RELIABILITY REPORTING INQUIRY

Staff Findings and Recommendations

2018

Prepared by:
Jason Ball
Christopher McGuire
David Panco
Andrew Roberts

UTC
Washington Utilities and Transportation Commission

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Executive Summary

The Utilities and Transportation Commission (UTC) began requiring electric utilities to submit reports on reliability in 2001. Since that time, changes in technology and policy have fundamentally altered the concept of reliability. The UTC began this inquiry to understand the value of the reliability reports as they stand today. While reliability has always been a core function of electric utilities, it has historically been analyzed in a silo. Reliability is now understood to be the result of multiple decision processes across a company.

Unfortunately, most of the information the UTC requires Washington electric investor-owned utilities (IOUs) to provide in the reliability reports is not useful in understanding these decisions. Instead, the reliability report has become a catch-all for multiple issues, some of which are only tangentially related to service reliability. This review is a comprehensive analysis of the relationship between reliability and distribution planning, supporting infrastructure, emerging technologies, and investment decisions.

Through investigation and discussions with each electric IOU, this inquiry identifies the following five concerns about reliability reporting:

1. **Reliability benchmarking does little to clarify investment decisions.** Individual distribution system investments rarely have a direct reliability goal, though they may offer system-wide reliability benefits. As such, reliability and business-specific needs should be evaluated holistically. Further, benchmarks should not be used to establish penalties as these metrics are too aggregated to be affected by short-term projects.

2. **Reliability rarely serves as an exclusive rationale for a company's business decisions.** However, it is unclear how utilities develop investment budgets for reliability-only projects, versus projects for the general distribution system. Companies should provide additional transparency into the budgeting process. Companies should also identify the degree to which reliability performance impacts budgeting or vice versa.

3. **Emerging technologies will continue to impact utility reliability.** Software that integrates current and future technologies is key to addressing reliability issues. Utilities should establish pilot projects and a collaborative environment to help regulators evaluate emerging technologies.

4. **Evaluating critical infrastructure security, both physical and cyber, remains a key consideration.** Electric IOUs should conduct a risk evaluation that includes the existing critical infrastructure security reporting structure.

5. **Emergency management, asset management, outage classification, and vegetation management are beyond the scope of reliability reporting.** A workgroup made of the electric IOUs, commission staff, and stakeholders should identify the appropriate methods for and utility of reviewing these topics.

Overall, the current reliability reporting structure is unwieldy, calling into question its usefulness as a regulatory tool. This inquiry provides several recommendations to reduce regulatory burden for utilities and ensure reliability reporting is useful to stakeholders, the UTC, and customers.

Summary of all Recommendations

The recommendations identified below focus on the requirements of reliability reporting. However, some of these topics could be folded into new or existing processes (such as overall planning requirements). Staff recommends addressing all of the issues identified in their appropriate venues. The most important goal of these recommendations is to streamline the reliability reporting structure to keep it relevant in modern conversations.

I. Reporting Requirements

Staff, the electric IOUs, and stakeholders should have follow-up conversations focused on the purpose of the reliability report. These discussions should result in recommendations for changes to the IOU Monitoring and Reporting (M&R) plans. At a minimum, each IOU M&R plan should follow a consistent framework of reporting structures and terms.

II. Benchmarking & Penalties

When making reliability investment decisions and presenting them to the UTC, companies should include a comprehensive business case showing how a reliability-specific investment ties to a company's reliability objectives. Further, these presentations should offer evidence supporting reliability objectives given measured historical performance and discuss the validity of company benchmarks used to justify improved or relaxed reliability performance.

The commission should not pursue penalties for failing to meet targeted reliability benchmarks (e.g., SAIDI or SAIFI). A punitive structure is not an appropriate means to mitigate service quality impacts, including the potential for degradation of service quality from decoupling mechanisms.

III. Reliability Investment Decisions & Planning

Reliability planning is a supporting—rather than a foundational—component of distribution system investment decisions and should not be made into a separate planning process.

Staff is uncertain how budgets for reliability projects, or distribution system investments more broadly, are established. While the IOU's have provided some insight into these processes, additional transparency is needed. So far, staff has been unable to identify, if possible, the degree to which reliability performance necessitates a larger distribution capital budget and a commitment to projects that specifically improve reliability.

IV. Emerging Technologies

IOUs should conduct more pilot projects to test newer technologies, with the UTC's recognition that not all projects may present positive financial value. Pilot programs should specifically consider initiatives that analyze the benefit and costs of individual technologies. This process should be adaptive and responsive to new technologies as they are developed.

V. Critical Infrastructure Security

The current critical infrastructure security reporting structure should be separate from reliability reporting. For example, an electric IOU risk evaluation that is inclusive of critical infrastructure security may be helpful in determining overall risk to companies and consumers. However, the commission should continue to provide oversight without dictating specific operational practices for the companies or requiring the reporting of sensitive information.

VI. Additional Topics

A workgroup made up of the utilities, commission staff, and stakeholders should identify the appropriate methods and venues to review four other identified topics: emergency management, asset management, outage classification, and vegetation management.

I. Overview

Background

Washington's electric investor owned utilities (IOUs) are required by rule to submit annual reliability reports to the UTC.[1] After reviewing the 2017 filings, UTC staff needed further clarity about the reports' context and content. A team comprised of staff from the UTC's regulatory services, policy, and consumer protection sections was assembled to evaluate the complexities of reliability. The team's objectives were to:

- Gain a better understanding of the context in which the reports originated and are continuing to evolve;
- Explore the way utilities collect and present data;
- Discuss possible report improvements to provide stakeholders with useful reliability information; and,
- Develop a briefing on staff's findings and recommendations.

This inquiry began as a simple discussion of each IOU's practices. During multi-day on-site meetings, the utilities provided the team with substantial exposure to a set of different and powerful project planning and investment structures. We express our gratitude to Avista Corporation, Pacific Power & Light Company, and Puget Sound Energy for their time and effort in working with the team to understand these issues. Each discussion has been integrated into this document as a snapshot in time of current company operations.

This inquiry aims to bridge the gap between regulators and companies on the topic of reliability. Background information and high-level discussions, included in a variety of appendices, provides a common framework from which to ask questions. This inquiry does not attempt to pass operational judgment—these discussions are not exhaustive, nor are they a guide on best practices. Most importantly, this report is focused on improving regulatory processes to ensure regulators and stakeholders have an accurate and consistent picture of reliability-related decisions made by the IOUs.

Current Electric Reliability Report Requirements

In an effort to meet annual reporting requirements and provide information on the state of reliable service for Washington customers, utilities engage in numerous and varied practices concerning system reliability. While the specific terms of reliability are defined by commission

[1] Per WAC 480-100-398.

rule, utilities' reports have expanded over time with settlement-stipulations and staff requests. Each report differs based on the circumstances and experiences of each utility. In some cases, topics in the reliability reports are not related to the topics required by rule.[2]

Current commission rules require each IOU to provide the following information in their annual report:

1) A set of baseline reliability statistics (including SAIDI/SAIFI)[2] and a comparison of new statistics to the baseline, for a minimum of seven years;
2) Any changes to the collection or calculation of reliability data;
3) Geographical areas of greatest concern, the causes of concern, and how concerns are being addressed; and,
4) A utility's total number of complaints about reliability, power quality, or major events.

Utilities must also provide information consistent with their Monitoring and Reporting (M&R) plans on file with the commission. These requirements include, at a minimum, detail on the reliability statistics and information companies must report to the commission. Additionally, the rules require a timeline for establishing baseline reliability statistics.[3]

These are the only components of a company's annual report required by rule. The table below outlines the additional information included in each utility's reliability reports.

Table 1: Electric Reliability Reporting Components

Component	Description	Avista	Pacific Power	PSE
Critical Infrastructure Security Report	Provides information on current practices of cyber and physical security at an IOU. The report is included as an attachment to the annual reliability report and is provided in response to an ongoing request by commission staff. More information is available in Section V.	✓	✓	✓

[2] The System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI) are standard industry metrics that calculate the length and rate of power failures for a given utility. A full list of key terms and definitions are included in Appendix B. Additional information about the history of reliability reporting can also be found in Appendix E.
[3] WAC 480-100-393

Component	Description	Avista	Pacific Power	PSE
Outage Cause Analysis	Outage analysis identifies the root cause behind a company's baseline statistics. However, the reporting and analysis covers a range of topics well beyond the direct scope of reliability, such as how vegetation management budgeting is determined.	✓	✓	✓
Service Quality Indicators	Measures the quality of customer service, as required through a variety of sources, such as specific commission orders, merger agreements, or settlement agreements. Refer to the discussion below for more information.	✓	✓	✓
Proposed Customer Notice about Reliability	Included as a component of informing consumers about the most recent reliability results, each utilities proposed notice differs both in content and format.	✓		✓
Targeted Reliability Improvements and Pilot Projects	Provides a high-level overview of investments made to improve reliability.	✓		✓
Gas Outlying Area Emergency Plans	Includes emergency response information for gas service in specific areas. It is unclear where this requirement originated.		*N/A*	✓

Inconsistencies Exist in the Interpretation of Reporting Requirements

Each IOU provides an annual report that varies in format and includes additional information at the request of stakeholders, staff, or the UTC. The reports often include a wide range of topics only tangentially related to reliability. The M&R Plans only discuss some of these requirements, and differ by IOU. The result is an inconsistent narrative that prevents an easy comparison across the three electric IOUs.

A good example of inconsistency is the labeling and use of customer-focused metrics. These metrics are known by a number of labels, such as customer service quality metrics, customer service measures, customer guarantees, or service quality indicators. For consistency's sake, this report will use service quality indicators, or SQIs, for measures designed to show how customer-focused operations are performing and to what degree.

SQIs may technically meet the definition of a reliability statistic, but they also take into account broader company service concerns and have little bearing on the overall state of system reliability. For instance, a Pacific Power measure identified as "CG7" ensures the company will provide customers at least two days' notice of planned interruptions prior to turning off power.[4] While important from a customer engagement perspective, it has little value in understanding the reliability of electric infrastructure.

SQIs are more relevant to customer satisfaction than reliability, yet they are included as a part of the reliability reports (this is most likely due to the amassing of requirements over time). Including these measures in reliability reports creates a document bloated with information that is ineffective at discussing the specifics of reliability.

To clearly separate reliability from other consumer satisfaction concerns, metrics should be grouped by function (to the extent possible) or they should be reported in a different document altogether. One option would be to update M&R Plans to reference external documents with a customer satisfaction focus. This way, consumer-centric reports can maintain their original purpose while the utilities' burden of reliability reporting and follow-up analysis is reduced.

The designation of "areas of concern" presents an additional inconsistency. The reliability rules require IOUs to identify "geographic areas of greatest reliability concern."[5] Over time, the phrase "geographic areas" has been interpreted as a summary of specific circuits. Each circuit is monitored for its performance relative to others, using such metrics as frequency of outage (SAIFI) or outage duration (SAIDI).

Including this data in a report focused on system-wide metrics blurs the line between detailed operational data and broader, aggregate performance scores. These circuits can have operational difficulties that depend on the location of the circuit, geography, age of infrastructure, or the type of asset (such as underground versus overhead). Each of these factors plays a key role in influencing performance, but they do not appear in broader metrics.

However, there will always be a "worst performing circuit" when the measure is the remainder of the system. If the comparison is other assets, there does not exist an intrinsic need for a circuit upgrade. To think otherwise leads to overinvestment in the distribution system, which should not be the goal of reliability reporting. Rather, as will be discussed in Section III, investment decisions concerning specific circuits are driven by more than just a specific outage measure. Reliability as a value proposition appears only as a secondary component of most capital business cases.

[4] *Pacific Power 2016 Electric Service Reliability Report* at 4 (May 1, 2017).
[5] WAC 480-100-398 (3).

There exists, then, a mismatch between how reliability reports characterize areas of concern and how a company manages its capital investment programs. It is important to recognize the disconnection between the circuit-level detail provided in the reports and the actual decisions that impact those areas. To ensure the continued value of the reliability reports, the M&R plans should reference a more robust investment planning process.

Major events constitute a final example of inconsistency in the reliability reports. A major event is a window of time during which a reporting metric exceeds a company-specific threshold. Major event days are generally excluded from baseline reliability statistics to remove the effect of extreme weather events.

Some IOUs, such as Pacific Power, file notices following any major event. However, PSE provides a petition to remove specific events from certain statistics. The inconsistent treatment results in confusion of how each metric is calculated, how to find information concerning major events, and the manner in which complaints are tracked. Ultimately, this information is supposed to be used to determine the treatment of regulatory accounting petitions when the costs associated with an event response are deferred for possible recovery. The lack of consistent information and presentation style makes the process cumbersome.

Summary

Staff's review of the 2017 reports identified multiple inconsistencies in format and content between the IOUs. While the rules requiring reliability reporting are relatively limited in scope, the content of the reports includes multiple requests from stakeholders, staff, and the UTC. In addition, some of the elements of the reports do not seem to directly relate to reliability. This includes specific SQI metrics, identifying the geographic areas of concern, and identifying major events.

Recommendations for Reporting Requirements

Staff, the electric IOUs, and stakeholders should have follow-up conversations focused on the purpose of the reliability report. These discussions should result in recommendations for changes to the IOU Monitoring and Reporting (M&R) plans. At a minimum, each IOU M&R plan should follow a consistent framework of reporting structures and terms.

II. Benchmarking & Penalties

Summary

In 2015, UTC staff began investigating reliability benchmarking. This investigation clarified the strengths and purposes of industry-wide performance measures. Unfortunately, the staff investigation and this reliability inquiry also revealed a flaw: performance benchmarks offer limited value in understanding individual distribution system investments, even those that have a direct reliability focus. This is true even if an investment confers reliability benefits to the system as a whole. Therefore, aggregated reliability metrics (e.g., system-level SAIDI or SAIFI scores) do not solely justify investment in reliability infrastructure.

Although this reliability inquiry has shown reliability-specific project decisions must, in some way, relate to reliability objectives, this does not necessarily include individual benchmarks. The lack of granular value means that penalties associated with failing to meet targeted reliability scores are not an appropriate means to mitigate service quality impacts.

Benchmarking Methods

There are two primary methods for benchmarking reliability performance: econometric and traditional.

The first, econometric benchmarking, requires the derivation of reliability targets like SAIDI and SAIFI using a utility's unique service territory characteristics. This information quantifies the relationship between specific service territory attributes and reliability performance. This can inform how individual utilities should perform given their unique service territories.

Econometric benchmarking for reliability is meant to address the primary shortcoming of traditional approaches. Specifically, a utility's peers will never have the same set of unique service territory challenges; such as the amount of urban versus rural customers served by the utility. There are a number of factors that are relevant to reliability challenges, and no two utilities are the same with respect to the full suite of those factors. Resolving these concerns necessitates a "hypothetical peer utility" with a service territory identical to the utility in question. This results in a statistically modeled SAIDI and SAIFI performance for the "peer utility" that can serve as a scientifically derived benchmark.

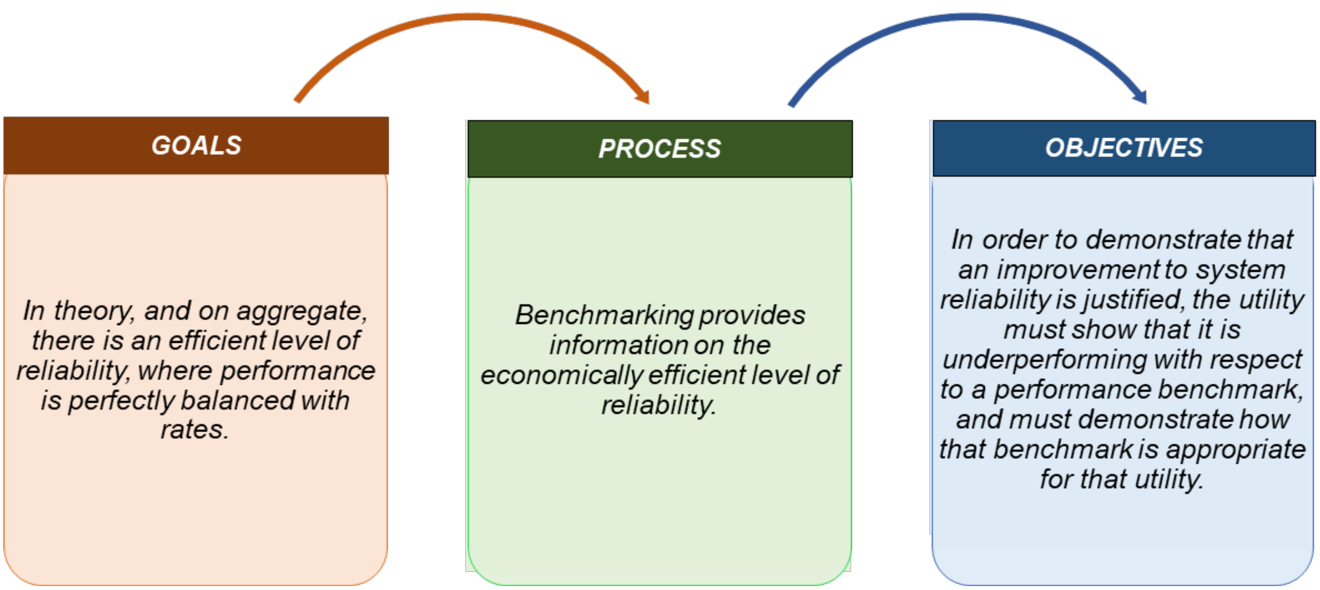
To investigate the validity of an econometric approach, the commission opened an investigation under Docket U-151958. As part of that investigation, the commission contracted with Power System Engineering, Inc. of Madison, Wisconsin, to perform an econometric benchmarking study. The final report, titled "Reliability Targets for Washington's Three Investor-Owned

Utilities" was filed with the commission on June 7, 2017. Staff prepared a memo in Docket U-151958 that provides more detail on the specific information contained in the report. While the investigation revealed important information about the calculation of reliability benchmarks, Staff recommended closing the investigation. The reason for this is because, as discussed below, there is little more that can be gained from evaluating aggregate benchmarks on their own.

The second method, traditional benchmarking, primarily relies on a combination of peer group comparisons and historical trending. In general, peer groups are utilities from across the country that have similar service territory characteristics. This approach assumes that utilities will target a performance similar to the selected peers. Alternatively, utilities can rank their performance relative to other utilities across the country and target a specific quartile (e.g., better performance than 50 percent or 75 percent of the utilities across the country). As long as historical trends are moving in a positive direction, or at least holding steady, performance is often deemed to be acceptable.

The development and historical use of these benchmarks is derived from a complex relationship between competing business investment decisions. As shown in Figure 1, the development of benchmarks is an interaction between three categories:

Figure 1: Benchmarking Development and Relationships



Each of these categories can be further broken down:

- **Goals:** Reliability benchmarking is a barometer for managers developing reliability objectives. There is an inherent struggle, without an objective framework, to communicate why an improvement or even the maintenance of current reliability performance is justified.

Absent an objective benchmark, it is nearly impossible to know whether a utility has under- or over-invested in reliability. Investment in reliability is therefore an economics problem: a utility should supply the level of reliability demanded by its customers. In aggregate, under-supply of reliability implies customers can tolerate higher prices for more reliability, and over-supply implies customers would tolerate lower reliability in exchange for lower rates.

- **Process:** Implementing benchmarking traditionally involves peer comparisons. It can be argued that the full population of peer utilities across the country will have, on balance, achieved a reasonable level of aggregate reliability. Small peer-group comparisons serve a similar function; by selecting a group of similarly situated peers, a utility can measure itself against those peers. As an alternative, econometric benchmarking provides a unique calculation specific to the utility's service territory characteristics. It utilizes statistically significant relationships to identify the drivers of reliability in a statistically valid manner. Either by accepting the collective wisdom of peers, or utilizing econometrics, the utility develops a benchmark for itself.
- **Objectives:** Regardless of the benchmarking method used, econometric or traditional, the purpose is to inform the utility whether the level of reliability it supplies is approximately efficient. This provides a meaningful basis for establishing reliability objectives. Reliability-specific investments should relate to those objectives. For example, if a utility is making an investment specifically to "improve reliability," management has authorized improved reliability as an actionable business objective. Therefore the "improved reliability" objective must also be shown to be justified.

Conclusions Regarding Reliability Benchmarking

While an econometric approach produces the most meaningful benchmarks for each individual utility, those benchmarks are of limited value when evaluating typical distribution system investment. The benchmarking investigation, based on multiple sources of information, exposed weaknesses in relying on aggregate reliability performance benchmarks to justify individual investment decisions.[6] This conclusion is foundational to the discussion below in Section III; investments depend on business cases and have only tangential relationships to aggregate reliability metrics. The decision to move forward with an investment is informed by system benefits beyond just meeting reliability objectives. Further, when a utility makes an investment for reliability purposes, it often does so for a targeted solution to a clearly identified problem. This decision is made without consideration of system-wide, aggregate reliability performance.

[6] Staff was informed by multiple sources of information and feedback. Beyond its review of the econometric benchmarking report produced by Power System Engineering, staff considered comments filed by utilities and interested parties in Docket U-151958, discussions at the workshop in that docket, including a discussion led by Joe Eto of Lawrence Berkeley National Lab, and discussions with utilities through this inquiry.

However, benchmarks could be useful for utilities attempting to justify investments that are specifically targeted to improve aggregate reliability performance. In such a case, utility management will have defined “improved reliability” as a business objective. This objective would be, in turn, supported by a firm reasoning for why improved reliability is appropriate.

It should be noted that as there is substantial statistical uncertainty associated with any benchmarking approach, including econometric benchmarking. It is difficult for utilities to fully commit to a target that is imprecisely derived. Therefore, utilities should be encouraged to use a combination of approaches, including the development of new, more sophisticated means to establishing performance benchmarks. Those approaches can work in concert to help utilities improve or relax reliability performance.

Penalties

The prevalence of decoupling mechanisms leads to questions of the need for performance metrics to ensure utilities do not sacrifice reliability for short-term profitability. The current reliability statistics and their benchmarks (e.g., SAIDI or SAIFI) are fundamentally out of sync with the operation of penalty mechanisms. Generally penalty mechanisms associate targets (such as a specific level of improvement in a SAIDI score) with costs of failing to meet those targets (usually a monetary penalty).

However, only specific types of projects can impact reliability and improve system-wide SAIDI or SAIFI scores. These projects are typically large and require long lead-times. It would be difficult to assign meaningful timeframes and associated penalties to their implementation. Penalty mechanisms also need to take into account the full scope of a company’s operations and overall reliability. This is not a useful exercise at this time, given that no mechanism exists for the commission to provide input in the initial response planning for a failed benchmark.

Benchmarking Recommendations

When making reliability investment decisions and presenting them to the UTC, companies should include a comprehensive business case showing how a reliability-specific investment ties to a company’s reliability objectives. Further, these presentations should offer evidence supporting reliability objectives given measured historical performance and discuss the validity of company benchmarks used to justify improved or relaxed reliability performance.

The commission should not pursue penalties for failing to meet targeted reliability benchmarks (e.g., SAIDI or SAIFI). A punitive structure is not an appropriate means to mitigate service quality impacts, including the potential for degradation of service quality from decoupling mechanisms.

III. Reliability Investment Decisions & Planning

Summary

Informal discussions with the commission following the final workshop on reliability benchmarking identified the need for a forward-looking planning document. The discussions pointed specifically to the reliability reporting process as an avenue for understanding reliability investments and how IOUs decide to pursue them.

A reliability planning document would need to discuss specific projects, how they are identified, and how they relate to reliability objectives. Because the project decisions must in some way relate to reliability objectives, companies would also need to discuss how objectives are determined, why those objectives are appropriate, and how they are economically justified.

Analyzing reliability planning requires detailed information on how investment decisions, specifically for reliability, are made. Further, these projects would need to directly tie to a company's reliability objectives. Based on information provided by the IOUs, there does not seem to be any reason to distinguish reliability project planning from business planning as a whole.

Reliability Investment Decisions

Reliability is one of a number of different benefit streams for various investment options. Investments that provide the most value across a number of categories receive the highest priority—they are most likely to be funded. Utilities do not typically make distribution system investments to solve poor reliability performance. Rather, reliability performance is simply a consequence of a company's aggregate distribution system investment choices. Therefore, reliability-related investments should not be considered distinct from a broader category of investments, distribution or otherwise.

The decision to invest in infrastructure should depend on the total business case, inclusive of reliability. Ideally, utilities have a tool to enable investment decisions that maximize value where all benefits streams are monetized, and investments are compared on a net present value basis. This creates an optimal portfolio, where the highest value projects are funded given limited annual budgets. To the extent that an optimized portfolio does not achieve reliability benefits in line with overall objectives, company managers must decide whether to:

1) Re-prioritize projects toward those with larger reliability benefits, or
2) Provide additional budget authority for distribution investments.

Companies rarely consider the first option, which undermines the inherit value of the model. Since these models have carefully established weights for multiple value vectors, and are generally capital constrained, prioritizing specific reliability projects is equivalent to arbitrarily downgrading other projects. The second option, however, is limited by a company's overall budget and capital spending allotment. Therefore, reliability performance planning is not a separate process that drives distribution system investment decisions for a typical investment plan.

Reliability Planning

This inquiry included a significant amount of information concerned with how and why investment planning is related to reliability objectives.[7] Based on the information provided by the IOUs, a single conclusion can be reached: reliability does not serve as an exclusive rationale for business decisions as these decisions often include multiple inputs from joint sources and shared products.

This conclusion is significant because it forces reliability planning to become a discussion about capital investment in the distribution and transmission system.

This is not to say reliability cannot be planned for as a single element of a larger plan. Rather, an adequate review of reliability investment necessitates a wide-ranging discussion that, as more and more requirements are added, has the potential to stray ever farther afield. Such a process needs to be holistic from the start. Otherwise, it will result in a moving target with inconsistent messaging to IOUs and consumers about reliability priorities.

The planning conversation should focus on investments as a whole, with reliability identified as a specific benefit/cost stream of individual projects. This is because, as discussed previously, it does not appear possible to analyze what a particular level of reliability would be given a discrete investment or set of project expenditures. Reliability it seems, is one of the many attributes for a project and usually an ancillary one at that. It is possible, if not likely, that improvements in reliability performance necessitate a larger distribution capital budget and a commitment to projects that specifically improve reliability.

Using the approach described here, a strategic planning process can identify the least cost way to improve system reliability. As discussed in the previous section, benchmarking performance is a necessary component to meet established reliability objectives. Folding these objectives, and their source, into wider investment plans provides the best picture of actual electric IOU operations.

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[7] For a detailed discussion about each IOU's practice, refer to Appendix F.

Reliability Investment and Planning Recommendations

Reliability planning is a supporting—rather than a foundational—component of distribution system investment decisions and should not be made into a separate planning process.

Staff is uncertain how budgets for reliability projects, or distribution system investments more broadly, are established. While the IOUs have provided some insight into these processes, additional transparency is needed. So far, staff has been unable to identify, if possible, the degree to which reliability performance necessitates a larger distribution capital budget and a commitment to projects that specifically improve reliability.

IV. Emerging Technologies

Summary

Emerging technologies will impact reliability through the physical and virtual operations of the utilities. The software necessary for integrating current and future emerging technologies will be key to addressing reliability related issues. In order for a utility and its customers to realize the maximum benefit offered by these technologies, the implementation of an advanced distribution management system (ADMS), including advanced metering infrastructure (AMI), is essential.

While not all grid modernization efforts will directly influence a utility's reliability metrics, technology can provide a more resilient grid, improve energy efficiency, and encourage conservation. For example, the installation of self-healing grid components and AMI should accelerate outage restoration, reduce the number of customers affected by power disruption, and increase customer awareness of utility operations.

IOUs use a variety of software packages to enable multiple distinct services. These systems are highly customized, require specialized training, and are key to effective service.[8]

Advanced Distribution Management Systems (ADMS)

ADMS is the software platform that supports the full suite of distribution management and optimization technologies. It includes automatic outage restoration, performance optimization tools, fault location, isolation and service restoration (FLISR), volt/volt-ampere reactive optimization, conservation voltage reduction (CVR), peak demand management, and support for micro grids, distributed generation monitoring, and electric vehicles.[9]

Notably, the industry is in early stages of adopting ADMS, which appears to be a necessary foundation for distribution automation. Distribution automation uses digital sensors and switches with advanced control and communication technologies to automate feeder switching and provide enhanced system monitoring. For example, FLISR schemes are DA tools that utilize strategically-placed communication-enabled fault detection devices, distribution re-closers, and motor-operated switches to automatically reconfigure the distribution network in response to an outage.

[8] For a detailed discussion of the various software packages necessary for operations and in use at each IOU, refer to Appendix G.

[9] Gartner IT Glossary (February 6, 2018) https://www.gartner.com/it-glossary/advanced-distribution-management-systems-adms/.

[10] *Insights into Advanced Distribution Management Systems*, Department of Energy (February, 2015).

The implementation of ADMS is a necessary step on the path towards grid modernization. A key feature of these newer software and hardware systems is increased processing power. With modern computing, ADMS can be deployed as a comprehensive service that integrates and disseminates data through multiple vectors. This forms a solid foundation for evaluating and adopting modern technologies.

Pilot Projects & Grid Modernization

Pilot projects provide the commission and IOUs an opportunity to directly respond to disruptive or emerging technologies. In particular, pilot projects help identify the range of products available and the extent to which they may offer non-financial value. Additionally, newer technologies should be evaluated for potential costs and benefits before being integrated into the system.

As ADMS and other software upgrades change the operational landscape, a new suite of applications will be available. Enabling access to these applications will require regulators and the IOUs to be nimble, responsive, and on the cutting edge.

The following sections provide an overview of current pilot projects for each IOU.[11]

A. Puget Sound Energy

In 2007, Bellevue unveiled plans for a transit-oriented urban village dubbed the “Spring District.” The 36-acre construction project is located between the city center of Bellevue and Redmond, consisting of residential buildings, office and commercial space, a hotel, and a light rail station. Concurrent with the first phase of the Spring District in 2017, PSE identified the location as ideal for a smart grid demonstration project. The Spring District project offers a complete "ecosystem” for PSE to evaluate emerging smart grid solutions; for example, the roadway improvements included in the project allowed for the buildout of several underground infrastructure deployments at minimal cost.

Dubbed the “Living Lab,” PSE’s smart grid pilot includes plans for numerous technologies, including AMI, distributed energy resources (DER), energy optimization equipment, self-healing grid technologies, smart-street lighting, and electric vehicle charging stations. The smart switches (required for a self-healing grid) are already installed, while AMI, DERs, lighting, and EV charging hubs are planned for installation.

PSE will also experiment with different program offerings, customer classes, and the effects of layering these technologies in a high-density population area to improve strategies for the

[11] Information regarding past pilot projects can be found in Appendix H.

company's larger service territory. One example is a study of how different smart grid technologies might best adapt to the intermittent energy requirements of the passing light rail trains.

B. Avista Corporation

In recent years, Avista initiated a number of reliability and grid modernization pilot projects. The company tends to adopt new technologies early in the innovation lifecycle.

Avista annually evaluates emerging technologies through "innovation sprints," internally named "Grid Edge," which are brainstorming sessions to determine how different products might provide benefits to customers and affect the company's system. Examples include DC micro grids, combined heat and power, electrification of buses and trolleys, standby generation, utility-scale solar, and data collection devices on utility poles. Grid Edge sprints may also result in company-sponsored pilot projects such as the turner energy storage project, an electric vehicle supply equipment pilot, or a micro-transaction grid pilot.

Spokane's smart city initiative, dubbed Urbanova, aims to harness data to solve urban challenges in new ways. Urbanova's efforts are focused around Spokane's 770 acre University District. Avista is one of six founding partners, which also include the City of Spokane, Washington State University, Itron, the University District, and McKinstry.

Avista is also gathering data from its Smart and Connected Streetlight Pilot to increase energy efficiency. They are also utilizing these same streetlights for air quality research through sensors attached to poles. The Shared Energy Economy Model Pilot will allow for the evaluation of assets such as solar panels and battery storage for system efficiency and grid resiliency efforts.[12]

C. Pacific Power & Light Company

Pacific Power does not currently have any active reliability or grid modernization pilots in Washington. During conversation with Pacific Power, two former pilot projects were briefly discussed: a distribution automation pilot and a fuse saving scheme.

Emerging Technology Recommendations

IOUs should conduct more pilot projects are needed to test newer technologies, with the UTC's recognition that not all projects may present positive financial value. Pilot programs should specifically consider initiatives that analyze the benefit and costs of individual technologies. This process should be adaptive and responsive to new technologies as they are developed.

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[12] This is not an all-inclusive list of Urbanova pilot components. The elements included here have a reliability emphasis. The full collaborative is an integrated approach to solving issues from multiple infrastructure services

V. *Critical Infrastructure Security*

Summary

With new technology deployments and an increasing availability of software based operations, cyber and physical security remain critically important. The commission's current reporting mechanism involves high-level documentation with follow-up discussions. There has been concern, however, that the current reporting framework is inadequate.

In general, infrastructure security policies, procedures, and implementations vary by electric IOU. What the utilities do have in common is a cyclical process of security awareness. Each company is making sure that no one area becomes overdeveloped at the expense of others. The Companies have also incorporated security into their culture, through annual conventions, routine training or reminders, and surprise testing.[13]

Reporting Structure

Each IOU includes as an attachment to their reliability report a high-level summary of both physical and cyber security. This information is provided through an on-going staff request, not through a formal rule requirement. The questionnaire includes 11 questions with multiple subparts.

Since cyber security and physical security are sensitive topics, confidential information is passed along to staff through in-person meetings with each IOU. This format, as well as the attachment of the information to the reliability reports, appears to have little relation to the deployment and planning of reliable service. Rather, physical security and cyber security are components of a utility's overall operational portfolio. Each electric IOU has different means to balance cyber security risk throughout their services. Reporting this information through the reliability documents mixes important objectives, such as reliability investment planning with overall business risk management.

Critical Infrastructure Security Recommendations

The current critical infrastructure security reporting structure should be separate from reliability reporting. For example, an electric IOU risk evaluation that is inclusive of critical infrastructure security may be helpful in determining overall risk to companies and consumers. However, the commission should continue to provide oversight without dictating specific operational practices for the companies or requiring the reporting of sensitive information.

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[13] More information about critical infrastructure security can be found in Appendix I.

VI. *Additional Topics*

During the inquiry, staff recognized a need for more information on certain topics. Some of this data is included in the reliability reports, and some isn't. This does not imply that the reliability reporting structure should be expanded. Rather, a workgroup of interested stakeholders should identify an appropriate vehicle for this information.

Emergency Preparedness

Each of the IOUs have a common conceptual approach to emergency preparedness and response. Storm operations are a subset of their response operations. Overall, exogenous influences like weather (particularly wind and ice), wildfires, or unplanned interactions between utility system assets and the public (such as vehicle accidents and structure fires) can significantly impact distribution reliability.

All of the IOU emergency plans are based on the National Incident Management System (NIMS) framework, a comprehensive set of standards intended to coordinate a range of public and private sector entities. These same standards are utilized throughout the first responder and law enforcement communities.

The tools that are currently used by each of the IOUs provide investment guidance to target overall system reliability while allowing equipment, materials, and personnel to be redeployed to address emergent issues. Not only are these systems robust, they are also pervasive, impacting nearly every aspect of an IOU's operational and decision-making structure.[14]

Asset Management

Asset management includes the monitoring of capitalized equipment (such as large transformers), inventory procurement and deployment, capital management, and expense monitoring and reduction. Each IOU has a unique approach to balance these objectives. Additionally, PSE and Pacific Power have both undertaken improvement programs for certain asset management components.[15]

Outage Cause Analysis

The three electric IOUs vary significantly in how they identify and classify the root cause of an interruption in service. When the outage cause is not certain, some utilities allow field personnel

[14] More information about emergency preparedness can be found in Appendix J.
[15] A detailed discussion of each IOU's asset management programs can be found in Appendix K

to identify the most likely cause based on circumstances, historical event knowledge, or observations in the field. Other utilities require any event without hard evidence be classified as “unknown.”

Comparing the electric IOU to their established benchmarks (or even to each other) requires a clear identification of the root cause for each outage. The varying policies to manage cause code tracking can lead to disparate numbers of “unknowns” or “others.” This in turn can lead to the wrong investment focus.

Vegetation Management

The electric IOUs have identified effective vegetation management as a key component of system reliability. The practices followed by the three utilities have some variation but generally follow the same industry practices. Cyclical budgeting and operational programs are a key component of each IOU’s plan. Since vegetation management makes up such a large component of overall reliability, it seems wise to address its underlying budgetary process in a separate forum.[16]

Recommendations

A workgroup made of the utilities, commission staff, and stakeholders should identify the appropriate methods and venues to review four other identified topics: emergency management, asset management, outage classification, and vegetation management.

[16] More information about vegetation management can be found in Appendix L.

VII. Summary of Findings

Conclusions

The IOUs engage in a myriad of reliability practices, but it is sometimes challenging for them to communicate to regulators their purpose and scope. While some information currently reported to the commission may have reliability implications, not all of it is useful in measuring reliability. More importantly, some content of the report is generally irrelevant to understanding the purpose of specific investments. The recommendation of this inquiry is that reliability reporting needs to be more precise and transparent.

Each electric IOU's reliability report needs to be more digestible. Topics beyond a strict interpretation of "reliability" may be better addressed in arenas with more complete and deliberative conversations. This is especially true for distribution system investment decisions, given that reliability benefits typically do not serve as the exclusive business rationale. Investment decisions often rely upon multiple inputs from joint sources and shared products. To properly understand utility operations and investment decision-making, IOU's need to provide the UTC a holistic business case for their investments.

The tools to evaluate utility reliability metrics require updating. The current discussions about critical infrastructure security and emergency management make it clear that some level of electric IOU risk assessment should be developed. While this is not a specific recommendation of this report, it is a topic in need of further discussion.

It is no secret that the electrical industry is undergoing significant changes. Modern and still emerging technologies have the potential to radically reshape the electric landscape. The changing landscape has also led to broader and more diffuse notions of utility service quality and electric service reliability. Addressing these topics through the narrow lenses of reliability performance distracts from important questions about investment decisions and business practices.

It is imperative to take action now to reduce regulatory burden, ensure the monitoring of reliability remains useful, enable utilities to consider the changing needs of customers, and to be more agile in adapting to rapidly evolving technology. Continued discussions with each IOU and associated stakeholders is the most reasonable next step to improve reliability reporting.

ACE	Area Control Error
ADMS	Advanced Distribution Management System
AHI	Asset Health Index
AMI	Advanced Metering Infrastructure
ARRA	American Recovery and Reinvestment Act
BAA	Balancing Area Authority
BPA	Bonneville Power Administration
CIP	Critical Infrastructure Protection *(NERC Standards)*
CSC	Critical Security Controls
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DEI	Distribution Efficiency Initiative
DER	Distributed Energy Resource
DGA	Dissolved Gas Analysis
DREE	Distribution Reliability and Energy Efficiency *(Avista Program)*
EIM	Energy Imbalance Market
EMS	Energy Management System
EOC	Emergency Operations Center
ERP	Enterprise Resource Planning
ERT	Engineering Round Table
EV	Electrical Vehicle
FERC	Federal Energy Regulatory Commission
FIRE	Frequent Interrupters Requiring Evaluation *(Pacific Power tool)*
FLISR	Fault Location, Isolation and Service Restoration
GIS	Geographical Informational System
GPS	Global Positioning System
GREATER	Geographic Reliability Evaluation and Analysis Tool (*Pacific Power)*
HMWC	High-Molecular Weight Cable
IEEE	Institute of Electrical and Electronics Engineers
IOU	Investor Owned Utility
IR Scanning	Infrared Scanning
kVA	Kilovolt-Ampere *(also referred to as reactive power)*

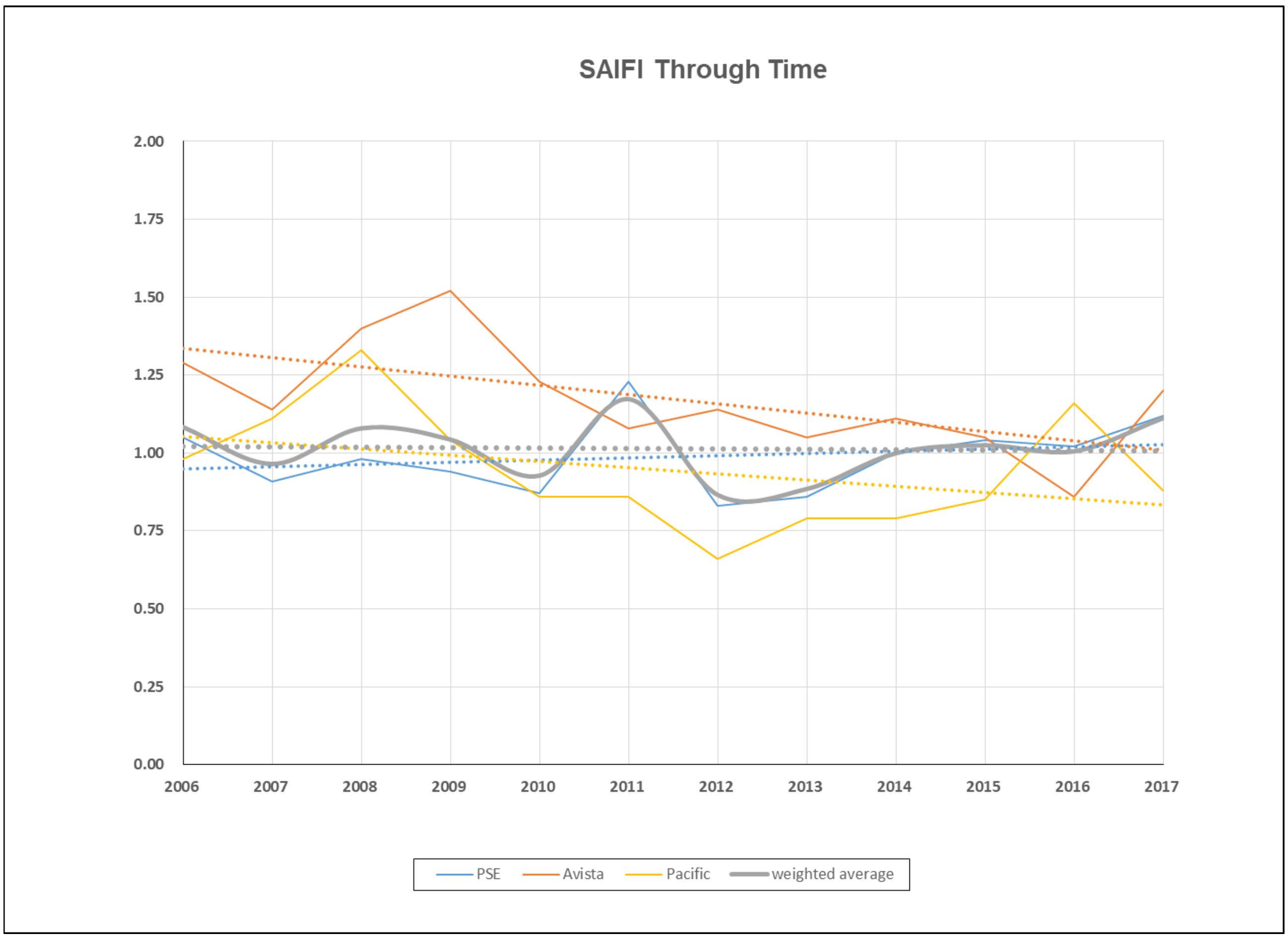
LiDAR	Light Detection and Ranging
M&R	Monitoring and Reporting *(WAC defined plan for reliability)*
MW	Megawatt
NEEA	Northwest Energy Efficiency Alliance
NERC	North American Electric Reliability Corporation
NIMS	National Incident Management System
NIST	National Institute of Standards and Technology
NWPP	Northwest PowerPool
OMS	Outage Management System
RDADs	Remote Data Acquisition Devices
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SGDP	Smart Grid Demonstration Project
SQI	Service Quality Indicators
UTC	Washington Utilities and Transportation Commission
WAC	Washington Administrative Code
WRMAA	Western Region Mutual Assistance Agreement
WSU	Washington State University

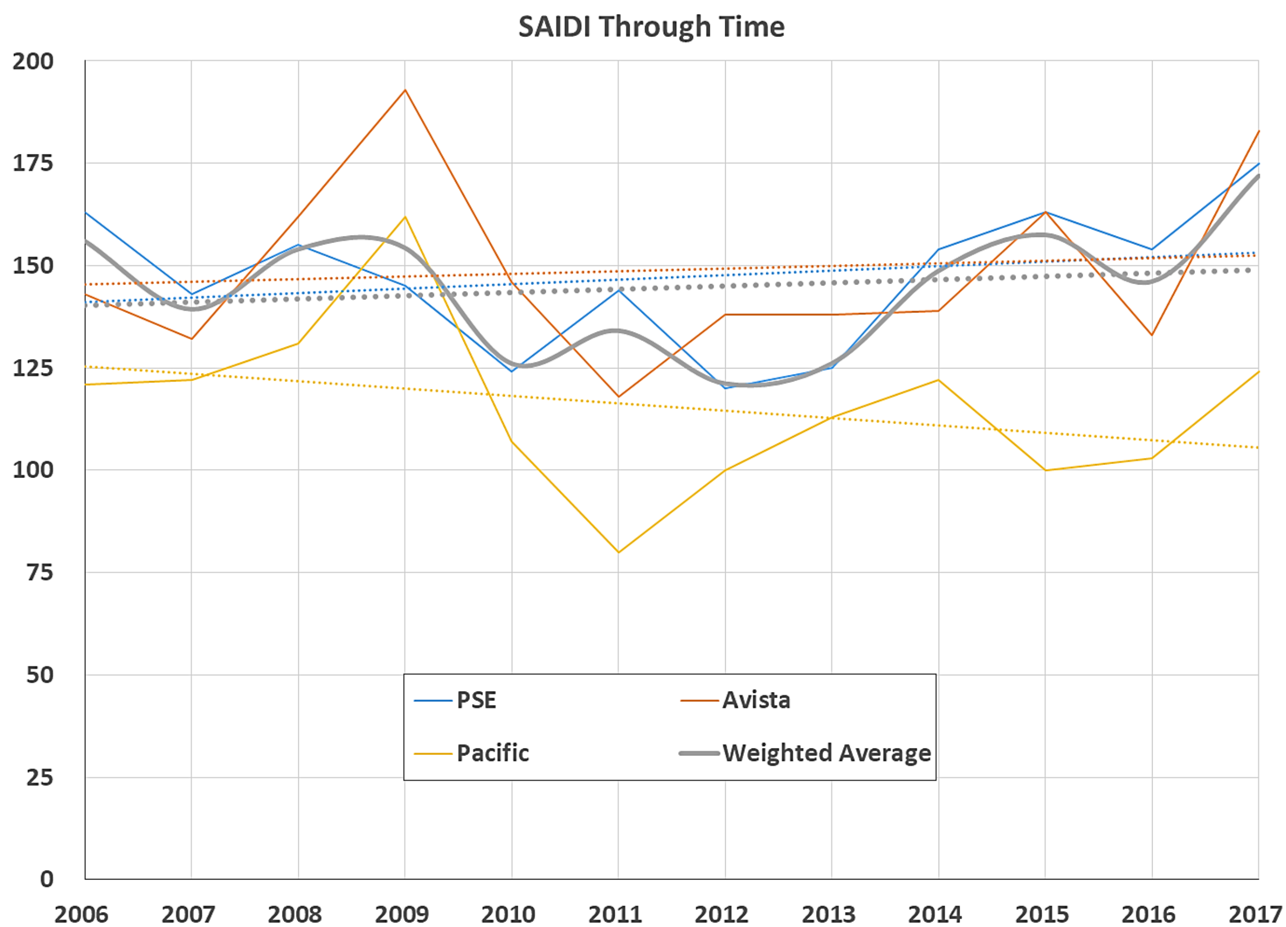
Electric service reliability	The continuity of electric service experienced by retail customers.
Baseline reliability statistic	A number calculated by the company measuring aspects of electric service reliability in a specified year that may be used as a comparison for measuring electric service reliability in subsequent years.
Full-system	All equipment and lines necessary to serve retail customers whether for the purpose of generation, transmission, distribution or individual service.
Major event	An event, such as a storm, that causes serious reliability problems, and that meets criteria established by the company for such an event.
Power quality	The characteristics of electricity – primarily voltage and frequency – that must meet certain specifications for safe, adequate and efficient operations.
Reliability statistic	A number, which may include multiple components (for example, service interruptions, customers, and hours), that measures electric service reliability.
SAIDI	System Average Interruption Duration Index calculates the outage duration for utility customers on an aggregate basis using the total minutes of all customer interruptions divided by the total number of all customers interrupted. Minutes and customers associated with momentary outages (less than five minutes) as well as major events are excluded from this calculation.
SAIFI	System Average Interruption Frequency Index calculates the number of power failures for utility customers on an aggregate basis using the total number of customer interruptions divided by the total number of all customers served. Interruptions and customers associated with momentary outages (less than five minutes) as well as major events are excluded from this calculation.
Sustained interruption	An interruption to electric service that has a length of duration specified by the electric company, but in any case not less than one minute.

Summary of IOU Characteristics *(Washington Only - 2018)*

	Avista	Pacific Power	PSE
Service Information			
Number of Customers	248,923	130,569	1,135,044
Service Territory (sq. miles)	16,000	2,729	5,475
Bulk Power System (Transmission)			
Substations	13	18	81
Line Miles	1,230	605	2,110
Remote Monitored	92%	100%	99%
Distribution System (Local Areas)			
Substations	66	32	298
Line Miles	7,550	4,354	23,705
Remote Monitored	88%	87%	95%

Trends in Reliability Metrics




SAIDI Through Time
200
175
150
125
100
75
50
25
0
2006
2007
2008
2009
2010
2011
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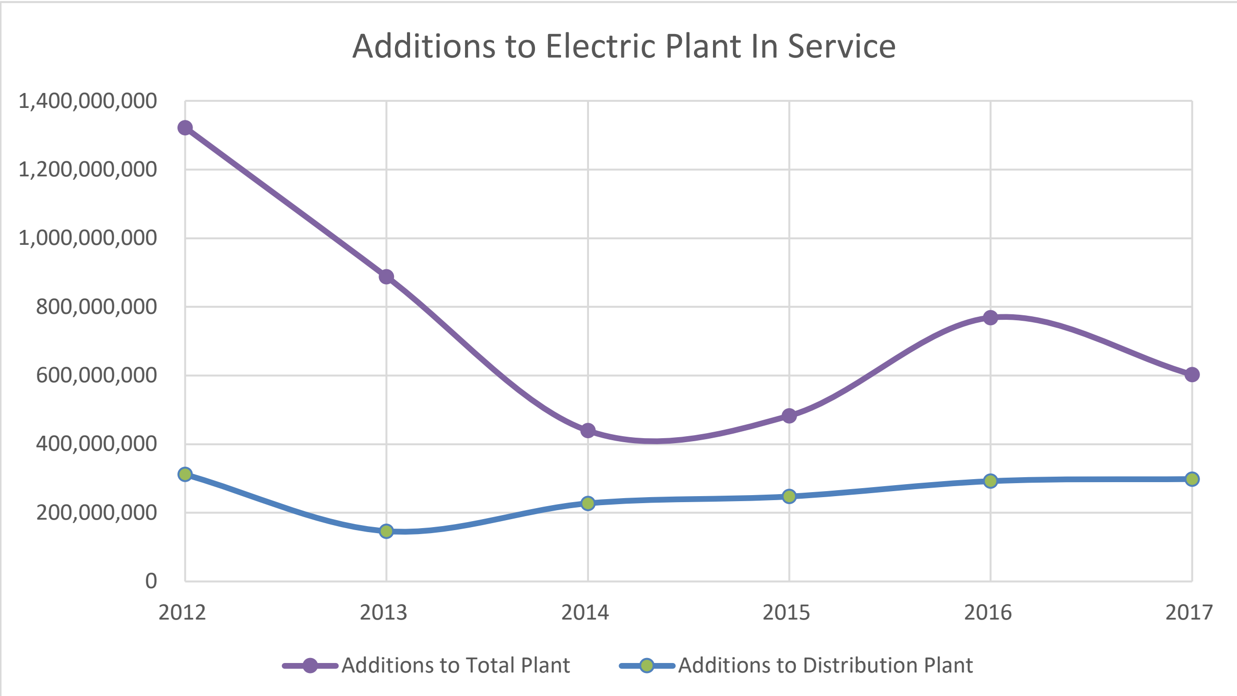
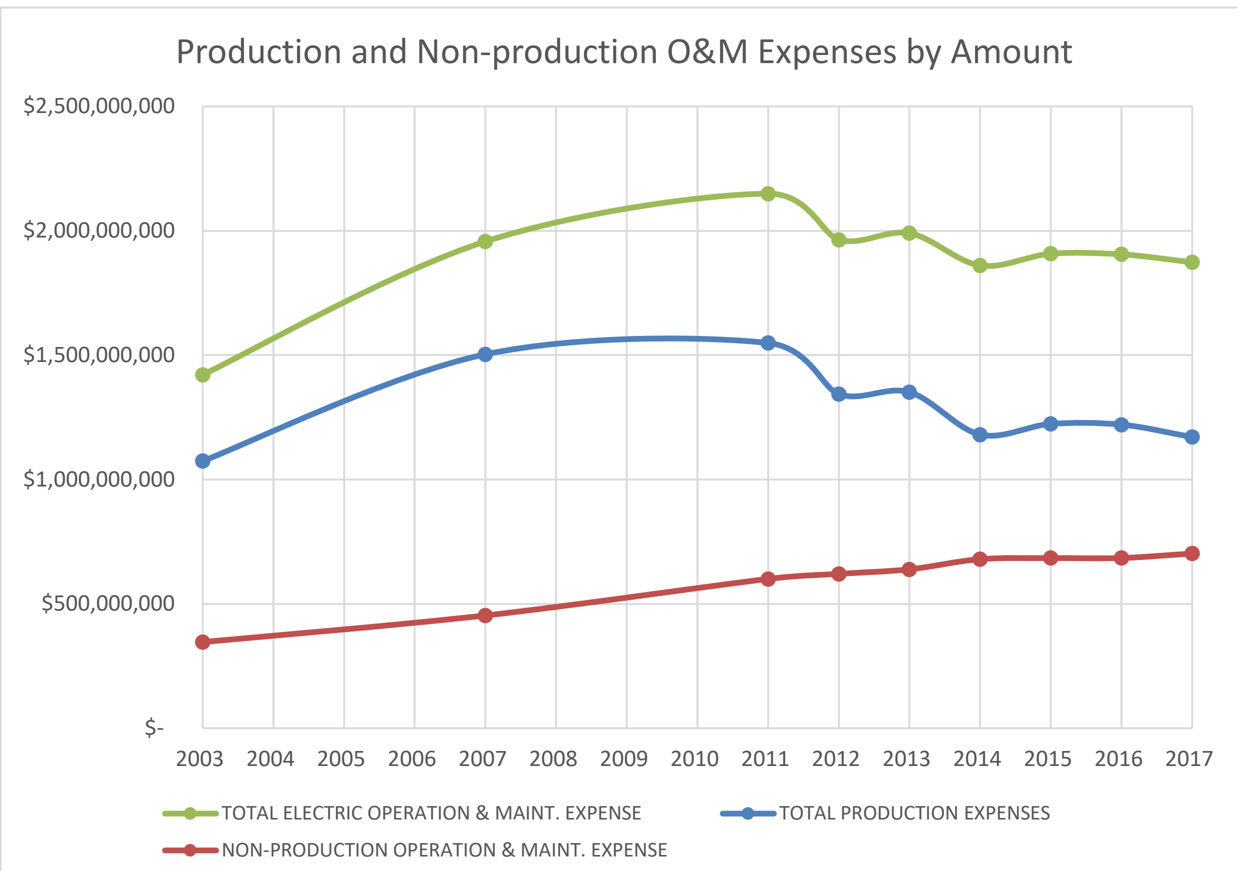
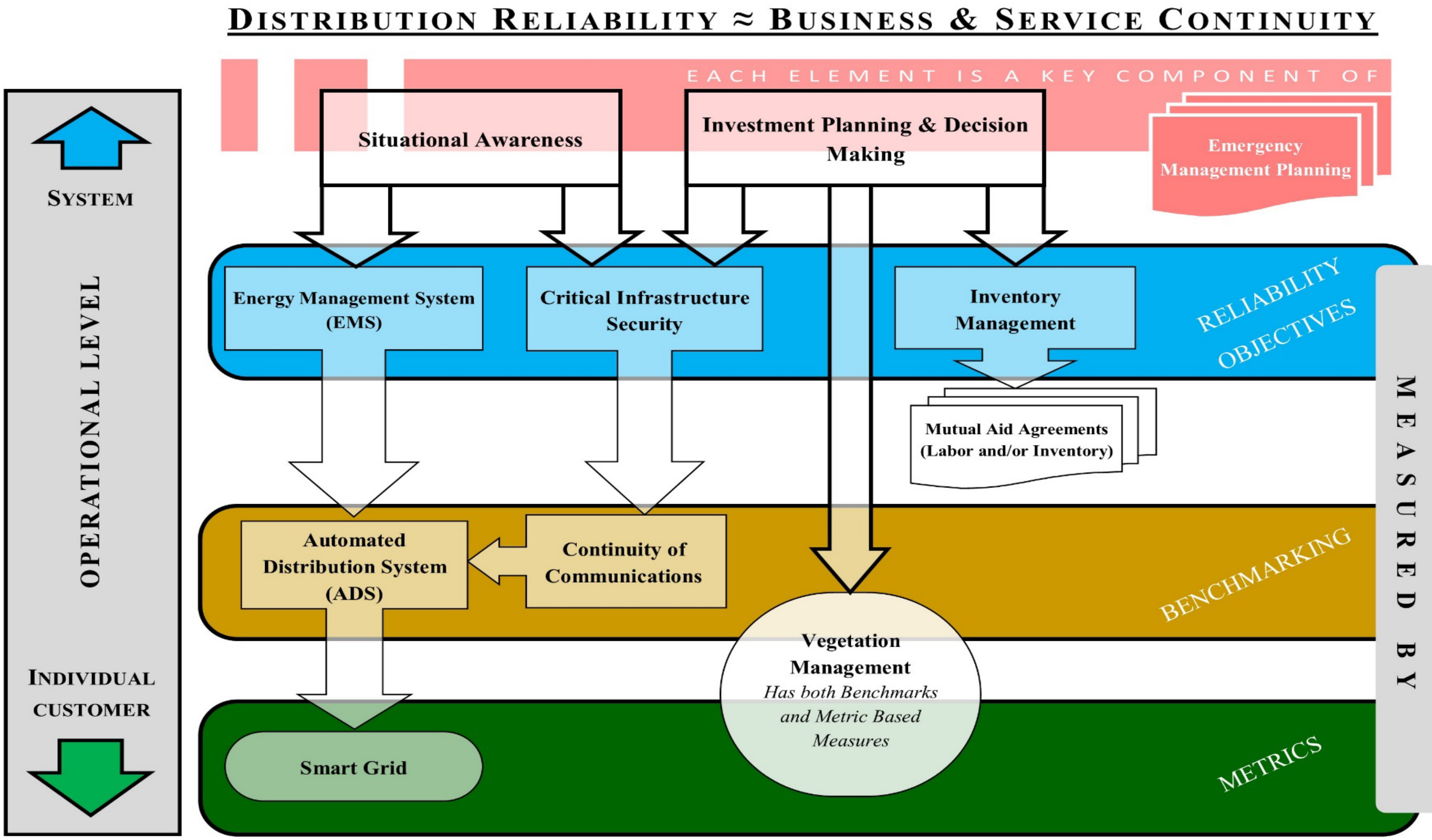
2017
PSE
Avista
Pacific
Weighted Average

Trends in Utility Spending (Washington Only – Aggregate)







This graphic illustrates the interactions between multiple components of reliability. This is not an exhaustive chart, nor does it go into explicit detail. However, it is useful in seeing the level at which each reliability component functionally exists, the way it is measured, and the overall strategic goal it represents.

Appendix E – History of Reliability Reporting in Washington

The UTC's current reliability rules became effective on April 22, 2001. These rules were adopted as a result of an Electric System Reliability Rulemaking.[17] The UTC initiated the rulemaking to "obtain reliability data from each of the three jurisdictional electric utilities," and to "establish reliability monitoring and reporting requirements … not [to] set performance or program standards." Specifically, the rules "address interruptions to service as opposed to fluctuation in power quality," and they explicitly "do not address reliability of power supply."[18] The general requirements were to file a Monitoring and Reporting (M&R) Plan, and to subsequently submit annual Electric Service Reliability Reports.

The 2001 docket was undertaken, at least in part, as a response to the 1998 Washington State Electricity System Study.[19] Service quality and electric service reliability are two of the nine topics outlined in that study. The purpose of the study was to inform policy on "preserving the desirable characteristics of the existing system and responding to market changes that [were] already occurring."[20]

During the mid to late 1990s, electric market deregulation was in full-swing and there was a real possibility of it occurring in the northwest. At the same time, the regulation of reliability was limited to requiring companies to provide "adequate service," "avoid interruptions," and "reestablish service with a minimum delay."[21] At the time, staff believed it possible that reliability could suffer in an environment of increased competition. Further, staff found that the available IOU reliability statistics were imprecise, unavailable or nonexistent; therefore, staff could not say with confidence that utilities were maintaining past levels of reliability.[22]

During a similar window of time, industry-wide metrics of distribution system reliability were emerging led by the Institute of Electrical and Electronics Engineers (IEEE). In 1998, the organization's Distribution Reliability Working Group (previously named the Group on System Design) developed *IEEE Standard 1366, IEEE Guide for Electric Power Distribution Indices*. This standard included the oft used system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI).

Other organizations had previously developed reliability indices for power transmission and industrial systems, but this was the first such set of indices available for power distribution. To

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[17] *In the Matter of Adopting WAC 480-100-388; 480-100-393, and 480-100-398 Relating to Electric Service Reliability,* Docket UE-991168.

[18] Open Meeting Memo, UE-991168 (3/14/2001)

[19] Conducted in 1998 jointly in compliance with ESSB 6560 by the Washington UTC and the Washington Department of Community, Trade and Economic Development.

[20] *Washington State Electricity System Study* (Dec. 31, 1998) https://www.utc.wa.gov/regulatedIndustries/utilities/Documents/6560fullversion.pdf

[21] Open Meeting Memo, UE-991168 (Sep. 8, 1999)

[22] Open Meeting Memo, UE-991168 (Mar. 14, 2001)

counter the perception of ineffective statistics, each of the three Washington regulated utilities proposed changes to their M&R Plans including specific performance and program standards.

The IEEE standard were adopted industry wide but were revised in 2003 to clarify existing definitions, and to provide a statistical methodology to determine "Major Event Days" as differentiated from normal, day to day, operations. Also in 2003, IEEE began annual, voluntary benchmarking of key reliability metrics across the wide range of electric distribution utilities in North America.[23]

In 2007 and 2011, the UTC changed how reliability statistics were recorded Washington utilities. The most recent update recognized the importance and impact of major events, as defined by IEEE. The updates also addressed other customer focused measures which lead to changes in the annual report titles. Each electric IOU now labels their report differently, with variation reflecting the inclusion of other ancillary topics. Various settlement agreements throughout this time frame added commitments for various customer service quality measures called Service Quality Indicators (SQIs), such as response time to customer calls, and keeping appointments.

IEEE adopted further revisions to Standard 1366 in 2012. These revisions introduced two new indices, provided clarification of several definitions, and discussed the distinction and possible treatment of catastrophic days.[24] In 2014, IEEE adopted an additional standard, *IEEE Standard 1782, IEEE Guide for Collecting, Categorizing, and Utilizing Information Related to Electric Power Distribution Interruption Event*. This newest guideline is designed to promote consistency in how the industry collects and categorizes data. Standard 1782 is designed to promote consistent data collection practices across all utilities to increase the value of performance benchmarking.

[23] *Benchmarking of Reliability: North American and European Experience* (June, 2015) http://cired.net/publications/cired2015/papers/CIRED2015_0182_final.pdf

[24] *IEEE Standard 1366*, IEEE Guide for Electric Power Distribution Indices at ix (2012).

Puget Sound Energy

Overall, the PSE approach to investment optimization is encouraging. In particular, the optimization model used by PSE is driven by an economic rather than a subjective analysis. This allows PSE to make decisions based on a value assigned to qualitative benefits, such as public perception.

It appears that the distribution planning group is responsible for communicating the optimized reliability benefits for a given budget. The executive management team is then responsible for determining whether those reliability benefits are making reasonable progress toward reliability objectives. Unfortunately, there is currently little clarity around this process from a regulatory perspective.

It also appears that the model is subject to an iterative budgeting process. For example, if the optimization model does not align with PSE's reliability objectives, the distribution planning group's budget may be changed. This is especially true when specific reliability objectives, sponsored by specific management members, are not achieved through the initial budget.

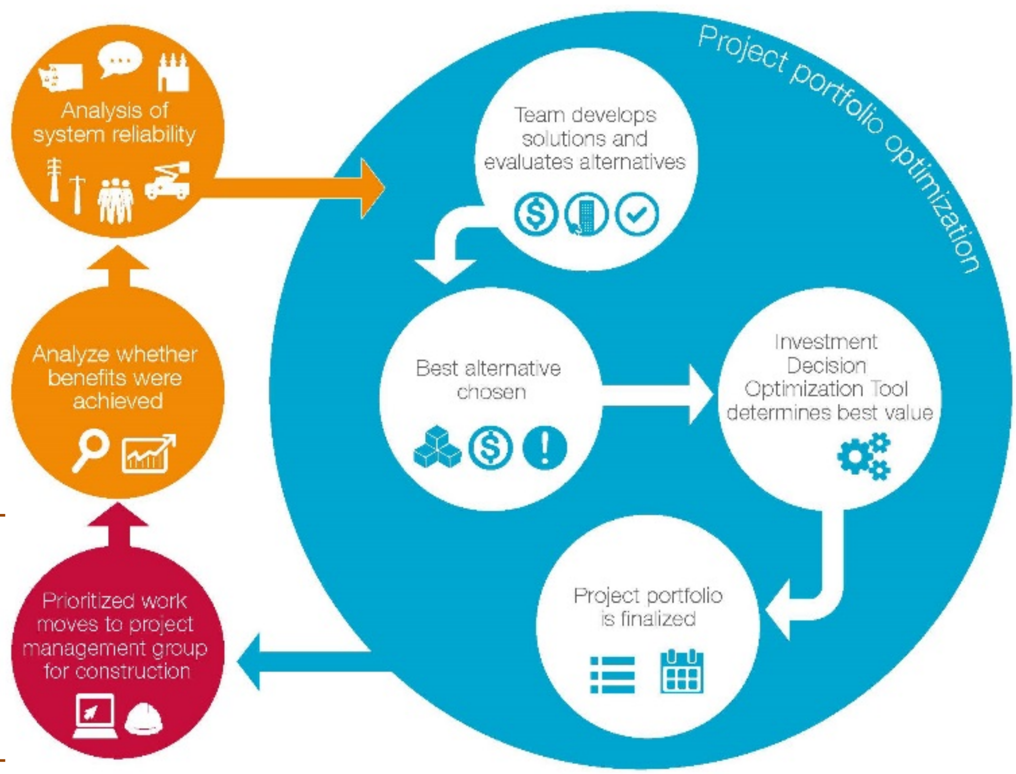


Figure F.1 – Project Portfolio Optimization is a series of processes involving multiple groups and authorities[25]

[25] Graphic provided by PSE.

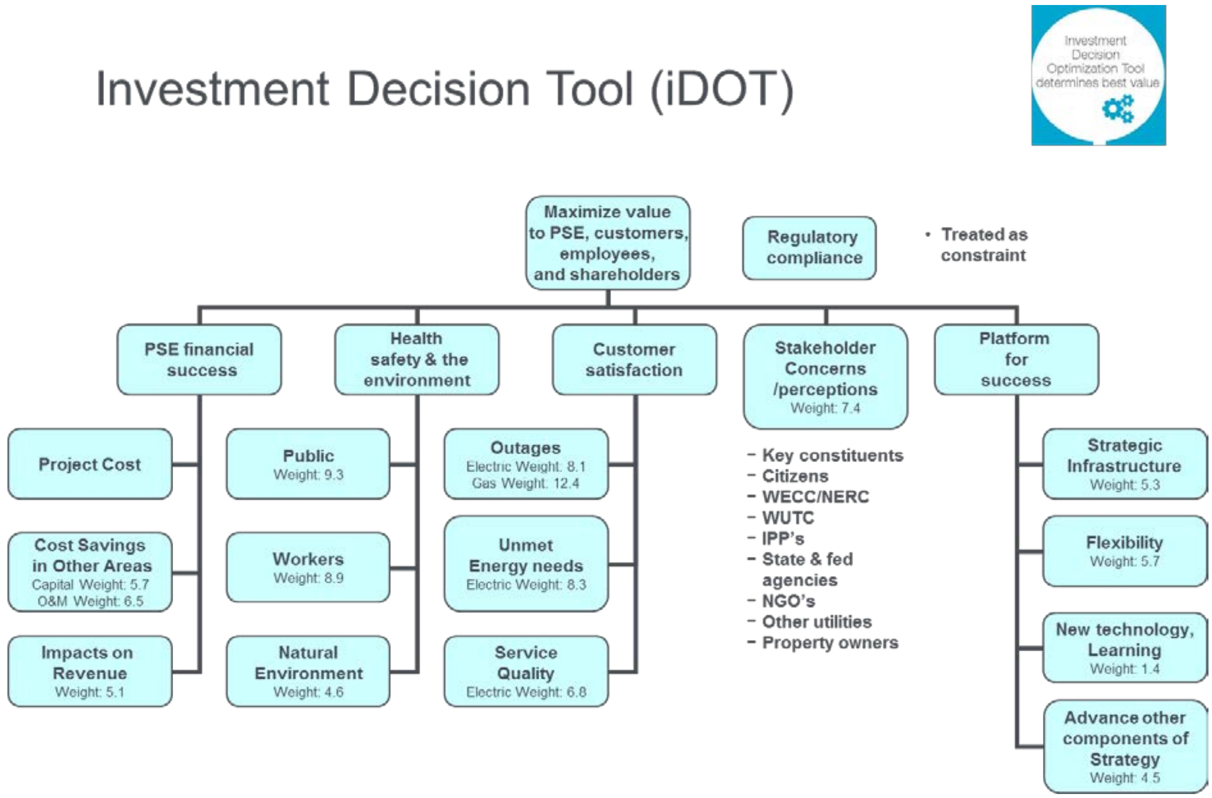


Figure F.2 – PSE's planning decisions are guided by the Investment Decision tool (iDOT).[26]

Given a budget, iDOT identifies the projects that provide maximum value to PSE and its customers. PSE has quantified the benefits associated with a variety of categories. The economic benefits of each category, like public safety and worker safety, are all weighted and monetized with a "poker chip" process. PSE's optimization model then maximizes the benefits of the potential project portfolio on a net present value basis, while simultaneously imposing a budget constraint.

It is also unclear how PSE balances capital budgeting with annual maintenance expense. For example, the company can improve its reliability performance by increasing tree trimming (an expense) or by investing in tree-wire (a capital project). The planning optimization model appears to only consider capital expenditures.

While, the PSE iDot model has several encouraging aspects, the process surrounding its optimization is not well understood by staff. There is needed transparency in how the corporate budgeting process is performed and how capital improvements are balanced with operations and maintenance work.

[26] Graphic provided by PSE.

Pacific Power

Pacific Power uses its corporate structure to establish roles and responsibilities at each managerial level. This translates into a relatively clear process in identifying projects, but it is unclear how budgeting and performance metrics work. The company seems to rely heavily on data visualization to ensure effective communication.

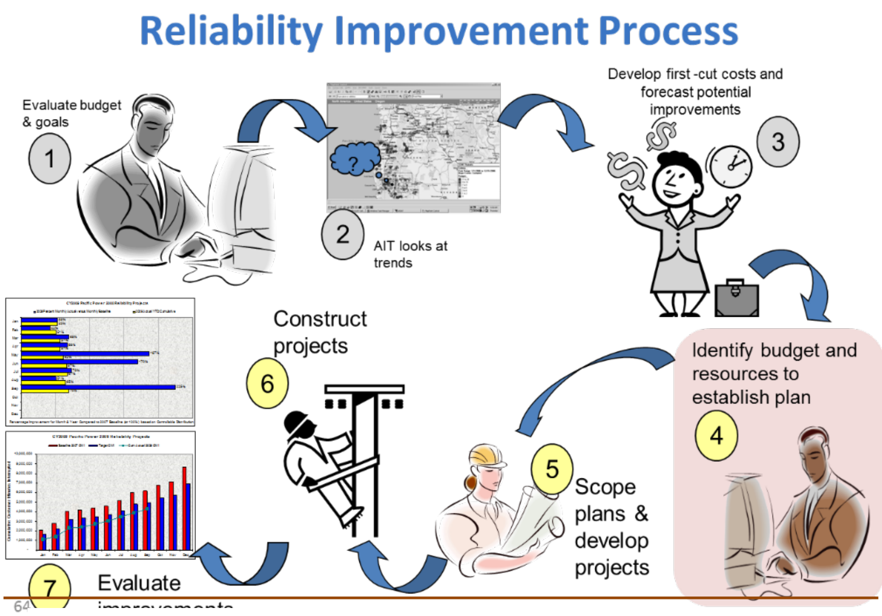


Figure F.3 – Pacific Power defines its process with specific standards and clear assignment of authority.[27]

Overall, Pacific Power's investment process is based historical analysis and trends in operational data. Analyzed across multiple time frames, this analysis looks at every part of the system to determine whether assets are performing as expected. A key enabler of this analysis is the Frequent Interrupters Requiring Evaluation (FIRE) system and Geographic Reliability Evaluation and Analysis Tool (GREATER).

Both FIRE and GREATER integrate asset monitoring information with Geographical Information System (GIS) data to create a visual representation of reliability. The first system, FIRE, prompts for operational action when certain thresholds are exceeded. For example, a series of sustained outages involving trees may prompt an overall line inspection to determine where and what is causing the problem. The second system, GREATER, is a more strategic tool for assessing network reliability performance. GREATER has a wide range of users and enable consistent communication throughout Pacific Power. While each system has multiple functions, from outage management to cause analysis, they also are key in identifying areas for reliability related actions.

In conjunction with the trending tools and evaluation, Pacific Power establishes short and medium-term performance goals and budgets. These budgets inform, and to some degree are informed by the underlying trends of actual asset performance.

[27] Graphic provided by Pacific Power.

The Pacific Power process follows a pretty straight-forward path from budgeting to construction to post-project effectiveness. This last step ensures that each project yields the expected benefits.

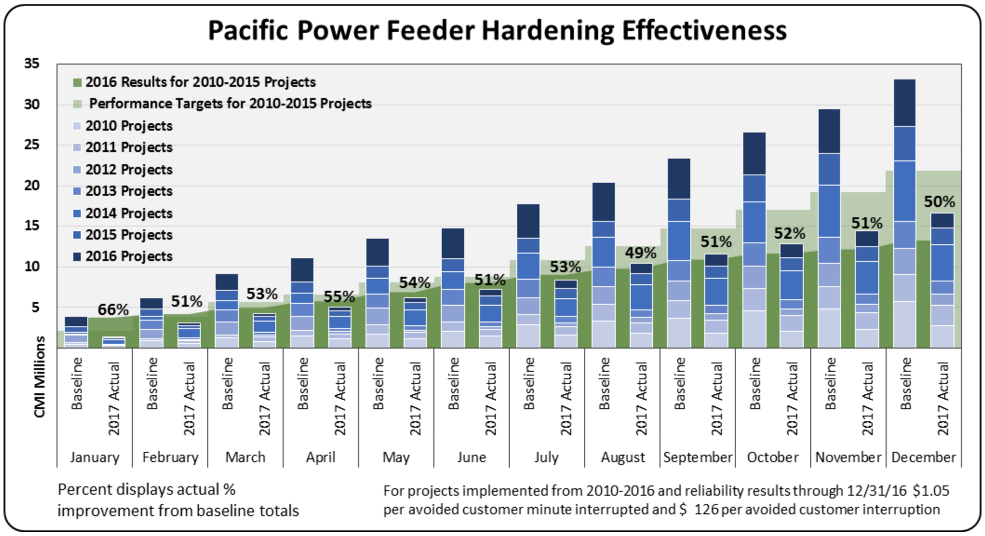


Figure F.4 – Performance measures can exist along multiple time horizons and become iterative. It is therefore necessary to compare outcomes based on initial projections and expected baselines.[28]

Unfortunately, staff is unsure how the initial budget priorities are determined or how performance goals are set. From what we understand local area managers are responsible for developing these budgets. Following a series of aggregating steps, and filtering through multiple levels of management, these proposals yield a five or ten-year corporate plan. Staff is unsure to what degree executive management is involved in shaping the underlying performance objectives, or how individual goals are identified and weighted.

It does appear that the local manager approach has the advantage of creating area-specific measures that are tailored to the specific needs of the location. However, it is not well understood how this allows projects to compete against each other or how the needs of a certain area is prioritized over another. Staff is also unsure to what degree this approach impacts O&M expense or whether the aggregate plan is capital only.

Pacific Power's overall process establishes clear chains of authority and guidelines for project selection and valuation. However, more transparency is needed in order to evaluate the end-to-end decision making process for reliability related investments.

[28] Graphic provided by Pacific Power.

Avista

Avista's investment planning process is similar to the approach taken by PSE. Though the prioritization of projects is somewhat subjective, Avista does have multiple categories of benefits, a weighting of each category, and five degrees of impact that quantifies the projects' value.

Avista reviews projects though an engineering roundtable process, and prioritizes projects based on a project scoring protocol. Performed through SharePoint, the ERT requires information on compliance, asset condition, age, and other statistics to function. Project approval is given by a cross-sectional group of engineering and planning employees. In some cases, projects can "short-circuit" the approval and review process and move forward rather quickly (such is the case with regulatory mandates). The final output of the ERT is the Revenue Requirement Resource Model from which the Capital Planning Group creates a 5-year rolling Avista-wide business case.

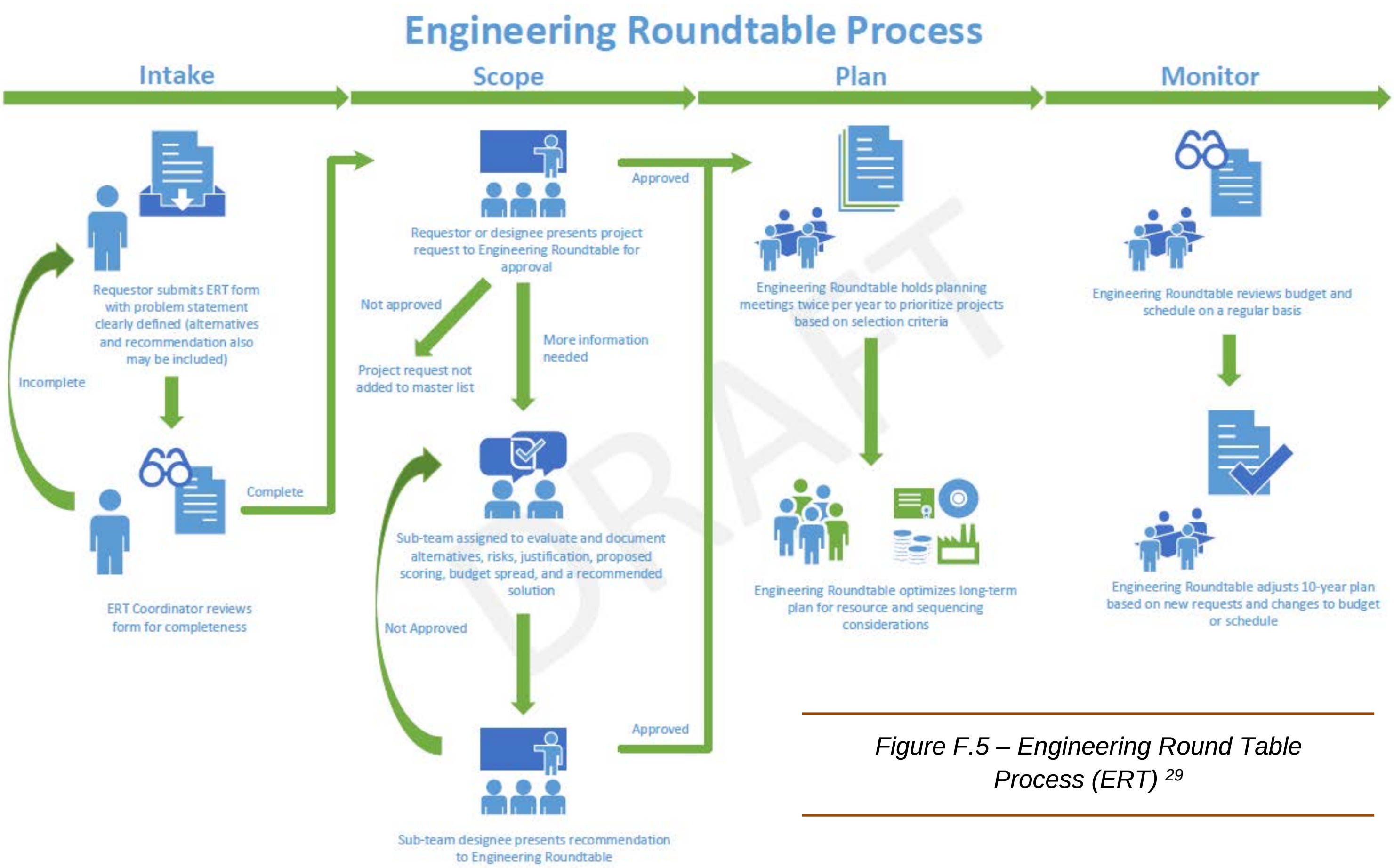


Figure F.5 – Engineering Round Table Process (ERT) [29]

[29] Graphic provided by Avista.

However, the decision to move forward on any given project is subject to considerations beyond project score, such as budget constraints, project risks, and the availability of viable alternatives. An important aspect of Avista's distribution planning is its optimization of three main areas: [30]

a) The overall demand for distribution investment;
b) The specific requirements of the projects and programs proposed for funding, and the potential consequences associated with deferring needed investments; and,
c) A balance among the needs and priorities of all investment requests across the enterprise, and Avista's investment planning principles (referred to as the "Key Planning Principles").

A large component of these investment plans seems to be historical spending and trending, both internally and within the industry. This results in an interesting conclusion: *modern technologies have not been fused with the electric sector.* Capabilities just now being implemented are already out dated from the customer perspective. Avista's planning grouping is spending considerable effort on finding flexibility in its distribution system architecture to integrate future technology. It remains to be seen how and to what degree this may impact the investment decision process.

Figure F.6 – Multiple processes and divisions intersect in the field of planning. Each of these areas has a specific strategic focus but all must be balanced in order to create a functional business plan.[31]

While clearly in existence, staff is again at a loss as to how the investment workflow develops. Specifically, to what degree the ERT interacts with the overall capital budget and vis-versa. O&M spending is another area where the specific decision process and planning interactions have not been identified. Additional transparency is needed in these areas to complete the picture of investment spending at Avista.

[30] Avista Electric Distribution Infrastructure Plan (June, 2017) at 17
[31] Graphic provided by Avista

Energy Management Systems (EMS)

An EMS is comprised of multiple services, equipment, and responsibilities at the core of utility operations. Through the use of electronic tools, personnel can monitor the relationships between generation and load, control the transmission of electricity, and optimize the efficiency of the utilities' portfolio. A large degree of these functions are based on Supervisory Control and Data Acquisition (SCADA) systems. SCADA encompasses multiple computer software programs and other tools to provide operators with contingency analysis, voltage regulation, response times, generator info, load projections, and system balancing information.
A major purpose of SCADA and EMS is to ensure compliance with the regulations administered by the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC). This includes compliance for adequate voltage and frequency levels. Deviations from the standard 60 cycles per seconds is measured in part by the Area Control Error (ACE). As ACE fluctuates from second to second, the operator's job is to utilize SCADA and EMS to balance the real-time load demands for electricity generation. Figure I.1 on the next page provides a graphical representation of EMS through time.

A. Regional

Each electric IOU operates within a Balancing Area Authority (BAA), or two in the case of multijurisdictional utilities such as Pacific Power. BAA's represent "pockets" of load and generation that must be balanced at any given time. In this way, the Western Electric Interconnect under the supervision of NERC and Peak Reliability is divided into smaller, more easily controlled groups. Regionally, each of the three IOUs have a different impact depending on geographic location, customers served, generation assets, and overall load profile. This is represented in how N-1 events (indicators of how resilient the system is in the event of the failure of a critical asset) are different between the IOUs.[32] For example, the largest at risk resource in the Northwest Power Pool (NWPP) is approximately a 1,000 MW plant, while Avista's largest generating station is only 315 MW. From a regional perspective, Avista has a smaller impact on reliability than does the Bonneville Power Administration (BPA) who operates the Grand Coulee Dam. This is not to say that the obligations to provide reliability and respond to an N-1 event is relieved, but rather that the scope and importance of these requirements change by region and utility.

[32] N-1 Contingency Analysis is defined by NERC Standard TPL-001-1 as the loss of a single generator or transmission component.

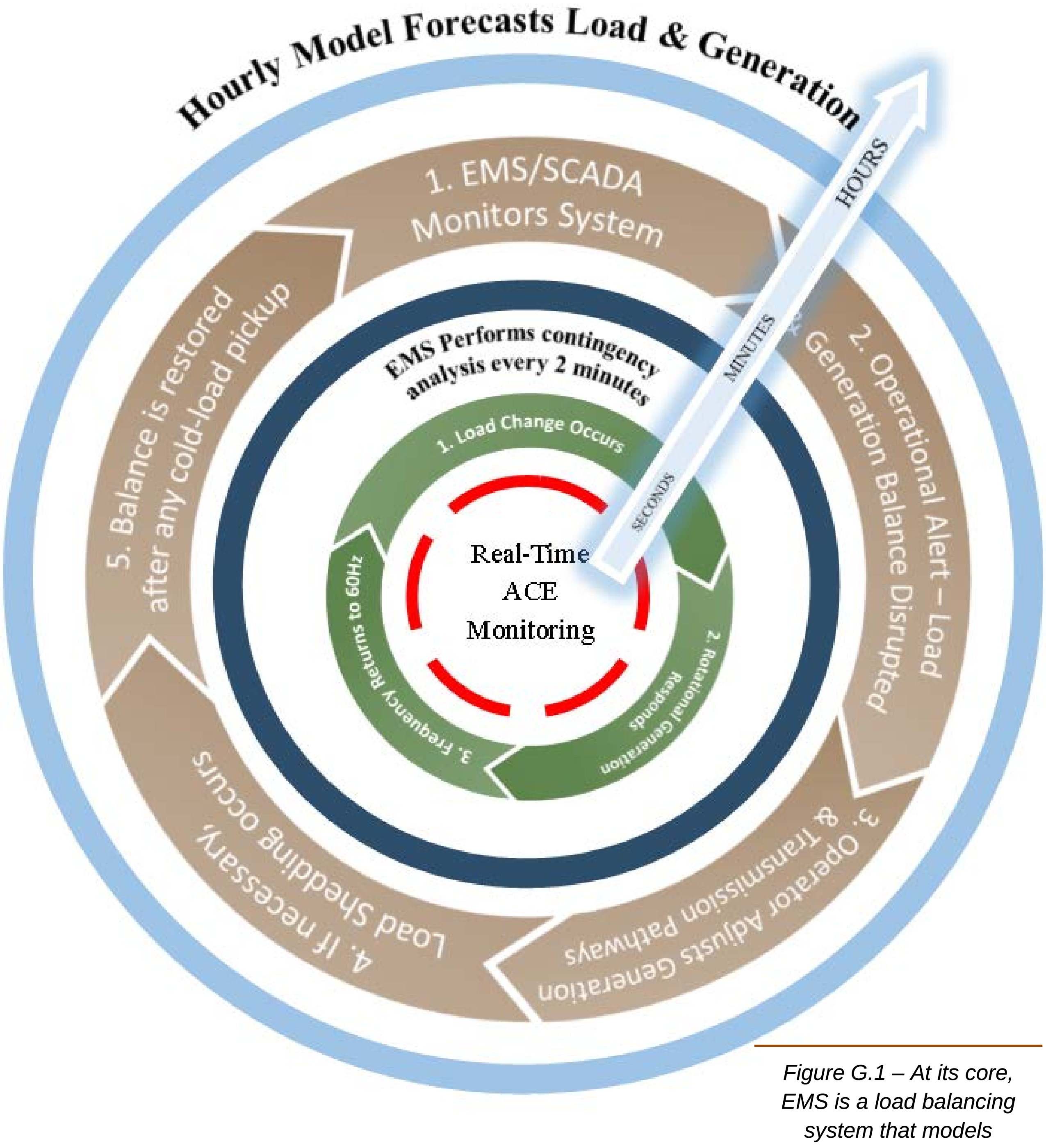


Figure G.1 – At its core, EMS is a load balancing system that models generation and energy needs across multiple time horizons.

B. Physical Relays

A key issue in maintaining reliability and operating SCADA and EMS is communications. Real-time telemetry requires dedicated primary and secondary communication pathways. Even so, communications cannot always be guaranteed. In such instances, fully redundant relays exist that will open independent of remote control schemes. These backup controls systems are the electric grids underlying physical operation that ensures reliability, equipment protection, and life safety. In most circumstances, the failure rate on relays is at or below 0.001 percent - two relays grouped together all but eliminate improper operation. From a hardware redundancy perspective, the use of physical relays is a very robust architecture.

C. Lightning

While not thought of as a typical problem in the northwest, lightning is a good illustration of the difficulty in operating an electric system with remote generating assets. The further from a load source, the more transmission and substations are required to serve that load. All along those paths, lightning strikes can happen and have overloading effects on equipment. While ground cables and insulation can minimize this risk, it is not possible for a human to react fast enough to save the equipment. It is also possible for a lightning strike to overload local and automatic controls. For instance, lightning can create a standing electrical wave form that travels along a line toward a substation. If the lightning arrestors are installed and rated properly the fault is dispersed to ground, however if not designed correctly service interruptions can occur. One company provided such an example indicating it had installed 1100 kV lightning arrestors but only 900 kV breakers on a particular line. This lead to a series of interruptions when the breakers became overloaded. Rather than an operational issue, this was a fundamental design failure. The issue was not identified until the actual trip of the breakers. Substations with this design have since been retrofitted and the company has updated its overall design standards.

Outage Management System (OMS)

An OMS serves as the backbone of distribution operations. It is a critical asset to restoration efforts and customer communications. Typically, OMS is a layered system consisting principally of a GIS with respective asset locations, SCADA systems for distribution monitoring and control, ADMS, and dispatch coordination.

While traditional utility functions are served well by current OMS models, distributed technologies are becoming increasingly common. Unfortunately, distributed technologies are upsetting traditionally centralized utility practices with a high degree of evolution. The modern utility, and by extension its operating systems, are serving more as an integrator of services rather than just as the sole provider of power. Unfortunately, the impact of this functional change is both poorly understood and unplanned for. It is paramount that the systems on which utility

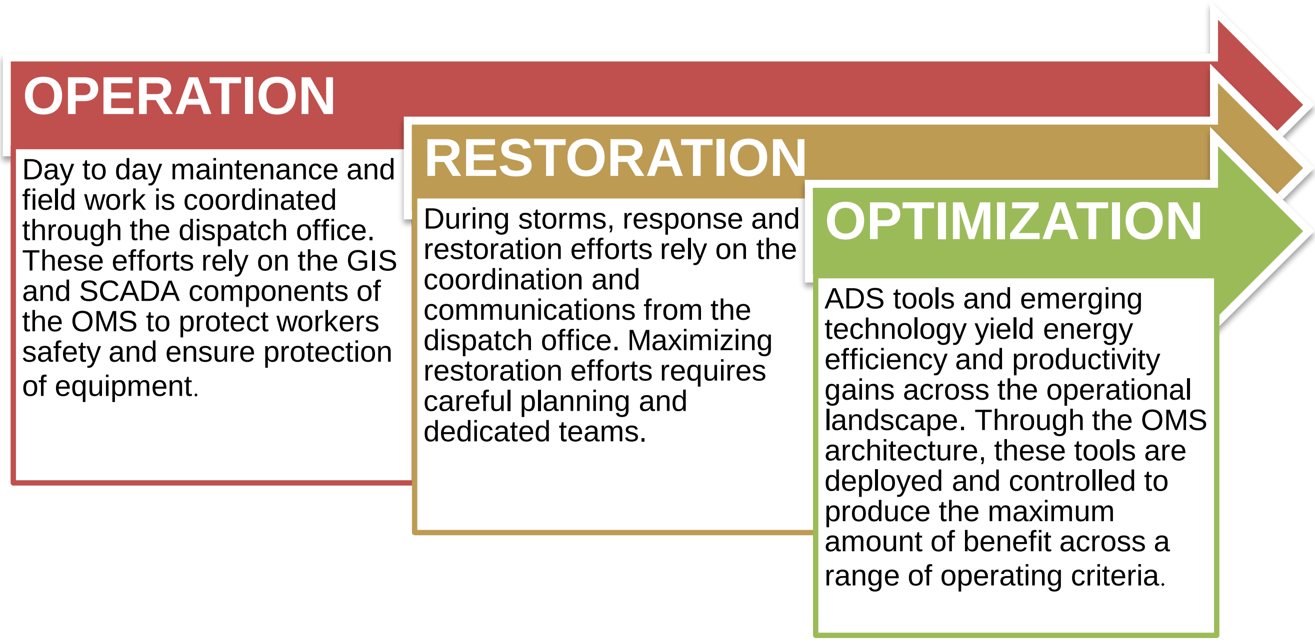


Figure G.2 – Utility operations are continuous flows of three primary objectives: Operating electric services, maintaining and restoring power, and optimizing each component of the grid to maximize efficiency.

operations rely be adapted to meet consumer needs as a service integrator. Figure I.3 above shows the hierarchical functions of a standard OMS implementation.

In order to maintain a functioning OMS and EMS, secure and consistent communication lines are crucial. A variety of technologies is available and used to provide this service. The primary forms of communications for all three IOUs is the use of leased lines from existing communication providers, dedicated fiber optic cable laid alongside transmission right-of-ways, and microwave high-frequency communication. Additional communication channels are also available including point-to-point radio, HAM radio including UHF and VHF functionality, and Power Line Communications.

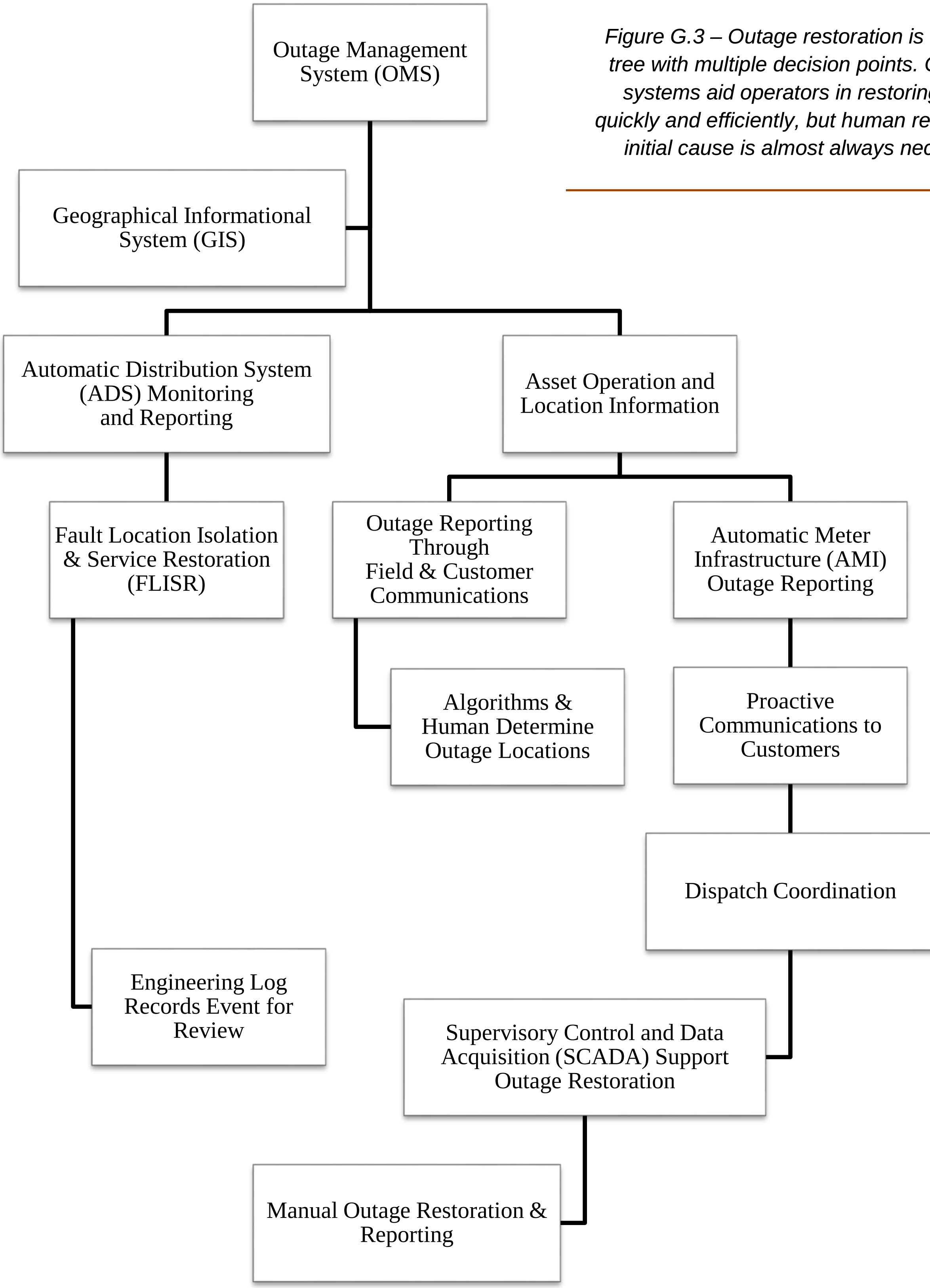


Figure G.3 – Outage restoration is a process tree with multiple decision points. Computer systems aid operators in restoring power quickly and efficiently, but human review of the initial cause is almost always necessary.

Puget Sound Energy

OMS: PowerOn	EMS: e-terra*platform*
Vintage: 4/1/2013 Trained Users: 65 Notable Features: • Predicts size of outage based on calls. • Increasing adoption of newer communication channels: texting, apps, and web resources.	Vintage: 2012 Trained Users: 40 Notable Features: • Models power flow based on actual system. Contingency analysis runs multiple scenarios including: 1) Full generation 2) No Generation 3) Flow North 4) Flow South. • Provides estimates without or without a full data set and runs real-time every 2-minutes.

A. Operations

PSE operates a robust network with about 98 percent of its transmission system controlled or monitored with remote tools. However, remote control for the distribution system has a much lower penetration, at around 40 percent.[33] Further, a portion of existing SCADA systems are still tonal based (similar to rotary phones) and have not been switched to a more modern internet protocol. Since these systems still function normally, capital dollars have not been allocated to upgrading these systems.

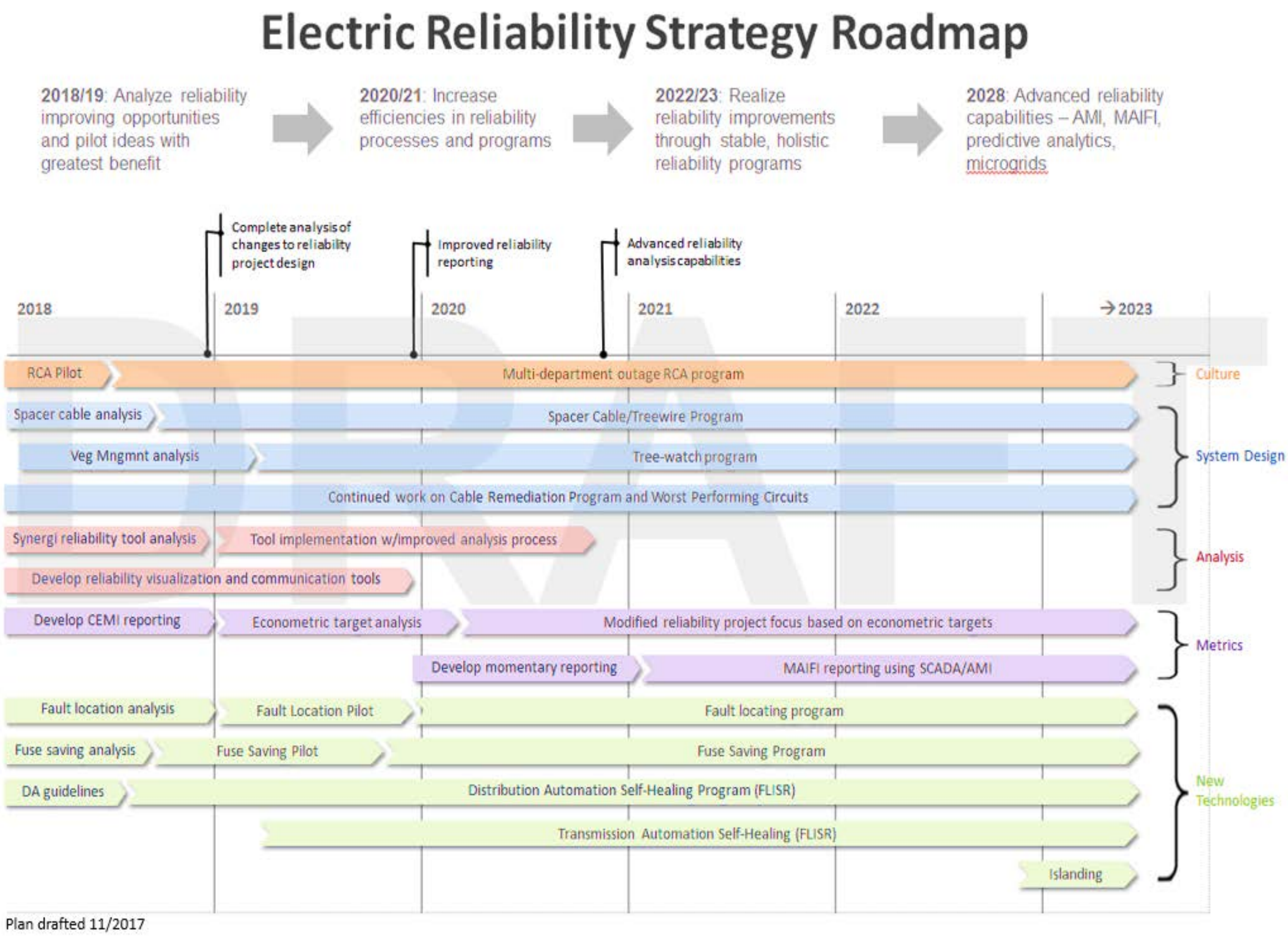
B. Restoration

PSE's control center has multiple personnel and equipment ready to respond during outages and storms. With a focus on continued development, PSE is revamping its internal training program due to cyclical retirement of personnel. Through efforts to create continuous performance improvement, emphasis can be placed on dynamic plans and initiatives. For instance, momentary outages (usually defined as less than 5 minutes) don't suffer from cold-load pickup problems so reducing outage duration yields significant operational advantages. Unfortunately, 80 percent of transmission outages are not momentary. These longer restoration times create additional complications because frequency, voltage, and rotation all have to be in perfect synchronization to reconnect large load pockets. ADMS deployment and other pilot projects are attempting to reduce the impacts of load outages and thus reduce average costs.

[33] The company has indicated that monitoring only capabilities exist at between 95 to 99 percent of its entire network.

C. ADMS Deployment

In its draft *Electric Reliability Strategy Roadmap*,[34] PSE anticipates implementation of DA across its transmission and distribution system over the next five years to improve its reliability capabilities and facilitate other technological deployments extending through 2028.



34 Graphic provided by PSE.

Pacific Power

OMS: MCG-COMPASS	EMS: OSI Monarch
Vintage: 2006 Trained Users: 1100 Notable Features: • Integrated with GIS and other company operational programs to provide flexibility.	Vintage: 2016 Trained Users: 185 Notable Features: • A newer system implemented in 2016, the EMS was replaced because the existing system was no longer supported.[35] • Utilizes off the shelf hardware to minimize replacement time and costs.

A. Operations

Pacific Power utilizes discrete procedures with a high level of data integration. The company has dedicated SCADA connections at 100 percent of transmission substations and 87 percent of distribution substations in Washington. These systems are also integrated with the Pacific Power GIS, providing a high degree of operational visibility at the local level. Further, the GIS is a single-record system with tight turn-around requirements. There are strict rules to keep this system up-to-date including who can implement changes; dispatchers have the authority to update the GIS system based on information from field personnel.

Pacific Power has actively implemented system-wide efficiency and reliability technologies such as FLISR and auto sectionalizing equipment (installed during the 1990's and early 2000's), line scopes for distance to fault detection, single phase tripping, fuse savers, Conservation Voltage Reduction (CVR), and Volt/VAR optimization.

B. Restoration

Pacific Power's operational priorities are to restore the greatest number of customers as possible in the shortest amount of time. As each restoration from transmission, to high-voltage distribution, to feeder and tap lines are followed, additional priorities may occur. For instance, life safety or other dangerous situations have a high degree of focus especially when 911 and other emergency operations are involved. Power restoration efforts are prioritized and concentrated in areas needed most such as hospitals, police and fire stations, or medical baseline customers. These coordinating actives and intermediate steps are generally determined through OMS critical customer flags, field engineer reviews, and conversations with local area managers.

[35] Refer to the direct testimony of Stuart J. Kelly, Exhibit No. SJK-1T in Docket UE-152253 for more information.

C. Load Planning

Using a new model from CYME (Synergy), Pacific Power is focusing on customer centric data at substation and circuit level, including kVA and feeder metering to create monthly load cases. Since N-1 events don't happen every day, load-cases are generally built after the fact and then used for load planning. The new model has the advantage of integrating GIS and is described as the "difference between a pocket switch-blade and a Swiss-army knife."[36]

D. ADMS Deployment

Around the year 2000, Pacific Power completed a DA pilot in Portland, OR. The DA pilot was completed at the substation level but due to certain components (*e.g.,* motor-operated switch gear) not operating reliably, the function was disabled; the unexpected component performance outweighed any benefits delivered.

The company is currently scoping a DA pilot project in Lincoln City, Oregon. At the start of this project, Pacific Power analyzed 35 potential circuits, based on a prescribed set of system requirement. The focus was on feeders with the highest potential to reduce customer minutes lost using a FLISR scheme. The company identified its Devil's Lake feeders as having the best opportunity for substantial learning opportunities while simultaneously reducing the magnitude and number of interruptions. Pacific Power plans to install advanced metering infrastructure in the near future in the Devil's Lake area to help support this DA scheme.

Unfortunately, Pacific Power does not anticipate deploying DA across its entire service area for a couple of reasons. First, Pacific Power's service territory is comprised of long circuits with generally low population density, which the company stated leads to a decrease in DA effectiveness.[37] Second, depending upon the time of year and Pacific Powers participation in the Energy Imbalance Market (EIM), there may not be capacity on certain lines for DA to switch load. While a fully automated system may not provide the most cost effective method for reliability in Pacific Power's territory, technology is evolving and the company expressed it will continue to evaluate options.

[36] This description was provided by an employee during an onsite review with the company.

[37] Pacific Power stated their service territory averages 13 customers per square mile as compared to southern California with 350 customers per square mile. The southern California reference was provided by a current Pacific Power employee with employment history at SoCal Edison.

Avista

OMS: Avista Facilities Management	EMS: Alstom GRID
Vintage: 2004 Trained Users: 22 Notable Features: • Prior to 2004, the original OMS was built in-house and at the time it was state-of-the art. The newer, currently operating OMS utilizes the ESRI-GIS Model. • An important upgrade is the ability to monitor all three phases to improve safety.	Vintage: 2012 Trained Users: 66 Notable Features: • Multiple roles allow for a wide variety of users and operational capabilities.

A. Operations

Avista network has implemented SCADA controls to approximately 78 percent of its network. The company has stated that it has a goal to achieve remote operational control of 100 percent of its system. SCADA systems used by Avista have an “Isolated Operation Mode” that allows systems to operate independent of central command and control. This physical fallback capability combines security with redundancy by decentralizing the overall operation. As a result of this structure, equipment engineers examine the logs from daily operations to determine if assets are operating within normal specifications. These reviews contribute to Avista’s operational awareness of its assets.

B. Restoration

The underlying corporate philosophy of Avista contributes to its restoration approach. Integration of communication technologies with field personnel ensures timely and accurate reporting of operations. Avista recently deployed iPad’s using the existing cellular networks and now field personnel can upload damage reports in real-time. OMS and GIS data can be cross-referenced with these reports to ensure timely restoration of service.

C. Dispatch Automation

A key component of the OMS used by Avista is the incorporation of real-time telemetry into traditionally static field operations. By instantly recognizing a fault and testing to isolate both the upstream and downstream effects, response times are increased and field efficiency is improved. Normally this role is serviced by a dispatcher, but relies on human interfaces that are located at same place as the fault. Through algorithms and data integration, a more proactive response capability is realized.

D. ADMS Deployment

Avista has numerous stand-alone operational systems ranging from off-the-shelf, to customized and proprietary technologies. These include the OMS, EMS inclusive of SCADA, and a meter data management system for AMI. All of these systems are supported by a GIS and interconnect with the ADMS. Avista's strategy is to avoid duplicate data by using compatible technologies. This allows employees (depending on their individual user rights) to access the system of record regardless of the operational system they are actively using. The chart above shows the integrational of the GIS data with their various other operational systems.

As of fourth quarter, 2017, Avista has automated approximately one-third of its circuits. While the company intends to deploy AMI in Washington, DA benefits will vary depending on the area. Rural areas do not have the same availability for redundancy and limits to the benefits of self-healing grids. While rural areas will not have "downstream" restoration available, the system will be able to restore "upstream" customers due to the linear nature of the rural network.

E. Other Current Technologies:

- *Integrated Volt/VAR Control* – Relaying on load tap changers and other monitoring equipment, this technology sources out trouble spots in need of capacitors. Where the traditional response to a localized problem would be a new bank of capacitors, now the electric waveform can be flattened with Voltage profiling. Avista is able to track as closely to load as possible and reduce excess voltage, leading to ~1 percent energy savings.
- *Switch Doctor* – A monitor of sorts for the OMS and ADMS servers that ensures their underlying data are in sync.
- *Relay Management* – Avista operates nearly 7,800 relays ranging in age from recently installed to 66 years old. All relays are fully redundant, independent, and based one of two technologies:
    - *Electro Mechanical* – The original version of these technologies that is still in use to exhaust previously purchased spares. As spares are exhausted, they are upgraded to relays that are more modern. These types of relays have a six-year testing interval.
    - *Circuit Based Relays* – A small microprocessor provides event analysis every day to ensure it is operating within tolerance limits. These type of relays are required for transmission systems. They have a 12-year testing interval. Avista's vendor offers protection packages that are designed to deliver reduced maintenance, installation times, and time-based test intervals. The new circuit based relays have self-contained auto-testing software that have integrated SCADA connections.

F. Emerging Technologies

- *Dynamic Resistance Measurement* – Designed to provide analysis of larger transformers with load tap changers. The procedure is non-invasive and takes about one hour to complete. This technology has only been available for a few years but it is gaining acceptance at IEEE, which has a usage guide under development. Avista currently performs a review of tap changers every five years.
- *Traveling wave systems (TWS)* – A portable device with the ability to locate a line fault to within 300 feet. In the newest relays, TWS is integrated so this function can be performed via SCADA. TWS installation can also occur on a permanent basis at distribution feeders with known reliability issues.
- *Local Phase measurement* – Currently, this technology is used by WECC to measure the change in frequencies across the western interconnect. In simplest terms, it is designed to provide a holistic measure of system stability. Modern relays usually come with this technology onboard, but it requires SCADA integration to utilize the information.

Puget Sound Energy[38]

A. Transmission & Distribution Intelligence Upgrades

Over the years, PSE has been continually installing three phase re-closers on distribution feeders to reduce the impact of outages; in 2009, a more aggressive program was initiated to improve overall reliability. Additional reliability initiatives focused on communications came online when fiber optics cabling upgrades were made at key transmission substations.

B. Distribution Automation-Large Customer Campus

In the late 1990s, a large customer requested and paid the incremental cost for a more robust and reliable distribution system at its service location. The initial project installed SCADA switches at a select number of critical campus buildings. The project size has since increased from 6 to 42 SCADA switches. Through SCADA, PSE's system operator can remotely monitor and control the buildings connection, and is alerted in real-time if an outage event occurs. The remote operation also allows the operator to open and close switches in order to isolate the outage and restore power to the rest of the sections.

In the early 2000s, this deployment was enhanced to include a "self-healing" function, again focusing on critical buildings. At over half of the campus, SCADA switches are now automated with logic schemes similar to those used for PSE's transmission system automation. The logic schemes can automatically detect an outage, isolate the problem section, and restore power to the rest of the sections with minimal operator intervention.

C. Conservation Voltage Reduction (CVR) – NEEA Pilot

PSE originally conducted its first CVR study on ten residential feeders in 1983. In 2006, PSE and 13 other Pacific Northwest utilities participated in the Distribution Efficiency Initiative (DEI) study, convened by The Northwest Energy Efficiency Alliance (NEEA). The DEI study was intended to quantify the effects of power consumption in relation to the applied voltage. Design and operational techniques were used to optimize the performance of a distribution system and achieve energy and demand reduction.

The DEI study was comprised of two independent projects: the Load Research Project and the Pilot Demonstration Project. The results of the 2006 study conclusively showed that operating a utility distribution system in the lower half of the acceptable voltage range (114-120 Volts) would result in reducing electric usage and demand and reactive power requirements on the customers' side of the meter without negatively impacting the customer.

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[38] Information here is partly based on PSE's *2016 Smart Grid Technology Report*, Docket UE-161048 (September 1, 2016).

Successful results of the 2006 NEEA CVR Pilot led PSE to analyze 12 substations by the end of 2012. PSE then implemented CVR on three substations in 2013, and on more substations in 2014.

D. Remote Data Acquisition Devices (RDADs) Pilot

In 2012, 60 RDADs were installed in Bellevue's Central Business District to support fault detection for the underground network. This technology has the potential to aid PSE system operators with normal operational switching. It also allows quicker response to faulted equipment by reducing the need for troubleshooting. As of 2014, PSE has installed 90 RDADs, with two-thirds of them located in the Bellevue Central Business District.

E. Grid-Scale Energy Storage

In 2013, PSE began efforts to develop grid-scale energy storage capabilities. This starts with working demonstrations of dispatchable resources within PSE's service area. In February 2016, PSE completed construction of a 2.0 MW storage system in Glacier, WA. Energy storage has the potential to assist PSE with shaving peak demand, reducing outages by dispatching stored electricity, and providing system flexibility. Most importantly, storage can help balance electric supply and demand and thus ease the integration of intermittent renewable energy generation into the grid. For remote and vegetation-dense parts of PSE's service territory, a key use of energy storage will be as backup power during grid outages.

Avista

A. Distribution Reliability and Energy Efficiency (DREE)

As early as 2004, Avista systemically rebuilt distribution feeders based on historical failures and a desire to reduce energy loss. Subsequently, the company created DREE to leverage geographical information and outage management data using newly available sensors in the then nascent "smart grid".

B. Smart Circuits

The American Recovery and Reinvestment Act (ARRA) provided Avista with federal grant monies in 2009 to invest in various smart grid research and investments projects. The Smart Circuits project updated 58 electric distribution feeders and 14 substations in the greater Spokane area. The upgrades included intelligent transformers, line devices, and control system software to enable smart grid capabilities.

C. Smart Grid Demonstration Project (SGDP)

The SGDP was a larger project that lasted from 2009 to 2014. Avista partnered with numerous collaborators, administered by the Battelle Memorial Institute, in Pullman, Washington. For Avista, the SGDP involved the automation of many parts of its electric distribution system using advanced end-use metering, enhanced communication networks, appliances within customer premises (primarily smart thermostats), substation automation, and transmission line sensors. The SGDP also deployed the fiber infrastructure and wireless mesh network that serves as the communication backbone necessary for AMI. Today, Avista is actively deploying AMI across its entire Washington service territory.

D. Additional projects with reliability components[39]

- The Turner Energy Storage System
- Substation Integration and Smart Grid Communications Backhaul
- Fault Circuit Indicator Deployment
- Fault Detection, Isolation, and Restoration Deployment
- Integrated Volt/VAr Control

Pacific Power

In 2014, Pacific Power piloted fuse saving technology in Walla Walla. Fuse saving schemes are used as a strategy to attempt to prevent permanent outages when transient faults (*e.g.,* tree branch hits a line but falls off) occur beyond tap fuses on a distribution system. Under fuse saving schemes, the system will automatically reclose a predetermined number of times before the fuse is blown for a sustained fault. This resulted in the entire Washington service territory using a fuse saving scheme.

Based on Pacific Power's 2016 Smart Grid Report, it appears that the majority of the company's grid modernization efforts are focused in other operating jurisdictions. A number of these projects may end being implemented company-wide but for now are localized to areas other than Washington.

[39] Based on Avista's *2016 Smart Grid Technology Report*, Docket UE-161045 (September 1, 2016).

Physical Security

At a national level, NERC's recent advancement of physical security through Critical Infrastructure Protection standards (CIP) has resulted in a concerted effort by utilities to identify and address potential physical security weaknesses. Each electric IOU has implemented this process in a slightly different manner. Some of the key components of physical security are listed below.

- Executive level governance with input from across the organization into potential weaknesses.
- A defined and mature corporate policy with a clear focus on continuous improvement.
- Defined budgeting process to identify retrofits and upgrades using the needs of specific sites.
- Centralization of security through a single division to prevent information silos and maximize situational awareness of hybrid threats.
- Identification and ranking of critical assets, such as substations, transmission lines, distribution feeders, buildings, and generation sources.
- Implementation of specific physical upgrades such as circuit hardening, security perimeters, and electromagnetic pulse protection.

Cyber Security

A. Framework

Numerous competing standards of measuring and addressing cyber security make it impossible to identify a single set of best practices. Each model has unique advantages in benchmarking security and a comparable range of adoption across the electric sector. However, for the three electric IOUs in Washington, two frameworks stand out:[40]

[40] When asked about the C2M2 model, the general response was a lack of specifics in that frameworks approach.

SANS Top 20 Critical Security Controls (CSC)	*NIST Cyber security Framework*
A principal benefit of the Controls is that they prioritize and focus a smaller number of actions with high pay-off results. The Controls are effective because they are derived from the most common attack patterns highlighted in the leading threat reports and vetted across a very broad community of government and industry practitioners. [41]	*Created through collaboration between government and the private sector, [the framework] uses a common language to address and manage cyber security risk in a cost-effective way based on business needs without placing additional regulatory requirements on businesses.* *The Framework focuses on using business drivers to guide cyber security activities and considering cyber security risks as part of the organization's risk management processes.* [42]

B. Phishing

In general, the utilities have focused a large portion of their efforts on countering phishing attacks. Phishing involves a targeted attempt at gaining sensitive information by pretending to be a trusted entity.[43] While malware and viruses attack a computers infrastructure, phishing exploits the human element of a corporation. Here the work of the utilities vary to some degree.

All utilities have routine phishing tests. Each test presents employees with controlled and unannounced email phishing attempts. Click rates varies from as low as 0.3 percent to as high as 20 percent. All three IOUs required a user to immediately complete additional cyber-security training after falling for a phishing email.

For at least two of the electric IOUs, corporate policy has integrated these tests into employee performance. Failing more than one phishing test is a performance issue that has escalated disciplinary actions. This can range from management involvement, to removal of external email privileges, to termination.

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[41] More information is available at https://www.sans.org/critical-security-controls.

[42] *Framework for Improving Critical Infrastructure Security, version 1.0*, National Institute of Standards and Technology (February 2, 2014) at 1 https://www.nist.gov/sites/default/files/documents/cyberframework/cybersecurity-framework-021214.pdf.

[43] Examples include an email from the IRS requesting additional information about a tax return or a bank requesting login information. Spear phishing is a much more concentrated approach where certain individuals are targeted using personal information of either the victim or a colleague.

C. Ransomware

Ransomware remains one of the most threating versions of malware in existence. Recent examples include: WannaCry, Bad Rabbit, and NotPetya. Last year, ransomware saw a 46 percent increase in new variants.[44] Recent versions of more common ransomware applications can encrypt entire network drives in under 60 seconds.

Currently, the most effective counter to a ransomware attack is routine and remote data backup. Information Officers must also have quick and efficient restoration plans in order to counter these types of programs. Although some ransomware algorithms have been broken so that restoration can occur without the need for a private key, most have not. Therefore, the only other option is actually paying the culprit to unlock the computers.

Operational networks may have some vulnerability to this type of software, simply because they are computers. However, the underlying physical nature of the system operations, and their interfaces, offer some protection form cascading real-world effects. The employment of air-gapping, redundant firewalls, dedicated communications networks, and high-level encryption all serve to reduce this risk further.

D. Supply Chain Attacks

Perhaps the most troubling development over the last year has been the increase in attacks through vendors that are in the supply chain for the actual target. 2017 saw an increase in these types of attacks by over 200 percent.[45] Security experts believe this is largely due to successful security awareness campaigns that have led to patching and proper security hygiene. The IOUs have placed considerable emphasis on ensuring supply chain security through standardized contract terms and requirements.

E. Information Sharing

The Washington electric IOUs also participate in numerous information sharing organizations. However, reactions to these groups is mixed. While some groups have provided useful and sometimes critical information, the sheer number of groups seems to be hampering their effectiveness. This is not a condemnation of the organizations, the participation by the IOUs, or the act of information sharing itself. Rather, a more cohesive national leadership may be the only way to address the inefficiencies of this organizational structure.

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[44] *2018 Internet Security Threat Report – Executive Summary*, Symantec (March, 2018) https://www.symantec.com/content/dam/symantec/docs/reports/istr-23-executive-summary-en.pdf.

[45] *Id.*

Overview

Emergency response centers at each of the three electric IOUs operate like an expansion of regular, day-to-day dispatch operations. These centers are activated, staffed, managed, and stood down according to predetermined protocols. When the number of incidents exceeds the capacity for regular dispatch, the emergency plans are activated.

Storm events are the most common cause of emergency response center activation. Additionally, both Avista and Pacific Power noted wildfire events as significant hazards for which they have response plans. Escalation of a response is also predefined. For example, an outage caused by a vehicle-pole collision or a downed conductor would be handled as a normal daily response activity. As the incident level increases, so does the need to engage and coordinate response activities with other entities. This is balanced with the need to communicate more broadly with affected customers and the larger community.

Current emergency preparedness plans are strongly influenced by detailed debriefs following significant incidents. Avista conducted 17 debriefing meetings following their 2015 windstorm response, including a post-storm survey with 396 respondents, and engaged a third party to review their storm response. Both successes and opportunities for improvement are identified, with action plans developed to address the latter.

Customer Communications

A key component of emergency preparedness and response is effective communication with the local government, regulatory bodies, and the public at-large. Each of the utilities has dedicated regulatory liaisons tasked to staff their Emergency Operation Center (EOC) during activations. These liaisons serve as a consistent contact point to provide updated information as needed. Additionally, each electric IOU identified specific processes in place for maintaining contacts with local government.

Interacting with the public involves broad-communication schemes. The primary tool for the dissemination of information is the internet. Following the 2015 Windstorm, Avista created an enhanced outage map to provide more information directly to customers. PSE has also implemented a customer auto-notification system with a call-back feature. When power is switched back-on, customers can notify PSE of failed restorations.

Mutual Aid and Inventory

The ability of a utility to effectively respond to a significant incident is enhanced by the existence of standing mutual aid agreements. Each of the three utilities are members of the Western Region Mutual Assistance Agreement (WRMAA) that was signed in 2003. It represents an effort by gas and electric utilities throughout western North America to support one another in the event of emergencies affecting generation, transmission, distribution, or other vital services. The signatories convene every year to share best practices, discuss key emergency response issues, review the agreement itself, and handle administrative details.

Each of the three utilities also participate in Edison Electric Institute’s electric transformer sharing program in order to potentially alleviate the long lead times associated with acquiring such equipment and the high cost of independently maintaining spare transformers. Pacific Power is somewhat uniquely positioned in being able to draw on the resources, expertise and personnel of sister company Rocky Mountain Power and other Berkshire Energy resources via an inter-company agreement.

Avista’s response to the 2015 windstorm provides an example of mutual assistance activation. The company normally has 10 crews in the Spokane area. Over the course of the 2015 response, 118 contract crews and 480 linemen from 22 different companies were utilized. This assistance was dispatched in waves, using an on/off-boarding process that was developed before the first outside assistance crew arrived. Based on feedback provided to the company, the process was very effective with its success attributed to the pre-planning efforts.

Puget Sound Energy

A. Asset & Materials Management

For PSE, asset management is a way of replacing something before it becomes a failure. Life-cycle predictive modeling, yielding a probability of failure, helps PSE minimize real-world events. Generally speaking, these approaches are applied to assets that have been fully depreciated.

PSE is doing a significant amount of work with vendors and industry leaders to identify failure indicators and ensure proactive asset management. For example, gas and particulate build-up occurs based on the type of fuel or oil that is used. This can result in significant wearing of metal and lead leading to considerable wear and tear on the system over time. To combat this, PSE has evaluated several options from changing the type of oil used to investing in more advanced forms of Dissolved Gas Analysis (DGA).

PSE has an aggressive pole inspection program designed to test whether a poll will make it to the next inspection. Wood pole inspection is cyclical with a 10-year length for both the transmission (2018 is the 10th year) and distribution system (currently in year 5).

In order to reduce costs, PSE is looking into new programs that can extend pole life. Historically, metal poles were not considered economically viable, but reduced costs of construction and right-of-ways are changing the financial analysis of this option. Another example is the use of support bands at the bottom of a poll that prolong the useful life.

B. Transformers

Transformers are part of PSE's proactive replacement strategy given the lengthy lead/lag times from order to receipt. The cost of new transformers require senior level review coordinated through the Major Equipment Committee. The committee is charged with the review of long-term asset acquisition and to re-task products to solve new problems. This can unfortunately lead to an almost three month lead time in approval since the committee meets once a quarter.

C. Improvement Programs

- <u>Enhanced Systems</u>: In an effort to enhance its asset management program, PSE is setting up back casting and proactive scoring systems. The hope is that these systems will help them identify trends in asset lives that may be useful in the future.

- <u>Cable Remediation</u>: Older, high-molecular weight cable exists (HMWC) on about 1,800 miles of PSE's distribution system. Because HMWC has a high failure rate, PSE has begun upgrading these assets to reduce outages. This program has had significant success and may be expanded in the future.

- New Technologies: IR Scanning allows PSE to identify hotspots on both insulators and cables, detect failures, or locate potential overloading. This has also been used in varying degree to identify where trees have grown too close to transmission lines.

Avista

A. Asset & Materials Management

Replacement of capital assets typically does not occur until the equipment exceeds its specified O&M budget or operational parameters. However, run-to-fail-objectives are generally avoided because they are not the best indicator of replacement needs. If replacement is needed, on a non-emergency basis, then executive level sign-off is required. For example, the use of DGA in transformers has significantly improved the ability of engineers to predict the timing of failures. Newer technologies, such as on-line DGA, can provide consistent reports about transformers that historically had troubles. In at least one case, the use of DGA helped to prevent an imminent catastrophic failure. A counter example is the development of Smart Transformers with integrated SCADA monitoring. Unfortunately, the deployment of AMI technologies made Smart Transformer upgrades to be cost ineffective from a reliability perspective.

Avista utilizes Oracle based Enterprise Resource Planning (ERP) with an inventory management focus on safety and necessary stockpiling. In general, inventory levels are based on historical demand (using the weighted average of expected lead times) and meeting the needs of expected projects. From here, assets are organized into specific, localized “stores.” Staffed with dedicated storekeepers, this creates a regional focus that has strong heterogeneity. Storekeepers are expected to have in-depth knowledge of historical events (often they are locals) that assist them in maintaining adequate inventories.

Avista maintains an approximately 3-day storm inventory reserve throughout its service territory. As storms approach, the storerooms can make extra arrangements based on communication with field personnel and the corporate office. Using an analysis of the last 7-10 storms, Avista created a correlation tool that updated what needs to be procured and stockpiled. The system includes forecasts with alerts setup for buyers and planners. Mobile inventory sites and storm lists can then be prepared ahead of time to enable materials flow to crews. This is especially important for onboarding contractors and mutual aid groups.

B. Transformers

Large transformers are bulky equipment that are capitalized at receipt. This allows Avista to track each transformer through the entire asset management cycle. Because of the long lead times in procuring these assets, Avista has worked to connect procurement officers with area engineers. This relationship enables the identification of future asset needs to reduce the lead/lag time in procurement.

Pacific Power

A. Asset & Materials Management

Pacific Power utilizes specific sets of standard operating procedures to maintain assets. To ensure uniformity, Pacific Power uses an Asset Health Index (AHI) system. The AHI is designed to study large categories of assets and produce an overall risk score. The largest system of its class available, AHI was first used in the UK by the Norther Power Grid Company (another Berkshire Hathaway IOU).

Previously, Pacific Power used a serviceability review that centralized asset management. However, AHI has a number of advantages. One advantage is the weightings that determine “health” using based on factors like load, age, history, reliability impacts, critical customers, and safety. Although these weightings can be value based or subjective, it yields a probability score for failure and risk identification. The AHI is a holistic view of overall assets to minimize costs. Since age and type of assets don’t necessarily dictate end-of-life, performance is the most important factor.

To manage assets its assets, the company groups them at the circuit level. For example, pre-load limits on motors can be understood via such things as heat cycling. Higher pre-load could reduce overall circuit and system health. To date, there has not been an effort to correlate this information with O&M. Another example is with transformers; the AHI can use DGA to determine when a transformer might fail and what the downstream effects might be. Because assets can be grouped by importance, the amount of testing can then be increased and the stress trends identified.

Material standards are slightly different across each of the utilities – internally or externally. In general, there is more alignment within specific geographic regions. This is especially true for Pacific Power which has established a significant storage depot in what might appear to be a remote locality. In actuality, the location is centralized to provide resources across two different service territories.

The coordinated approach extends to Pacific Power’s contracting strategies. When soliciting bids, the company tries to start building using a single specification. This way they are able to leverage buying power and achieve cost reductions. When executing the actual contracts, specific standards are set for universal provisions like warranty, security, and insurance. In addition, contracts have quality assurance components and performance requirements to ensure that everything is built to Pacific Power standards.

Pacific Power does not stockpile and has limited inventory for operations. The current program focuses on just-in-time management with inventory, as needed, located throughout the service territory. According to Pacific Power, the reason for this approach, and the biggest problem with stockpiling, is that a very small percentage of items can be held as inventory.

B. Transformers

There are two challenges with transmission level transformers:

1) Control of quality at the construction site, and
2) Transportation and delivery.

According to Pacific Power, the recent successful bidders are relatively new market entrants from Asia that offer less expensive (as much as 50 percent less) products than previous providers. Specifically, these companies are opening up their factories to quality assurance checks well beyond previous providers. Not only has this significantly reduced costs, but it helps reduce average lead/lag times.

C. Improvement Programs

- Equipment Voltage Standardization: There is a high historical degree of variation between voltage classes across Pacific Power and other electric utilities. While there has been some plan to standardize equipment, most efforts do not seem to be cost-effective or are too complex from a system perspective. Even still, improvements are evaluated on a case-by-case basis for potential benefits.

- Rapid Improvement Substation Plan: Initiated in 2016, this process replaces or upgrades circuit breakers and relays. Each plan is validated by engineers and other participants through a review process.

- Cable Management: Pacific Power is looking into a process that identifies problems with feeders and cables, including underground and vaults. Functionally, this requires more automation because manually reviewing these assets is difficult and time intensive. Regarding cables, such a program would look at cable failure rates, inspections, asset class, conditions, history of repairs, splice points, criticality of assets, line performance, partial discharge testing, and concentric neutral testing.

Avista Corporation

A. Business Practices

The table below outlines Avista's budget for vegetation management over the past few years.

O&M Vegetation Management						
O&M						
	2012	2013	2014	2015	2016	2017
Requested	$6,441,000	$6,743,000	$6,900,000	$6,748,000	$7,520,000	$7,079,000
Approved	$7,650,000	$6,733,000	$6,846,860	$5,889,000	$5,977,000	$6,400,000
Spent	$7,800,000	$6,207,000	$6,795,000	$5,889,000	$5,914,000	$6,467,000
Capital Wood Pole Managment Follow-up						
CAPTIAL						
	2012	2013	2014	2015	2016	2017
Requested	$9,714,952	$10,015,415	$10,325,170	$10,644,505	$10,973,717	$11,313,110
Approved	$9,485,693	$9,281,686	$9,900,011	$11,000,009	$7,840,001	$9,600,000
Spent	$10,062,694	$9,258,713	$9,512,319	$9,789,649	$8,601,732	$9,644,000
O&M WPM Pole Inspections						
O&M						
	2012	2013	2014	2015	2016	2017
Approved	$995,135	$813,128	$818,778	$706,686	$789,631	$640,491
Spent	$1,062,459	$925,846	$879,521	$695,470	$938,398	$643,000

While the requested budgets for vegetation management have grown, the approved budgeted amounts have remained relatively stable. To ensure low costs and efficient operations, Avista has made several business improvements to its vegetation management activities. A few of these improvements are discussed in detail below.

i. Cycle Management

Avista's vegetation management is currently on a six-year cycle, with a goal of being on a five-year cycle. Inspecting each distribution line with greater frequency would allow Avista to prevent more outages before they occur. The frequency of inspection has also become more important as Avista's service territory has seen a 250 percent increase in pine beetle infestations, which can turn a healthy tree into a hazard within a year. This same vegetation has also been stressed by seasonal drought.

ii. Billing

Avista has moved its vegetation management contractors from a pay-per-mile system to a unit based system. By tracking an inventory of over 300,000 units and the hours spent per unit, the company is able to achieve operational efficiencies under most circumstances. For instance, the graph below compares the unit based cost versus the time and material approach. In four out of the five months, unit based costs were lower with the respective contractors.

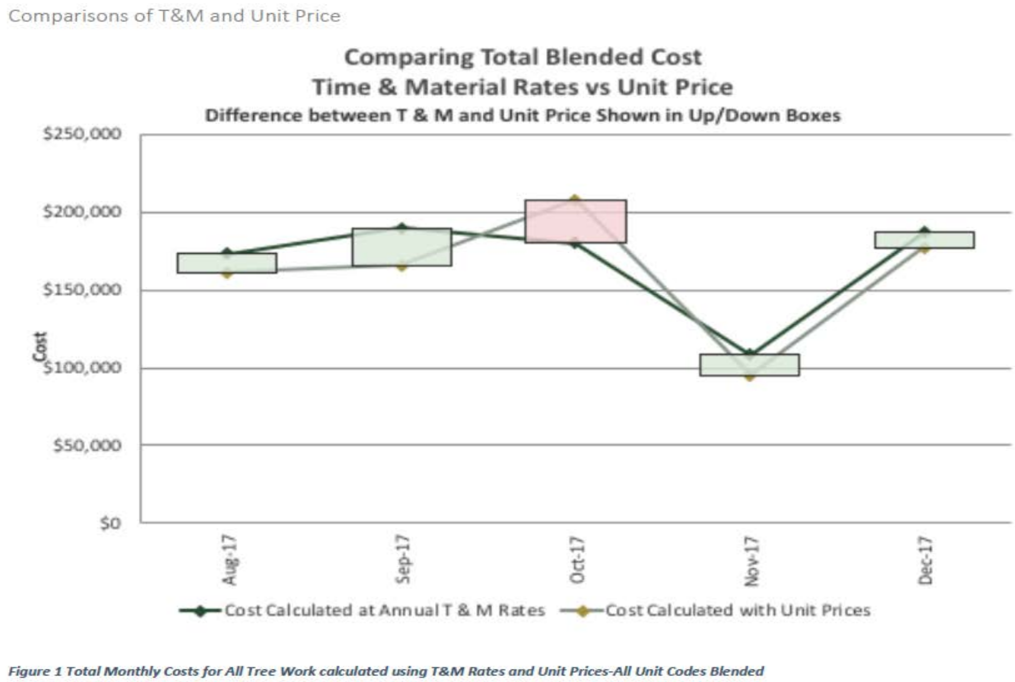


Figure L.1 – Avista's pay-for-performance model has resulted in cost savings in most circumstances. However, if there are more trouble spots in a centralized area the overall cost may be higher.[46]

[46] Graphic provided by Avista

iii. Customer Service

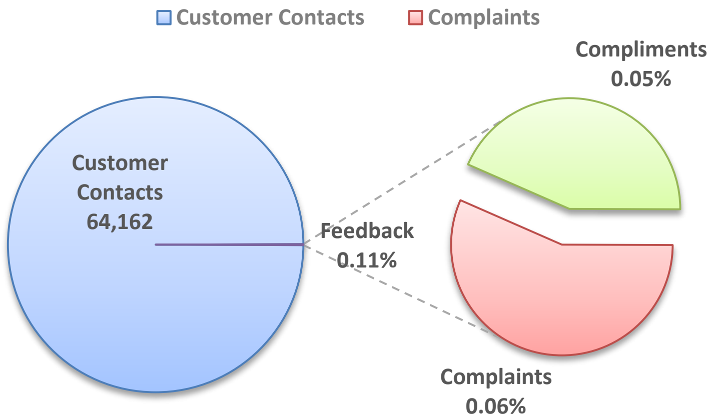


Figure L.2 – Customer complaints related to vegetation management is a very small fraction of overall customer interactions.[47]

A focus on customer service has limited the number of complaints received regarding tree trimming work. A key reason for this success has been a focus on effective communication pre- and post-vegetation work in private right-of-ways.

B. Operations

Off right-of-way trees pose one of the largest risks to Avista's distribution and transmission lines. To address this problem, Avista implemented the Cycle Buster Tree Replacement Program. This program works with property owners to remove off right-of-way trees, which has become increasingly important in recent years because of the increased pine beetle infestations. Removing the problem trees quickly helps to combat the spread of infections and reduces the risk to utility infrastructure.

Avista also works with owners of trees in the right-of-ways that may be healthy, but are not appropriate for close proximity to the company's infrastructure. The company found that the cost of trimming a tree in an urban area is approximately double that of a tree located in a rural area. For this reason, property owners are encouraged to plant species that pose less hazard to infrastructure. Avista's tree removal rate has doubled since 2016.

Avista works with multiple jurisdictions when conducting right-of-way work on its transmission system because some infrastructure is located on National Forest Service, Bureau of Land Management, and Tribal lands. By focusing on building relationships with these jurisdictions, Avista is able to realize efficiencies in its inspection and management of over 830 miles of rural transmission lines.

[47] Graphic provided by Avista.

i. Feeder specific operations vs. geographic focus

Working within a condensed geographic area provides additional operational efficiencies because worker mobility is taken into consideration. Planning vegetation management activities by geographic area minimizes the number of times workers need to traverse busy roads and arduous terrain. Transitioning from a pen and paper based work plan to an electronic system also increase efficiency. The deployment of mobile technology (such as tablets) now allows field workers to incorporate photos, written descriptions, and GPS data, such the locations of hazard trees, immediately into Avista's monitoring system.

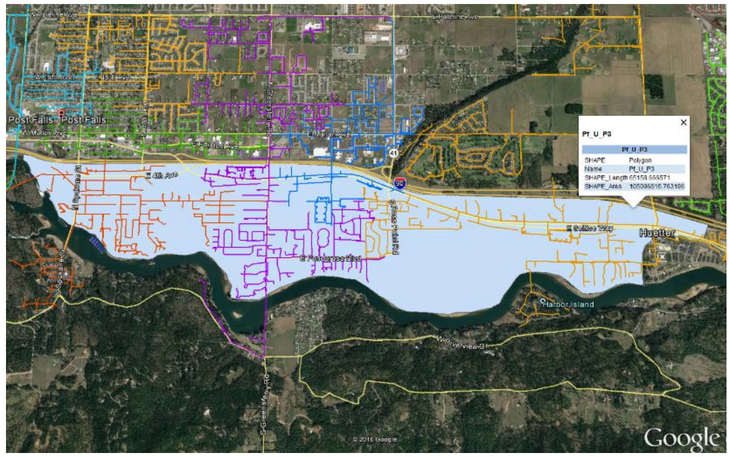


Figure L.3 – The feeders are visible as lines, with each color noting a specific feeder. The light blue shape that follows the river denotes the geographic work area.[48]

ii. Sustainable Practices

The vegetation management program has incorporated arborists into their teams to achieve sustainable tree management efforts and improve overall effectiveness. For instance, the program has moved from treating all geographic areas and species the same to a more customized tree trimming approach. This has reduced the unnecessary trimming of trees and provides for a more targeted cyclical management program.

When removing right-of-way trees on forest lands, Avista has multiple techniques that are environmentally friendly, such as using a chainsaw to girdle a tree. This process kills the tree over several years, creating a habitat for wildlife and retaining soil nutrients. This process also encourages the growth of smaller plants in the vicinity. Another enviro-friendly solution is the use of ferns in the company's right-of-ways because the plant secrets a chemical that discourages future tree growth.

[48] Graphic provided by Avista

Puget Sound Energy

A. Business Practices

PSE utilizes contractors for vegetation management services. The table below summarizes the vegetation budget over the last five years.

Year	Pole Management		Vegetation Management	
	Budget	*Actual*	*Budget*	*Actual*
2017	$ 19,000,000	$ 6,553,903[49]	$ 17,824,493	$ 17,359,873
2016	$ 3,710,687	$ 4,883,102	$ 16,162,006	$ 17,453,000
2015	$ 7,160,726	$ 4,578,452	$ 14,493,944	$ 13,397,000
2014	$ 8,135,537	$ 5,679,261	$ 13,622,000	$ 13,601,000
2013	$ 5,099,349	$ 8,820,324	$ 14,142,000	$ 14,108,000

PSE also provides proactive communications to its customers regarding landscaping which can help mitigate future problems.[50] These recommendations help consumers identify tree and shrub varieties that are friendly to electric lines.

B. Operations

PSE's service territory has approximately double the number of trees per square-mile when compared to the average U.S. utility. To combat the risk associated with this high tree density, PSE has developed a robust tree management program.

i. Cyclical Pruning

Vegetation along 358 miles of 230 kV infrastructure is trimmed annually, in compliance with NERC standards. Vegetation along 1,752 miles of 55/115 kV transmission infrastructure is trimmed on a three-year cycle. Urban distribution lines are trimmed on a four-year cycle, and rural distribution lines are on a six-year cycle. The distribution system consists of over 23,705 miles of lines in need of inspection.

[49] The pole management budget was initially budgeted higher in 2017 to address backlog pole replacements. The back pole replacements were put on hold while PSE reviewed our pole inspection methodology with industry best practices.

[50] An sample communication can be found here: https://pse.com/safety/Tree-Trimming/Documents/1225_energy_landscaping.pdf

ii. Tree Watch

Through its Tree Watch program PSE works with property owners to remove hazard trees that are at risk of falling. Generally, PSE arranges for tree replacement to acquire infrastructure-friendly replacement trees. Unfortunately, property owners may see an opportunity to get a tree removed at little or no cost to them, resulting in company staff visiting properties where the vegetation does not pose a threat to PSE's infrastructure. Additionally, the local jurisdictions tend to require somewhere between a 3 to 1 to 6 to 1 replacement for removed trees, even if those trees pose a danger. The Tree Watch program seems to have decreased as a priority over the years; the underlying cause of this decline is unclear. PSE's electric reliability strategy roadmap indicates that PSE plans to place more emphasis on this program in 2019.

iii. Hotspot Trimming

This program handles reports from field technicians and customer requests to trim hazardous vegetation on an emergency basis. Three to 5 percent of total vegetation management funding is spent on this program.

iv. Technology Improvements

- Spacer cable - PSE is currently conducting an analysis whether spacer cable could help combat service interruptions. Spacer cable reorganizes the traditional flat layout of power lines to a triangle or diamond formation. This design tends to be more resilient to branch and some tree strikes as the branch or tree can roll over the line instead of pulling the line down or snapping the pole. PSE has not installed any spacer cable since a 1990s pilot project.

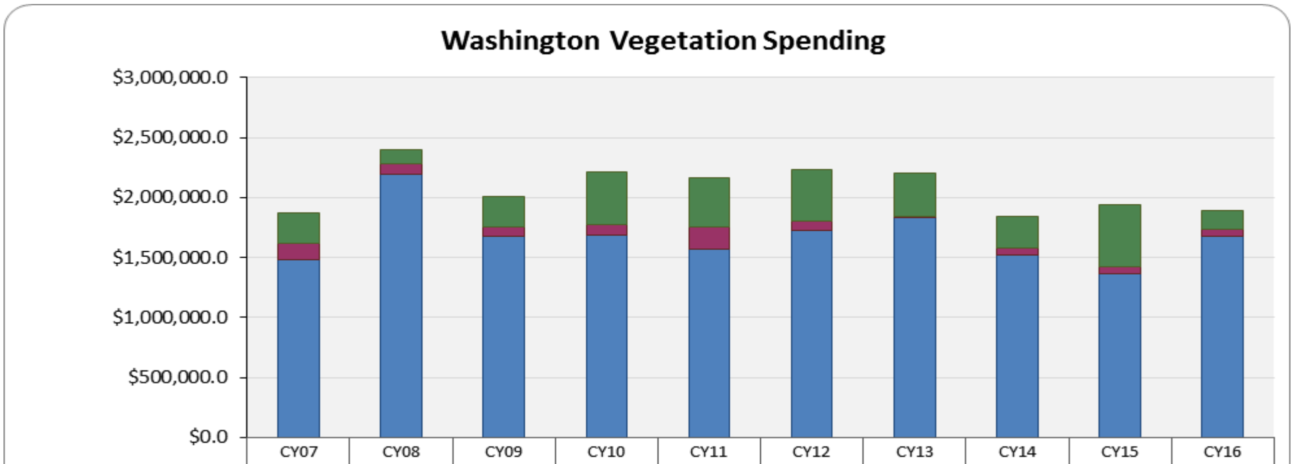
- Tree wire - Tree wire distribution construction costs typically run about 10 percent higher than overhead bare line construction costs. The use of tree wire requires a larger pole class to accommodate the heavier tree wire conductor.

Pacific Power & Light

A. Business Practices[51]

Pacific Power recently switched to a competitive bidding process to reduce its overall vegetation management costs. The company previously relied upon a single vendor but now utilizes the services of three vendors. Pacific Power also uses a zero-based budgeting approach in an effort to "right size" vegetation management efforts each year. While this can reduce spend-to-budget policies, it means that budgets are not consistent between years.

[51]Graphic provided by Pacific Power.



	CY07	CY08	CY09	CY10	CY11	CY12	CY13	CY14	CY15	CY16
Main Grid Transmission	$253,627	$117,166	$258,378	$438,152	$403,979	$423,375	$361,333	$267,957	$519,338	$159,435
Local Transmission	$140,017	$94,106	$73,715	$88,069	$184,698	$78,189	$12,415	$51,660	$55,418	$58,130
Distribution	$1,478,147	$2,188,306	$1,678,125	$1,687,253	$1,570,998	$1,729,537	$1,830,106	$1,525,005	$1,368,959	$1,675,949

B. Operations

Pacific Power employs a seven member International Society of Arboriculture certified team. This team is responsible for crafting the vegetation management plan each year, with an overall three-year cycle. The company has found that the cycle-based approach may not be the most effective from a reliability perspective because it does not mitigate high-risk areas. However the alternative, metric-based plans, do not account for off right-of-way vegetation. To combat these problems, Pacific Power is placing an increased emphasis on hotspot response.

i. Hot spot process

Approximately 80-85 percent of vegetation related outages are caused by off right-of-way vegetation. Pacific Power utilizes a collection of both field processes and technology to identify at-risk assets:

1) Operational personnel advise when they observe problematic trees during outages, field response, or patrol activities.
2) Foresters perform inspections when requested by the public or government (such as a fire department).

ii. Advanced Technologies

- Light Detection and Ranging (LiDAR) - Pacific Power has also been using LiDAR to monitor vegetation growth. This is particularly useful in remote locations. Remote transmission infrastructure is often difficult and costly to reach on foot. Because of the rough terrain, Pacific Power is also experimenting with drone-based systems to further reduce costs. Ultimately, the LiDAR and drone data is overlaid with reliability information in a GIS system. Crews and operators can then use the data to aid in identification of trouble spots.

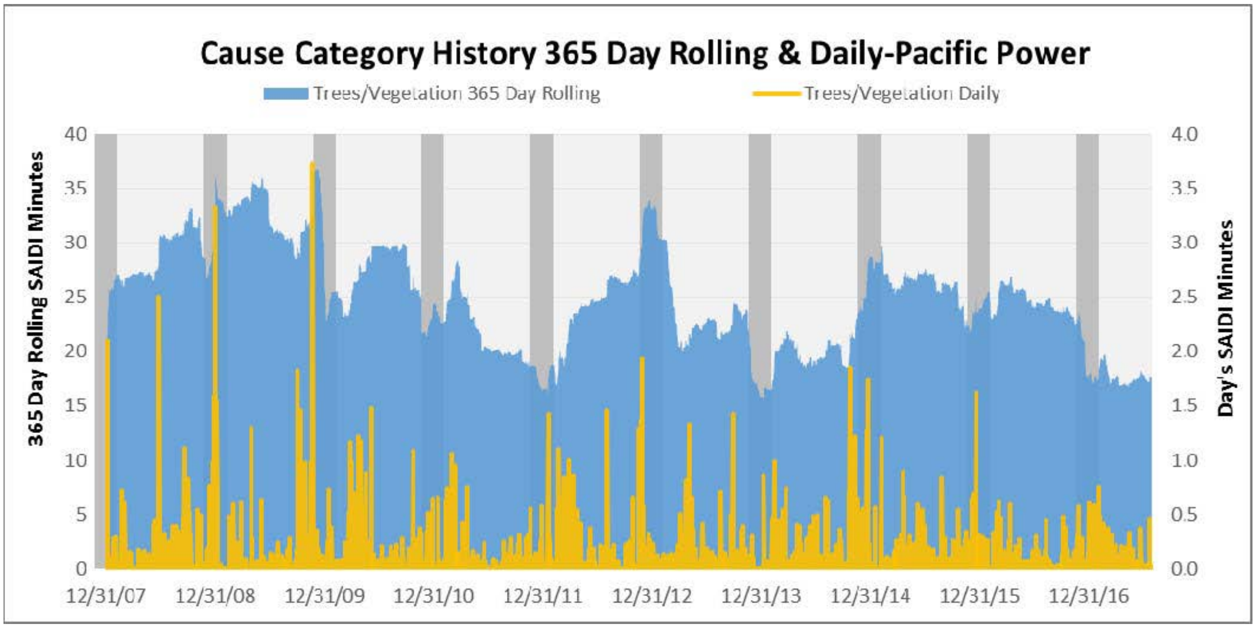


Figure L.4 – Pacific Power utilizes visual tools to identify trends in overall data. This graph overlays SAIDI trends on a daily and yearly basis to show the general decrease of outage frequency. This also illustrates the spikes that tend to occur with each season or weather event.[52]

Pacific Power also administers a tree replacement program that provides property owners with vouchers for new infrastructure-friendly trees, similar to that of PSE and Avista.

[52] Graphic provided by Pacific Power.