine percent, which was the same value reported, coincidentally, for the Company's worst feeders program. The calculated lifecycle value for the grid modernization program was reported at 6.4%, which includes Avista's approach for replacing wood poles and transformers during a feeder rebuild project.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	05/03/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Josh Diluciano
REQUESTER:	Public Counsel	RESPONDER:	Dan Burgess/Tamara Bradley
TYPE:	Data Request	DEPT:	Electrical Engineering
REQUEST NO.:	PC - 331	TELEPHONE:	(509) 495-7896
		EMAIL:	Tamara.Bradley@avistacorp.com

SUBJECT: AMI-Enabled Energy Efficiency

REQUEST:

Please refer to Attachment B provided by the Company in response to Public Counsel Data Request No. 321(b).

a) The formulae in columns “K” and “L” in tab “Future Grid Mod” refer to a value denoted only as “AE”. PC interprets this value to represent “avoided energy” costs. Provide the amount represented by “AE” for rows 2 through 40 in columns “K” and “L” in this tab.
b) For each value provided in response to subpart (a), provide all calculations, assumptions, estimates, details, worksheets, and other support for the value.
c) The formulae in column “K” in tab “Grid Mod AMI Augmentation” refer to a value denoted only as “AE”. PC interprets this value to represent “avoided energy” costs. Provide the amounts represented by “AE” for rows 2 through 40 in column K in this tab.
d) For each value provided in response to subpart (c), provide all calculations, assumptions, estimates, details, worksheets, and other support for the value.
e) The formulae in column “M” in tab “X&R Savings” refer to a value denoted only as “AE”. PC interprets this value to represent “avoided energy” costs. Provide the amount represented by “AE” for rows 2 through 40 in column M in this tab.
f) For each value provided in response to subpart (e), provide all calculations, assumptions, estimates, details, worksheets, and other support for the value.
g) Describe the approach Avista will employ to get “X&R Savings” benefits from CVR.
h) Describe the approach Avista will employ to get “Grid Mod AMI Augmentation” benefits from CVR. In this description, be sure to describe the difference between “X&R savings” and “Grid Mod AMI Augmentation”.
i) Describe the approach Avista will employ to get “Future Grid Mod” benefits from CVR. In this description, be sure to describe the difference between “Grid Mod AMI Augmentation” and “Future Grid Mod”.

RESPONSE:

a) Excel allows a user to assign a name to a cell or range of cells, and the name ‘AE’ refers to cell M4 on the tab labeled ‘Summary by Year’ in PC-DR-321 Attachment B. As such AE refers to the Avoided Cost of Energy ($/MWh). The image, below, from Attachment B, which contains the subject cell M4 lists the individual names used by Avista to reference Key Benefit Assumptions relied upon in the analysis. This explanation for the definition of the name ‘AE’ is also applicable for parts (c) and (e) in this request.

	Key Benefit Assumptions:	
LF	Load Factor	0.38
AE	Avoided Cost of Energy ($/MWh)	68.00
CVRf	CVR Factor (if not known)	0.87
Life	Project Life (years)	20.75
XR	X&R Volt Drop	1.25
AMIVoltDrop	AMI Volt Drop	2.00

b) Calculation of the value of the Avoided Cost of Energy is provided in the tab labeled 'Avoided Costs Reference.' This calculation, from a 2013 Avista Electric Resources Integrated Plan (IRP) presentation, which Avoided Cost includes the cost of Energy, Capacity Savings, Risk Premium, the Preference percentage, Distribution Capacity Savings, and Avoided T&D line losses. The per MWh Avoided Cost of $68.05 is the sum of the two subtotals ($56.26 and $9.79). Such calculation reflects Avista's then actual avoided cost properly determined as part of its Commission IRP process. This explanation for the calculation of Avoided Energy Costs is also applicable for parts (d) and (f) in this request.

g) This response is also applicable to parts (h) and (i) of this request. For reference to the explanation of the CVR analyses conducted for the Company's 2016 AMI business case, please see the information excerpted below, which explains the sources of the benefits related to the subject categories "X&R Savings," "Grid Mod Augmentation," and "Future Grid Mod."

Pertaining to 'the approach Avista will employ,' the Company has previously described the process it is currently using to determine the CVR potential from a feeder. This process was presented during our online meeting with Public Counsel held on April 1, 2021 in response to the request in PC-DR-260. As explained in the meeting, Avista is applying that process to all candidate feeders, regardless of the subject prior classification of feeder groups, noted in this request.

From Avista's 2016 AMI Business Case…………………

Avista's Washington Advanced Metering Project

Description of Quantified Customer Benefits

Area of Benefit
Conservation Voltage Reduction
Customer Value
As a result of the deployment of advanced meters across the Company's Washington service territory, Avista will be able to achieve additional savings through conservation voltage reduction, which will reduce the cost of providing service to our customers.
Background
The electric utility industry has generally agreed that lowering the voltage delivered to a customer meter, while maintaining the minimum required voltage, results in both reduced losses for the electric distribution system as well as reduced consumption for the customer. The methodology used to achieve the savings associated with

lower voltage is referred to as conservation voltage reduction (CVR). This involves lowering the operating voltage of the distribution system toward the lower half of the acceptable range (126 V to 114 V) as defined by the American National Standards Institute (ANSI)[49]. Avista has attained a weighted average savings of 2.02% in its CVR deployments in Spokane and Pullman, as validated by Navigant Consulting. Advanced metering data from 13 of the feeders, located in Pullman, suggests that an additional increment of approximately 2% can be achieved with the installation of AMI.

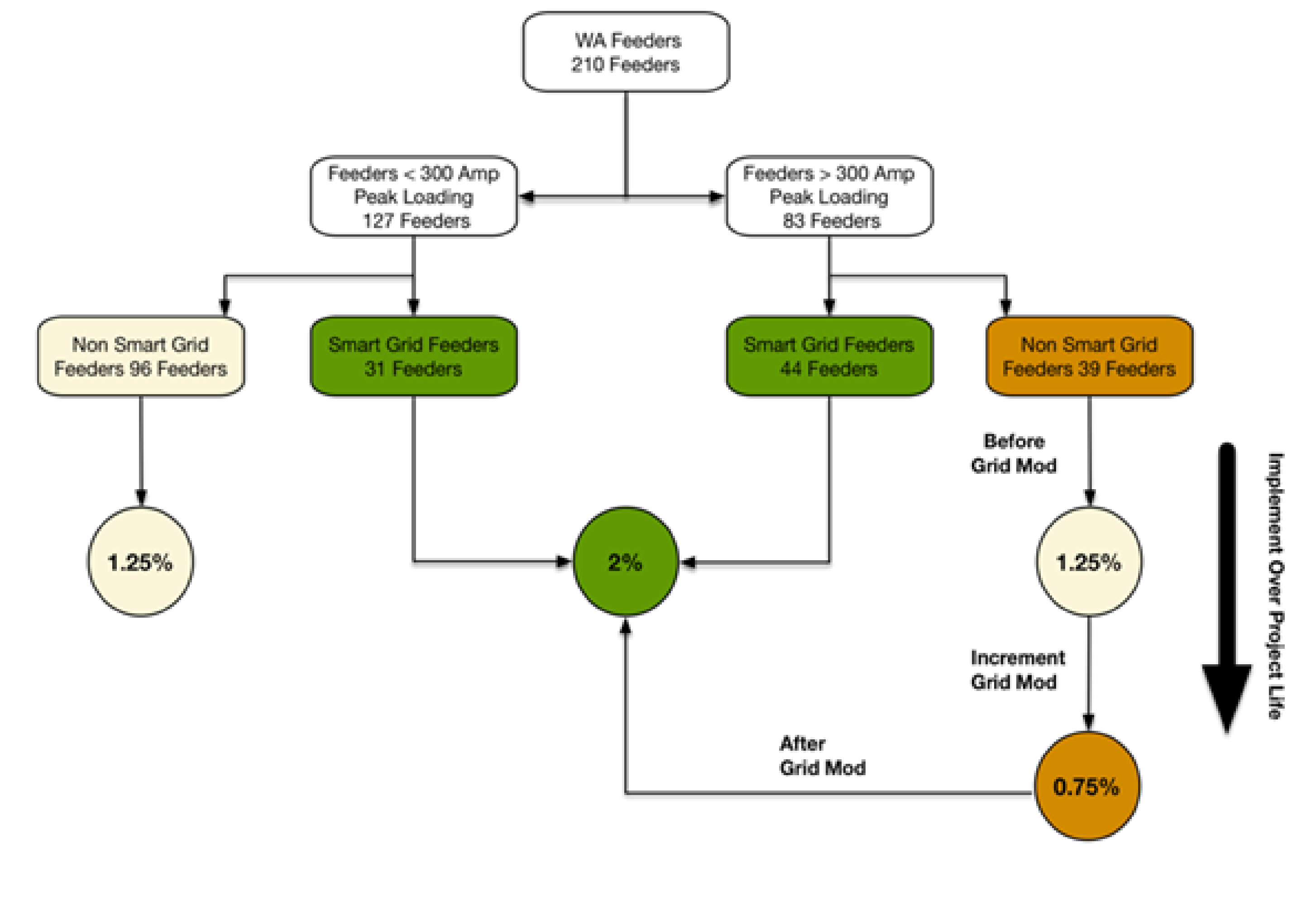
Calculating the Benefit Value

Avista serves its Washington electric customers from 210 electric feeder lines. The diagram below outlines the anticipated savings from groups of feeders based on the load levels and planned upgrades under Avista's Grid Modernization Program (Grid Mod). For feeders loaded at less than 300 amps, CVR will be accomplished by making more aggressive voltage regulator settings (X&R savings) as determined from readings taken by the advanced meter. Avista estimates this methodology can provide an average savings of 1.25%. This estimation is based on the advanced metering data from the system in Pullman. These savings can only be achieved because the voltage reading from the advanced meter enables the reduction while ensuring the customer receives adequate voltage. For feeders with more than 300 peak amp loading, the grid modernization program will implement conservation voltage reduction with smart grid technologies over a 20 year period (approximately two feeders per year). Voltage savings will be captured with aggressive X &R savings until the feeder is converted, at which time the remaining savings can be achieved. The feeders have been prioritized for conservation voltage savings by highest to lowest peak load levels.

To achieve the target savings will require us to install active mitigation at some points along the feeder which are associated with customer service drops and dynamic customer loads. The capital and expense costs required to complete and maintain the anticipated mitigation work is included in the estimated cost for the Washington AMI Project.

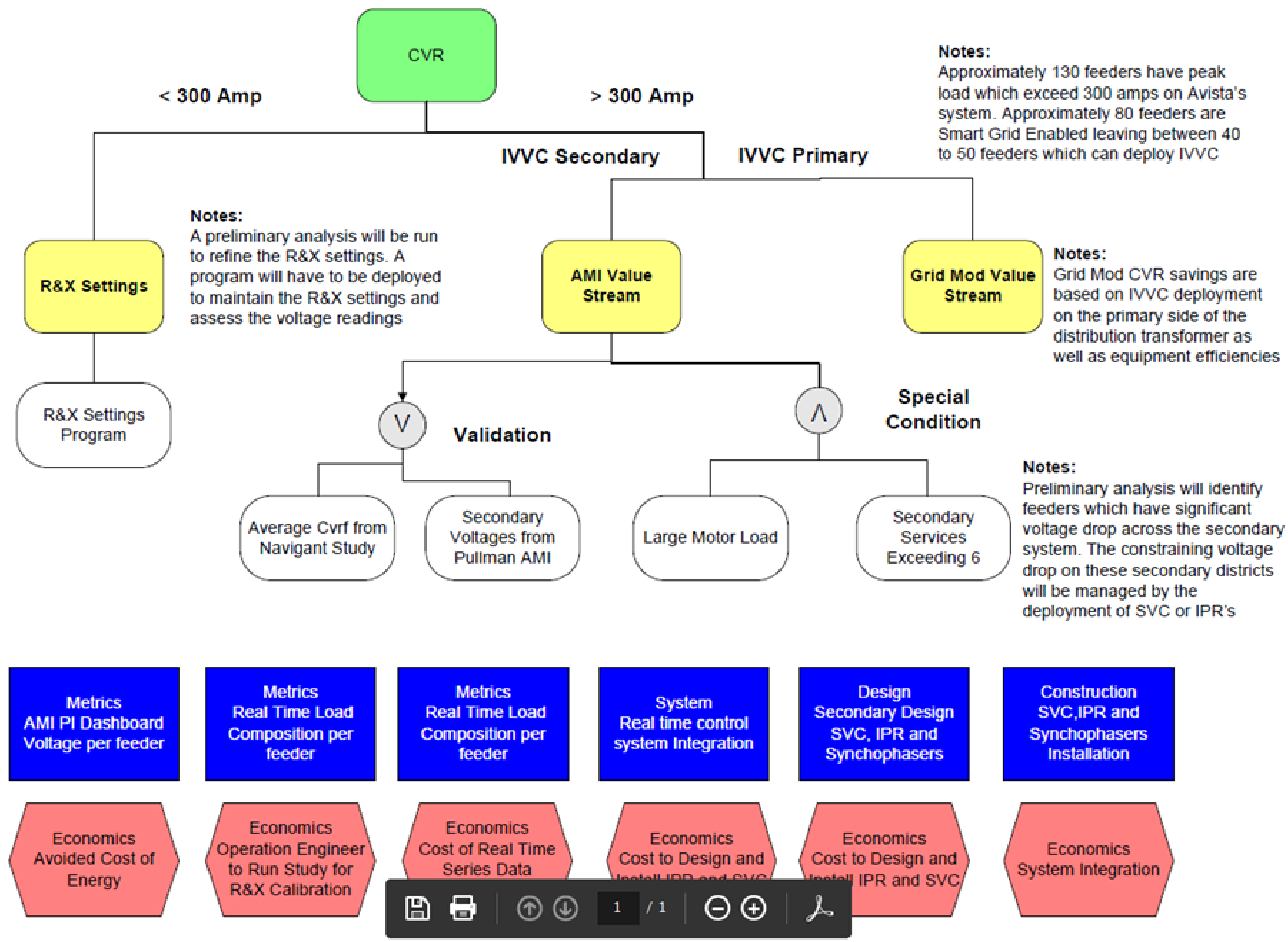
The diagram below depicts the Company's electric feeders in Washington, based on loading (AMPS), and identifies the source of the conservation voltage savings to be achieved over the Washington AMI Project lifecycle.

[49] American National Standards Institute (ANSI), ANSI C84.1, ELECTRIC POWER SYSTEMS AND EQUIPMENT - VOLTAGE RANGES 1-2006



Supporting Information

The engineering models used to estimate the potential value to be achieved with AMI-enabled conservation voltage reduction, are shown schematically in the diagram below. Models include the "SynerGEE" engineering models, the DMS model, the GIS model, OsiSoft PI Historian, and all the AMI register and interval data as well as exceptions and events.



Data supporting the calculation of this customer benefit is provided in the attached electronic workbook titled "Avista AMI Customer Benefits" included on the Compact Disc provided at the end of Attachment B, Project Costs. The workbook contains the cost information for the activities associated with conservation voltage reduction used in determining the quantified value of this benefit.

1. Open the Benefits Workbook and select the tab "Summary Detail."
2. Select "Conservation Voltage Reduction" under that area of benefit.
3. This tab contains the cost information for the expected savings for this benefit, and the forecast of benefits through the Project lifecycle.

Functional Requirements

Where conservation voltage is to be implemented on feeders through grid modernization (AMI augmentation), using the distribution management system (DMS):

- The AMI data must be analyzed thoroughly to understand voltage reduction opportunity.
- The DMS set points must be modified and monitored for maximum benefit.
- Dashboard components will need to be created for the capture of real time savings.
- Mitigation strategies may need to be implemented.

Feeders leveraging X&R settings will require:

- Engineering analysis to thoroughly understand voltage reduction risk/opportunity.

- Regulator X&R settings must be modified by relay technicians and monitored for maximum benefit.
- Mitigation strategies may need to be implemented.

Additional tasks may include:

- Setting changes must be implemented quickly after AMI deployment.
- Dashboards may be necessary in order to better analyze conditions as system changes are made.
- Ongoing distribution system operations and PI[50] support will be necessary.

Additional Requirements

Costs - The various costs for the applications and reporting systems required to implement the conservation voltage benefits are included in the estimated capital and expense costs for the Project.

Business Process Changes - The Distribution Management System (DMS) process to establish voltage set points and produce metrics will need to be integrated with AMI data pre and post deployment.

Key Metrics

Actual conservation voltage savings will be tracked and reported over the Project lifecycle.

Benefit Realization Schedule

The ramp up in benefits and the expected annual savings in each year of the Project lifecycle are shown in the electronic workbook discussed above.

[50] "PI" is the application system used by the Company for various types of data capture and reporting.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	05/20/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Peggy Blowers
TYPE:	Data Request	DEPT:	Enterprise Asset Management
REQUEST NO.:	PC - 332	TELEPHONE:	(509) 495-4789
		EMAIL:	Peggy.Blowers@avistacorp.com

SUBJECT: AMI-Enabled Energy Efficiency

REQUEST:

Please refer to the Company's response to Public Counsel Data Request No. 322, subpart (f), which refers Public Counsel to the Company's response to Public Counsel Data Request No. 295, subpart (a). Public Counsel is interested in how the Company maintains and operates the Availability Workbench software and the software's broader role in the Company's approach to asset management.

a) Provide a description of the Company's asset management function, including staffing, organizational structure, hierarchy through which the function reports, functional (departmental) objectives, functional (departmental) business processes, and all Company polices which relate to the asset management function (department).

b) Identify any and all consultants the Company uses to assist in the asset management function, as well as their roles within the asset management descriptions provided in response to subpart (a).

c) Identify any and all consultants the Company uses to assist with the operation and use of the Availability Workbench software.

d) Identify any and all employees who populate the Availability Workbench software and use it to estimate "End of Life" and "Total Cost of Ownership" curves for various types of equipment.

e) List all performance measures the Company used to evaluate its Asset Management function in 2020, along with the Company's assessments and descriptions of the actual performance achieved on these Asset Management performance measures in 2020.

f) In what year did Avista first license the Availability Workbench software?

g) In what year did Avista first begin using Availability Workbench software to estimate "End of Life" ages and "total cost of ownership" curves for various types of equipment, and begin using this data to determine when to replace various assets?

h) Explain how Avista estimated "End of Life" ages for various types of equipment before it began using Availability Workbench software.

i) Explain how Avista estimated "total cost of ownership" curves for various types of equipment before it began using Availability Workbench software.

j) Explain how Avista determined when to replace various types of equipment (the old method) before it began using Availability Workbench software, end-of-life estimates, and total cost of ownership curves.

k) Provide any evidence Avista has which indicates that the new method of determining optimum asset replacement timing is superior to the old method of determining optimum asset replacement timing in terms of system-wide SAIFI performance. Provide all worksheets, assumptions, calculations, and other support for Avista's response to this subpart (k).

l) Confirm that Avista's current method of determining optimum asset replacement timing results in more frequent equipment replacement than the old method of determining optimum asset replacement timing. If this cannot be confirmed, please explain.

m) Confirm that replacing equipment more frequently results in greater distribution rate base, and therefore higher customer rates, than replacing equipment less frequently. If this cannot be confirmed, please explain.

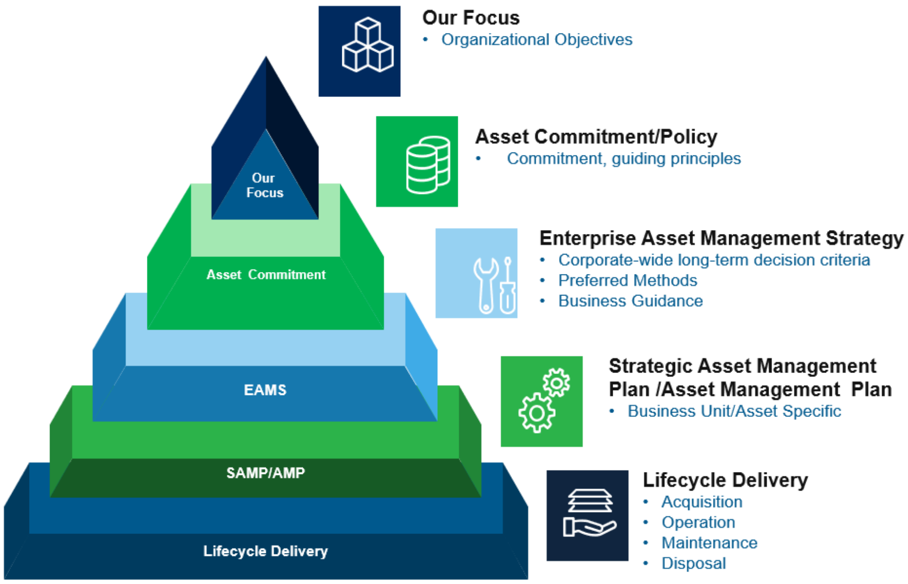
n) Estimate the increase in dollars of annual capital investment resulting from Avista's switch from the old method of determining when to replace various types of equipment, as described in response to subpart (j), to Avista's current method for determining when to replace various types of equipment. Provide all worksheets, assumptions, calculations, and other support for Avista's response to this subpart (n).

RESPONSE:

a) Avista's approach to Asset Management has evolved over the years from its inception in energy delivery in 2002, to an enterprise-wide 'hub and spoke' model of Asset Management core team practitioners partnering with Asset Management Engineers/Subject Matter Experts from key business areas, as represented in the diagram below. Over time, the reporting structure changed from energy delivery to the office of the CFO, consistent with this enterprise-wide philosophy. The Company's Asset Management Engineers, instead of residing in the Asset Management department as in times past, are now placed in key business units and have a formal reporting relationship with the Manager of Enterprise Asset Management. For a long time now, Avista has had Asset Management Engineers specializing in electric Transmission, Substations, Distribution, Natural Gas and Generation, and has expanded this expertise to include System Planning, Information Technology, and Facilities/Fleet (shared services).

As sponsored by Avista's senior leadership, Avista's Asset Management Office has also undertaken the work of developing the framework and processes needed to formalize our Enterprise Asset Management Strategy. In this effort, Avista continues to align itself with the asset management processes and practices of the ISO 55000 series international standards for asset management, and specifically, with the Institute of Asset Management (IAM) 'Asset Management Maturity Framework 2015.' In this effort, Avista continues its tradition of implementing industry-standard best practices and analytics as defined by the Subject Specific Guidelines produced by the IAM. The alignment of Avista's corporate values and mission, objectives, strategies and goals with Asset Management strategies and plans is integral to successful Enterprise Asset Management. The figure below depicts the desired "line of sight" hierarchy that helps align asset decisions with customer and regulatory expectations and corporate objectives. Key elements of this hierarchy, now in development, include:

Avista Corporate Strategic Initiatives and Goals – Avista's strategic focus areas include 'Our Customers,' 'Our People,' 'Perform' and 'Invent.' The Asset Management Function and objectives align with the key Focus Area of "Perform." This initiative will define how the Company's Asset Management Performance Metrics and Goals (in development) will be aligned and reviewed with other Corporate initiatives in this key focus area.



Asset Management Commitment Statement – Will provided visible support from Avista's Executive Leaders outlining the guiding principles for performing and executing Asset Management processes and decisions, outlined in the Enterprise Asset Management Strategy.

Enterprise Asset Management Strategy (EAMS) – Avista's strategic approach to Asset Management and the development roadmap for Avista's overall Asset Management System (currently in review).

Strategic Asset Management Plans and Asset Management Plans – Continuing in the Company's tradition of developing and delivering capable asset management analysis and decision support for managing a wider range of assets through the lifecycle process.

Asset Lifecycle Delivery – More broadly formalizing our decision support processes around the acquisition, operation, maintenance and other lifecycle characteristics of an asset.

b) ARMS Reliability – Availability Workbench training; updates to Aldyl A Pipe failure analysis. UMS Group – Reliability organizational planning; Rodney Pickett – Consultant.
c) Rodney Pickett.
d) Company employees who have been formally trained and have used the Availability Workbench application include:

i.	Glenn Madden	Asset Management Engineer/Manager
ii.	Karen Cash	Asset Management Engineer
iii.	Rodney Pickett	Asset Management Engineer/Manager
iv.	Kristin Busko	Asset Management Engineer
v.	Rob Gray	Asset Management Engineer
vi.	Greg Smith	Asset Management Engineer
vii.	Rubal Gill	Asset Management Analyst
viii.	Lisa La Bolle	Asset Management Analyst
ix.	Dan Wicker	Asset Management Engineer
x.	David Thompson	Asset Management Engineer
xi.	Rendall Farley	Asset Management Engineer
xii.	Amber Gifford	Asset Management Analyst
xiii.	Kyia Douglas	Asset Management Analyst
xiv.	Mary Jensen	Asset Management Engineer
xv.	Doug Forkner	Asset Management Engineer

xvi.	Jeremiah Webster	Asset Management Analyst
xvii.	Brandy Weatherly	Asset Management Analyst
xviii.	Valerie Petty	Asset Management Analyst
xix.	Tia Benjamin	Asset Management Analyst
xx.	Jeff Smith	Asset Management Analyst
xxi.	Amber Blackstock	Asset Management Engineer
xxii.	Craig Brourassa	Asset Management Engineer
xxiii.	Chris Lum	Asset Management Engineer
xxiv.	Tracey West	Asset Management Engineer
xxv.	Tia Benjamin	Asset Management Analyst

e) Please see part (a), above.

f) 2006.

g) 2006-7.

h) Avista considers the terms end of useful life, end of life, lowest lifecycle cost, economic optimum, total cost of ownership or economic end of life, as emerging with the recent development (last 20 years) of the science and standards of Asset Management and the analytical principles and capabilities of Lifecycle Cost Analysis. Avista's prior practices for determining how best to perform inspections, testing, maintenance, repair and replacement of equipment were based on specialized engineering experience, expertise and evaluation, application of conventional RCM practices, including quantitative methods and qualitative processes focused on subject matter expertise, experience, and the judgement of technical and field employees from a range of work groups, etc.

i) Please see part (h), above. Avista's early Asset Management Engineers (back in 2005) did attempt to construct home-made failure curves using Excel format files, but were overwhelmed by the complexity of the effort (please see PC-DR-341 and the reference to the **"Weibull Analysis Handbook**"). We realized we could not perform the computations required to support our nascent Asset Management program without use of the applications provided in Availability Workbench (or some similar set of models). Even conducting such failure analysis, as described in the "Weibull Analysis Handbook" gives Public Counsel some idea of the complexity of that undertaking.

j) Please see part (h), above, which also included the BOGSAT approach.

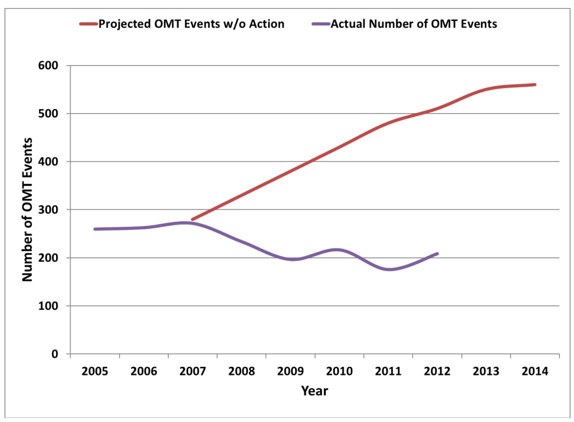
k) Results of analyses provided in response to the requests of Public Counsel demonstrate just a couple of ways the engineering science of lifecycle cost analysis is superior to conventional utility methods Avista employed prior to applying the Asset Management principles and analytics we use today. Consider *only* the capability of reliability forecasting, which provides not only the forecast of future asset performance, but also the complex analysis of alternatives for responding appropriately, including the integrated analysis of groups of assets and integrated alternatives, such as represented in the Company's Reliability Strategy Analysis tool, which capabilities are described in the excerpt below from PC-DR-296 (b).

> Results of analyses completed, among the many other examples provided, which validate the efficacy and cost effectiveness of Avista's end of life designation for the subject assets have been provided in response to PC-DR-118, for example. This analysis presents results of the Availability Workbench modeling (described at length, including in PC-DR-121, PC-DR-122, PC-DR-235, PC-DR-236, and PC-DR-295, among many others), which conclusively shows the dramatic increase in customers costs, which analysis was performed at the request of Public Counsel, which would result from the Company abandoning its designation of end of life for these subject assets in favor of a blanket run to fail strategy.

Another example of our early use of this forecasting ability was provided in response to PC-DR-223 (d)(f), as excerpted below.

> More important than the annual number of cutout failures shown in Figure 23 is the modeled forecast of cutout failures <u>that would likely have occurred if not for the systematic replacement of these devices as undertaken by the Company</u>. The figure below shows actual failures that resulted in an outage for customers (Actual OMT Events), and in the red line, the projected number of events, which were forecast to nearly double over the time frame shown, had Avista not undertaken the systematic replacement of these high-risk cutouts through Grid Modernization and Wood Pole Management. Accordingly, the measure of the customer value achieved through the replacement is not the reduction stated in the request above, rather, it's the reduction from approximately 560 annual outage events projected by in the figure below, compared with the number that actually occurred.

Table PC-DR-223 part (d) Outage Forecasts for High-Risk Cutouts without Systematic Replacement, and With Replacement as Conducted by Avista.[51]



> Avista does not agree with the oversimplified characterization used by Public Counsel as "preemptive replacement." The Company replaces assets in service at the end of their useful lives. Some assets are allowed to 'run to fail' if the combined risk costs associated with the failure are less than the costs required to systematically replace the equipment before it fails in service. Designation of run to fail for certain assets, however, is not a static determination because it is based on the cost of undertaking an effort to replace the asset prior to failure on a standalone basis – that is, based on the unit cost to canvass the system in an operation to replace only that one type of asset, and nothing else. A good example of this is Avista's subject replacement of cutouts (and distribution transformers). For both these assets, the Company's typical approach is to replace these assets when they fail in service. This makes sense because the failure typically results in an outage for a small number of customers, the replacement assets are readily available, and the time required for repair/replacement is not unreasonable. As an alternative, replacing these two assets at end of life but prior to failure, in a standalone replacement effort, would still result in an outage for customers.

[51] The forecast of outages resulting from cutout failures "projected OMT events w/o action" is based on lifecycle cost modeling using the Isograph Availability Workbench model initially performed in 2007-2008. The figure shows results of the initial model forecasts without action compared with then-current actual outage events through year 2012. Figure 23 in PC-DR-105 Attachment A shows the continuing reduction in cutout failures for the years 2013 through 2016, to the approximate number of annual failures predicted by the modeling.

> Avista notes that Figure 23 represents the annual number of cutout and transformer failures that resulted in a service outage for customers for the period of time 2005 through 2016. It's also important to note that the reduction in number of outages shown in the figure represents only one of the risk costs associated with these assets. And, as noted above in part (d), the reliability benefit is not measured by the difference in numbers observed in 2005, for instance, compared with results for 2016, <u>it's measured from the high end of the forecast of the outages (not shown in Figure 23) that would have occurred absent the systematic replacement program, such as shown in Figure PC-DR-223 part (d) for high-risk cutouts</u>.

And in PC-DR-293, excerpted below.

> The forecast of high-risk cutouts, which as noted in response to PC-DR-292 are nearly all Chance cutouts, was developed from actual failures of these cutouts, based on known failures experienced by Avista, modes of failure and service life. The forecasts were performed using the Availability Workbench modeling to develop failure curves (and subsequent lifecycle cost modeling), which process has been described by the Company in numerous data requests, including PC-DR-118, PC-DR-121, PC-DR-122, PC-DR-223 Revised, PC-DR-221, PC-235, and notably in PC-DR-236 where Avista offered to provide the subject models and/or an online working session, PC-DR-294, PC-DR-295 PC-DR-296, and by reference in responses to PC-DR-298 through 305. The forecast failures shown for 2007-2014 for high-risk cutouts is a mathematically sound representation of expected failures based on known failure data and expected remaining units in service at the time the forecast was performed. Of interest in the forecast is the predicted 'flattening out' of the failure curve in years 2012-1014, which would be as expected for the population of Chance cutouts that was being depleted in the model via the rapidly increasing number of annual failures. Finally, the fit of the failure forecast appears to be more consistent with the prior years' actual failures when a longer period (such as 2001 – 2007) is used to show the history instead of just two years. The purpose of the illustration was not to show history, but rather, to forecast failures reasonably expected to occur without systematic replacement of the clearly end of life assets.

l) This cannot be confirmed by the Company as a broad generalization. Some assets are replaced earlier today than they might have been otherwise, but others are not replaced as early as they once were and are kept in service longer, as a result of our application of lifecycle cost analysis. The reason for some assets remaining in service longer today is that we now better understand the consequence costs, as one example, of allowing an asset in one application to fail in service compared with another. Another reason some assets remain in service longer today, as result of lifecycle cost analysis, is that asset condition and age, as it relates to expected life are better understood quantitatively, which information is used to better guide replacement decisions made by field employees, etc.

But importantly, **the premise of this request misses the entire point of lifecycle cost analysis**, as practiced by Avista, and which has been amply demonstrated to Public Counsel, which point is articulated clearly in response to PC-DR-288 Revised, as excerpted below (emphasis added).

> As we have stated in response to numerous requests, the Company replaces electric system assets when they are deemed to have reached the end of useful life. Further, we have explained and demonstrated that 'end of useful life' is determined through asset failure analysis, and evaluation of costs, benefits and risks in both simple analyses and very complex lifecycle cost modeling – all to identify the replacement strategy (and the ultimate

> designation of end of life) that allows us to deliver service to our customers at the lowest reasonable optimized cost. Therefore, Avista does not preemptively or prospectively replace equipment, rather, **we replace assets at a point in time and in a manner that delivers our customers the greatest overall value**. Accordingly, there is no 'one size fits all' definition of what constitutes the end of useful life for an asset. It's defined by the specific context and application for each asset, based on analysis of those specific risks, consequences and costs associated with that equipment failing in service, the unique costs of replacement, in that particular application and context.

And, again, as noted in response to PC-DR-296 (a), which excerpt is provided below (emphasis added).

> Avista does not 'prospectively' replace equipment, rather, as previously stated, we replace equipment at the end of its useful service life, which is based <u>on achieving the lowest optimized total lifecycle cost of ownership for our customers</u>.

m) Avista rejects this premise as false. The manner in which the Company replaces equipment, whether earlier in time, or later in time than our historic practices, delivers service to customers at the reasonably lowest lifecycle cost, which **results in rates for customers that are lower than they would otherwise have been** without such practices. Avista has amply demonstrated this through discovery.

n) The Company's capital investments today, whether they arise from regulatory or infrastructure needs, as a couple examples discussed in Avista's various infrastructure plans, **are lower than they would otherwise have been absent the application of Avista's Asset Management principles and lifecycle cost analyses**. As demonstrated repeatedly to Public Counsel in explanations, examples and results of financial analyses, our current practices deliver service to our customers at the lowest reasonable lifecycle cost, which literally means, lower than the cost of any reasonable alternative practice or set of practices, which would include at least some of the practices previously followed by Avista.

One simple demonstration of this was provided to Public Counsel in response to PC-DR-294 (a), which financial analysis for managing Chance cutouts (<u>which analysis would not have been possible without our use of the Availability Workbench application</u>) shows the significant cost savings for customers (<u>lower rates than would otherwise have been the case</u>) associated with our systematic replacement of these high-risk cutouts. In this analysis, results of which are presented below, "Today's Case" represents the customer costs associated with the alternative of replacing these cutouts when they fail in service, while the "Planned Replacements" column includes the customer costs for the systematic replacement of these cutouts. Our customers' rates were kept lower under the systematic replacement of these cutouts (replaced earlier than they would have been otherwise) compared with the alternative of leaving them in service until they failed.

Avista's response to PC-DR-294 (a)

Option Comparison – 10 Year Outlook

Model	Today's Case	Planned Replacements
Cutout Failure Rate	400 per year	46 per year
Customer Cost	$2.2 million	$0.26 million
Minor Safety	0.8 events	1.3 events
SAIFI Impact	0.05 added	0.006 added
Avg Annual Capital Budget	$475,000	$192,000
Avg Annual O & M Budget	$268,000	$32,000
IRR (Lifecycle Cost)	0.7%	19.1%
Levelized ROE	$92,000	$44,000
Expected Value to Implement	$6.2 million	$4.6 million

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	05/20/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Peggy Blowers
TYPE:	Data Request	DEPT:	Enterprise Asset Management
REQUEST NO.:	PC - 333	TELEPHONE:	(509) 495-4789
		EMAIL:	Peggy.Blowers@avistacorp.com

SUBJECT: Avista Asset Management

REQUEST:
Please refer to the Company's response to Public Counsel Data Request No. 322, subpart (f), which refers Public Counsel to the Company's response to Public Counsel Data Request No. 295, subpart (a). Public Counsel is interested in how the Company uses the Availability Workbench software in Avista's asset management function. Avista employee Rodney Picket is quoted in the vendor's promotional materials as saying "Without ARMS and Availability Workbench™, our asset management program would have failed years ago and never made an impact on how we manage our assets."[1] Further, according to the vendor's website, the Availability Workbench software consists of six modules, including (i) RCM Cost; (ii) AvSim; (iii) Life Cycle Cost; (iv) ERP Interface; (v) Process Reliability; and (vi) Weibull Analysis.

a) For each of these six modules, provide a detailed description of how Avista uses each in its asset management function. For any module Avista does not use, explain why Avista does not use it.
b) For each of these six modules, provide a detailed description of how ARMS and Availability Workbench "made an impact on our (Avista's) asset management program". For each module described in subpart (a), include a list of impacts to Avista's asset management program prompted by each module and/or ARMS consulting services and associated descriptions of each.
c) Explain how Avista's asset management program would have "failed" without ARMS and Availability Workbench. Include in this explanation Avista's definition of asset management program "failure".

RESPONSE:

a) Avista uses the following modules: (i) RCM Cost; (ii) AvSim; (iii) Life Cycle Cost; (iv) ERP Interface; and (vi) Weibull Analysis. Avista has not recently used the ERP Interface.

   i. Reliability-Centered Maintenance (RCM) is a procedure for determining maintenance strategies based on reliability techniques and encompasses well-known analysis methods such as Failure Mode Effects and Criticality Analysis (FMECA). RCM procedures take into account the prime objectives of a maintenance program, which are to minimize customer costs and meet a range of operational objectives, such as reliability. The RCM process begins with a failure mode and effects analysis that identifies the critical failure modes in a systematic and structured manner. Next, the examination of each critical failure mode or cause is performed to determine the optimum maintenance policy to reduce the severity (risk costs) of each failure. The chosen maintenance strategy must take into account cost, safety, environmental and operational consequences. The effects of redundancy, spares costs, maintenance labor costs, equipment aging, and repair times are also taken into account, as has been explained by the Company.
   ii. The AvSim module of Availability Workbench enables us to simulate the performance of "systems," as a whole, taking into account dependencies between the individual components. This is how Avista is able to model all of the interdependencies of the equipment in one substation to determine the optimum times for inspection, testing, maintenance, repair and

replacement of substation equipment, as we have explained in response to numerous data requests. By simulating how the system will perform, we can determine the effects of design and operational changes, to optimize system performance.

iii. The Life Cycle Cost (LCC) module of Availability Workbench, which Avista has discussed extensively in response to the requests of Public Counsel, allows the Company to incorporate the range of asset costs expected over its lifecycle, whether defined as time-dependent cost equations, probability dependent, or simple numerical values. The resulting cost predictions may also be linked to cost predictions produced by the RCM cost or AvSim modules.

iv. The Weibull module, which Avista has also discussed at great length, is used to analyze historical failure data by assigning probability distributions that represent the failure characteristics of a given failure mode. The failure distribution, based on time in service to failure, may then be assigned to failure cause modes in the RCMCost module location hierarchy diagram or failure models in the AvSim module. Assigning failure distributions to historical data in this way enables Availability Workbench to simulate the effects of failures on individual assets and asset systems.

b) Avista uses these modules in an integrated manner to provide our customer's the lowest reasonable lifecycle cost for the infrastructure and management practices required to serve them. One example of this integration is described above in (a)(ii) "**This is how Avista is able to model all of the interdependencies of the equipment in one substation to determine the optimum times for inspection, testing, maintenance, repair and replacement of substation equipment, as we have explained in response to numerous data requests**." But the AvSim module is supported by, and is interdependent with, the other modules we have described above. Evidence of how these integrated modules have "made an impact on our (Avista's) asset management program" and our ability to deliver the lowest reasonable optimized lifecycle cost for our customers has been provided in various ways in responses to PC-DR-121, 122, 162, 163, 172, 198 Revised, 223 Revised,226, 228, 231, 235, 245, 246, 284, 288 Revised, 293, 294, 295, 296, 297, 299, 300, 301, 302, 303, 304, 307, 308, 309, 310, 313, 314, 318, 319, 322, 323, 324, 325, 326, 327, 328, 329, 330, 332, 333, 334, 335, 336, 337, 338...

c) Engineers who were part of the Company's nascent Asset Management program were experiencing difficulty, relying only on the Company's then-extant analytical methods, as generally described in response to PC-DR-332, helping the Company understand and prepare for the coming long-term impact of our aging electric utility infrastructure, as well as how to determine the best financial approach for managing failing equipment like the Chance cutout. Our definition of a "failed Asset Management program" is best depicted in the financial consequences of the default Run to Fail strategy recommended by Public Counsel, which customer financial consequences are provided in response to PC-DR-118, PC-DR-122, and PC-DR-235, as examples.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	05/20/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Peggy Blowers
TYPE:	Data Request	DEPT:	Enterprise Asset Management
REQUEST NO.:	PC - 334	TELEPHONE:	(509) 495-4789
		EMAIL:	Peggy.Blowers@avistacorp.com

SUBJECT: AMI-Enabled Energy Efficiency
REQUEST:
Please refer to multiple Company responses to Public Counsel Data Requests which mention the Availability Workbench software, including Public Counsel Data Request Nos. 121, 122, 235, 236, 293-296, 301, 307-309, 313, 314, 318, 322, and 325-330.
For each of these data request responses, describe any role played by Avista consultants in responding to each Public Counsel data request, and identify such consultants.

RESPONSE:

121 Support for Avista's Reliability Strategy Analysis tool; Rodney Pickett

122 Support for Avista's Reliability Strategy Analysis tool; Rodney Pickett

235 None

236 None

293 None

294 None

295 None

296 None

301 None

307 None

308 None

309 None

313 None

314 None

318 Expertise extracting and producing 1.7 million failure analysis data points; Rodney Pickett

322 None

325 None

326 None

327 None

328 None

329 None

330 None

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	05/20/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Glenn Madden
TYPE:	Data Request	DEPT:	Substation Engineering
REQUEST NO.:	PC - 335	TELEPHONE:	(509) 495-2146
		EMAIL:	glenn.madden@avistacorp.com

SUBJECT: Lifecycle Cost Modeling

REQUEST:

Please refer to the first chart provided in the response to Public Counsel Data Request No. 307, subpart (a), and specifically the charts presenting the total cost of ownership curves, as well as the Company's response to Public Counsel Data Request No. 323.

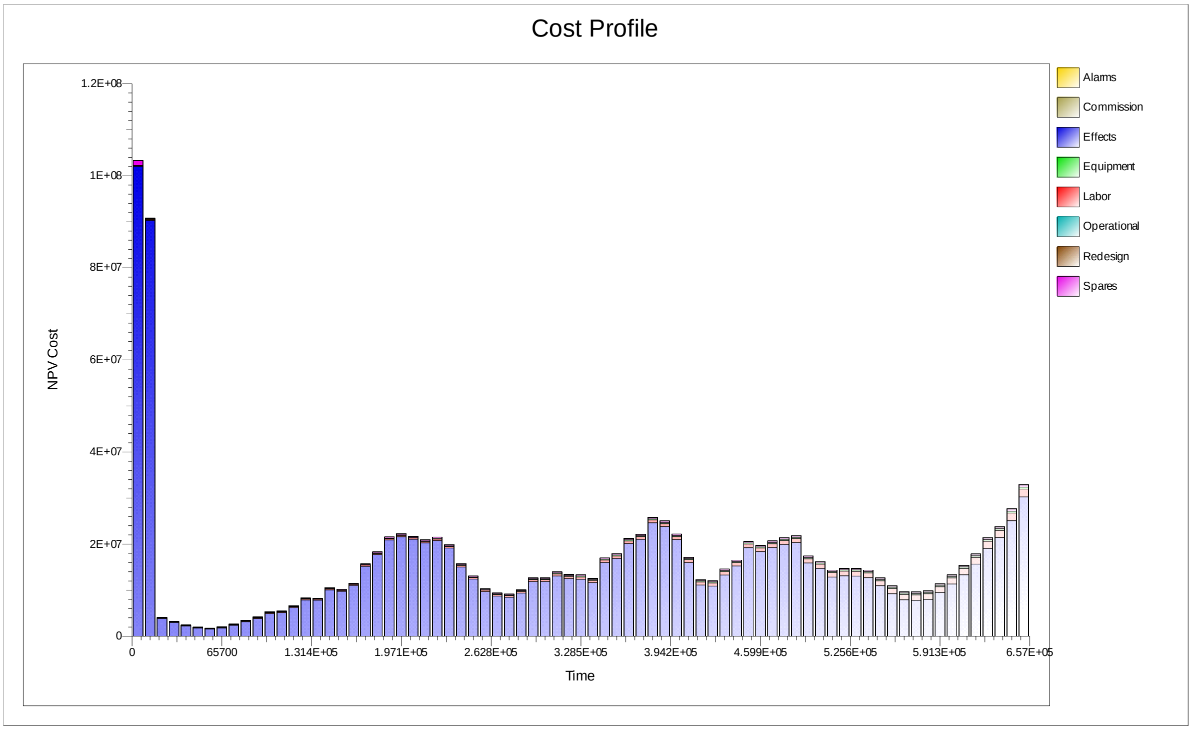
For the asset type "substation power transformers", please provide:

a) The actual total cost of ownership curve for that asset type.
b) The actual inputs used to develop the total cost of ownership curve for that asset type, including (i) "initial investment;" (ii) "maintenance" costs; (iii) "replacement" costs; and (iv) "operation and failure in service" costs, including all components (outage risk; safety risk; environmental risk; and "others").
c) The actual formulas, with calculations, which translate the inputs into the values represented in the total cost of ownership curve for that asset type.
d) Provide any and all Weibull curves that were used to develop the equipment failure rates used in the development of the total cost of ownership curve for that asset type. Please do not provide unreliability curves or outage data, only failure rate data that shows failure relative to the age of the equipment. Further, in any Weibull curves provided, please ensure the horizontal axis is denominated in years.
e) For any and all Weibull curves provided in response to subpart (d), provide the historical actual data for asset type "substation power transformers" used to develop those Weibull curves.
f) Provide any and all actual historical data used to justify any inputs into the total cost of ownership curve for the asset type "substation power transformers", including (i) "initial investment;" (ii) "maintenance" costs; (iii) "replacement" costs; and (iv) "operation and failure in service" costs, including all components (outage risk; safety risk; environmental risk; and "others").

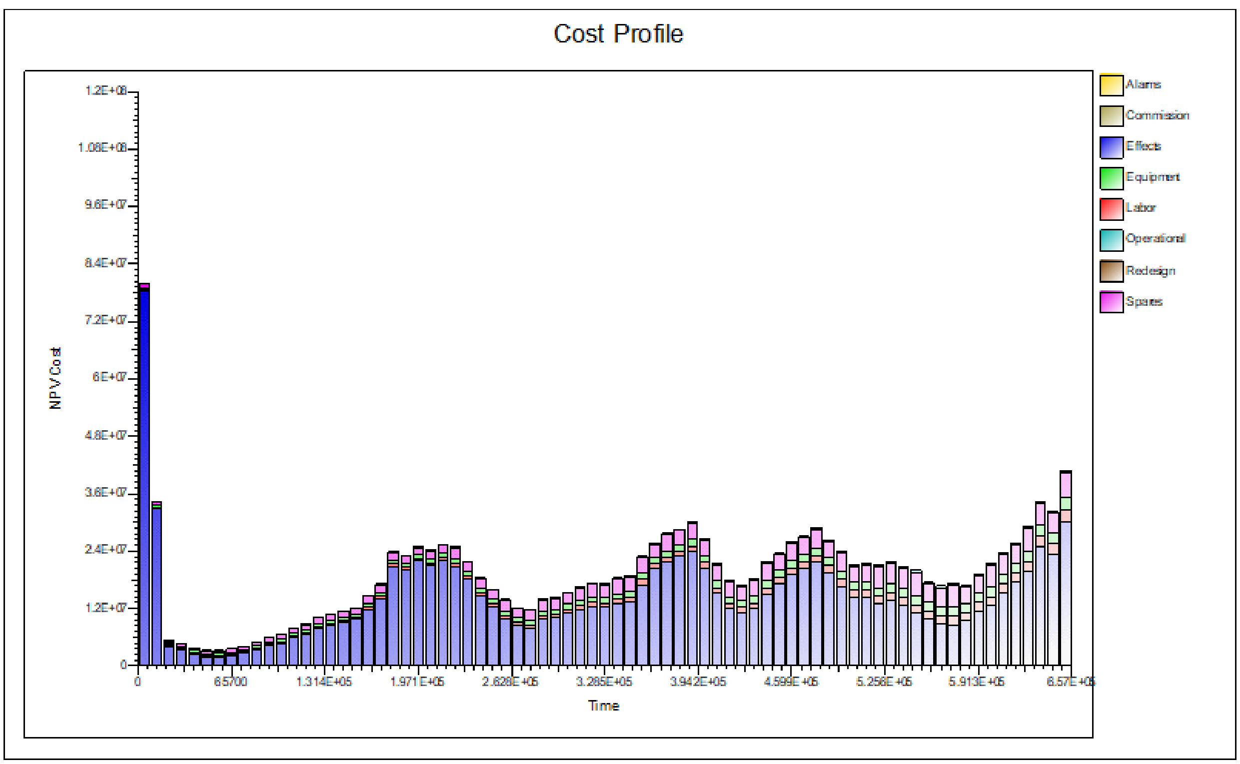
RESPONSE:

c) The total cost of ownership curves depicted in the illustrations provided in response to PC-DR-307, as noted in the response are illustrative. As such, they represent an idealized lifecycle cost curve for an asset installed new and managed throughout its lifecycle, emphasizing in particular, the point of lowest lifecycle cost. In the actual application of lifecycle cost analysis, as Avista has done for substation power transformers using Availability Workbench, you begin with a fleet of assets of widely-varying ages that are already in service. While a total cost of ownership curve can be developed from the asset data, Avista has not done so in this case because the practical need being addressed is how best to manage the fleet of assets we have going forward in time. Accordingly, the cost profile produced by Availability Workbench provides a forecast of costs based on the fleet of transformers in service, as presented in the cost profile illustrations below. The first cost profile is for the "Base Case" analysis, and the second profile represents costs for the "Planned Case" alternative.

"Base Case" Cost Profile



"Planned Case" Cost Profile



b) Avista has provided two Excel files that contain all the input values used in creating the cost profiles shown above for the Base Case and Planned Case as PC-DR-335 Attachments A and B, respectively.

c) Formulas used in the Availability Workbench application to calculate the costs presented in the cost profiles, above, are provided in the workbook pages provided in PC-DR-335 Attachment C.

d) Weibull failure statistics for several failure modes are presented below.

- Broken or Damaged Gage – Bi-weibull eta1 = 85380000 hrs beta1 = 0.8 eta2 = 1069000 hrs beta2 = 2.9
- Gasket Leak – Weibull eta1 = 262800 hrs beta1 = 3
- Transformer Internal Subcomponent failure – Weibull eta1 = 5361120 hrs beta1 = 1

Weibull failure curves for the other failure modes are provided in PC-DR-335 Attachment D. Availability Workbench displays failure curves for unreliability with the time function available only in hours. We have included, however, an Excel file that converts hours into years, which is provided as PC-DR-335 Attachment E.

e) The data are provided in PC-DR-335 Attachments A and B, in the tabs labeled "WeibullSetItems." If the "Suspended" column is True then that particular asset was functioning and not failed at that particular age. If the "Suspended" column is false, then the asset had failed at that given age. As we have already explained, non-failed assets must be included in the data set to create a failure curve that properly reflects the quantity of failures to expect in future years.

f) The input data are provided in the remaining workbook tabs of PC-DR-335 Attachments A and B (not including the Weibull Sets). Avista's Standard Assumptions Document 2019 provides documentation for much of the source data, along with the derivations needed to incorporate other factors into the data.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	05/19/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Peggy Blowers
TYPE:	Data Request	DEPT:	Asset Management
REQUEST NO.:	PC - 339	TELEPHONE:	(509) 495-4789
		EMAIL:	Peggy.Blowers@avistacorp.com

SUBJECT: AMI-Enabled Energy Efficiency

REQUEST:

Please refer to the Company's response to Public Counsel Data Request No. 327, subpart (d), which states "Availability Workbench has been adopted particularly by leaders in the systematic application of asset management principles to electric utility infrastructure. Among these leaders are utilities in Australia, New Zealand, Europe and Canada."

a) Provide a list of utilities in Australia, New Zealand, Europe, and Canada which are paying for Availability Workbench subscriptions.

b) Provide a list of utilities in Australia, New Zealand, Europe, and Canada which are paying for ARMS consulting services.

c) The vendor's website lists Portland General Electric, an investor-owned utility, as a user of Availability Workbench.[4] Explain why Avista failed to list Portland General Electric in its response to Public Counsel Data Request No. 327, subpart (d), and describe the current status of Portland General Electric's license and use of Availability Workbench software.

RESPONSE:

a) Avista does not formally track utilities making use of the Availability Workbench applications, or involve itself in the details of their contracting for such services, unless by request. Nor does the Company, attempt to formally track the degree to which national and international energy utilities have formally adopted Asset Management principles, practices or the use of sophisticated analytical tools, such as Availability Workbench.

ARMS Reliability lists several utilities in Australia and New Zealand using Availability Workbench, which nondisclosure agreements prevent them from sharing particulars of their applications. If interested, Avista suggests Public Counsel perhaps contact ARMS Reliability directly for such a potential list.

<u>Australia</u>

AusNet
AusGrid
PowerLink
TransGrid
Endeavour Energy

<u>New Zealand</u>
TransPower
Meridian Energy

Powerco

b) Please see part (a), above.

c) The subject data request, excerpted below, specifically requested such information for distribution asset management. To the degree that Avista was last aware of PGE's use of Availability Workbench, it was for generation infrastructure only.

PC-DR-327 (d)

Provide a list of investor-owned utilities which license and use the Availability Workbench software for distribution asset management.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	05/19/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Peggy Blowers
TYPE:	Data Request	DEPT:	Asset Management
REQUEST NO.:	PC - 340	TELEPHONE:	(509) 495-4789
		EMAIL:	Peggy.Blowers@avistacorp.com

REQUEST:

Please refer to the Company's response to Public Counsel Data Request No. 327, subpart (d), which states "In Avista's experience and view, American utilities, and in particular, investor utilities, have until recently, been behind the global curve in the adoption and application of asset management principles and the utilization of sophisticated analytical tools, such as provided by Availability Workbench."

a) Explain why Avista's "experience and view" is that American utilities are "behind the global curve" in the adoption and application of asset management principles.
b) Explain why Avista's "experience and view" is that investor(-owned) utilities are farther behind the global curve than other American utilities (as indicated by the phrase "in particular").
c) Explain why Avista's "experience and view" is that, more recently, American utilities, and in particular investor-owned utilities, have been catching up to the global curve in the adoption and application of asset management principles.
d) List and describe the "asset management principles" for which American utilities, and in particular investor-owned utilities, have been behind the global curve in adopting.

RESPONSE:

Please also see our response to PC-DR-339 (a).

a) Because this is what we have noticed over the years through our membership in the Institute of Asset Management, and other global forums, as described in response to PC-DR-341.
b) Because, in our experience, as noted in our peer contacts, industry publications and stories, perspectives of consultants, and conference presentations, etc., public utilities have led investor utilities in the adoption of asset management practices. This, in spite of the fact, that public utilities have no incentive to replace assets as quickly as possible once they are fully depreciated.
c) Because this is what we have noticed over the years, which we believe in part is the result of pressure to better demonstrate the prudence of their infrastructure management and customer costs.
d) Please see the Company's response to PC-DR-341.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	05/20/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Peggy Blowers
TYPE:	Data Request	DEPT:	Asset Management
REQUEST NO.:	PC - 341	TELEPHONE:	(509) 495-4789
		EMAIL:	Peggy.Blowers@avistacorp.com

REQUEST:

Please refer to Avista's response to Public Counsel Data Request No. 326, in which Avista explains the workings of its economic end-of-life model. Also refer to Avista's response to Public Counsel Data Request No. 307, subpart (b), which explains that Avista uses its economic end-of-life model to determine the appropriate age at which to replace assets of a particular type. Provide a list of independent, professional organizations, such as IEEE; EPRI; ISO (55002 Asset Management; 31000 Risk Management); IEC (31010 Risk Assessment); or any other independent, professional organization which endorses the economic end-of-life approach to asset replacement timing Avista follows.

RESPONSE:

Lifecycle cost analysis, as properly performed by Avista, produces financial results that help an organization determine how to manage their assets in the least costly manner, while meeting a range of business-critical objectives. Whether it's when an asset fails, or it's worn out and fails testing, or it's reached a point in its service life when keeping it in service longer begins to add unnecessary costs, then the asset has reached the "End of Life," or "End of Useful Life," or "Economic Optimum," or "Economic End of Life," or "Lowest Lifecycle Cost." It doesn't matter what name or term you use to describe that point, it's simply the point where you remove the asset from service, because keeping it in service longer is wasting your money or your customers money.[52] The term "Economic End of Life" is used by Avista to help you understand how a cutout that is typically run to fail, with failure being the economic optimum in the default case, can have a different, lower-cost economic optimum if the default conditions, such as replacement cost or risk costs, that led to its initial designation, change. It's the Lifecycle Cost Analysis process that is paramount, not the terminology that an organization uses to describe the point of its lowest lifecycle cost.

Following is a summary of the independent, professional organizations, etc., that endorse various elements of Lifecycle Cost Analysis in the manner performed by Avista.

1. Avista follows the **Institute of Asset Management Subject Specific Guidance** manuals number 16, titled **"Reliability Engineering,"** and number 8, **"Lifecycle Value Realisation"** as the primary frameworks and guides for its lifecycle costs analyses, including its determination of economic end of life, and the other analyses we have presented to Public Counsel.
2. These **Subject Specific Guidance** manuals comport with the **International Standards for Asset Management, PAS-55 and ISO 55000**, etc., which international standards the **Institute of Asset Management** was instrumental in leading and supporting in their development and implementation.
3. **Subject Specific Guidance** manual number 8, **"Lifecycle Value Realisation,"** lists on page 10, the following statement: The 'end of life' can be determined in several ways, which three approaches are listed and briefly described in the image excerpt from that page, below.

[52] Even when there is remaining service life

"Economic end of life" as defined by the Institute of Asset Management, which practices are congruent with the ISO and PAS international Asset Management Standards, and which has been defined and properly implemented by Avista, is a mainstream application of lifecycle cost analysis, used to determine the replacement strategy that allows us to deliver service to our customers at the reasonably lowest optimized cost.

> The 'end-of-life' can be determined in several ways, for example:
>
> - The technical: where 'useful' or functional life refers to the period of asset capability in relation to functional need.
> - The economic; where life is derived from an analysis of functional benefits (e.g. revenues) versus the costs and risks of ongoing ownership.
> - The book life; where there is often an accountancy or 'book' life that is calculated from generic depreciation and taxation treatments of the capital investment and its balance sheet impact.
>
> Institute of Asset Management, Subject Specific Guidance (SSG) Manual number 8, "Lifecycle Value Realisation," page 10.

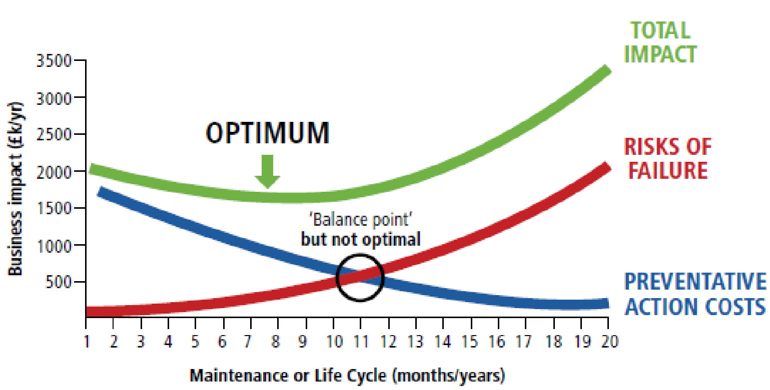
4. The **Institute of Asset Management** is widely recognized as the leading professional association advancing the policies, science and practices of asset management. **Avista has been a member** of the Institute of Asset Management since 2006.

5. The **Availability Workbench** application used by Avista is consistent with, and supportive of the IAM documentation for performing Failure Analysis and Comprehensive Lifecycle cost analysis, consistent with Avista's response to PC-DR-332.

6. Following is a clip from the Institute of Asset Management's "Reliability Engineering" Subject Specific Guidance Handbook – 16, illustrating Avista's practice of conducting lifecycle cost analysis, referred to in the manual as Cost Risk Optimization (CRO).

5.9.2 When is it used?

CRO is often used for long term investment planning activities to model the impacts of multiyear factors and look for optimal solutions as to when to repair, refurbish, or replace assets while maintaining an acceptable risk profile and balancing multiple constraints. These techniques can be focused on organisational processes (Bayesian approach) or specific assets, or groups of similar assets modelled together based on specific shared characteristics or individual asset characteristics.



Following, is some additional supporting evidence of the independent, professional organizations, etc., that endorse Lifecycle Cost Analysis in the manner performed by Avista.

"Weibull Analysis Handbook," - An early reference to the emerging science of Lifecycle Cost Analysis, which is titled "Weibull Analysis Handbook," and which was relied upon by Avista early in its efforts to develop a home-made Weibull failure distribution tool, as described in our response to PC-dR-332, is provided in PC-DR-341 Attachment A. The publication, from 1983, was a joint effort involving Pratt & Whitney Aircraft, reporting methods that had been used in modeling aircraft engine failures (typically high consequence costs), but which had not been published prior to that time. This technical provides a substantial foundation for understanding the construction, interpretation and use of the failure characteristics of assets as one fundamental elements of lifecycle cost analysis.

Institute of Asset Management - The subject request naturally mentions the ISO standards for Asset Management, which followed development of the first international standard for asset management, PAS 55, which pioneering work was led by the Institute of Asset Management (IAM). The Institute of Asset Management, headquartered in England, also played a key role in the development of the ISO standards, which were inaugurated in London in 2014. The Institute of Asset Management is widely recognized as the leading professional association advancing the policies, science and practice of asset management. Avista has been a member of the Institute of Asset Management since 2006. A clip of the IAM website is provided below, accessible from the link IAM - About the IAM

IAM "Subject Specific Guidance" - One of the many functions of the Institute of Asset Management has been their collaboration with other organizations to develop consensus on the major subject areas within asset management, which 39 subject areas are intended to describe the complete scope of topics under the discipline. The Institute of Asset Management has focused on the development and distribution of 'how to' manuals, referred to as "Subject Specific Guidance" for each of these 39 Areas, to help organizations achieve greater asset management capability and competency. These manuals, like all of the IAM practices flow directly from the International Standards noted above, which IAM was instrumental in leadership and support for implementation.

You can see the individual Subject Specific Guidance posted for sale on the IAM website shown below by 'clicking' on the "SHOP" icon on the right of the header bar. Avista has an extensive library of these Subject Specific Guidance, which listing, among other reference documents retained by the Company, is provided in the image that follows the IAM webpage, below.

The Institute of Asset Management

About the IAM

The Institute of Asset Management (the IAM) is the international professional body for asset management professionals.

The IAM develops asset management knowledge and best practice, and generates awareness of the benefits of the asset management discipline for the individual, organisations and wider society.

Established in 1994, the IAM currently has over 2000 Individual and 300 Corporate Members and a network of over 30,000 people globally.

The Institute of Asset Management (the IAM) is a not-for-profit, professional body. We are owned and controlled by our members and committed to remaining independent from commercial and trade associations.

We exist to advance the discipline of asset management, not only for people and organisations involved in the acquisition, operation and care of physical assets but also for the benefit of the general public.

<u>230/115 Autotransformer</u>	<u>Continuous MVA</u>	<u>4-Hour Rating MVA</u>	<u>1-Hour Rating MVA</u>
Westside 230/115 #2	413 Winter 338 Spring/Fall 304 Summer	473 Winter 404 Spring/Fall 378 Summer	478 Winter 431 Spring/Fall 378 Summer

Distribution

Reliability Coordinator

Version History

Version	Version Date	Action	Change Tracking	Reviewed By
0	02/18/2010	Create procedure	New	R. Hydzik
1	06/21/2010	Annual Review	None	R. Hydzik
2	06/07/2011	Annual Review	None	R. Hydzik
3	07/11/2012	Annual Review	None	R. Hydzik
4	06/28/2013	Annual Review	None	R. Hydzik
5	06/27/2014	Update with autotransformer short term ratings, 80% operating limits	Update	R. Hydzik
6	10/13/2014	Updated ratings at Cabinet and Pine Creek	Update	R. Hydzik
7	12/05/2014	Updated ratings at Beacon	Update	R. Hydzik
8	01/12/2015	Updated ratings at DryCreek, Benewah, Boulder, Shawnee	Update	R. Hydzik
9	06/23/2015	Annual Review	None	R. Hydzik
10	07/29/2015	Updated ratings for Rathdrum	Update	R. Hydzik
11	10/02/2015	Corrected one-hour summer rating for Rathdrum	Update	R. Hydzik
12	06/21/2016	Updated PineCreek #1	Update	R. Hydzik
13	06/27/2017	Annual Review	None	R. Hydzik
14	06/26/2018	Update rating on Westside #1	Update	R. Hydzik
15	07/12/2018	Update rating on Cabinet 230/115	Update	R. Hydzik
16	04/02/2019	Update Shawnee X-H rating to 280	Update	R. Hydzik
17	06/17/2020	Annual Review	None	R. Hydzik
18	09/30/2020	Update Westside #2 rating	Update	R. Hydzik

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION STAFF
RESPONSE TO DATA REQUESTS

DATE PREPARED: May 13, 2021	WITNESS: Aimee N. Higby
DOCKETS: UE-200900-901/UE-200894	RESPONDER: Aimee N. Higby
REQUESTER: Public Counsel	TELEPHONE: 360-664-1312

REQUEST NO. 1:
RE: Capital Additions — Pro Forma

Please refer to the Response Testimony of Aimee N. Higby's Exhibit ANH-1T, at 34, which recommends that pro forma adjustments Avista requests for ER 2204 Substation Rebuild capital and ER 2470 Distribution Grid Modernization capital be approved because they "are consistent with the Commission's view of programmatic investments" required to qualify as pro forma adjustments.

a) Please confirm that Staff did not specifically examine the prudence of the Company's Substation Rebuild of Distribution Grid Modernization capital spending. If this cannot be confirmed, please provide any analysis Staff completed regarding the prudence of these investments.

b) Please confirm that Staff recommends the referenced pro-forma capital spending adjustments due solely to the fact that they qualify as pro forma adjustments, and that Staff presumes these particular capital investments to be prudent absent a specific prudence review. If these cannot be confirmed, please explain.

RESPONSE:

a. Not confirmed. Staff reviewed the following materials to establish familiarity with the Company's Substation Rebuild and Distribution Grid Modernization capital spending and to develop a baseline for distribution system planning and grid modernization:

1. Company provided documentation:
    i. Exh. HLR-1T, Direct Testimony of Heather L. Rosentrater
    ii. Exh. HLR-2, Avista's Electric Distribution Infrastructure Plan for 2020
    iii. Exh. HLR-7, Avista's Substation Infrastructure Plan for 2020
    iv. Exh. HLR-10, All program investments for 2018 and 2019
    v. Exh. HLR-11, Capital Business Case documents
    vi. Exh. KJS-1T, Direct Testimony of Kaylene Schultz
    vii. Exh. KJS-2, Capital Additions Transfers to Plant, 2018-2020
2. Data Request Responses
    i. UTC Staff Data Request Nos. 89, 90, 91, 107, 145, 152, and 154
    ii. Public Counsel Data Request Nos. 37, 105, 110, 111, 118, 119, 222, 223, 228, 256
3. Reports:
    i. "Utility Investments in Resilience of Electricity Systems," Berkley Lab, Report No. 11, April 2019
    ii. "Modernizing the Electric Grid: State Role and Policy Options," National Conference of State Legislators, November 2019

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REQUESTER: Public Counsel | TELEPHONE: 360-664-1312

iii. "Reimagining the Grid," Southern California Edison, December 2020

4. Presentations:
   i. "Making the Distribution Grid More Open, Efficient and Resilient," Paul De Martini, March 26, 2015

After reviewing the materials listed above as well as others that Staff did not retain copies of, Staff did not find reason to challenge the prudence of the Company's Substation rebuild or Distribution Grid Modernization capital spending. Staff's assessment of whether the programs appear rational and reasonable was informed by the knowledge gained from review of the above documents.

b. Not confirmed. Staff is not contesting the inclusion of these pro forma programmatic investments based on the documentation reviewed in the course of this proceeding and Staff's understanding of the Commissions standards regarding pro forma capital additions.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION STAFF
RESPONSE TO DATA REQUESTS

DATE PREPARED: May 13, 2021
DOCKETS: UE-200900-901/UE-200894
REQUESTER: Public Counsel

WITNESS: Amy I. White
RESPONDER: Amy I. White
TELEPHONE: 360-664-1247