EXH. CAK-5 (Apdx. D)
DOCKETS UE-22___/UG-22___
2022 PSE GENERAL RATE CASE
WITNESS: CATHERINE A. KOCH

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	Docket UE-22____ Docket UG-22____

APPENDIX D (NONCONFIDENTIAL) TO THE FOURTH EXHIBIT TO THE PREFILED DIRECT TESTIMONY OF

CATHERINE A. KOCH

ON BEHALF OF PUGET SOUND ENERGY

JANUARY 31, 2022

CABLE REMEDIATION

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

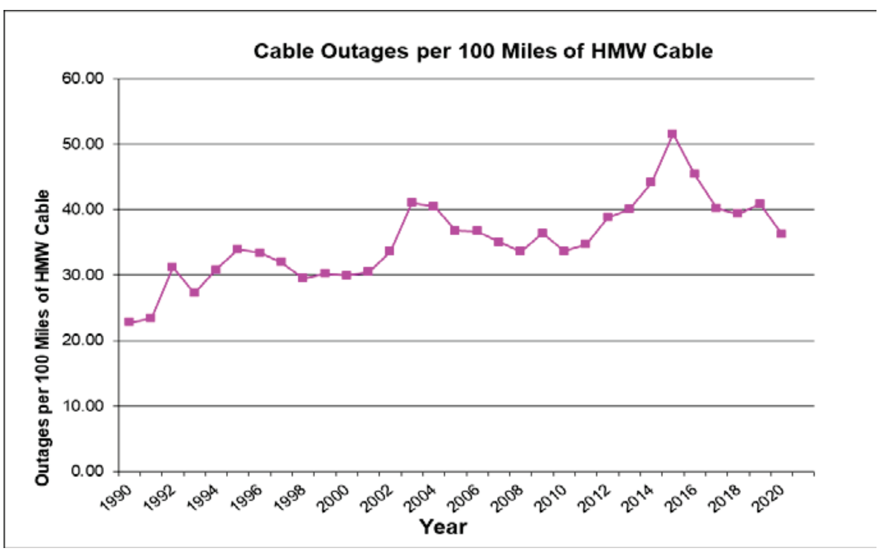
The cable remediation plan is a reliability initiative to remediate primarily direct buried bare concentric neutral cables belonging to Puget Sound Energy's (PSE) underground residential distribution system that have a trended probability of failure, of which high-molecular weight (HMW) cable type is the worst offender.

2. BACKGROUND

PSE began installing direct buried bare concentric neutral HMW underground cables mainly for residential distribution just prior to 1965. This type of cable was installed nation-wide by multiple utilities during the housing construction boom of the 1970's. PSE and other utilities began to experience cable failures just after 20 years of service as the insulation of the cable became susceptible to formation of "water trees" allowing ground water to migrate to the conductor and cause electrical faults. Warm weather can increase the probability of failure.

As part of the 1988 Puget Power (PSE's former name) 'Underground Cable Failure Report', an in-depth analyses of three test years (1985-1988) showed that more than 95% of cable failures were due to pre-1983 HMW insulated cable. Similar failure rates were experienced on a per mile basis between utilities across the industry, which resulted in an industry wide concern. The report determined that PSE experienced an average failure rate of 25 failures per 100 mile of HMW cable in 1990 which increased to over 50 failures per 100 miles of HMW cable installed by 2015.

Figure 1: Outage Per 100 Miles

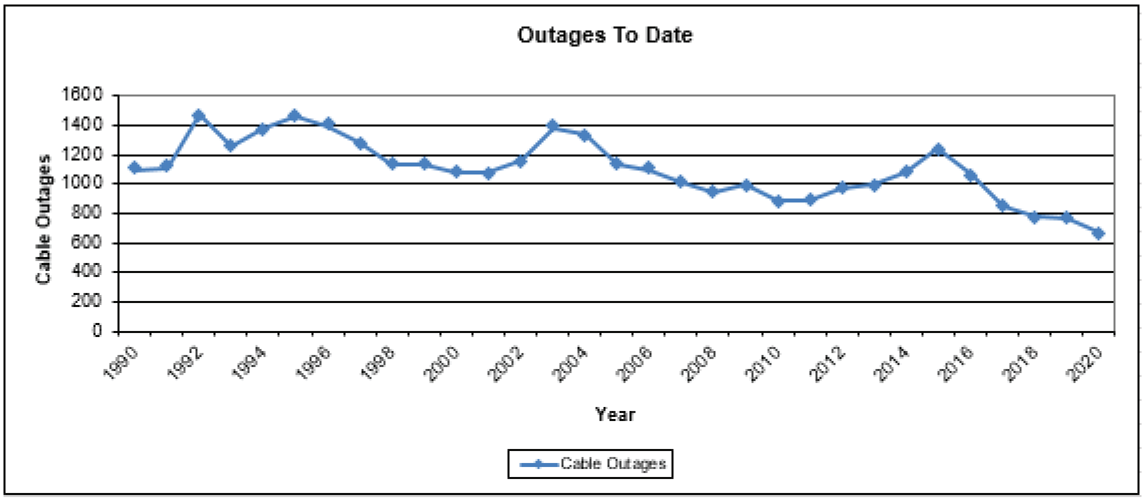


Direct-buried cables of this generation also include a bare concentric neutral cable which is subject to corrosion over time and will compromise the integrity of the neutral. This poses risk to the customer and people working with the cables.

In 1990, the increase in cable failures was the basis and background to initiate the Cable Remediation Plan, as other utilities in the US were also experiencing similar reliability issues with direct buried cable including HMW. In 2016 PSE established the Electric Reliability Plan (ERP) to ramp up the replacement of HMW cable.

Since this initial report was written in 1988, PSE has tracked monthly outages each year and have been averaging over 1000 failed cable related outages per year until approximately 2015 where the outages began to decreases as can be seen in Figure 2.

Figure 2: Historic Cable Failure Related to Outages



The majority of these cables have been remediated through replacement, however a smaller population were injected with silicone to remediate the insulation and extend the life of the cable. Since 2016, the plan has focused on replacement which has had notable improvements on cable failures.

3. STATEMENT OF NEED

This plan targets the improvement of system reliability, aging infrastructure replacement, reduction in customer complaints and reduction of outages due to cable related failures. In 2015 alone, 1,243 cable failures caused approximately 57,000 customer outages. PSE had experienced typically over 1,000 cable failures per year until recently. Repeat cable related outages can result in customer complaints that sometimes are escalated to the Utilities & Transportation Commission (UTC). PSE's reliability performance index (SAIDI & SAIFI) has scored in the third quartile compared with over 100 other utilities in the United States on the IEEE Reliability benchmarking survey during 2018 and 2019. Based on this performance, PSE determined that a programmatic approach would be required to help reduce outages caused by this failure prone cable.

3.1. Need Drivers

- **Grid Modernization**
  - **Reliability** –Underground cable failures typically have been the largest source of PSE equipment related failures impacting customers and the PSE SAIDI & SAIFI reliability performance indexes. Replacing aging direct buried HMW cable with new TRXLPE cable technology in conduit and modern construction techniques improves customer reliability and eliminates the typical outage causes. Average outage duration since 2016 is about 8 hours per outage, however outage frequency has reduced since 2016. Since HMW type cable is direct buried, it requires more time to locate failure, repair or replace as opposed to new cable in conduit. Replacing direct buried cables supports Grid modernization efforts by improving the reliability of the infrastructure and reduce maintenance repair costs.
  - **Safety –** Direct buried cable of this generation includes a bare concentric neutral which corrodes over time and compromises the integrity of the neutral. Modernization of the PSE underground residential distribution system eliminates the need for bare concentric cables and thereby protects the safety of the public and employees from stray voltage concerns.
  - **Resiliency** – The PSE underground distribution system built over many years is aging and unreliable which needs to be resilient if it is to provide quality service to a growing demand. Modernizing PSE's aging infrastructure will harden and protect the underground distribution system and bring it up to latest standards which supports and enables future Grid modernization plans. By replacing old HMW cable technology and installing new cable in conduit, this allows PSE to replace cables quicker, reduce outage duration and restore power quicker to customers. New cable and hardware install will provide improved operational flexibility and improved resilience through improved design and service connection to customers.

3.2. Integrated Strategic Plan (ISP) Alignment

This Plan aligns primarily with the Processes & Tools category of the ISP:

- System Reliability and Integrity: The principal driver for this plan is to reduce the number of cable related outages and improve customer reliability. Through the replacement of aging infrastructure and System hardening, PSE is improving the integrity of its distribution system which supports operational excellence and provides customer satisfaction.

- Customer Focus: The plan is a very customer focused plan as it addresses their needs directly by maintaining safe and reliable service, and by being able to restore power as quick as possible to demonstrate our commitment to customer satisfaction. This improves the image and reputation of PSE. This plan also aligns with Customer focus as PSE drives to improve the customer experience through working with the community providing clear communication of planned project updates, scheduled outages and estimated completion of neighborhood projects. Through effective planning and communication, the plan can address customer complaints which are sometimes escalated to UTC by prioritizing and accelerating cable replacement projects.

4. PLAN DETAIL

4.1. Plan Size/Population

Since the failure rate of direct buried cables ramped up between the 1980's and the 1990's, the plan has been funded every year since 1990. Beginning in 2016, PSE has ramped up the plan considerably through 2020, resulting in replacement of over 500 miles in 5 years with a notable decrease in cable outages. The table below outlines the history of the HMW cable family replacement progress and remaining HMW cable miles.

Table 1: HMW cable population

CRP Status	Total miles
Total family of cables installed 1965-1980	4,800
Cables replaced in conduit prior to 1990	500
Cables silicone injected from 1990 to 2018	513
Cable replaced from 1990 to 2020	2,484
Remaining cable miles end of 2020	**1,303**

4.2. Proposed Completion date

Through the plan, PSE has remediated approximately 3500 miles of the HMW type of cable as of 2021. Based on the average rate of HMW cable replacement, the estimated forecast completion of the full HMW population is **2035.**

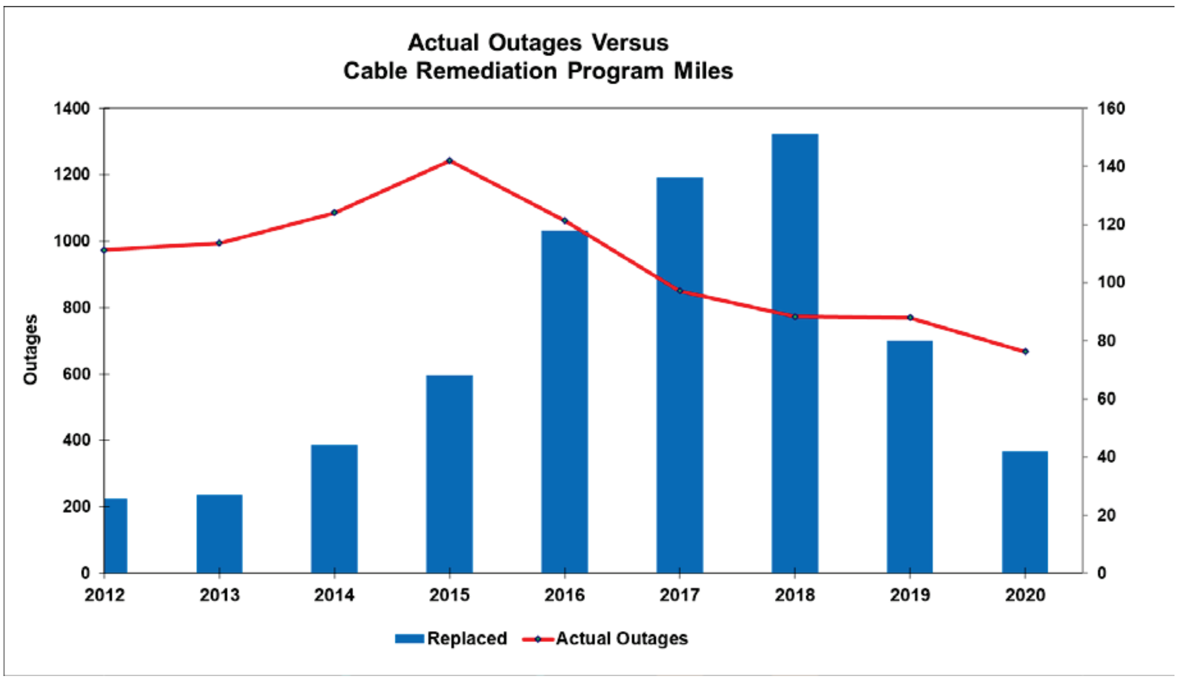
4.3. Summary of plan Benefits

Addressing the failure prone cable has been one of PSE's priorities since the 1990's to improve system reliability, address safety and customers concerns, and upgrade its aging infrastructure. Since the 1990's the plan has replaced on average 100 miles of cable per year increasing in 2016 through 2018 to approximately 140 miles per year, which reduced the number of cable related outages significantly, evident in Figure 3 on page 5. The new cable design is resilient to deterioration and dig-ins, which results in less disruption and enhances public safety. This improves the customer experience and overall reliability. The benefits of the plan include reduced outages and avoided customer minute interruptions (CMI) which affect PSE SAIDI. Table 2 below includes actual benefits since the plan ramped up in 2016.

Table 2: 2016-2019 Cable Remediation Actual Benefits

Year	Budget ($M)	Cable Per Year (miles)	CMI Avoided	SAIDI Saved (mins)
2016	37.565	120	2,127,787	2.4
2017	55.8	136	1,461,587	1.9
2018	61.2	151	2,268,933	1.3
2019	33	80	3,129,866	2.7
2020	21.9	42	1,115,626	1.0

Figure 3: Cable Replacement vs Outages 2012 - 2020



4.4 Primary iDOT Categories

PSE's employs an Investment Decision Optimization Tool (iDOT) to evaluate benefits of projects and optimize the annual portfolios for construction. The top primary iDOT Categories this plan addresses are:

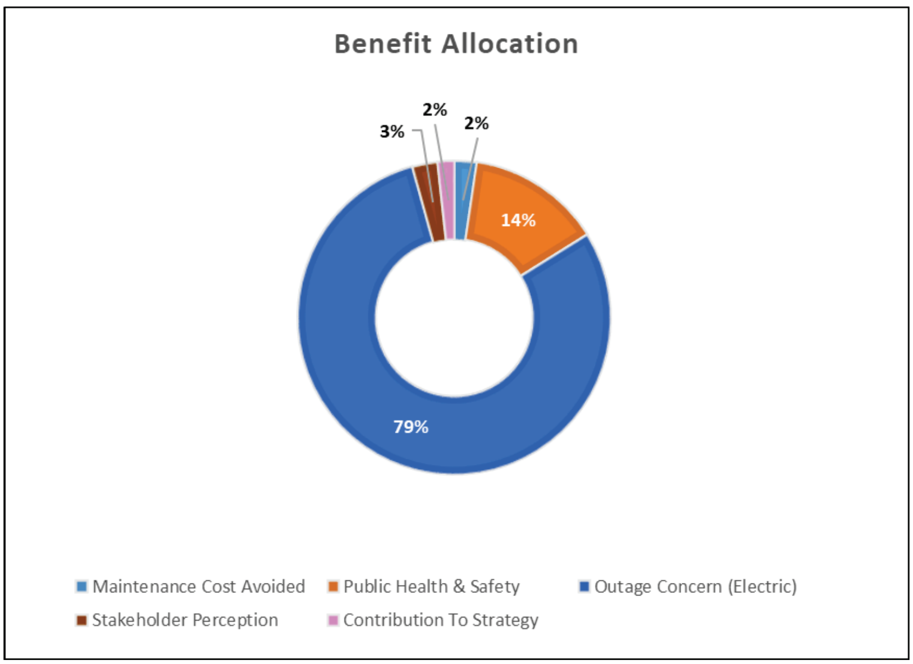
- Outage Concern - per impacted customer with the project
- O&M Costs Avoided –emergencey repairs for failures
- Health & Safety - impacts and risk reduction if plan is funded
- Stakeholder Perception – of complaints that will occur if project is funded

All benefits inputs into iDOT based on most recent 2021 plan inputs and averages. Table 3 below shows plan costs and benefits through 2026 to replace approximately 462 miles of cable, the remaining cable miles to complete the plan will be evaluated with current data annually to ensure cost effectiveness and iDOT will be updated each year to determine benefits for ongoing 5 year plan.

Table 3: Total Population, Cost and Benefits

2022-2026	Non-MED CMI Saved (M)	Number of Cable Miles	Budget ($M)[1]		NPV ($M)[2]	iDOT B/C Score[3]
			Capital	OMRC	Total Benefits	
Total	**27.6**	**462**	**220.7**	**1.76**	**129.4**	**0.69**

Figure 4: Benefits Allocation[2]



4.5 Estimated Costs

For Electric System Planning estimated costs are generated based off of historical costs on similar types of projects, allows for variations in project scope, increase in project cost due to inflation, and added contingency to account for unforeseen conditions associated with the project.

Historical actual cost are $74 per cable foot, future estimated cost are $91 per cable foot.

The projected programmatic remaining costs to complete the cable remediation plan from 2021 until 2034 will be approximately $650 million based on about $50 million per year after 2026.

5. ALTERNATIVES

5.1. SOLUTION ALTERNATIVES

No Action - Without a plan in place or a run to failure approach, PSE would face increased interruptions due to cable failures, customer dissatisfaction and increased emergency repair expenses annually. Cables will fail repeatedly and will only be repaired and eventually replaced on an unplanned basis, which increases emergency O&M repair costs and become a safety concern. Also, repeated outages have a negative impact on system and customer reliability and can lead to customer complaints that get escalated.

5.2. FUNDING ALTERNATIVES

Increased Funding - With increased funding of the CRP, there are multiple benefits to PSE metrics such as customer outage count and SAIDI performance, whilst reducing unnecessary O&M emergency repair costs. See Table 4 of the historical emergency repair costs which could potentially increase again without the current levels of funding. Increased plan funding could reduce O&M in a shorter timeframe and improve reliability to customers.

Decreased Funding - Reducing the current funding levels for CRP in a given year has an immediate impact on cable related outages the following years. Repeated failures on the same cable drive customer UTC complaints impacting PSE's reliability performance and reputation. There is also a risk with decreasing the funding as more aging direct buried cables have compromised neutrals and become a safety concern for both the public and PSE employees. Decreasing funding automatically means an increase in emergency repair costs. Without a plan in place the failure rate would increase substantially each year driving up repair costs and putting our customers and PSE personnel at risk.

Table 4 –O&M Costs vs. Cable Outages

Year	Cable failure Outages	O&M related Costs $
2007	963	$4,761,300
2008	877	$4,898,727
2009	986	$5,478,010
2010	848	$5,358,133
2011	892	$6,099,790
2012	965	$5,872,954
2013	984	$7,022,820
2014	1083	$7,776,259
2015	1241	$8,288,034
2016	1030	$5,133,580
2017	824	$5,650,491
2018	758	$4,135,799

2019	770	$3,466,761
2020	667	$2,947,391

6. PLAN DOCUMENT HISTORY

Date	Reason(s) for Update	Summary of Significant Change(s)	Modified By
10/25/2019	CRP Business Case - New plan template	Documenting CRP kick-off from 1990 and Program ramp up in 2016 – Summarize historical plans	Stephen Hartnett
4/16/2020	Revision	Need drivers; iDOT categories & benefits	Stephen Hartnett
03/16/2021	Revision	Annual Program Updates	Stephen Hartnett
7/13/2021	Used and Useful Policy guidance	Add alternatives and cost information	Stephen Hartnett
12/1/2021	Annual Review	Minor word and format changes	Stephen Hartnett

7. SUPPORTING DOCUMENTATION

Document Name
PUGET POWER UNDERGROUND CABLE FAILURE REPORT (AKA CHICKEN LITTLE REPORT)
CEATI ASSESSMENT CRITERIA USED TO REPAIR, REFURBISH OR REPALCE UNDERGROUND CABLE
IEEE INSULATED CONDUCTORS COMMITTEE – POWER CABLE RELIABILITY SOLUTION
IEEE - TRENDS IN UNDERGROUND RESIDENTIAL DISTRIBUTION CABLE SYSTEMS
2017 AND 2018 RELIABILITY PLAN

SUBMARINE CABLE REPLACEMENT

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

The Submarine Cable Replacement plan is a reliability initiative to proactively replace Puget Sound Energy's (PSE) transmission and distribution submarine cables based on condition assessments or cable history. These cables can fail for various reasons due to their age, physical characteristics and the surrounding environment, spread over multiple locations in the PSE territory. The transmission cables are self-contained fluid filled cables (SCFF). The response to each circumstance is unique, can be expensive, and be more time consuming than any other type of electrical system failure.

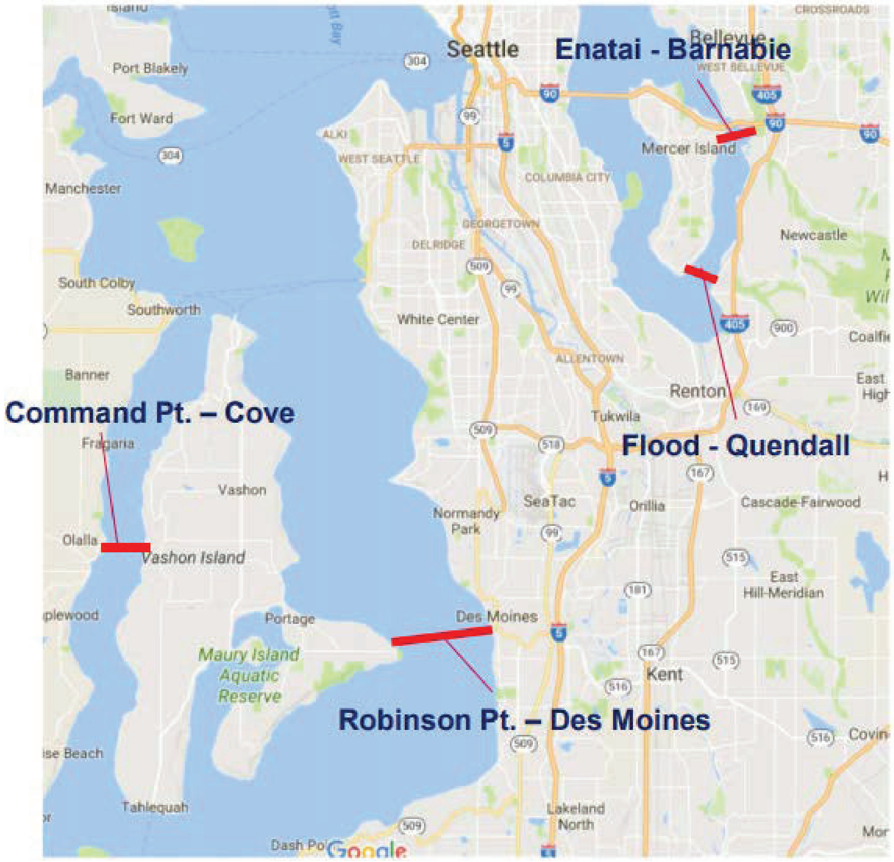
2. BACKGROUND

Table 1 shows a list of current transmission submarine cables in service. There are 3 or 4 submarine cable runs between each station totaling a little over 18 circuit cable miles. It can also be seen that all of these cables are beyond the expected design life of 40 years for that cable type. From a economic lifecycle point of view, these cables have passed their normal design life and have fully depreciated. These are displayed in map 1. The Vashon Island crossings serve 6,977 customers. The Mercer Island crossings serve 10,937 customers.

Table 1: Transmission Submarine Cables

Transmission Submarine Cables					
Station-Station	**Cable Type**	**Length (miles)**	**Runs**	**Year Installed**	**Cable Age**
South Des Moines-Robinson Point	115-kV 600-kcmil Cu, SCFF	2.681	4	1962	59
Command-Cove	115-kV 600-kcmil Cu, SCFF	1.175	4	1962	59
Quendall-Flood	115-kV 600-kcmil Cu, SCFF	0.606	3	1964	57
Barnabie-Enatai	115-kV 600-kcmil Cu, SCFF	0.321	4	1960	61
Total Cable Miles		18.526			
Total Faults & Repairs		61			

Map 1: Transmission Submarine Cable Crossings



There are a little less than 3,000 distribution customers being energized or backed up by distributions submarine cables. Table 2 outlines the amount of customers fed from the specific crossings as well as if there are alternative sources available if there were an outage on the submarine cable.

Table 2: Distribution Submarine Cables

Distribution Submarine Cables				
Crossing Name	**Number of Customers**	**Year of Installation**	**Alternative Sources Available**	**Plan if cable fails**
Guemes Island	908	1977	NO	Replace
Silcox Island (American Lake)	31	1994	NO	Repair/Replace
Ben Ure Island	7	1984	NO	Repair/Replace
Blake Island	4	2000	NO	Repair/Replace
Lumni Island	972	2002	NO	Repair if possible Replace if necessary
Black Lake	386	1994	YES	Repair/Replace

Enatai to Mercer Island *	0	1978	YES	Repair/Replace
Enatai to Mercer Island *	0	1978	YES	Repair/Replace
Olympia Yacht Club *	0	2003	YES	Repair/Replace
Lake Tapps *	0	2013	YES	Repair/Replace
Lake City to Tilicom (American Lake) *	0	1982	YES	Repair/Replace/ Retire/Remove Cost Dependent
Port Gamble Bay	453	1980	YES	Retire/Remove
Fragaria to Cove *	0	1957	YES	Retire /Remove
Fragaria to Cove *	0	1959	YES	Retire /Remove
Bangor to Coyle (Hood Canal)	17	1980	NO	Retire (Jefferson County PUD)
Salsbury to Shine (Hood Canal) *	0	1999	NO	Retire (Jefferson County PUD)

*Not primary feed for distribution load in the area

PSE began installing distribution submarine cables in 1916 from the Enatai neighborhood in Bellevue, to Mercer Island. The transmission submarine cables were introduced to PSE's system in 1960 from Enatai cable station to Barnabie cable station and then in 1962 an additional transmission cable from South Des Moines to Robinson Point cable station. When dealing with a submarine cable failure, there are 4 steps PSE follows.

1. Collect Information
2. Locate the Failure
3. Assess the Damage
4. Make Repairs, Replace the Cable, or Abandon It

PSE has some spare cable and accessories on hand to replace some short distribution type cables or splices. There is not enough spare cable for the specific type of transmission cables installed. There is only enough to carry out repairs and add splices.

There are 3 replacement/repair methods available to install submarine cable:

1. Floating Method
2. Messenger Method
3. Submarine Cable-Laying Vessel

These methods have disadvantages such as complications during wind, high current, and with deep crossings. They also can be complicated, costly, long lead times, and difficult to retrieve or back up. Most of the time, these cables are viewed as non-emergency work and are required to go through the appropriate permitting process. As a cable ages, there are more repairs and replacements required as opposed to a new cable. If the cable is the only feed to the island, PSE installs and operates a portable generator until the cable is restored.

These older generation of sub marine cable which used oil filled insulation methods, have created more problems for repairs and may become an environmental risk if a catastrophic failure was to occur. PSE has documented history and evidence of many years of repairs to these cables that require extensive outages in order to locate failures and then repair cables by raising them to the water surface to carry out splicing or repair localized damage to the armor.

There have been roughly 61 faults and repairs documented up to 2015 amongst all of the submarine transmission cables. The repairs are primarily issues of the lead and armor or due to oil leaking. The armor wires are severely corroded or completely gone at places. The lead sheath now carries the circulating current and even fault current, the lead is known to become fatigued over time. Multiple reactive and proactive repairs have been carried out on the bonding boxes for each of the cable terminations at each of the cable stations since initial installation.

There was an increase in repair costs from 2014-2016 due to oil leaks at the bonding boxes and PSE had to respond reactively to these leaks. PSE had proactively replaced bonding boxes after these incidents to avoid oil leaks which cause environmental issues. There are no oil containment system deployed to mitigate oil leaks. These repairs, planned or unplanned, ranged from $250,000 to $700,000 per incident for the bonding boxes

There is a leak being investigated in 2021 with costs unknown at this time for the Barnabie-Enatai line. This line segment last had a repair in 2016 and 5 years later has a new leak. There is a project team of 13 individual contributors assembled with additional individuals providing comments and oversight throughout the process. The demand has grown in these areas served by the submarine cables and there is a risk of overload on the remaining cables if the island were to lose a feed. If there is an overload, there will have to be load shed. Due to these risks, it is recommended that PSE takes a proactive approach and plan for submarine cable replacement while the current cables are still operational. As these cables continue to age, these issues are anticipated to increase in frequency. Utilities around the United States have used SCFF cables from as early as the 1920s. Utilties from the East Coast, Midwestern, West Coast, and even as close as the Grand Coulee Dam, have replaced these SCFF cables due to an increase in leaks, failures, corrosion, and various other issues associated to these cables. SCFF cable systems require highly specialized personnel to monitor, operate, troubleshoot, and repair them. The new industry trend is extruded solid dielectric cable systems such as cross-linked polyethylene (XLPE) and ethylene propylene rubber (EPR) due to the cables containing no oil with an overall operation and maintenance procedure being relatively similar to typical distribution cable systems. With stringent cable manufacturing control and testing, these cables have a low failure rate.

Regional Planning has evaluated the distribution cables based on loading and feeds available to determine if cables should be replaced or repaired in future events. Conditional assessments should be performed to determine accurate remaining life on cables based on cable loading history and previous repairs. Distribution cables have 66 failures documented with a histroy of splice failures, anchor strikes, ferroresonance, armor corrossion, and pothead failure. The most recent distribution submarine cable replacement was for Lummi Island with a $1,443,675 cost. There are new industry wide submarine cables for fresh and salt water use which should be explored for future replacement as a PSE standard. There are cables identified for retirement when they fail as they are no longer needed for the area due to additional infrastructure being added throughout the years. The cable conditions are unknown, at this time we will perform condition assessments on the distribution lines that are identified to be replaced to learn more about estimated remaining life of these cables. With that information we can create a more economical replacement plan.

A study has been completed for Vashon Island's 115 kV submarine cables by Power Delivery Consultants, Inc. on March 2021. Remaining useful life calculations based on cable conditions and loading history have aged the cables to an average of 72 years, placing them near or at end-of-life. The cables are aged beyond their service life due to a significant number of leaks, faults, third party anchor strikes, improper loading applications, armor wire corrosion, lead alloy sheath fatigue, cable abrasions, aging splices, and aging fluid fittings. SCFF cables are no longer industry standard resulting in a delay for repair work which lengthens unplanned outages beyond that of regular underground cable work. A similar study should be conducted for the Mercer Island fresh water submarine cables. The second assessment will include project costs and the anticipated return date is 9/30/21. The project costs will be updated based on those new estimates.

Testing and monitoring the submarine cables could indicate remaining years of useful life while we plan for a replacement. Electrical testing detects existing defects and cable performance, however this testing equipment and ability is not availabele within PSE. Cost estimates from PDC consultants for testing the Vashon Island 115kV submarine cable are outlined in Table 4 below.

Table 4: Condition Monitoring Tasks, Costs, and Estimated Duration

Assessment Task	Contractor Cost Estimate Range	Estimated Testing Duration
Marine Surveys	\$120,000-\$150,000	2-4 Weeks (not including processing, reports and mapping)
ROV Survey	\$120,000-\$150,000	3-5 Weeks
Dissipation Factor Testing	\$170,000-\$225,000	1 Week (Line outage required)
Line Resonance Analysis	\$40,000-\$60,000	1 Week (Line outage required)
Asessment of Mechanical Concerns	\$45,000-\$65,000	-
Total	**\$495,000-\$650,000**	

If the cables fail and cannot be repaired, the Island's lose redundancy and are relying on one feed for the entire Island for a potentially months long outage while a project is designed, permitted, and sent to construction with foreign crews who are capable of installing submarine cables.

3. STATEMENT OF NEED

This plan targets the improvement of reliability, aging infrastructure, and a reduction of outages due to submarine cable related failures. PSE's electrical system consists of 18 circuit miles of submarine transmission cables and 35 circuit miles of submarine distribution cables. PSE wants to strengthen the transmission system that serves the Kitsap peninsula and Mercer Island and provide increased reliability into their operations.

As the infrastructure has aged, failures have become more frequent in the last ten years. Even though PSE proactively replaced all bonding boxes, terminations are subject to lightning strikes, vibrations, and earthquakes and cable splices are subject to fail and leak.

Leak and fault location and oil containment is very time-consuming, difficult, and even impossible with a remotely operated vehicle (ROV). In-service components, such as immersion reservoirs, oil gages, and alarm systems, and spare parts, such as cable and splices, may not be replaceable or usable. The cable armor has been determined to be severely corroded. Due to the corrosion, it is difficult to repair the cable and the cable cannot be used for its full rated capacity. Through replacement of the oil filled cables with new submarine cable technology, PSE will save emergency repair costs on an annual basis whilst providing a safe reliable service to the region and its customers.

3.1. Need Drivers

- **Grid Modernization**
  - **Reliability** –Replacing aging submarine cable with new submarine cable technology improves system and customer reliability and eliminates the aging infrastructure outages and repairs. This supports Grid modernization efforts by improving the reliability of the new infrastructure and cable configuration.
  - **Safety –** Modernization of the PSE submarine system protects the public and employees from stray voltage concerns. Corrosion can create small pits of the splice box and grey oxide that forms on the cables both in and off shore of the splice can deteriorate the armor. Divers have reported feeling a "tingle" when repairing the submarine cables in the past.
  - **Resiliency** – The PSE submarine cable system was built over many years and is aging and unreliable. These cables need to be resilient to provide quality service to a growing load demand, especially in Kitsap. Modernizing PSE's aging infrastructure will harden and protect the submarine cable system and bring it up to latest standards which supports and enables future Grid modernization plans. Optimized submarine cable design and configuration with redundancy built in, will reinforce power supply and improve PSE's ability to restore power faster as needed.

3.2. Integrated Strategic Plan (ISP) Alignment

This Plan aligns primarily with the Processes & Tools category of the ISP:

- System Reliability and Integrity: The principal driver for this plan is to reduce the number of submarine cable related outages and improve customer reliability. Through the replacement of aging infrastructure and System hardening, PSE is improving the integrity of its submarine cable system which supports operational excellence and provides customer satisfaction.

4. PLAN DETAIL

4.1. Plan Size/Population

The first submarine transmission cable was installed in 1960 and this system consists of 18 circuit miles of submarine transmission cables and 35 circuit miles of distribution cables.

Final design configuration has not been determined for the existing cable projects, so this estimate is based on like for like replacement. If we were to replace the transmission submarine cables with the 4 runs, three phases and a spare, then the estimated completion cost is approximately 120 million dollars. Table 5 shows the total cost estimates for each section.

Table 5: Transmission Submarine Cable Project Cost

Estimated Project Cost ($ M)				
	Submarine Cable Installation	**Cable Station Work**	**Underground Work**	**Total Project Cost**
South Des Moines-Robinson Point	53.62	6	1	60.62
Command-Cove	23.5	6	1	30.5
Quendall-Flood	12.12	6	0.5	18.62
Barnabie-Enatai	6.42	6	0.5	12.92
Total	**95.66**	**24**	**3**	**122.66**

4.2. Proposed Completion Date

This will be an ongoing plan anticipated to complete in the next 10 years. Once the plan is funded, PSE will start the process of investigation, engineering and the replacement of approximately 18 transmission submarine cable miles in the next 5 to 10 years with an estimated starting date in 2022.

The Vashon Island transmission submarine cables are being reviewed currently as an alternative solution for the Kitsap Initiation study. The design configuration has not been finalized, however estimates are based on like for like replacements. Once completed, the Mercer Island transmission submarine cables are projected to be next. Table 6 shows the potential plan of activities and steps to complete each submarine cable. Vashon cable are being prioritized first due to cable history and because the salt water cables corrode quicker than the Mercer Island cables in fresh water.

Once the submarine transmission cables have been replaced, PSE will begin to start planning the replacement of existing submarine distribution cables which are smaller and do not have the same cable station need.

Table 6: Submarine Cables Project Timeline

Estimated Project Timeline	
Year	**Project**
2022	Perform Assessment 1 for Mercer Island- Loading history Condition Assessment 2 for Vashon and Mercer Island Engineering/Permitting for Vashon Island
2023	Complete South Des Moines Substation Work
2024	Complete Robinson Point Substation Work
2025	Complete Substation Work for Command and Cove Complete Engineer/Permitting for Quendall-Flood & Barnabie-Enatai
2026	Perform Condition Assessments on Distribution Cables
2027	Install Submarine Cable for South Des Moines - Robinson Point
2028	Install Submarine Cable for Command – Cove
2029	Install Submarine Cable for Quendall - Flood Plus Substation and Trenching Work
2030	Install Submarine Cable for Barnabie - Enatai Plus Substation and Trenching Work

4.3. Summary of Plan Benefits

The submarine cable replacement plan will improve current and future system reliability for Vashon Island, Mercer Island, and the Kitsap area. Upgrading this aging infrastructure will provide eliminate the possibility of environmental damage due to oil leaks either from cables or the bonding boxes. There are 18 transmission cable miles to be reviewed and engineered for replacement. Replacing aging cables ensures our system is resilient to deterioration and provides long term stability to the region. Being proactive in this approach allows PSE to replace the cables while the areas are served with the aging submarine cable system and minimizes overload or load shedding scenarios.

4.4. Primary iDOT Categories

iDOT is the Investment Decision Optimization Tool that PSE uses to score projects.

The primary iDOT Categories related to this plan are:

- Outage Concern – per impacted customer without the project
- Stakeholder Perception – of complaints that will occur if project is funded
- Environmental Impact –Avoided if project is funded
- Operation and Maintenance Cost Avoided - if project is funded on annual basis
- Contribution to Strategy - if project is funded on annual basis

The iDOT benefits review for the years 2022 through 2026 would cover mostly engineering development, permitting and some cable station upgrades, and would not include submarine cable replacement until 2027. Capital costs are high level estimates until cable design and construction costs are finalized.

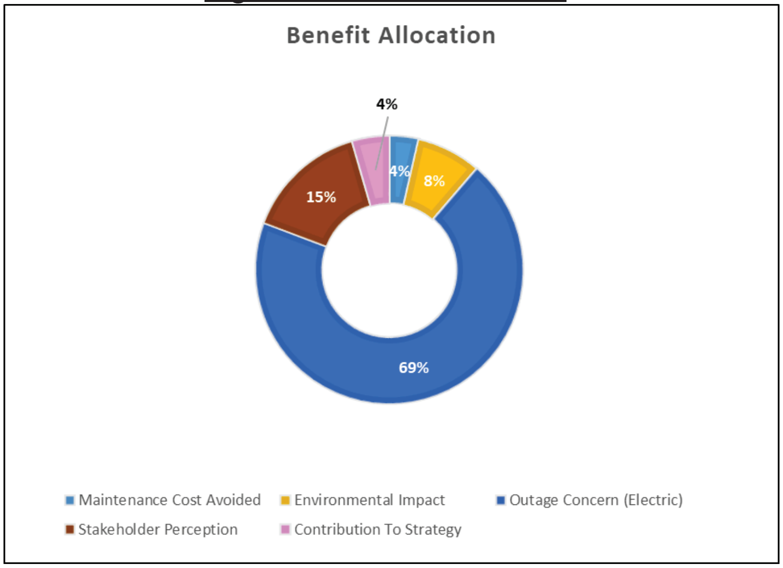
Assumptions include average O&M cable repair costs since 2014. Outage concerns based on both sub marine cables failing at Vashon Island, with 12 hour impact before energizing spare phase if repairs are not possible. Outage concerns are not based on actual outage history since there are redundancy measures in place in the event of a single cable failure, they are based on worst case scenario of both cable failing. For Mercer Island the assumption is both submarine cable feeds to island failing with 8 hour impact before energizing spare phase.

Table 7: Summary of Plan Benefits, Population and iDOT B/C Score

2022-2030	All-In CMI Saved (M)	Number of Cable Miles	Budget ($M)[1]		NPV ($M)[2]	iDOT B/C Score[3]
			Capital	OMRC	Total Benefits	
Total	**20.5**	**18.5**	**122**	**0**	**45.5**	**0.56**

[1] Budget indicate are sum of future year budget as it is allocated for that specific year
[2] Benefits indicated are Net Present Value (NPV) sum of future year benefits allocated for that specific year
[3] B/C Score uses NPV of Benefits and Budget

Figure 1: Benefit Allocation[4]



4.5. Estimated Total Costs

For submarine cable installation, we estimated \$20M per mile which is general estimate given by consultants, then added \$6M for substation work for each location, and approximately \$0.5M to \$1M for trenching for each location. Refer to Table 5 for estimate breakdown.

A report provided by PDC consulting has various options that range from \$36M to \$89M, but this range does not include any contingency nor any engineering, project management, site surveys, field supervision, overheads or other costs. They only price cable materials and installation costs

5. ALTERNATIVES

5.1. Solution alternatives

No Action – Without a submarine cable replacement plan, PSE would face increased interruptions due to submarine cable repair downtime in the event of a failure. This impacts customer dissatisfaction and increased emergency repair expenses annually. Manufacturers do not provide spares for this type so it will not be possible to carry out future cable repairs in the event of another failure. The risk to environmental damage increases with the longer these cables exist in Puget Sound and Lake Washington. Doing only repairs when needed , puts the remaining cable integrity at risk during the repair stage as it must be maneuvered and raised which adds stress to the fragile cable, meaning the cable could break apart at multiple locations during this process.

[4] Risk of not achieving budget and expected benefits is 4%

5.2. FUNDING ALTERNATIVES

Increase Funding from Proposed – With increased funding for the submarine cable replacement plan will allow PSE to start prioritizing, developing, engineering, and permitting transmission and distribution replacement projects. It will reduce unnecessary O&M emergency repair costs and provide improved system reliability from an operational perspective. Depending on final design configuration of the new transmission cables, PSE could potentially increase the transmission capacity to and from the region and support new grid changes or renewable resources. Increased funding will enable PSE to remove aging infrastructure and install latest submarine cable insulation technology, and simultaneously build in additional redundancy.

Decrease Funding from Proposed –Decreased funding will delay the opportunity to replace them while they are functioning and in service. Without the funding, this automatically translates into additional maintenance costs on cables and at the bonding boxes in each cable station. Without a planned plan in place the risk of failure will increase over time.

6. PLAN DOCUMENT HISTORY

The current version of the project summary supersedes all previous versions.

Date	Reason(s) for Update	Summary of Significant Change(s)	Modified By
12/1/2010	Initial Plan	Initial Document	Puneet Janda

7. SUPPORTING DOCUMENTATION

Document Name
PSE SUBMARINE CABLE REFERENCE BOOK
CONDITION ASSESSMENT OF PSE'S 115-KV SELF-CONTAINED FLUID-FILLED (SCFF) CABLE SYSTEMS
VASHON ISLAND 115 KV SUBMARINE CABLES PHASE 1 CONDITIONAL ASSESSMENT REPORT
PDC COMMENTS ON PSE VASHON CABLES 8-3-2020

RESILIENCE ENHANCEMENT - COPPER CONDUCTOR REPLACEMENT

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

The Copper Conductor Replacement Plan is a safety, reliability and resiliency initiative to replace the highest priority 20% of aging #6 and smaller overhead copper (CU) conductor (the population of smaller CU conductor is small, 3.6 miles, and will henceforth be included and referred to generically as #6 CU) in PSE's primary distribution system over the next 10 years. This conductor is losing mechanical strength as it ages and has an increasing risk of failure. The most cost and performance effective strategy for replacement of specific segments of this conductor will be applied. The identification of projects to be included in this plan will first prioritize:

- Sections located in wildfire impact zones – estimated at 4.2 miles.
- Sections most at risk of failure considering their history of outages and/or splices in evidence on the conductor.

Other factors for consideration for prioritization may include:

- Location of the #6 CU in the distribution system
  - High impedance fault risk
  - Vegetation exposure
  - Customer density
- Conductor in the area of other projects such as New Customer Construction, Distribution System, PI and Pole Replacement projects.
- Voltage and capacity considerations
- DA needs
- DER hosting capacity needs

The most likely cost effective replacement option is assumed to be #2 ACSR bare or TW conductor. Replacement with bare or TW feeder, removal, re-route and underground conversion will be considered where appropriate.

2. BACKGROUND

The utility industry started using copper conductors in their distribution systems in the early 1910s. The switch from copper to aluminum conductors by the industry and PSE was made in the 1960s and early 1970s due to the high price of copper relative to aluminum and other benefits such as weight-to-conductivity ratio. In 1991, PSE officially categorized #4 and smaller CU as "for maintenance use only" but had adopted ACSR conductor as the standard for overhead lateral distribution construction much earlier. Given the industry and PSE data, it can be assumed that the small copper conductor in PSE's system is an average age of greater than 50 years.

With age, the single strand copper conductor loses mechanical strength and becomes brittle and increasingly prone to failure from tree contact as well as other physical stressers including snow and ice, construction and repair or maintenance activities. This is especially true of # 6 CU conductor due to its small diameter. Other infrastructure in proximity to the CU is often also aging beyond expected life including poles, triple link cut-outs, OH transformers and open wire secondary systems.

The small diameter of #6 CU conductor equates to high resistance making it prone to high impedance faults resulting in an increased risk of it being down and energized in the event of failure. The installation of Fuse Savers or 100T fuses on laterals with #6CU conductor is not suitable for a similar reason. The presence of small #6 CU can also contribute to low voltage in the areas in which it exists especially in situations where it is undersized for load or located at the end of the distribution circuit.

When line crews need to work on sections of #6 CU conductor, especially sections that have had historical failures (existing splices), they are unable to work it energized due to safety considerations around the possibility of a failure of the conductor while it is being handled. This necessary operational practice results in more scheduled service interruptions for PSE customers in order to provide safe working conditions for PSE line crews.

PSE has targeted the replacement of #6 CU beginning in 2010 when a specific budget line items were created for these projects. From 2010 through 2019 PSE replaced or retired approximately 161 miles of #6 CU conductor at a cost of approximately $20 million dollars. Throughout the industry there exist examples of utilities[1] with plans and strategies that target aging small bare CU conductor for replacement in order to maintain system reliability, accomplish system hardening, facilitate grid modernization, address wildfire risk and improve system safety.

3. STATEMENT OF NEED

PSE is committed to providing safe, reliable service to our customers and safe conditions for PSE employees. This plan targets the improvement of reliability, resiliency, and safety associated with aging #6 CU conductor and other associated aging infrastructure.

3.1. NEED DRIVERS

- **Grid Modernization –**
  - **Safety** – Aging #6 CU conductor is brittle and prone to failure while at the same time is at a higher risk of a high impedance fault due to its small diameter. This leads to an increased risk of a conductor being down and energized which can be a safety risk to both the public and to line workers.
  - **Reliability** – #6 CU conductor is aging, brittle and prone to failure. Replacing it will reduce CMI, SAIDI and SAIFI by eliminating or reducing outages to the customers served by these facilities.

[1] Examples: Duke Energy Florida, Inc 2018 "Distribution Reliability Report", Liberty-NH 2019 "Distribution Line Overarching Strategy", Avista Utilities 2020 "Wildfire Resiliency Plan"

- **Resiliency** - Replacement of #6 CU conductor with appropriate bare, TW or underground conductor will harden PSE's system against failures during major events.
- **Smart & Flexible** –Replacement of #6 and smaller copper in PSE's system improves the flexibility of DER adoption and load hosting capacity by increasing capacity and reducing voltage drop in the distribution system.

3.2. Integrated Strategic Plan (ISP) Alignment

- Processes & Tools
  - **System Reliability and Integrity**: Execution of reliability work- replacement of this aging infrastructure will increase reliability for customers in the area and will increase system resiliency.
- Safety
  - Replacement of aging #6 CU conductor decreases risk for both employees working on the system and the public from accidental contact with energized conductor.

4. PLAN DETAIL

4.1. Plan Size/Population

Currently PSE has approximately 587 total circuit miles of 1, 2 and 3 phase #6 CU and smaller primary conductor, mostly on overhead laterals, located on 640 circuits. This plan proposes to replace 20% of the #6 CU primary conductor in PSE's distribution system - approximately 116.7 circuit miles. The targeted 20% will address #6 CU in wildfire impact areas as well as address the most unreliable sections of #6 CU that will provide the most benefit to PSE's customers.

	Total Circuit ≤ #6 CU Miles by config				
Conductor	1 ph	2 ph	3 ph	3 ph Mix	Total
#6 CU	450.4	32.5	72.4	28.0	583.3
#8 CU	2.8	0.0	0.0	0.0	2.8
#9 Iron	0.8	0.0	0.0	0.0	0.8

4.2. Proposed Completion Date

This plan proposes to replace approximately 116.7 circuit miles of PSE's #6 CU over 10 years. Monitoring of the performance of the total population of this conductor as well as re-analysis of system needs will drive decisions regarding acceleration or expansion of the plan or continuation of the plan beyond 10 years.

4.3. Summary of Plan Benefits

Safety – A major benefit of the #6 CU Aging Infrastructure Replacement Plan is increased public and worker health and safety. Replacement of the most failure prone #6CU conductor reduces the risk of exposure of the public and line workers to contact with energized conductor.

Improved Customer Reliability - Replacing aging #6 CU will improve the reliability of PSE customers served by this infrastructure by replacing it with facilities, tree wire if needed, that are less prone to outages caused by vegetation and other physical stressors.

Improved System Resiliency - Replacing brittle, aging #6 CU conductor with new conductor, along with the replacement of associated aging poles, transformers and cut outs as indicated by evaluation of their condition, will harden PSE's system against the impacts of major events.

4.4. PRIMARY IDOT CATEGORIES

The primary iDOT Categories related to this plan are:

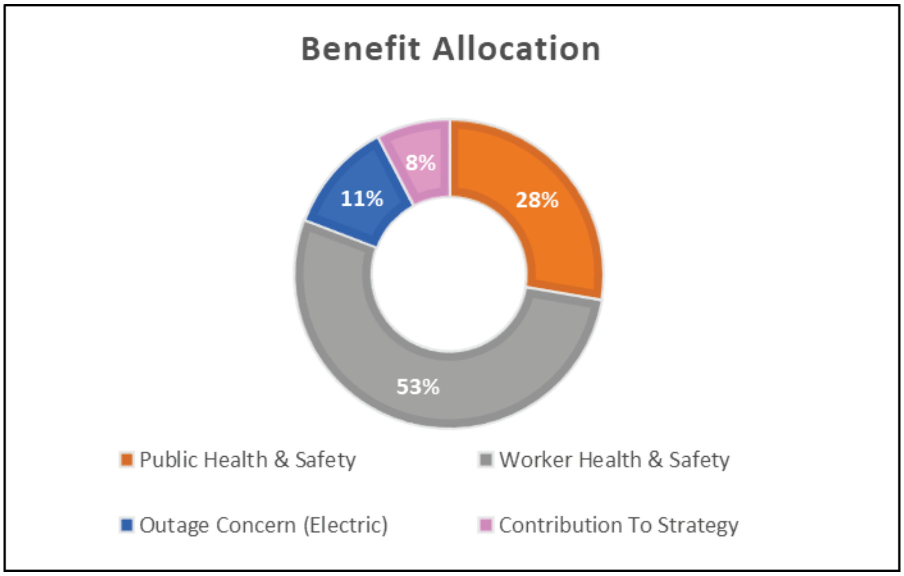
- Public/Worker Health and Safety: Addressing a potential hazard that has a chance of causing harm to the public or field personnel. The potential hazards do not include imminent threats to the public or field personnel, those are resolved immediately.
- Outage Concern: Preventing or reducing the number of future outages and outage duration experienced by customers.

Table 1: Total Plan Population, Cost and Benefits

2022-2031	Number of Miles Small CU (#6,8,9)	Budget ($M)[2]		NPV ($M)[3]	iDOT B/C Score[4]
		Capital	OMRC	Total Benefits	
Total	**116.7**	**35.0**	**1.16**	**40.3**	**1.59**

[2] Budget indicate are sum of future year budget as it is allocated for that specific year
[3] Benefits indicated are Net Present Value (NPV) sum of future year benefits allocated for that specific year
[4] B/C Score uses NPV of Benefits and Budget

Figure 1: Benefit Allocation[5]



4.5. Estimated Total Costs

For Electric System Planning estimated costs are generated based off of historical costs on similar types of projects, allows for variations in project scope, increase in project cost due to inflation, and added contingency to account for unforeseen conditions associated with the project.

Cost per #6 CU replacement project will vary depending on scope but the cost is estimated to average $300K per mile based on historical project costs, adjusted for rising costs. Total capital cost for the 10 year program to replace 116.7 circuit miles of #6 CU primary is estimated at $35 million. The estimated cost to replace all 587 circuit miles of #6 CU in PSE's system is estimated to be $176 million.

5. ALTERNATIVES

5.1. Solution alternatives

No Action – Lost opportunity to replace a significant quantity of #6 CU conductor in a targeted manner in order to maximize improvement to public and worker health and safety, customer reliability and system resiliency. The system would experience increased failures over time as the conductor and its surrounding infrastructure continues to age resulting in adverse impacts to system reliability, resiliency and increased risk to worker and public safety.

Include as part of other plans/project – This could be replaced as part of other plans such as pole replacement, WPC, Wildfire, targeted reliability or targeted capacity. It is

[5] Risk of not achieving budget and expected benefits is 0.3%

unlikely that we can meet our replacement goals for CU by including this work in other programs. This solution would also have result in adverse impacts to reliability, resiliency and increased risk to worker and public safety.

5.2. Funding alternatives

Increase Funding from Proposed – With increased annual funding, the goals and benefits of the 20% replacement plan could be achieved more quickly or the plan could be expanded to remove additional or all #6 CU conductor from PSE's system. This would result in increased overall plan benefits but cumulative cost may overtake benefits as we replace the most at risk conductors first.

Decrease Funding from Proposed – With decreased annual funding less #6 CU replacement projects would be completed with the corresponding decrease in risk abatement and reliability and resiliency benefits. As the #6 CU conductor that is not replaced continues to age safety, reliability and resiliency associated with this conductor will decrease.

6. PLAN DOCUMENT HISTORY

The current version of the project summary supersedes all previous versions.

Date	Reason(s) for Update	Summary of Significant Change(s)	Modified By
6/30/2020	Original Program Document - New plan template	Original Program Document– Summarize historical plans	Sue Cagampang
5/5/2021	Program Update	Revised budget and program duration.	Sue Cagampang
7/13/2021	Used and Useful Policy guidance	Add alternatives and cost information	Sue Cagampang
12/1/2021	Annual Review	Minor word and format changes	Sue Cagampang

7. SUPPORTING DOCUMENTATION

Document Name
N/A

POLE INSPECTION AND REMEDIATION

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

PSE's Pole Inspection and Remediation Plan is an asset management plan that maintains situational awareness of the structural integrity of the overhead electric system in order to optimize equipment lifecycle and effectively mitigate system risks in alignment with industry best practices. The PSE Pole plan is based on a 10 year inspection cycle which includes the following phases of the plan to be successful:

- Inspection
- Treatment
- Reinforcement
- Replacement
- Reporting and Data Integrity Improvement

This is intended to be a sustained plan with no end date where the full plan value is obtained through commitment to maintaining a 10 year inspection and treatment cycle, which is the foundation of the plan. The plan is well aligned with industry best practice, the NESC, USDA Rural Utilities Service and PSE's Grid Modernization plan.

2. BACKGROUND

PSE has been in the business of managing overhead electric system structures throughout its history. Originally, the ownership for overhead structural integrity management was delegated to the regional service centers. They were given autonomy in being able to address the systems needs that were at times unique to their regions. However, over the years and with some corporate organizational changes, PSE has developed a present day robust pole plan that came about through several iterations and previous foundations laid. Some of the milestones in the pole plan development are:

1995 – 2005: Programmatic Pole Inspections (primarily focused on the Transmission)

2008: Transmission Wood Pole Program was developed

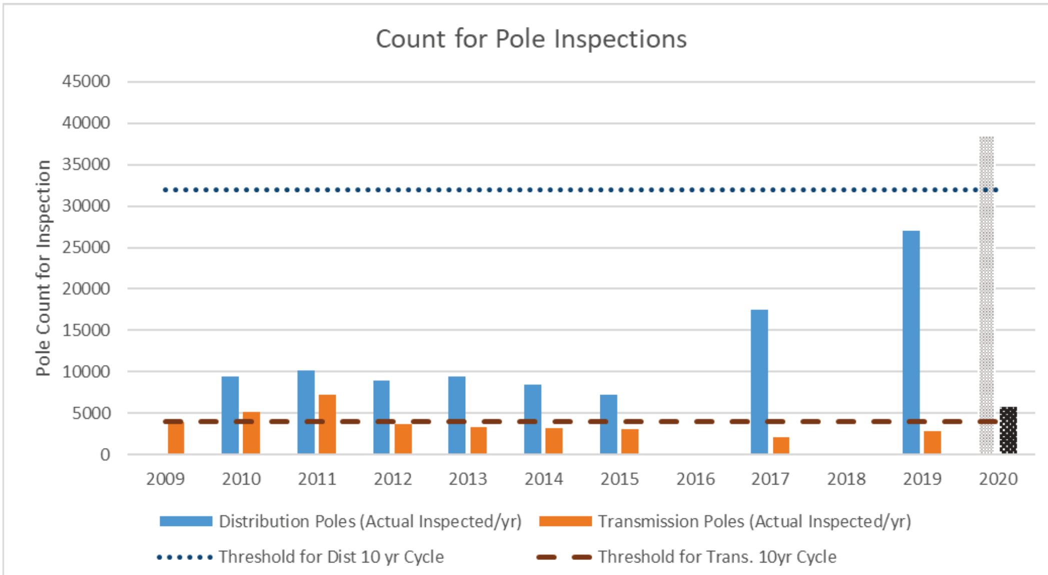
2010: Distribution Wood Pole Programmatic elements were incorporated into the plan

2018: The Pole Program was reviewed and updated

2019: Kicked off the first year of the Pole Program

Some of the historic counts of tasks completed are provided below:

Figure 1: History of Pole Inspections and Treatments



3. STATEMENT OF NEED

The development of the Plan came about through an increased awareness of the impacts degraded structural integrity has on system resiliency and reliability. In addition to the core driver in developing a mature pole plan, there have been additional departmental pain points discovered that this plan has now efficiently integrated. This plan greatly matures the asset management of overhead structures as it considers the lifecycle of the assets through decreasing system risk, increasing equipment performance, and optimizing costs.

The system integrity needs are found through inspection and testing on a routine basis at a 10 year cycle. The CMI related to pole outages is tracked as a measure of the plan success.

Decreasing Risk:

- As of 2019, PSE's CMI has shown a consistent increasing trend of overhead related structural failures. With the sustained effort to increase the system integrity, it is predicted that the CMI related to overhead structure related failures will decrease.
- Increasing system integrity and decreasing equipment failures of overhead equipment or poles increases the safety of the system to customer, communities, service providers, employees and the environment.

Increase Performance

- Structural integrity of the system has a direct relationship to the damage extent by external forces (trees, cars, etc.), as a result this will support the restoration rate and help decrease CMI.
- Having good system structural integrity increases the systems resiliency to external forces.

Optimize Cost

- Committed treatment of wood poles on the appropriate cycle sustains the life of the structure and can significantly increase the expected life.
- Application of reinforcement maintains the structural integrity in a cost effective manner
- Replacing structures as part of a planned process is more thorough, effective, and cost efficient than doing reactive unplanned emergent replacements.

3.1. Need Drivers

- **Grid Modernization**
  - **Safety -** As seen within the industry and within PSE, overhead equipment failures pose a very real safety concern to the public, service providers, employees and environment. This plan will directly decrease the potential for overhead equipment failures through increasing system resiliency by reinforcement or replacement of structural concerns. In addition to capturing the condition of the pole base, the plan now includes a focused visual inspection of the cross-arm, pole top, pole body, insulators, and hardware. These are all potential failure modes specifically reviewed for condition and addressed within the plan.
  - The targeted Wishbone replacements as part of the plan addresses an evolved design concern of a specific set of aging infrastructure that has posed an escalated safety concern.
  - **Reliability -** The plan will address structural integrity concern and therefore prevent what could have been future equipment failures that would impact the customer reliability.
  - As can be observed in the graph below in Figure 2, the CMI caused by overhead equipment failure has been significantly trending upward. This plan will help to improve the trend.
  - **Resiliency-** Having sound structural integrity imbeds a resilience or system hardness that minimizes the consequence of events or outages due to outside sources (vegetation, cars, etc.). This can result in decreased outage duration.
  - **Smart & Flexible-** Part of the plan involves an asset data acquisition which is then integrated into the SAP and GIS systems. This is going to be very valuable for the transmission structures as they are not fully represented in either system. Within the next 10 years it will greatly improve the data integrity & quality of our GIS and SAP systems as part of the plan.
- **Cost Optimization**

- o The application of reinforcement provides a cost effective way to sustain the integrity of the system and extend the life of the overall asset.

3.2. INTEGRATED STRATEGIC PLAN (ISP) ALIGNMENT

This plan aligns primarily with the Processes & Tools category of the ISP:

System Reliability and Integrity:

- o The Plan directly aligns with the ISP with its focus on System Reliability and Integrity. The routine overhead system inspection provides an awareness to the system condition that allows for the opportunity to proactively treat, reinforce or replace structures in need which sustains the overall overhead system integrity.

Streamline processes to drive effectiveness and efficiency:

- o This plan is integrated in several departments which increases departmental and organization efficiencies. Regional Engineers will submit structures of concern to the pole plan in order that the condition would be investigated more thoroughly and potentially replaced as part of the pole plan. This minimizes the number of potential unplanned replacements.
- o Transmission pole replacements will be completed in collaboration with Strategic System Planning and Transmission Line Design in order to prepare the system for future rebuilds.
- o Asset data recorded by the service provider (Osmose) is uploaded into SAP and it improves the asset data, and is given to Maps & Record and Transmission Line Design to update GIS and other electric system databases.

4. PLAN DETAIL

4.1. PLAN SIZE/POPULATION

The Plan is an asset management plan intended to last as long as there are overhead structures. This plan does not have an anticipated end day and is expected to encompass the entirety of the Distribution and Transmission overhead system as long as it exists. Some of the oldest poles remaining on the system were installed in the 1950's.

Table 1. Estimated Pole Count

Category of System	Pole Count
Distribution	~ 300,000
Transmission	~ 40,000

Table 1: The total pole count will fluctuate year to year. Therefore, given the knowledge of the unit count from Plant Accounting, the GIS System, SAP, and the Control Access Data Base, these conservative approximations are used for planning purposes.

4.2. Proposed Commitment to Achieve Routine Cycle

This plan is a cyclical plan with a 10 year cycle intended to sustain annual commitment in order to receive the plan value of increased resilience, decreased failures and equipment life extension. This level of investment will cover:

- Routine Inspections
- Treatment
- Reinforcement
- Replacement
- Backlog Replacement
- Wishbone Replacement
- Data Acquisition

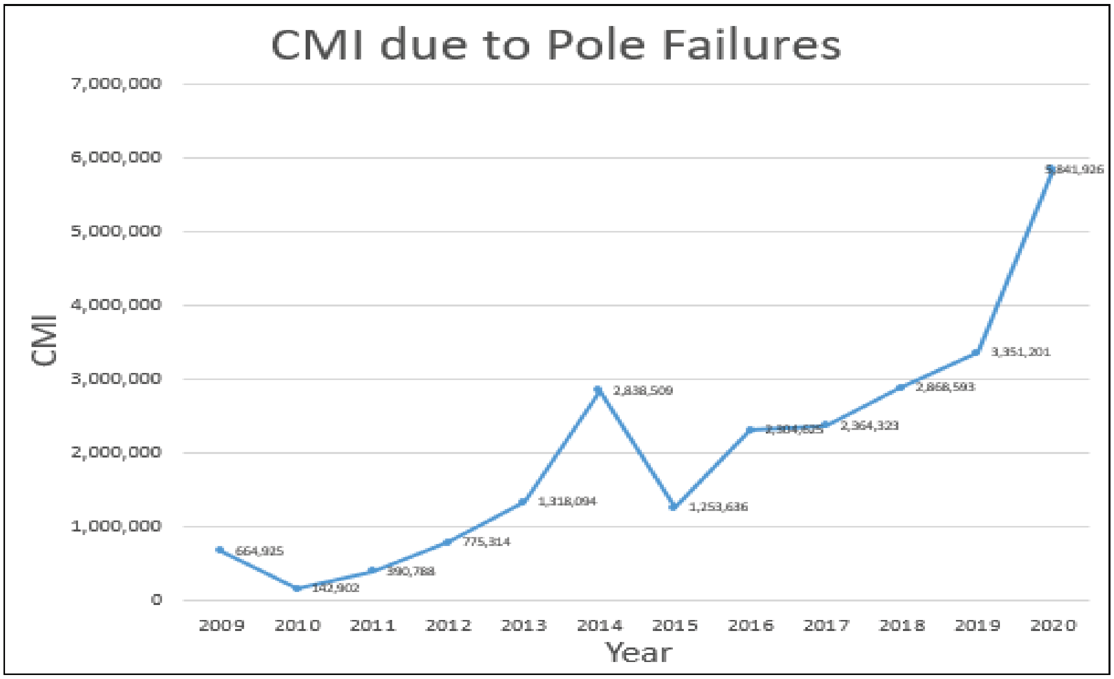
A key element to this plan is the commitment to sustaining the planned cycles of every 10 years inspecting all overhead structures. The current cycle (1) involves addressing a list of known backlog issues on the system through the replacement of these structures. The backlog of historic reject poles and wishbone structures is forecasted to be addressed by 2023, and the future steady state with an achieved decreased reject rate by 2029. Cycle 2 is from 2029 through 2038 where we forecast to have a more consistent budget level since there will be no backlog replacements should be complete.

4.3. Summary of Plan Benefits

4.3.1 Outage Trend Due to Overhead Equipment Failures

One of the primary benefits to the plan is diagnosing the condition of equipment which empowers proactive replacements before customers experience an outage. Presently, the trend for overhead equipment outages is notably increasing. This plan will in future years bring this down.

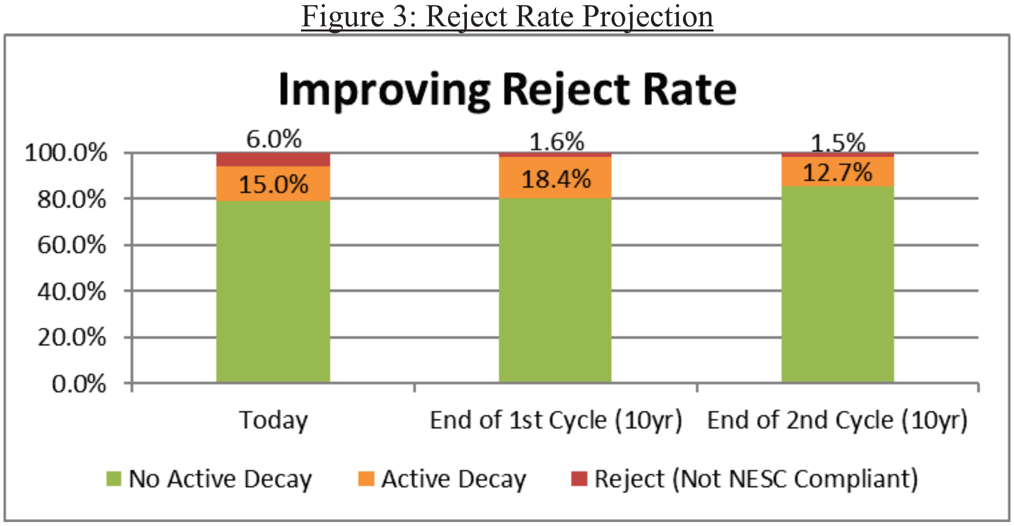
Figure 2: CMI impacts due to Pole related failures



4.3.2 Reject Rate

From the analysis Osmose completed in 2018 using historic pole inspection data from 2009 to 2017 and industry wide data, the below values are what to expect with regards to system wide reject rates when there is a committed 10 year cycle pole plan that covers inspection, treatment, reinforcement & replacement:

Figure 3: Reject Rate Projection



4.4 Primary iDOT Categories

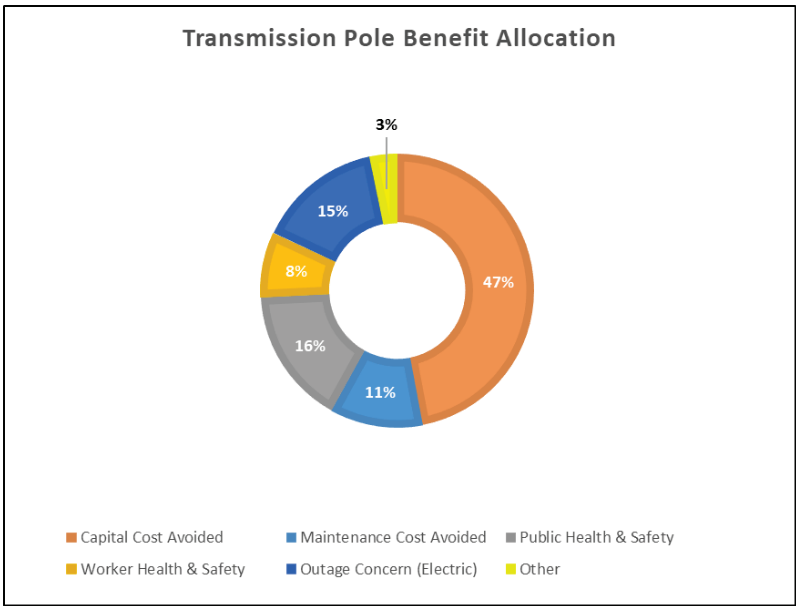
The primary iDOT Categories related to this plan are:

- Cost Avoided – future cost savings due to plan funding
- Public & Worker Health – impacts and risk reduction if plan is funded
- Outage Concern – per impacted customer with the plan

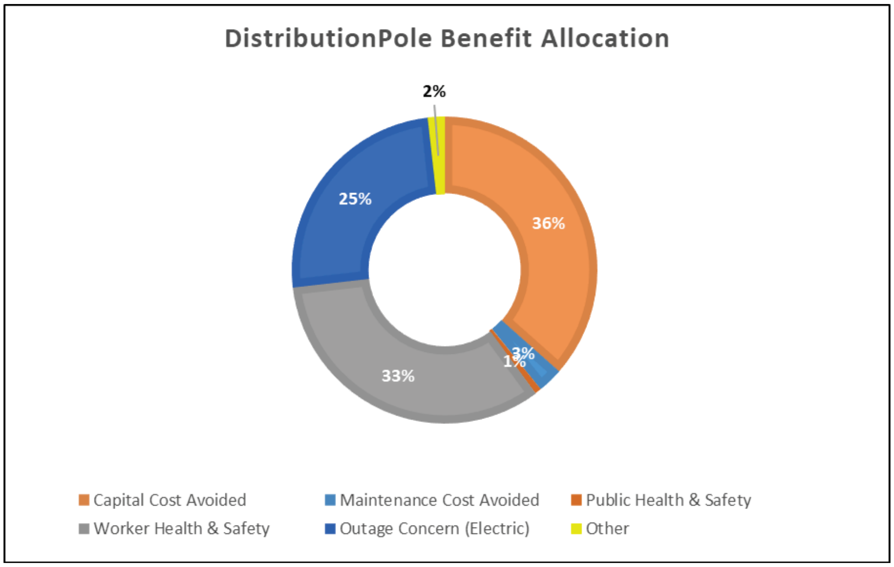
Table 2: Summary of Plan Benefits, Population and iDOT B/C Score

2021-2026	Non-MED CMI Saved (M)	Budget ($M)[1]		NPV ($M)[2]	iDOT B/C Score[3]
		Capital	OMRC	Total Benefits	
Transmission Total	**2.3**	**59.7**	**11.7**	**68.7**	**1.09**
Distribution Total	**17.3**	**43.2**	**4.8**	**131.4**	**3.1**

Figure 4: Pole Benefit Allocation[4]



[1] Budget indicate are sum of future year budget as it is allocated for that specific year
[2] Benefits indicated are Net Present Value (NPV) sum of future year benefits allocated for that specific year
[3] B/C Score uses NPV of Benefits and Budget
[4] Risk of not achieving budget and expected benefits: Transmission Poles is 1%; Distribution is 2%



4.5 Estimated Costs

For Electric System Planning estimated costs are generated based off of historical costs on similar types of projects, allows for variations in project scope, increase in project cost due to inflation, and added contingency to account for unforeseen conditions associated with the project. The following table indicates the average cost used for this business plan:

Line Item	Total
Avg Inspect/Treat Dist	$ 54.58
Avg Inspect/Treat Trans	$ 60.45
Avg Replace - Dist	$ 10,000.00
Avg Replace - Trans	$ 35,000.00

5. FUNDING ALTERNATIVES

5.1 Solution alternatives

No Action -

The alternative to this proactive program is waiting for pole failure to replace. The disadvantages of this option is the increasing risk of aging poles and overhead equipment that pose a safety concern to the public and the environment. By not inspecting the resilience of the overhead infrastructure will decrease faster over time as the herbicide life extending application will not be applied to health poles and there for pole degradation will increase for the entire population. Overtime more emergency O&M repair costs though pole and crossarm failures would be experienced These type of failures cause extensive outages that impact. Waiting longer to inspect, treat, and remediate will cause the reject rate of overhead structures to increase to about 6% (rather than achieving a 1.5-2% failure rate through this proactive plan).

5.2 Funding alternatives

Increase Funding from Proposed – If we were to increase the funding for a couple years that would not be a poor decision as it would help with getting use the Cycle 2 faster. However, per the recommendation of the USDA Rural Utilities Service the investment could be an over investment in the asset management of PSE's overhead structures that does not actually provide a return value to the customer. Several things this would impact are:

- Getting to Cycle 2 faster and therefore getting to a decreased reject rate faster
- structures trending toward failure would be addressed at a more frequent basis, but with an increased rate the projection is that the benefit would be marginal
- The backlog would be addressed faster
- From the industry research, PSE's service territory gives an expected life of treatment of about 10 years. Therefore, increasing the frequency would have a minimal benefit on the life extension of equipment

Decrease Funding from Proposed – The success of this plan is dependent on a commitment to a 10 year cycle which makes the decrease in funding very impactful to achieving the desired benefits of the plan.

- If inspection & treatment is detailed then structures will see an increased degradation and structures that could be reinforced my end up failing
- A backlog of inspection and replacements will begin to develop
- Lifecycle optimization will begin to be lost, which will decrease the cost optimization benefits
- Failures will increase
- The operational efficiencies of maintaining a consistent rhythm will be jeopardized. Some departments have begun to integrate their system planning based on the information that will be provided by the T&D Strategic Pole Plan and when there are delays this can have significant cascading effects.
- Safety concerns will increase

6. PLAN DOCUMENT HISTORY

The current version of the project summary supersedes all previous versions.

Date	Reason(s) for Update	Summary of Significant Change(s)	Modified By
6/9/2020	Creation of Business Case- New plan template	This is the initial write-up of the T&D Strategic Pole Program Business Case – Summarize historical plans	Kevin Gowan
3/26/2021	Annual Update	2020 Metrics update	Stephen Hartnett
7/12/2021	Used and Useful Policy guidance	Add alternative and cost information	Stephen Hartnett
12/1/2021	Annual Review	Minor word and format changes	

7. SUPPORTING DOCUMENTATION

Document Name
STANDARD 1025_1950: WOOD POLE INSPECTION, TREATMENT, AND REINFORCEMENT
STANDARD 0900_1060: IDENTIFYING POLE INSPECTION TAGS
PSE STRATEGIC POLE PROGRAM MANUAL
ABOVE GROUND PSE PHOTO GUIDE
POLE PROGRAM REPORTING GUIDE
PSE WISHBONE STRUCTURE VISUAL INSPECTION GUIDE
POLE PROGRAM PROCESSES

SUBSTATION RELIABILITY

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

The Substation Reliability Plan is an on-going proactive plan to replace major substation assets to reduce the risk and cost of unplanned outages due to equipment failure and to ensure continuous safe, reliable service and power quality to PSE's transmission grid and distribution system.

2. BACKGROUND

PSE's Aging Infrastructure Replacement plan has evolved into separate asset reliability plans, one of which includes the substation infrastructure. The Substation Reliability plan has matured over the last few years into a proactive programmatic approach to ensure the system's assets meet system performance requirements safely and reliably.

PSE has over 400 Transmission and Distribution substations combined that are key hubs connecting high voltage transmission lines with the distribution system, the stations provide the ability to deliver electrical loads to cities and large industrial zones at the appropriate voltages safely. Currently there is a large number of older major substation assets, which will need to be replaced gradually to maintain current reliability performance. By implementing the Substation Reliability plan, PSE can reduce system unplanned outages that affect its customers. Upgrades to the substations and equipment are important strategies for reliability and overall asset management. Specific types of equipment are proactively replaced to maintain system reliability, improve resiliency, reduce operational costs and offset impacts from aging infrastructure.

The substation assets of concern are identified above in Table 1. Each piece of equipment is vital to the safe and effective operation of the substation, however the major assets that make up the basis of the Substation Reliability plan are Transformers, Regulators, Breakers, Fuses, Electro-mechanical relays and Switches. Many of the larger assets are over 40 years of age

Table 1: Poor Condition Substation Asset Population

Asset Type	VBR	OBR	OSW	VSW	GSW	REG	LFR	XFR	CPB	Bank Fuses	EM Relays
Count	1305	82	40	156	326	63	276	143	280	80	156

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Table 2 below shows how many assets were actually replaced under the plan at current budget levels 2017-2020.

Table 2: Annual Asset Replacements

	Actuals			
Substation Asset	**2017**	**2018**	**2019**	**2020**
Batteries	13	10	13	11
Circuit Switcher	5	2	1	2
Dist. Transformer	3	8		2
EM Relays	10	8	31	5
Over-dutied Fuse	3	5	2	2
SPCC Upgrade	2			2
Oil Breakers	6	11	11	7
Transfer trip				1
Oil Switch				
Grand Total	**42**	**44**	**58**	**32**

2.1. Determining Equipment need & input for replacement

There are multiple decisions and inputs into considering proactive replacement of substation assets. The Considerations include the following items:

- Lifecycle optimization evaluation
- Specific asset class concerns
- Escalated concerns from maintenance and testing
- Escalated concerns from Engineering & Operations
- Escalated concern due to Dissolved Gas Analysis (DGA) monitoring
- Over-dutied equipment and Capacity concerns

2.2. Substation reliability asset background

The substation reliability plan is made up of multiple assets which are funded through various WBS (Work Breakdown Structure) codes. The breakdown of the plan is outlined below by the following WBS codes:

- Transmission & Distribution Battery Replacement (R.10009.14.01.02)
- Distribution Transformer Replacement (R.10009.14.06.01)
- Transmission Substation Breaker (R.10009.14.07.01)
- Electro-Mechanical Relays (R.10009.14.03.01)

- Over-dutied 115kV Fuse Replacement (R.10009.14.05.07)
- Circuit Switcher Installation (R.10009.14.05.05)
- Spill Prevention & Containment C? (SPCC) Upgrades (R.10009.14.04.01)
- Substation Reliability Improvements (R.10009.14.05.06)
- Other Substation Equipment & Plans

The Substation reliability projects are aligned as much as possible with Substation SCADA and Internet Protocol SCADA projects to take advantage of crew mobilization efficiencies and eliminating the need to take additional substation outages.

The addition of Dissolved Gas Analysis (DGA) monitoring equipment provides multiple benefits to maintenance and substation teams. By automatically monitoring the oil properties on a daily basis, PSE can determine the health of the equipment without having to take an outage or carry out major maintenance saving O&M dollars. The monitoring equipment is set up such that it sends an electronic alert to maintenance staff if it detects data outside its normal limits. This aids in decision making if PSE should replace or repair a transformer as it approaches end of life, so that an unplanned outage can be avoided for its customers.

3. STATEMENT OF NEED

The substation reliability plan is needed to improve system reliability performance from current levels. PSE has a number of aging equipment that is still functioning past its normal economic life, it becomes more cost effective to replace equipment than to continually maintain or repair units after a certain time period. The consequence cost of an unexpected failure can be costly if there is no other way to provide power to major customers.

Without a proactive plan, the risk of equipment failure increases over time. Not only is there a consequence impact to the customers, associated substation equipment may be damaged which increases the cost of managing the system. Unexpected failures of older generations of equipment can be costly to repair as spares may not be readily available. Such unplanned failures may require taking potentially lengthy outages and negatively impact PSE's reliability index and reputation.

Other drivers include NERC and WECC compliance for substation protection to ensure physical security and the installation of condition based monitoring systems to run diagnostic systems and reports on a regular basis independently. This plan also aligns with the Integrated Strategic Plan as PSE strives to reduce asset and system related SAIDI/SAIFI effects. Through effective implementation of the plan, there is also a reduction in O&M asset business expenses as equipment technology changes which decreases maintenance efforts.

Due to the quantity of the aging assets and the overall volume of assets, the risk of failures or outages increases over time with age as the current replacement rate is insufficient.

3.1. NEED DRIVERS

- **Grid Modernization**

- **Reliability** – Proactive replacement of equipment reduces unplanned outages and outage duration that impact customers due to substation equipment failures. This supports Grid Modernization efforts by improving the reliability of the infrastructure.
- **Safety –**Many pieces of equipment are oil filled and present the risk of fire to employees and the public in the event of a failure. Oil spillage is also an environmental risk. Replacing oil filled equipment reduces the risk. This reduces PSE's carbon footprint and oil storage needs. Replacing bank protection fuses which have exceeded their rating minimizes the opportunity for localized explosion/fragmentation during a fault. Such failures may also have detrimental effects on upstream and downstream equipment.
- **Resiliency** – Replacing PSE's aging substation infrastructure adds resilience to the system as the new equipment and technology enables faster recovery and restoration of power minimizing outage duration. Modernizing PSE's aging infrastructure improves its performance and supports the effective operation of future Grid Modernization plans.

3.2. Integrated Strategic Plan (ISP) Alignment

This plan aligns primarily with the Processes & Tools category of the ISP:

- **System Reliability and Integrity:** The principal driver for this plan is to reduce unplanned substation equipment outages cost effectively, improve reliability and deliver power safely to the customer. Replacing aging infrastructure improves the resiliency of the Transmission and Distribution systems and allows PSE to integrate new technologies and solutions that provide benefits to multiple stakeholders. This improves the integrity of the system which supports operational excellence and provides customer satisfaction.

- **Optimize Product and service portfolio consistent with long term strategy:** Alignment of the Substation Reliability plan with other plans such as Substation SCADA, IP SCADA and transient mitigation strategy can be done under one outage and save on mobilization and labor costs. The five year plan and budget will align plans to strategically optimize project alignment and selection that directly supports PSE's Integrated Strategic Plan (ISP) and Asset Management's long-term Vision.
- **Streamline processes to drive effectiveness and efficiency:** This plan drives effectiveness and efficiencies by addressing multiple benefit streams within the same scope of work. Replacement of aging equipment addresses reliability and safety concerns whilst also improving resiliency. It allows us to identify opportunities to replace other substation assets or integrate new products and create cost effective projects providing long-term benefits. Planned equipment replacement is significantly more effective and efficient than replacing as unplanned.

4. PLAN DETAIL

4.1. Plan Size/Population

The Substation Reliability plan is ongoing and addresses substation assets as they age each year, which means the count of aging equipment changes each year. Although some assets are replaced each year, other assets are being strategically phased out completely and replaced with new technology.

The below table reflects the count of aging equipment as of March 2021. Of the equipment identified, the oil breakers (OBR) and oil switches (OSW) are targeted to be replaced completely and replaced with new generations of oil-free substation assets. Other assets such as electro-mechanical relays (EM Relays), over-dutied fuses (OD Fuse) are being replaced with updated technology and equipment to improve their function and performance.

The Substation SCADA plan, which addresses distribution substation assets includes Capacitor banks (CPB) and Oil Switches (OSW) within the project scope as they provide benefit. In effect, the number of OSW's and CPB's replaced can be increased each year with both plans in place.

Other assets such as LFR transformers will remain and be replaced at an appropriate rate each year based on condition, performance and its lifecycle cost to maintain the resiliency of the substation infrastructure, they are not replaced based on past outage history. However there are many units over 40 and 50 years old which will be escalated via diagnostics and maintenance results if necessary.

Table 3: Aging Substation Assets

Asset Type	OBR	OSW	VSW	GSW	REG	LFR	XFR	CPB	Bank Fuses	115kV EM Relays
Count	82	40	156	326	63	276	143	280	80[1]	156

[1] 20 of the fuses are to be prioritized

4.2. PROPOSED COMPLETION DATE

The timeline to replace aging assets depends on different factors including severity of condition, available budget, crew resources and engineering delivery. There are two objectives to be achieved in this replacement plan. One is to replace aging assets which demonstrate poor condition, and the other objective is to retire oil filled assets that are being replaced with non-oil filled equipment, e.g. replacing OBRs with GBRs. For other existing asset types, the replacement plan shall be 'ongoing'. The 6 year budget through 2026 will enable PSE to replace the approximate number of the major substation assets per year as in Table 4 below:

Table 4: Annual Substation Reliability Replacements

Asset	Avg. Count/Yr.	Est. Replc. 2021-2026	Yr. Population retired
XFR Transformers	4	33	2046
Regulators	4	33	2032
Electro-Mechanical Relays (115kV)	23	101	2029

Oil Breakers (OBR)	11	67	2027
Oil switch (OSW)	7	8	2027[2]
Over Duty Fuses	3	18	2025
LFR Transformers	4	17	ongoing
GSW Circuit Switcher	10	62	ongoing

[2] OSW replaced under SubstationSCADA plan simultaneously

Although not all aging equipment can be replaced or retired in a short time-frame we continue to ensure reliable service to customers and improve the safety of the substation assets. Aligning with other plans and strategies may enable us to replace additional equipment more efficiently and effectively to reduce the timeline indicated above.

4.3. Summary of Plan Benefits

Although this plan is part of our reliability strategy, the primary benefit of replacing substation assets is to improve the reliability & resiliency of the overall substation infrastructure cost effectively. Improved reliability & resiliency through smarter, modern equipment enables quicker restoration of power to customers and reduces outage time. Through pro-active replacement of assets, PSE maintains service reliability to its customers and reduces the opportunity for unexpected equipment failure.

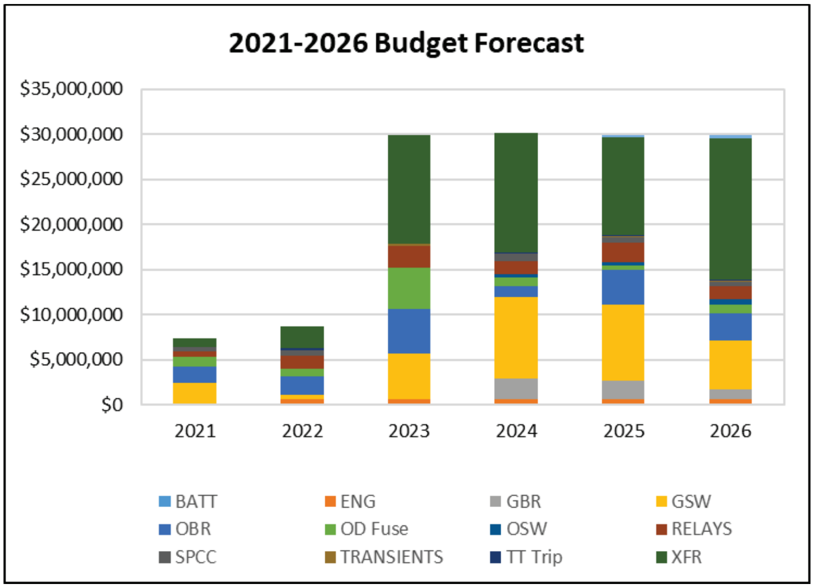
With proactive replacement, PSE can optimize the capital investment to replace the most at risk assets and maintain assets to extend the service life of others. Additional benefits are obtained during the Engineering pre-scope evaluation for each substation reliability project as it's an opportunity to increase system operational capacity, redundancy, and flexibility and reliability where applicable.

Through Asset Management implementation, PSE can proactively replace suspect transformer or breaker models that have developed an increased failure trend and prevent additional unplanned substation outage minutes.

Replacing bank protection fuses, oil breakers and disconnect switches with new technology reduces the risk of safety concerns. Also, replacing equipment with known concern for catastrophic failure increases safety to the Public and employees.

Figure 1 below shows the forecasted replacements by asset and cost from 2021 through 2026 under the new increased budget plan.

Figure 1: 2021-2026 Budget Forecast by Asset



4.4. Primary iDOT Categories

The top primary iDOT Categories this plan addresses are:

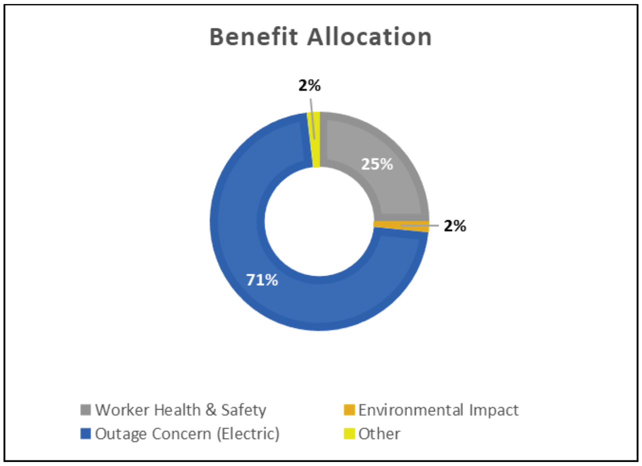
- Outage Concern - per impacted customer with the project
- Health & Safety Concerns – impacts and risk reduction if project is funded
- Environmental Impacts – reduction in environmental risks and impacts with project

Table 5: Summary of Plan Benefits, Population and IDOT B/C Score per Year

2021-2026	Non-MED CMI Saved (M)	Budget ($M)[1]		NPV ($M)[2]	iDOT B/C Score[3]
		Capital	OMRC	Total Benefits	
Total	**1.3**	**137.5**	**0**	**241**	**2.16**

[1] Budget indicate are sum of future year budget as it is allocated for that specific year
[2] Benefits indicated are Net Present Value (NPV) sum of future year benefits allocated for that specific year
[3] B/C Score uses NPV of Benefits and Budget

Figure 2: Benefit Allocation[4]



4.5. Estimated Costs

Estimates are based on replacement of like components to project future replacement cost. Replacement in size, quantity, and type of components will vary from substation to substation. The estimate also accounts for an increase in project cost due to inflation, and added contingency to account for unforeseen conditions associated with the project.

The costs to implement the Substation Reliability plan from 2021 until 2026 will be approximately $138 million. This does not guarantee replacing all aging assets, however, much of the oil filled aging equipment shall be replaced in that timeframe.

Table 6: 6 Year Substation Reliability Budget

Years	2021	2022	2023	2024	2025	2026
Substation 5 yr. Budget ($M)	$8.5	$9	$30	$30	$30	$30

5. FUNDING ALTERNATIVES

5.1. Solution alternatives

No Action: -

There will be increased risk to substation components failing unexpectedly, requiring more outage time to source parts and replace failed equipment. Some specific older type

[4] Risk of not achieving budget and expected benefits is 3%

of equipment do not have spares available so repair is not an option, a proactive planned replacement is preferred to reduce outage time and maintain system reliability. By waiting to replace equipment when it fails, there is a risk to safety to personnel and other substation equipment. Unplanned failures have a negative impact on customer reliability and add more emergency repair costs.

5.2. FUNDING ALTERNATIVES

Increased Funding: - With similar budget levels as the current 5 year plan, PSE can reduce the majority of the aging equipment backlog within the next 10 years. With new equipment, planned outages are reduced for maintenance activities, and this will also continue to strengthen the resiliency of the electrical system. This will help modernize PSE substation infrastructure to support more effectively Grid modernization changes and impacts on the daily energy usage. Increased funding may also allow for the further implementation of online diagnostic monitoring equipment that provides PSE alerts and condition data and which enables proactive decision making before an unplanned failure.

Decreased Funding: Will impact the overall resiliency and reliability of the electrical system which will negatively impact customers. The backlog will continue to grow in numbers and age which also raise PSE's level of risk. This will make a negative impression on major customers in this region as many rely on continuous service 24 hours per day, 365 days per year. Planning and prioritizing of so many aging units will not be as effective.

6. PLAN DOCUMENT HISTORY

Date	Reason(s) for Update	Summary of Significant Change(s)	Modified By
6/17/2020	Business Case Report – New Plan Template	Document history and development of the program	Stephen Hartnett
3/24/2021	2021 update	Annual update plus 5 year budget impacts on iDOT evaluation	Stephen Hartnett
7/12/2021	Used and Useful Policy guidance	Update current information; add alternative and cost information	Stephen Hartnett
12/1/2021	Annual Review	Minor word and format changes	Stephen Hartnett

7. SUPPORTING DOCUMENTATION

Document Name
PSE LIFECYCLE MODEL

PSE AGING INFRASTRUCTURE REPLACEMENT PROGRAM
PSE ELECTRIC ASSET MANAGEMENT STRATEGY DOCUMENTATION
SUBSTATION RELIABILITY 5 YEAR PLAN
SYSTEM PLANNING IDOT OPTIMIZATION TOOL

VOLTAGE REDUCTION

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

The intent of the Voltage Reduction Plan is the ability to operate the utility distribution system in the lower half of the acceptable voltage range (120-114 volts) to save energy, reduce demand, and reduce reactive power requirements without negatively impacting the customer.

2. BACKGROUND

Voltage reduction is primarily a plan motivated by Washington State Initiative 937 which is a clean energy initiatve that appeared on the ballot and passed in the November 2006 election. The initiative specifically pinpoints “cost-effective energy conservation” on the distribution system. Voltage reduction is a proven technology for reducing energy and peak demand. It is a measure implemented upstream of end service points in the distribution system so the efficiency benefits are realized by consumers and the serving utility. These combined benefits to consumers and distributing utility can achieve the requirements of Initiative 937. In 2007, PSE participated in a study with 13 northwest utilities and 395 residential households. This study was called the Distribution Efficiency Initiative (DEI). Each utility selected multiple substations and over the course of one year voltage reduction settings were administered at the substation breaker level (alternating day-on and day-off settings). Over the course of one year there were no customer complaints related to voltage reduction and the two PSE substations involved in the study saw an average of 2.5% energy savings for a 3 Volt drop (0.833% per Volt). The key finding was that substations serving primarily residential load will save energy when the voltage is lowered. This study determined a relationship by which PSE can calculate an estimated energy savings which is used in final reporting. The current voltage reduction methodology implemented by PSE is a simplified approach called LDC (Load Drop Compensation) often refered to as Conservation Voltage Reduction (CVR). The voltage reduction or inition CVR plan is dependent on using end of line AMI voltage data to verify the voltage reduction settings are correctly modeled and monitor the end of line customer voltages on each circuit for compliance to the standards. The end of line AMI voltage data is also used in calculating the energy savings after implementation of CVR. PSE’s Energy Efficiency programs capture the avoided cost benefits of CVR, using the term Distribution Efficiency. PSE’s AMI deployment expands the capability to implement CVR widely across PSE’s system.

3. STATEMENT OF NEED

Washington State Initiative 937 requires large utilities to obtain 15% of their electricity from new renewable resources such as solar and wind (but excluding hydro) by 2020 with incremental steps of 3% by 2012 and 9% by 2016. It also requires that utilities undertake all cost-effective energy conservation. Applying CVR to selected distribution circuits allows the system to be operated at the lower end of the voltage range which results in avoided energy costs.

3.1. Need Drivers

- **Compliance** - CVR is motivated by Washington State Initiative 937 which is a clean energy initiative that appeared on the ballot and passed in the November 2006 election. The initiative specifically pinpoints "cost-effective energy conservation" on the distribution system. I937 was further enhanced by the passing of Washington State's Clean Energy Transformation Act (CETA) in 2019.
- **Energy Conservation** – The passing of Washington State Initiative 937 resulted in the need for utilities to comply with this new clean energy legislation, but it also specified that "cost-effective energy conservation" measures were to be implemented on the distribution system.
- **Grid Modernization**

  Smart & Flexible – Implementation of CVR requires circuit load balance which in turn provides better circuit capacity utilization. With the adoption of smart grid technologies, the current CVR plan will mature to dynamic Volt Var Optimization (VVO)that promises greater efficiencies and flexibility. AMI meters in conjunction with the CVR plan provide other opportunities for improved data and system visibility to modernize the grid.

3.2. Integrated Strategic Plan (ISP) Alignment

This plan aligns primarily with the Processes & Tools category of the ISP:

- **Streamline processes to drive effectiveness and efficiency** – This plan drives effectiveness and efficiencies by operating the system to realize avoided energy costs within the scope of the work. These projects may also help with improving data quality/information in use of the AMI meters to verify the CVR settings and confirm integrity of service to the customer.

- **Extract and leverage value from existing technology and assets** – The project scope will utilize existing equipment to optimize the costs to attain the plan's goal and benefits.

4. PLAN DETAIL

4.1. Plan Size/Population

There are a total of 160 substations identified as possible candidates for the CVR plan out of a total of 278 distribution substations. At the end of 2020, 15 substations have CVR implemented.

4.2. Proposed Completion Date

The CVR plan in its current methodology is proposed to complete 55 substations over 2021-2025. The CVR plan schedule will coordinate with the implementation of ADMS at which time PSE will mature the methodology to VVO.

4.3. Summary of Plan Benefits

Energy Savings – The primary benefits of PSE's CVR plan is saving energy with some side benefits of reducing demand and reactive power. The Energy Efficiency team creates an annual report which is calculated savings based on CVR factors, (CVR Factor)(MWhrs) = Energy Savings. Note: Energy savings is realized when the system is at less than peak loading.

4.4. Primary iDOT Categories

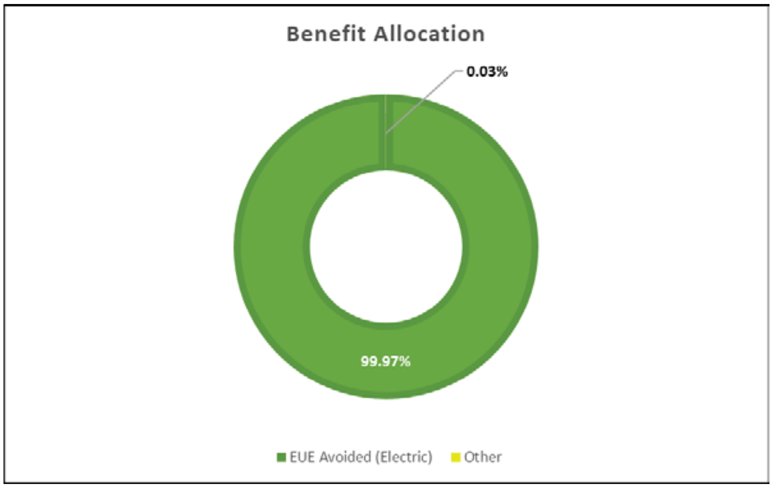
Expected Unserved Energy (EUE) - Addressing the need to have sufficient capacity to serve the increasing energy needs of customers. The EUE calculation for CVR is different than the standard way EUE is calculated for a typical capacity project. CVR saves energy and does not add capacity in the traditional way. To use the iDOT tool to reflect the energy savings, a calculated average energy savings has been entered on an annual basis. That calculated value has been entered into the EUE "do nothing" category and the EUE with project is zero rather than adding negative numbers. This is a reverse way of capturing the energy savings realized in the iDOT tool and calculating the benefits.

Table 1: Total Plan Population, Cost and Benefits

2021-2025	Number of Substations	Budget ($M)[1]		NPV ($M)[2]	iDOT B/C Score[3]
		Capital	O&M	Total Benefits	
Total	**55**	**13.75**	**2.2**	**$ 1,197**	**80.83**

[1] Budget indicate are sum of future year budget as it is allocated for that specific year
[2] Benefits indicated are Net Present Value (NPV) sum of future year benefits allocated for that specific year
[3] B/C Score uses NPV of Benefits and Budget

Figure 1: Benefit Allocation[4]



4.5 Estimated Costs

Estimated costs are generated based off of historical costs on similar types of projects, allowing for variations in project scope, increase in project cost due to inflation, and added contingency to account for unforeseen conditions associated with the project.

Historical actual cost for phase balancing are $33k per substation, future estimated cost are $40k per substation. The historical cost were O&M not capital. There was no cost associated with historical capital work, but for future work we're estimating $250k per substation. For a total of $290k per substation estimated cost.

The Voltage Reduction program 2021 - 2025 will address 55 substations with a proposed budget of $13.75M (Capital) and $2.2M (O&M).

Capital costs reflect the need for some system improvements like Line Regulators, Capacitors, Line/Phase upgrades. O&M costs reflect the need for phase balancing, study time and settings implementation.

5. ALTERNATIVES

5.1. Solution alternatives

No Action - The CVR program meets the I937 Initiative compliance driver as a cost effective energy conservation measure. No action or not implementing CVR would go against the I937 Initiative. VVO is the next step in achieving more energy savings. Since CVR is a static program which does not automatically react and adjust to large system changes, it is hampering our ability to implement Grid modernization programs like Distribution Automation on circuits with CVR. VVO is a dynamic program within ADMS that can dynamically monitor the system and adjust automatically.

[4] Risk of not achieving budget and expected benefits: CVR is 17%

5.2. Funding Alternatives

Increase Funding - With increased funding, energy savings through CVR could be achieved in earlier years, however, PSE is currently on a course where benefits are realized under the existing CVR plan until ADMS is fully implemented at which time the CVR plan transitions over to the more advanced Volt-VAR Optimization (VVO) technology.

Decrease Funding - Decreased funding reduces PSE's ability to realize available system/energy efficiencies through the CVR plan which meets the criteria of the I937 initiative.

6. PLAN DOCUMENT HISTORY

The current version of the project summary supersedes all previous versions.

Date	Reason(s) for Update	Summary of Significant Change(s)	Modified By
10/25/2019	Initial Document – New plan template	Initial Document – Summarize historical plans	Sam Di Re
4/14/2020	Revision	Added budget and iDOT details	Sam Di Re
5/06/2021	Revision	Added VVO alignment	Ray Hisayasu
10/26/2021	Used and Useful Policy guidance	Update for current information; add alternatives and cost information	Reid Shibata/Ray Hisayasu
12/1/2021	Annual Review	Minor word and format changes	Reid Shibata/Ray Hisayasu
1/19/2022	Revision	Updated iDOT values	Ray Hisayasu

7. SUPPORTING DOCUMENTATION

Document Name
Washington State Initiative 937
Distribution Efficiency Initiative report by Northwest Energy Efficiency Alliance, December 2007
2016 AMI Business Case

ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (ADMS)

Business Case

Prepared for Puget Sound Energy

By

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Acknowledgments

The following people were a part of the project team and contributed significantly to the development of this report. The report is significantly better due to their involvement.

Puget Sound Energy

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- Ryan Murphy
- Nhung Tran

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Table of Contents

Change Log

Revision	Date	Submitted by	Change Summary
MGS Baseline	05/05/2019	Dr. Mani Vadari John (JD) Hammerly	Reform the Business Case Document
MGS delivery	06/10/2019	Dr. Mani Vadari John (JD) Hammerly	Final MGS draft delivery to PSE
PSE Review	7/19/2019	Elaine Markham	PSE comments back to MGS and the Go-Ahead to make the changes and submit final delivery
MGS Delivery	07/25/2019	Dr. Mani Vadari John (JD) Hammerly	Final MGS delivery to PSE
MGS Delivery	08/16/2019	Dr. Mani Vadari John (JD) Hammerly	Added the executive summary
PSE Review and Update	08/26/2019	Elaine Markham	Reviewed and updated the MGS version and asked for MGS review and update to conclusions
MGS Delivery	08/28/2019	Dr. Mani Vadari John (JD) Hammerly	Updated Conclusions Section
PSE Update	10/3/2019	Elaine Markham	Benefits Update

1. Executive Overview

Puget Sound Energy (PSE) is facing a host of challenges, drivers of change, and opportunities. Some of these are coming at it from the regulator, some from the customer, and some from the industry. They are equal parts increasing customer expectations, regulatory expectations, the emergence of new distributed energy technologies, the need to increase reliability and efficiency, aging infrastructure and the maturing of a host of technologies that can now engage customers like never before. One of the most critical changes that has happened recently is the signing of the WA State Clean Energy Bill (SB 5116). The bill states that all IOUs in the state will need to eliminate coal-fired electricity, transition the state's electricity supply to one hundred percent carbon-neutral by 2030, and one hundred percent carbon-free by 2045. In addition, it also mandates a coal phaseout by 2025 and requires that utilities increase their clean-energy commitments over time. Further pressure for change is rooted in the constant drum beat of growth, where despite aggressive conservation efforts, demand still outpaces supply in many locations.

All of this points to a dramatically changing landscape that is facing PSE – one in which it must dramatically alter the mechanisms by which it plans and operates the distribution system all towards an interaction with the customer in a way very different than it does now.

The Advanced Distribution Management System (ADMS) is the platform that will enable this change and will allow PSE to position itself for this new future. The ADMS is the foundation which enables synergies from multiple intelligent systems and devices to be realized, and to optimize the collective portfolio of technologies used to manage the electrical distribution network. ADMS will support the monitoring, control and analysis of distribution assets. This platform will be utilized by System Operations effectively without encumbering the Load Office or requiring unnecessary NERC/CIP protection and security. In addition to this, the ADMS solution will support any distributed energy resources currently being used today, and in the future, automation, power quality applications, etc. It will also enable the security capabilities necessary to support future new potential NERC requirements as they expand beyond the traditional transmission domain, and into the distribution systems.

The ADMS is the nucleus, which enables real time integration, monitoring, analysis, control and optimization of the entire electric distribution system. In addition, it is also a decision support system that will assist the distribution system operators, engineers, technicians, managers, and other personnel in optimizing the performance of the electric distribution system while supporting the protection of the distribution assets. Lastly, it also contains key modules that will enable the field personnel to work safely in the field on distribution assets.

The specific deployment of ADMS at PSE will include enhanced Fault Location, Isolation and Service Restoration (FLISR); voltage optimization (conservation through voltage reduction); peak demand management; support for microgrids and electric vehicles, as well as distributed energy resources. It will also integrate and assume various distribution functions that now reside in an array of disparate PSE systems such as; EMS, OMS, D-SCADA, YFA and GIS to provide enhanced control and planning capabilities.

The ADMS will enable delivery on the following key objectives for PSE:

- Workforce and public safety through enhanced visibility and control that comes with more automation
- Customer satisfaction through quality and responsiveness, as well and new options for engagement and increased value.
- Competitive performance relative to industry by leveraging new technologies with existing infrastructure

- Minimizing the cost of providing services
- Optimizing asset utilization through condition-based maintenance
- Enhance reliability and efficiency of the power delivery
- Maximizing workforce productivity both in normal and emergent operating conditions
- Enhanced Security through greater condition recognition and speed of correction
- Accommodate Distributed Energy Resources (DER) through continuous multi-directional adjustments and optimization of the electrical power distribution network, and the management two-way power flow.

The remainder of this document will provide the justification for undertaking the Advanced Distribution Management System (ADMS) project based on the estimated cost of development, and the anticipated benefits to be gained; both quantitative and qualitative.

2. Introduction to ADMS

Perhaps to better understand this new era of the ADMS, it's best to take a step back to explore what initiated this software response.

Currently, our industry is headed for lots of changes. Regardless of how people feel about change, especially in the utility industry, change is inevitable to keep up with our times and the demands given to our industry. Most of the infrastructure and technology set out to support our energy demands and needs were put in place 20-30 years ago, if not longer. Twenty to thirty years ago, smartphones and smart technology were unpopular nor widespread, but today, the majority of people own and operates smartphones. So how does the influence of new technology and customer demand affect the utility business?

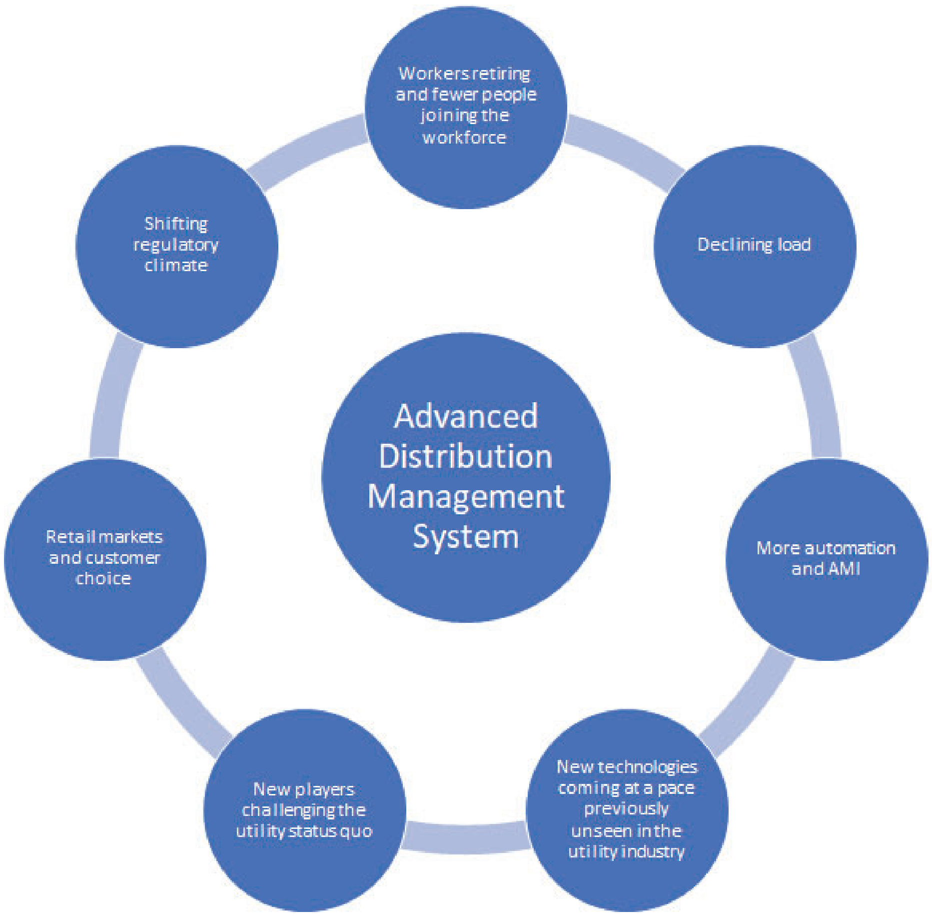

Figure 2.1: Utility challenges
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Figure 2.1 presents a high-level view of the challenges faced by today's utilities worldwide and especially PSE.

- **More automation:** Technologies such as distribution automation (DA) and Automated Meter Infrastructure (AMI) are being implemented in large quantities. These technologies support and enable the utility's ability to monitor and control parts of the distribution system that was not previously visible or controllable to them.

  These new devices allow the utility greater control over power system equipment and also communicate bi-directionally. For example, with the rollout of AMI meters, we can 'ping' meters down a long feeder to see if they're on or off.

- **Declining load:** Houses and buildings are becoming more energy-efficient, so they consume less energy. In addition, the introduction of distributed energy resources (DERs) into the system is making the customer's load less predictable.

- **Shifting customer expectations:** Our customers expect us to reduce our carbon footprint and be efficient in our power generation and distribution. They also expect us to decrease our outage time, be proactive and conscientious of how we conduct our business around energy matters, and maintain affordability.
- **New technologies coming at a pace previously unseen in the utility industry:** The old paradigm had regulators and utilities who controlled the pace of innovation through collaborative research with organizations such as EPRI and national labs. This is no longer the case. Startups and other fast-paced companies now greatly influence our business environment. Some of these technologies, such as DA, are within the grid, while other technologies, such as Smart Inverters are implemented by customers.
- **New sources of supply:** DERs and other non-wires alternatives (NWA) approaches are creating new sources of supply (and consumption) at the utility. Customers now can generate some or all of their power internal to their premises, store it, and even deliver it to back to the grid. In addition to creating load variability of load, it also creates a 2-way power flow situation in a mostly radially designed distribution grid designed for 1-way power flow.
- **New technical constructs:** New technical constructs such as microgrids are being implemented within a utility's footprint. These microgrids could be either utility implemented or customer implemented. Similarly, the potential exists for external aggregators to operate a customer microgrid and interact with the utility as an independent entity.
- **Workers retiring and fewer people joining the workforce:** Automation in the field and within the control center is allowing utilities to streamline operations while creating more value for customers.

  As the industry looks to the future workforce, a few difficult questions come to mind. Given the impending ubiquity of grid automation and advanced operational technologies, what skill sets do newer employees require? What impacts does this have on the universities that are generating the next generation of the utility employee, or power system engineer? The workforce of the future will be very different from that of today. They need to be technology-savvy because much of the automation is based on electronics, software and (as we go into the future) AI, which requires very different handling that today's equipment.
- **Transparency, retail markets, and customer choice:** DERs and NWAs are transforming the grid. States such as New York are providing unprecedented transparency by posting their feeder hosting capacities on the web.

  Various states are also beginning to discuss the possible development of retail markets, followed by the creation of Distribution System Operators (DSO). This will change the dynamics between the utility, other market participants, and customers, along with relationships within its utility departments.
- **Rapidly shifting regulatory and policy situation:** The regulatory and state policy is shifting rapidly, enough so that the utilities must have strategies, processes, and tools in place that are nimble enough to enable appropriate responses to the mandates.

Implementing the ADMS is a direct response to the changes we're undergoing. An ADMS system is a system that allows many independent systems such as outage management, switching, and distribution system management to work together on one platform. It pulls in all sorts of data such as SCADA data, distribution points, AMI meter readings, and distributed energy resources such as batteries and solar panels. The often-siloed equipment groups working in independent programs and independent specialty groups at PSE are now expected to come together and work dynamically with each other to be more effective.

2.1. What it is

An Advanced Distribution Management System (ADMS) is a system of integrated computer-aided applications and tools used by operators of electric distribution networks to monitor, control, and optimize the performance of the distribution system. Among other things, it allows the operator to

- Proactively manage the Distribution System
- Process real-time data quickly

- Provides decision tools for the distribution operator
- Delivers reduced outage duration
- Reduces crew patrol and drive times through improved outage locating, and
- Improve utility response in a disaster

All the while providing for increased customer satisfaction by providing the operator with an enhanced situational awareness of the grid and its impact on the service being delivered to the customer. The ADMS-enabled system operator now has access to more accurate information on outages, voltage/power quality, and others along with the controls which allow him/her to take action remotely and resolve the situation before (sometimes) the customer is even aware of the problem.

The ADMS has the following main components

- **D-SCADA:** Distribution SCADA (or D-SCADA) is a basic building block upon which provides the ability to monitor the distribution system components in real-time or near real-time. D-SCADA also enables operators to control devices located on the feeders remotely. Controllable devices include reclosers, capacitor bank switches, voltage regulators, and any other electrically operable device. D-SCADA is also being used to monitor and (in some cases) control the growing number of Distributed Energy Resources (DERs) being connected to the distribution system. DERs include distributed generating units (including renewables) and energy storage units.
- **OMS:** The Outage Management System (OMS) portion of the ADMS can either operate independently on be fully integrated within the ADMS. Its fundamental role is that of the single repository of all outages which could be either planned or unplanned (blue-sky mode, grey sky mode or emergency management mode). All outages, as they are identified through one of a series of potential incoming channels are routed into the outage management module, and the first step it takes is to identify the potential location of the fault. This information is used to work with field crews to fix the faults, and restore power to all the affected customers. The core output of the OMS is also called the "As Switched" state of the network which tracks the connectivity of the distribution power system.

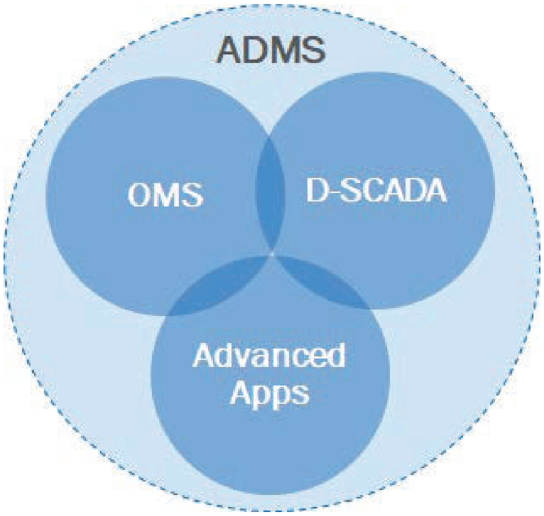


Figure 2.2: Key ADMS Subsystems

  A key part of the OMS module is also to support outage reporting, which is a regulatory requirement.

- **Advanced Applications:** There are several advanced applications that form a part of this module. The core capability here is the Unbalanced Three-phase Power Flow (UBLF, or just Power Flow). The Power Flow is a foundational model process that runs in the background in an ADMS. Power Flow takes the "As-Switched" state of the network and employs other information from the GIS model and injections from the EMS into the distribution system to calculate "As-Operated" state of the network, which includes items such as line flows (MW, MVAR), transformer switch positions, and node voltages.

  Other advanced applications that PSE would seek to implement in the future include Fault Location, Isolation, Service Restoration (FLISR), Volt-VAR Optimization (VVO), and Distributed Energy Resource Management System (DERMS). More information on these applications is provided in Appendix A (Section 12) of this document.

- **Geospatial Information System (GIS):** ADMS requires an accurate power system model to function. The ADMS applications explained above can only work as well as the power system model supplied to it. This aspect includes both the accuracy of the model as well as the extent of how much of the system is modeled.

  This also includes the ability to control field devices. If field devices are not modeled in the ADMS, they cannot be controlled remotely nor can their status be updated if they are controlled manually in the field. An ADMS uses its power system model, and analytic applications to faithfully represent the direction and magnitude of electrical flows in the distribution system, thereby creating the Power Flow as described above. It uses the topology to identify the most likely point at which a failure occurred de-energizing customers during an outage. Also, the topology enables tracing of circuits to a specific open switch based on the energization.

  While not a component of the ADMS, the GIS performs a critical service. It provides the "As-Built" power system model to the ADMS which then drives the "As-Switched" state in the OMS module and the "As-Operated" state in the Advanced applications. The "As-Built" state a resident in the GIS is maintained by the planners and asset managers at PSE and contains the following key sets of information: (1) type of device (circuit breaker , transformer etc.), (2) ID of the device (3) location of the device (generally defined through its locational GPS coordinates), (4) connectivity of the device (which other devices they are connected to), (5) their characteristics (size of the wire, resistance, inductance, etc.) and (6) their geospatial rendering.

With aging infrastructure and new technological advancement, the ADMS allows PSE to position itself to make decisions that will bring higher quality, more efficient, and effective service to our customers.

3. Impact of ADMS on PSE

Puget Sound Energy is the largest utility in the state of Washington, providing electricity to more than 1 million customers across 6,000 square miles. It currently has 1,073 distribution circuits, 428 transmission and distribution substations, and a total of 65,971 SCADA points, analogs, and counts modeled.

3.1. Setting the Stage

With the growing penetration of intelligent electronic devices on PSE's distribution grid to meet reliability, customer needs, and operational effectiveness, the need to both monitor and control these assets is currently being satisfied by the Energy Management System ("EMS"). The Load Office primarily utilizes the EMS for transmission and generation operations. Approximately 25% of the monitoring points in EMS are for distribution assets, and while the EMS application is scalable, these points impose a burden on the Load Office. Furthermore, few distribution-specific capabilities exist in the EMS application. PSE's ability to take reliability beyond historical levels and create alternatives to capacity constraints rely on these intelligent electronic devices and advanced distribution capabilities. Customers are increasingly demanding distributed energy solutions in this realm as well. Without an integrated and appropriately designed platform, full and effective utilization of these solutions are much less possible.

Further, NERC reliability and security requirements are levied on the EMS application, which imposes unnecessary effort to manage the distribution assets included in the EMS. Finally, technology maturity is connecting distribution management systems with outage management systems. PSE's Outage Management System (OMS) application recently underwent the final upgrade that will be provided by the vendor, hence the OMS is facing an obsolescence concern in the coming years and an opportunity to consider migrating OMS functionality to this platform intentionally. The urgency in addressing the current EMS situation is illustrated below in the looking at the demands on the EMS currently, and what those demands will look like in the future.

Table 3.1 EMS Current and future demands

Current State Situation Demands on EMS for distribution-level	Future State Situation Demands on EMS for distribution-level

• Distribution Automation (in EMS today)
  o Auto schemes changing and number of devices growing
• Bellevue Central Business District (CBD) switches (in EMS today)
  o SCADA switches installed throughout CBD
• CBD fault sensor monitoring
  o Phase I completed and in a 3rd party hosted monitoring system
  o Desire OMS/DMS integration for future phases
• Distribution SCADA reclosers (in EMS today)
• Distribution substation equipment (in EMS today)
  o Bank Temperature, Oil Level, Tap Position
  o DC Battery Monitoring
  o Circuit Breakers
• Grid-Scale Energy Storage
  o 2 Distribution use cases
  o 2 Transmission use cases
	• Distribution Automation
	  o 8-12 projects/year
	• Distribution SCADA reclosers
	  o ~25 new devices annually
	• Grid-Scale Energy Storage & Distributed Resource Integration
	  o Automated reconfiguration to island loads for outage mitigation
	  o Power quality and distribution grid stability
	  o Microgrid implementations
	• Conservation Voltage Reduction/VVO
	  o Closed-loop control of Load Tap Changers, capacitors, and voltage regulators using metered voltage reads for conservation, power quality, and peak reduction
	• Distribution grid sensor monitoring and load flow analysis
	  o Integration of fault sensors into OMS/DMS
	  o Possible line monitoring for situational awareness on momentaries, power quality, and load flow analysis

As we continue to integrate smarter assets such as our distribution automation devices to meet customer and industry needs, our system increasingly becomes more complex with time. Current tasks that require situational awareness from our operators become more convoluted and intricate, requiring the aid of software analysis to help with analysis. Without additional software support to help our operators carry out their tasks, there is a greater risk of increased time in mitigating issues and resolving problems.

To address the current constraints and burdens that come with distribution functions hosted in the EMS, the ADMS assumes the distribution functions currently burdening the EMS, as well as the OMS, D-SCADA, DMS, FLISR and Distributed Energy Resource Management. This sets the table to accommodate future smart grid demands and the insertion of new technology that emerges and requires the integration of intelligent controls throughout the distribution system. Without ADMS, the result will be a collection of many existing and future stand-alone systems that will still be needed to try and function “like” and Advanced Distribution Management system, but with far more complexity, cost and chance of failure, as the number of system interfaces would be dramatically increased. In addition to this, having stand-alone systems resolving issues separately and independently from one another inhibits having dynamic solutions leveraging the potential of the full suite of technology. ADMS is the foundation to satisfy a strategic imperative to strive for efficiency, reliability, and conservation.

Figure 3.1 illustrates what the Distribution Operations will look like when the ADMS platform is in place.

3.2. Business Drivers – Why ADMS and why now?

In the next five to seven years – PSE expects to see the following changes in its grid

- 75,000 – 150,000 EVs (fleet and customer), requiring as many as 10% of circuits needing improvement

- 200 MW rooftop solar which could impact 30 circuits with high solar penetration (25 in Kittitas)
- Ten microgrid circuits
- 20-40 circuits with VVO control
- 75 substations with FLISR
- 50 MW utility-driven storage

And now, with the signing of the **WA State Clean Energy Bill (SB 5116)**, all IOUs in the state will need to eliminate coal-fired electricity, transition the state's electricity supply to one hundred percent carbon-neutral by 2030, and one hundred percent carbon-free by 2045. In addition, it also mandates a coal phaseout by 2025 and requires that utilities ratchet up their clean-energy commitments over time. Coal accounted for 38 percent of the PSE's resource mix in 2017. While electricity sales must be carbon-neutral by 2030, utilities can meet 20 percent of that requirement with renewable energy credits, through an "alternative compliance payment" or by investing in "energy transformation projects" that reduce the generation of electricity like energy efficiency or transportation electrification.

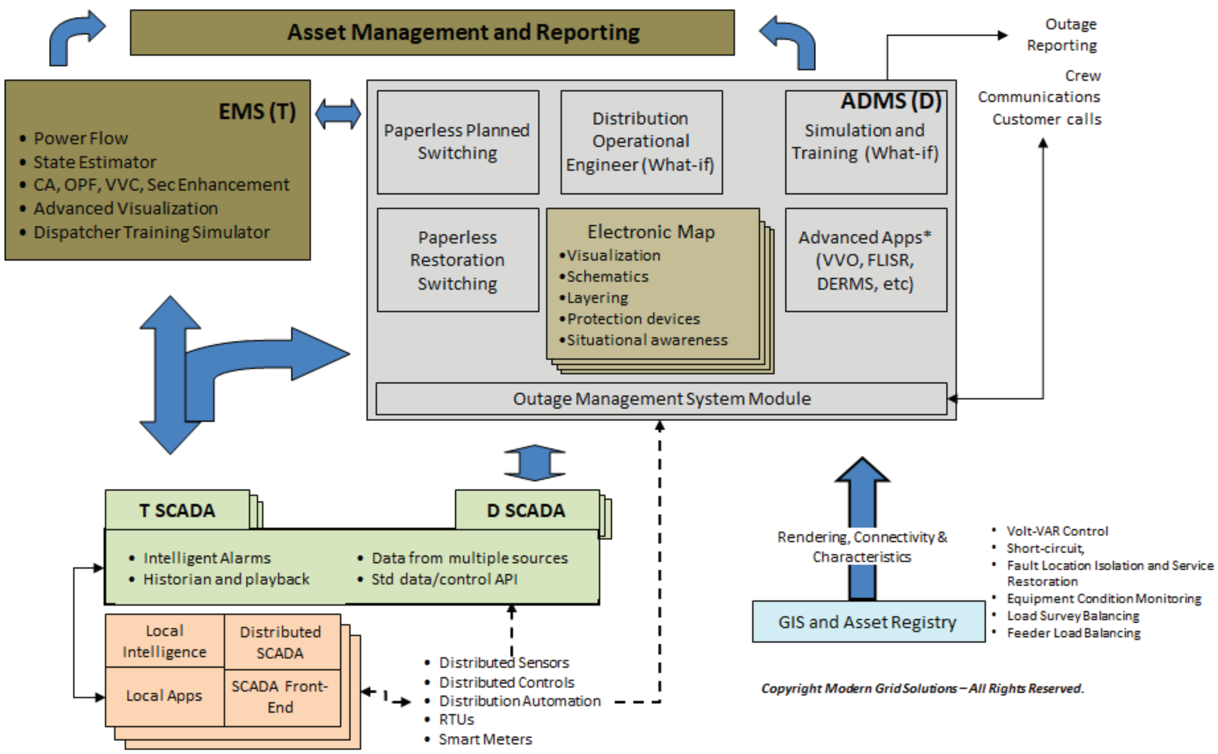


Figure 3.1: ADMS Center of Distribution Operations (Updated June 2019)

The requirements of the changing grid are expected to accelerate to meet the requirements of the mandate as identified in the bill. In addition, PSE is watching for other signals from the marketplace, such as:

- Planning: More NWA (+storage): It is expected that every electric system project moving forward (subject to some constraints) will be evaluated for non-wires alternative solutions. Many projects will likely find opportunities to utilize DERs as a component of the solution. This means that all of them will need to be operated in real-time by the operator/dispatcher.

- DERs: 50-200 circuits with extensive DER/Solar PV penetration delivering about 200-500 MW rooftop PV and growing. Also, thanks to SB 5116, by 2045, all supply shall be from renewable sources. This shift will require a significant shift from the present monitor, control, and dispatch of centralized generation to much broader management of distribution and centralized generation, much of which will come from the ADMS.

- EV Penetration: PSE estimates that about 35-50% of all vehicles within our service territory will be electric by 2045. EVs (residential, fleet, or the Light-Rail system will present a significant new load on the system of a non-conforming nature. This means that this new load will not conform to the normal load profiles that the system operators are used to in the past. The changes will be of the type (1) new load that will come on when first plugged in (2) the load is roughly the same as that of a typical single-family residence and (3) the load mainly appears at night.
- Microgrids in 20-30% PSE territory: Microgrids are technical and business constructs, some of which are PSE-owned while external entities may own others. Depending on the ownership, the control of the microgrid may either stop at the point of common-coupling or go all the way in (in which case, they would be treated as an extension of the distribution grid).
- Vehicle-to-Grid (V2G): V2G is still new and mostly functioning in a lab-like environment in several parts of North America and the world. Core to this functionality is the ability to use spare storage capacity in an EV to support the needs of the grid to offset local congestion.
- Grid-Edge (and beyond) systems: These are customer-owned (either individual customer or aggregator) systems and installations that require PSE's ADMS to interface with and use them as a support mechanism for grid reliability, power quality, and/or market-support. The grid-edge is a nascent area, and its impact on distribution operations and the ADMS is not yet fully understood.
- Retail market transformation: The NY REV (New York State Reform the Energy Vision) initiative was one of the first to define a DSO (Distribution System Operator) as the underpinning of the next stage of markets in the retail energy space. Core to the functionality required here were (1) grid operations, (2) market operations, and (3) enhanced planning (probabilistic hosting capacity). Somewhat like the role of the EMS in a wholesale market, it is expected that the ADMS will perform the same role in a distribution-level retail market.
- Community Choice Aggregate (CCA): These are entities whose role is performed by a broad set of entities, but mainly county and city governments in the United States. Their main purpose is to provide an alternative to energy supply from IOUs such as PSE.

  The general expectation here is that the incumbent IOU is still in charge of providing the T&D services, but the CCA chooses the power generation sources. Very often, these choices move in the direction of being more sourced from a renewable supply. CCAs are growing in number and popularity in several states and are in existence in the states of Massachusetts, New York, Ohio, California, New Jersey, Rhode Island, and Illinois. The most recent announcement of San Diego Gas and Electric (SDG&E) declaring it was going out of the business of buying electricity is one of the more prominent aspects of this construct.

  CCAs impact grid operations directly both at the transmission and distribution level due to the different energy procurement mechanisms and, in addition, the types of energy they tend to procure. Depending upon the granularity of the governmental entity making the change (City of County), the operation of the grid will change significantly. It all comes down to the amount of operational flexibility available to the system operator.

The ADMS integrated with a few systems (1) DERMS (either as an internal application or external) (2) grid-edge systems (to manage, control and dispatch) devices such as solar/PV, EVs, and other NWA installed behind the meter and (3) Microgrid Management Systems (either MGMS or MEMS) will become the foundational tools that will support PSE's needs to monitor and control the grid today and into the future.

3.3. What changes at PSE when the ADMS is fully implemented

We will start this section with a start/stop/continue aspect of – how the ADMS will change how work will get done at PSE. It will look something like this –

Table 3.2: ADMS – What's new, ending, and what it delivers

Category	What's Ending	What's New	What it delivers
• **Efficient distribution operations**	• Paper wall maps • Switching orders with many steps • Inadequate sensing and control abilities in the distribution grid • Several disparate systems are supporting the distribution operator. • Ambiguity around workforce switching skills and capability, leading to a small pool of trusted switchmen.	• Increased remote, SCADA-based controls for operating the network • Visibility of network status and information between control centers • Electronic schematics with real-time network status information • A single set of tags across all devices placed in one spot and visible from all. • Improved coordination of clearances and work with the goals of maximizing the amount of work completed with a given clearance and minimizing the number planned outages • Network operability is consistently factored into new designs • Streamlined switching orders coupled with the expectation that switchman have the proper skills • Operational preparation to accept new load on the system is uniform across all control centers • Improved integration between Operations, Operations Engineering, and Mapping • Improved integration between operations, asset management, field force,	• Reduction in network operations risk • Reduction in operating costs • Improved operator productivity • Improved safety • Better allocation of responsibility to skills • Shorter clearance times • Improved response to outages (shorter times) • Better utilization of planning/operating engineers • Improved customer service • Support system growth – major growth occurring in green-field locations

Category	What's Ending	What's New	What it delivers
		and work/resource management.	
• **Reducing outage times and reliable partner to restore on time**	• Customers and emergency agencies are primary methods for determining network problems	• Providing better information granularity for PSE to inform the customer that they are aware of the power outage at the customer residence and that (1) the crew is working on it and (2) the estimated time of restoration is x hours.	• Improved customer satisfaction due to better, personal and more accurate outage communication. • Savings for utility due to more efficient outage restoration.
• **Command of severe weather implications**	• Customers with outages experiencing long periods with inadequate information about the restoration • Customers calling the utility to inform them that their power is out • Utility using different tools, processes, and people to do resourcing in storms/events.	• Resourcing in storms/events is done from a centralized scheduling/dispatch center • Consistent, standardized business processes between control centers • Initial Estimated Time of Restoration is based on historical information and operating experience	• Improved response time during emergencies • Improved customer satisfaction and reduced outage durations. • Accurate estimated time of restoration information allows customers to reschedule their activities in anticipation of power coming back.
• **Better visibility into the distribution system**	• With the existing OMS/SCADA system – the basic visibility is limited to switch statues and specific analog measurements. ○ Switch statuses monitored remotely are brought in through the SCADA system and are available to the operator/dispatcher ○ Switch statuses not remotely monitored are dependent on the operator/dispatcher to work with field personnel to ensure the accuracy of switch statuses (open/close)	• The Power Flow solution provides insight into the various flows in the system in all directions providing the first set of visibility for the operator. • Once AMI (including net metering) is integrated into the system, the level of visibility will increase further due to more information being fed into the Power-Flow solution. • Once State estimator is working, the visibility will increase further because it will provide the potential to identify faulty switch statuses and analogs. * As identified here, some of the benefits come from increased sensors in the field	Increased visibility allows the system operator/ dispatcher to manage the operate the system much better because the increased information allows them to operate the system in a more optimal manner • The switching orders are more optimal and accurate because the decisions are made based on actual load flow versus planning data. • Outage contained within other outages (nested), common in storms can be more easily identified • Crew status and location are visible, overlaid on the geographical presentation of the grid allowing accurate guidance to faults

Category	What's Ending	What's New	What it delivers
	○ The only access to SCADA analogs and these are available on the SCADA displays and NOT on the OMS displays.	positioned at the right locations. This doesn't just apply to DER management but all aspects of the ADMS.	
• **Better control of the distribution system**	• Limited to SCADA and decentralized DA capability	• Allowing centralized model-based DA allows for optimized and effective distribution level control	• Moving DA from effectively functioning under normal operations mode to functioning under all modes is a significant improvement and provides for much better responses in fault situations.
• **Integration of DERs into the control paradigm**	• No visibility – purely reactive mode	• Power Flow solution supported by the IoT devices (Smart inverters and net metering) provide for increased visibility • With Smart inverters – there is an opportunity to perform control and some level of dispatch of the DERs as well.	• When DER penetration is low, their impact on operations is not significant enough. However, when this penetration increase to larger quantities and two-way power flow increases in quantity, it would be useful for the operator to have visibility into their activities as well as having control over their output when needed to support their reliability mandate.
• **Energy efficiency and Voltage/ power quality management**	• All in a manual mode or • Performed by devices in the field in a decentralized mode	• VVO/CVR which is Optimal Power Flow focusing on either Voltage, VAR or combined Volt / VAR management	• Better voltage profile and management focused on better visibility and control of the grid. • Reduction in consumption by better managing the voltage profile at different points on the feeder using existing and new controls such as cap banks, transformer taps, and others.
• **Personal acquisition of renewable energy**	• Utility generally not aware of customer installation of distributed renewables and localized sources of energy	• Utility working closely with customer for their distributed gen installation and has plans in place to take advantage of these	• The consumer becomes the prosumer – consuming and generating. • Customer and utility can work together to take

Category	What's Ending	What's New	What it delivers
		distributed sources of generation when needed for the grid. • In this, the utility may also work with the customer to install its own distributed generation at their site. * May require some regulatory approval for DER inclusion into utility plans.	advantage of opportunities

4. Alignment with PSE Strategy

Puget Sound Energy (PSE) is facing a host of challenges, drivers of change, and opportunities within the industry. These changes are driven from increasing customer expectations, regulatory expectations, the emergence of new distributed energy technologies, the need to increase reliability and efficiency, aging infrastructure and the maturing of a host of technologies that can now engage customers like never before. Further pressure for change is rooted in the constant drumbeat of growth, where despite aggressive conservation efforts, demand still outpaces supply in many locations. While not able to derive value by itself, the Advanced Distribution Management System (ADMS) is the foundation which enables synergies from multiple intelligent systems and devices to be realized, and to optimize the collective portfolio of technologies used to manage the electrical distribution network. ADMS will support the monitoring, control, and analysis of distribution assets. This platform will be utilized by System Operations effectively without encumbering the Load Office or requiring unnecessary NERC/CIP protection and security. In addition to this, the ADMS solution will support any distributed energy resources currently being used today, and in the future, automation, power quality applications, etc. It will also enable the security capabilities necessary to support future new potential NERC requirements as they encroach beyond the traditional transmission domain, and into the distribution systems.

4.1. Integrated Strategic Plan

The Advanced Distribution Management System (ADMS) is the nucleus, which enables real-time integration, monitoring, analysis, control, and optimization of the entire electric distribution system. The ADMS is also a decision support system that is intended to assist the distribution system operators, engineers, technicians, managers, and other personnel in monitoring, controlling, and optimizing the performance of the electric distribution system without jeopardizing the safety of the field workforce and the general public, and without jeopardizing the protection of electric distribution assets. ADMS includes functions that further automate outage restoration and optimize the performance of the distribution grid. Deployment of ADMS at Puget Sound Energy will include enhanced fault location, isolation, and restoration; voltage optimization (conservation through voltage reduction); peak demand management; support for microgrids and electric vehicles, as well as distributed energy resources. It will also integrate and assume various distribution functions that now reside in an array of existing PSE systems such as; EMS, OMS, D-SCADA, YFA, and GIS to provide enhanced control and planning capabilities, which will enable it to realize productivity benefits for its operators, engineers, and support functions.

Figure 4.1 PSE Integrated Strategic Plan – ADMS enabled strategies

The Advanced Distribution Management System is a foundational platform to enable delivery on the following key objectives:

- Workforce and public safety through enhanced visibility and control that comes with more automation
- Customer satisfaction through quality and responsiveness, as well and new options for engagement and increased value.
- Competitive performance relative to the industry by leveraging new technologies with existing infrastructure
- Minimizing the cost of providing services
- Optimizing asset utilization through condition-based maintenance
- Enhance reliability and efficiency of the power delivery
- Maximizing workforce productivity both in normal and emergent operating conditions
- Enhanced Security through greater condition recognition and speed of correction
- Accommodate Distributed Energy Resources (DER) through continuous multi-directional adjustments and optimization of the electrical power distribution network, and the management two-way power flow.

PSE Integrated Strategic Plan		Benefits Category					
Objectives	Strategies Affected	Control Center & Field Workforce Productivity Improvement	Safety: Public, Workforce, and Assets	Voltage Profile Improvement	Improved Reliability of customer service and Outage Response	Cost avoidance from systems that are no longer required	VVO Volt/VAR Optimization
Financial	Maximize Long-Term Value Grow New Business			▲		▲	▲
Customer	Execute the Customer Experience Intent Statement	▲	▲		▲		
Processes and Tools	Streamline Processes to Drive Effectiveness and Efficiency	▲		▲			▲
	System Reliability and Integrity	▲		▲	▲		▲
	Ensure Safety and Security of Systems, Information and Assets	▲	▲				
	Extract and Leverage Value from Existing Technology and Assets	▲					▲
People	Establish a Culture that Embraces "Ownership, Innovation and Continuous Improvement"	▲					
Safety	Reduce Injuries in the Workplace		▲				

Figure 4.2 Benefits alignment with PSE Integrated Strategic Plan

4.2. Integrated Project Strategy

The Advanced Distribution Management System (ADMS) aligns with several Integrated Strategic Plan (ISP) objectives of PSE. Deployed incrementally over time, there is a continuum of strategic objectives that will be addressed. The orange highlighted boxes in the following PSE ISP figure 4.1 are where the objectives and strategies which are most strongly influenced by ADMS deployment.

4.3. Project Strategy

As reflected in the preceding illustrations, the ADMS project strategy is to pursue an integrated platform for distribution system management and optimization. Due to the legacy environment that PSE has for distribution operations, migration to an ADMS is complex and requires specialized expertise to determine the best feasible implementation strategies.

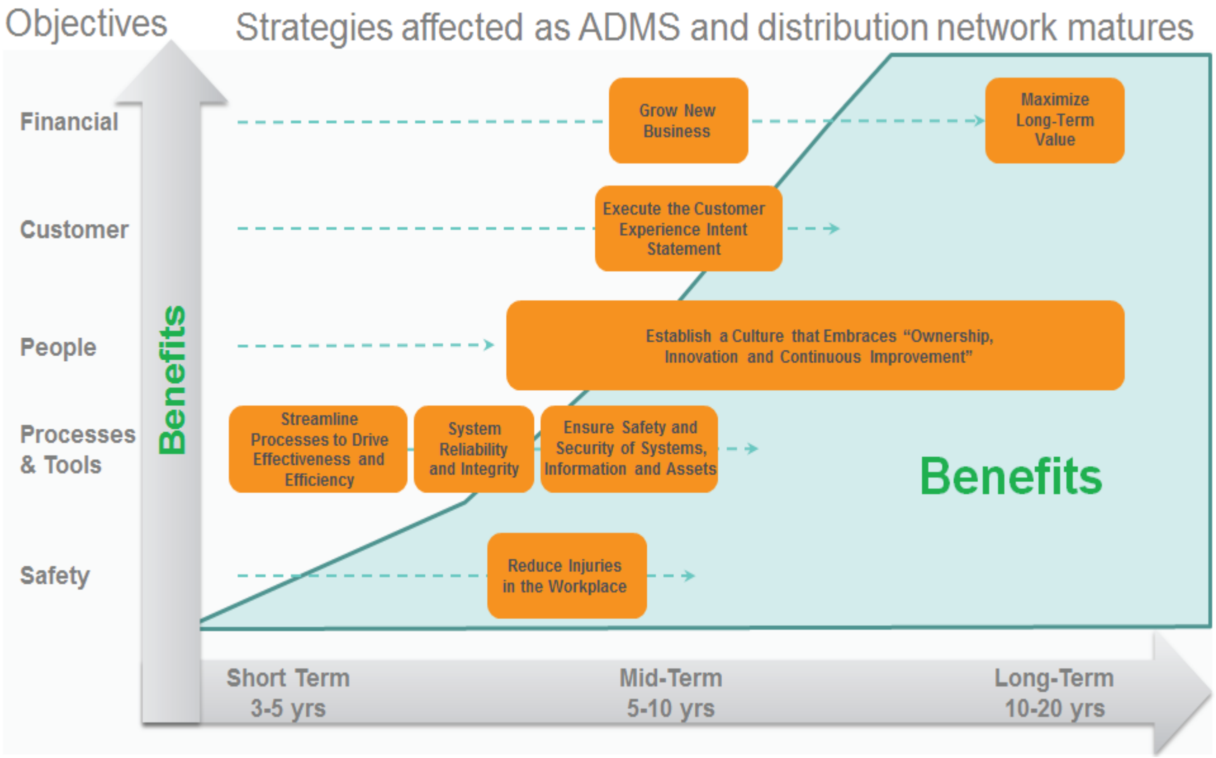


Figure 4.3 PSE Integrated Strategic Plan – ADMS strategy impacts over time

The prudent approach is for the ADMS solution to be implemented incrementally, starting with establishing a distribution model, aligning existing distribution SCADA points, replacing the legacy OMS, and implementing real-time load flow, state estimation, and operator training. PSE will then incrementally implement advanced capabilities including switching optimization, Volt/VAR optimization, situational awareness, self-healing, distributed energy resource integration, crew management integrated with IWM and outage management. The sequence and timing of further investment in load tap changers (LTC), voltage regulation and sensing equipment will be done based on careful analysis and prioritization of load demands on circuits and where the greatest benefits can be gained in the context of the total distribution system. Although not in the scope of the ADMS software implementation itself, a large part of the energy conservation potential brought by the platform, is dependent on incrementally upgrading substations and select feeders with intelligent LTC and regulators over time, so that the more advanced voltage optimization functions can be implemented and their benefits realized.

Figure 4.3 reflects how in the near term, ADMS will leverage existing infrastructure to optimize portions of the distribution network where the current technology can accommodate its functions and capabilities, as well as integrating the distribution DSCADA, existing advanced applications (both currently in EMS system), the OMS and the YFA systems. In the longer term, ADMS can have a material impact on system reliability with more robust condition-based maintenance, further optimization through Volt/VAR, new opportunities through the accommodation of emerging DER. Working as the nerve center of the PSE's Grid Modernization initiatives, the ADMS will ultimately enable the optimal customer experience through near-real-time access to demand (consumption), cost, and generation data.

Due to the integrative nature of this product, the project will also begin efforts in enhancing and developing new business procedures between different work teams and work areas.

5. Project Schedule

Below is a high-level schedule for the ADMS project and is subject to adjustment as the project team devises the detailed implementation plan. (Updated, August 2019)

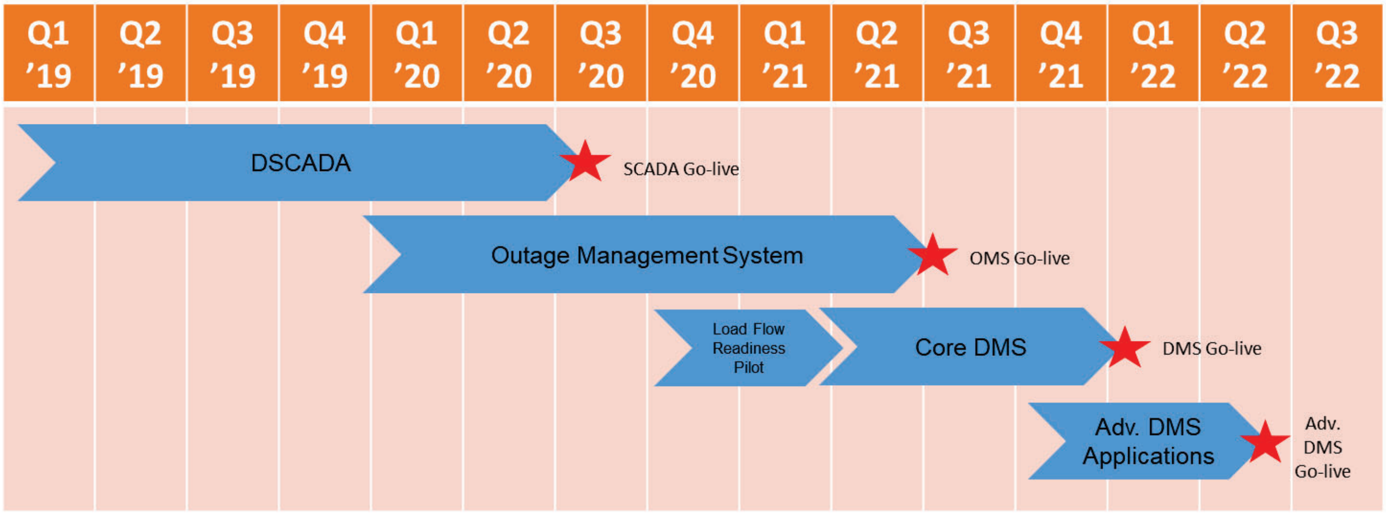


Figure 5.1 ADMS Project Schedule: 2019 – 2022

6. Project Costs

The primary ADMS project is estimated to be roughly $34.1M of O&M and Capex in the 2018-2022 five-year horizon, with potential further investments in more advanced Load Tap Changers at eligible substations and voltage regulators, sensing and controls equipment possible in the out years. The ADMS project costs include the integrated software platform for distribution system management, monitoring, control, analysis, and optimization. It also includes the cost of ADMS training, hardware costs, systems integration, procurement, implementation, and testing. As the ADMS is implemented, the OMS system costs will be absorbed within ADMS, as it will assume the functions of the OMS. Should the decision be made to enhance the ADMS with more new sensing and voltage adjustment equipment, additional infrastructure costs will be incurred over time. Benefits from the projects will begin as soon as the ADMS is in place and accumulate as multiple system functions, such as; OMS, D-SCADA, YFA are assimilated into the DMS. Also, some VVO benefits will be able to be realized as the overall Advanced Metering Infrastructure project progresses. Benefits due to the implementation of VVO are estimated conservatively.

Table 6.1 ADMS Project Costs

CAPEX Costs ADMS	NPV $ 2018-2037	Nominal $ 2018-2037
LABOR	$ 5,693,361	$ 6,958,484
OUTSIDE SEVICES	$ 16,784,700	$ 20,816,282
MATERIALS	$ 1,837,521	$ 1,980,722
HARDWARE	$ 984,760	$ 1,082,875
MISC	$ 9,096,001	$ 12,166,931
CONTINGENCY	$ 453,433	$ 575,439
Total Capex with Contingency	$34,849,776	$43,580,733

O&M Costs ADMS	NPV $ 2018-2037	Nominal $ 2018-2037
TOTAL PROJECT O&M	$545,651	$654,749
TOTAL O&M ONGOING + Uplift	$23,234,222	$52,286,245
Total O&M	$23,779,873	$52,940,993

Total ADMS Costs: Capex + O&M	NPV $ 2018-2037	Nominal $ 2018-2037
Total Capex	$31,432,088	$43,580,733
Total O&M	$22,063,345	$52,940,993
Total Costs	$53,495,433	$96,521,726

7. Project Benefits

The short-term benefits of implementing the Advanced Distribution Management System platform are difficult to quantify due to the complex interdependencies among many of the affected systems which will eventually consolidate into the ADMS. The real, quantifiable benefits come as the overall system, and smarter infrastructure becomes more and more mature. Advanced voltage profile improvement and Voltage optimization functions will begin to realize their true benefits as more voltage regulation, monitoring, and control infrastructure is inserted into the network to enable enhanced energy management and automated adjustments in the network to assure optimal voltage levels, and to achieve reduced energy losses, manage peak demand, and overall energy conservation. The non-quantified benefits are highlighted below in 7.2 and are not included in the benefits realization document. The more quantifiable benefits come with the future cost avoidance around voltage optimization and cost avoidance associated with not continuing the path of having multiple standalone and/or obsolete systems trying to achieve the objectives/functions of the ADMS by way of a further customized EMS, as well as the ever-increasing administrative burden driven by the need to integrate multiple systems instead of one.

7.1. Quantified Benefits –

The ADMS business case has identified several benefits that can be quantified. They are listed below and explained in more detail

- Cost avoidance by reducing software licensing, control points and ongoing maintenance on multiple systems through consolidation, including the avoided cost of replacing the OMS. Avoided FTE that would be required to operate and maintain multiple stand-alone systems is also included in this benefit.

- Volt-VAR optimization reducing energy and capacity cost
- Reduction in crew responses to single-customer false-positive outages
- Reduction in outages for all classes of customers by sectionalizing and restoring all but the faulted section(s)
- Improved operational efficiency through switching order management

Below are the quantifiable benefit range (low – high) of the ADMS project –

Table 7.1 ADMS Key Benefits

	Low ($NPV, 2018-2037)	Base ($NPV, 2018-2037)	High ($NPV, 2018-2037)
Volt VAR Optimization	$941,841	$2,092,981	$9,209,117
Cost Avoidance from System Consolidation	$34,879,621	$34,879,621	$34,879,621
Reduction of Crew Response to Single Outage False Positives	$2,728,323	$2,728,323	$5,456,646
Reduction of Outages in all customer classes	$836,030	$836,030	$1,672,060
Improved Operational Efficiency	$38,980	$155,919	$155,919
Total	**$39,424,725**	**$40,575,935**	**$51,373,363**

Category #1: Voltage Optimization (VO or VVO) Reducing Energy Cost

Although complex to estimate, the industry has demonstrated a range of value showing that with each 1% reduction in voltage, there is a corresponding 0.8 to 1.2% reduction in energy savings. ADMS will allow for additional savings beyond the reductions assumed for advanced voltage feedback control in the AMI business case. As the system and distribution infrastructure matures, the much more granular and advanced analytics gained by ADMS will enable it to identify more refined ranges for safe voltage reduction and will assure optimal power delivery customers. Using the model developed to analyze CVR benefit potential in the AMI business case, we have determined that a conservative estimate can yield an additional 0.5V+ reduction from Voltage optimization capability of ADMS. Multiple industry sources indicate a demonstrated range of expected energy saving from AMI/ADMS enabled, model-based Voltage Optimization to range from 3% to 6% depending on the level of maturity and penetration of voltage regulation and control devices at the substation and feeder lines.

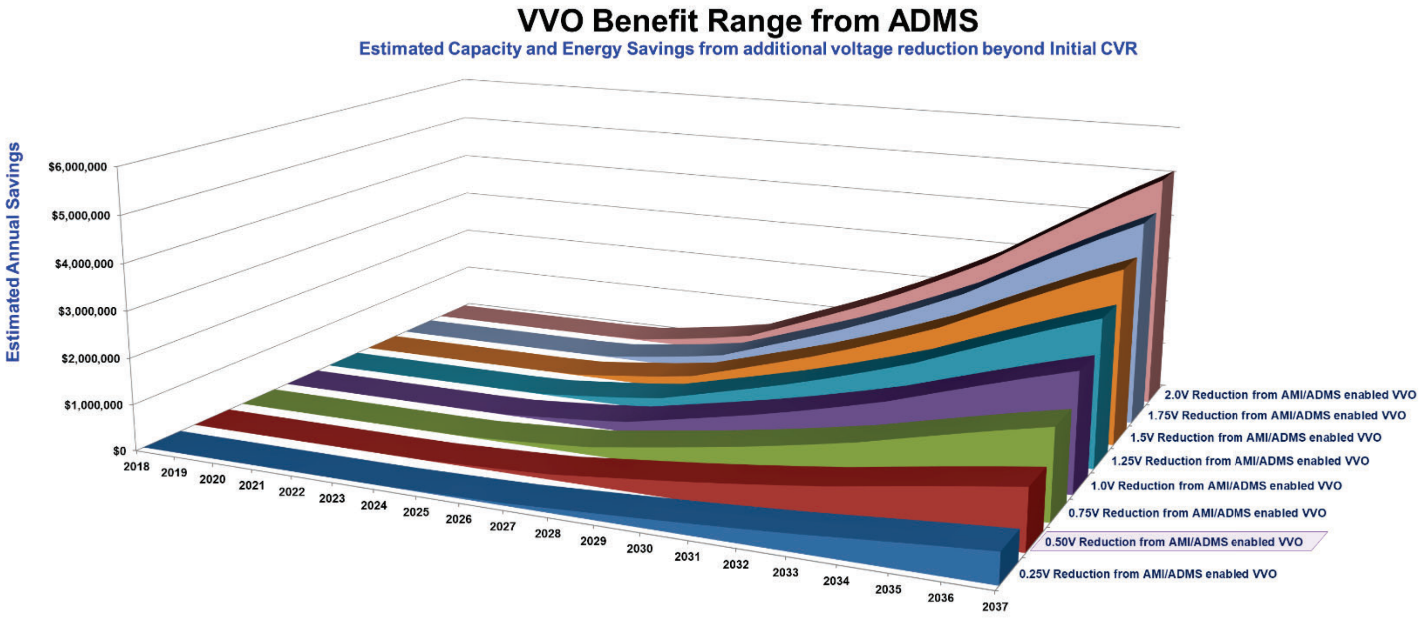


Figure 7.1 ADMS VVO Benefit range

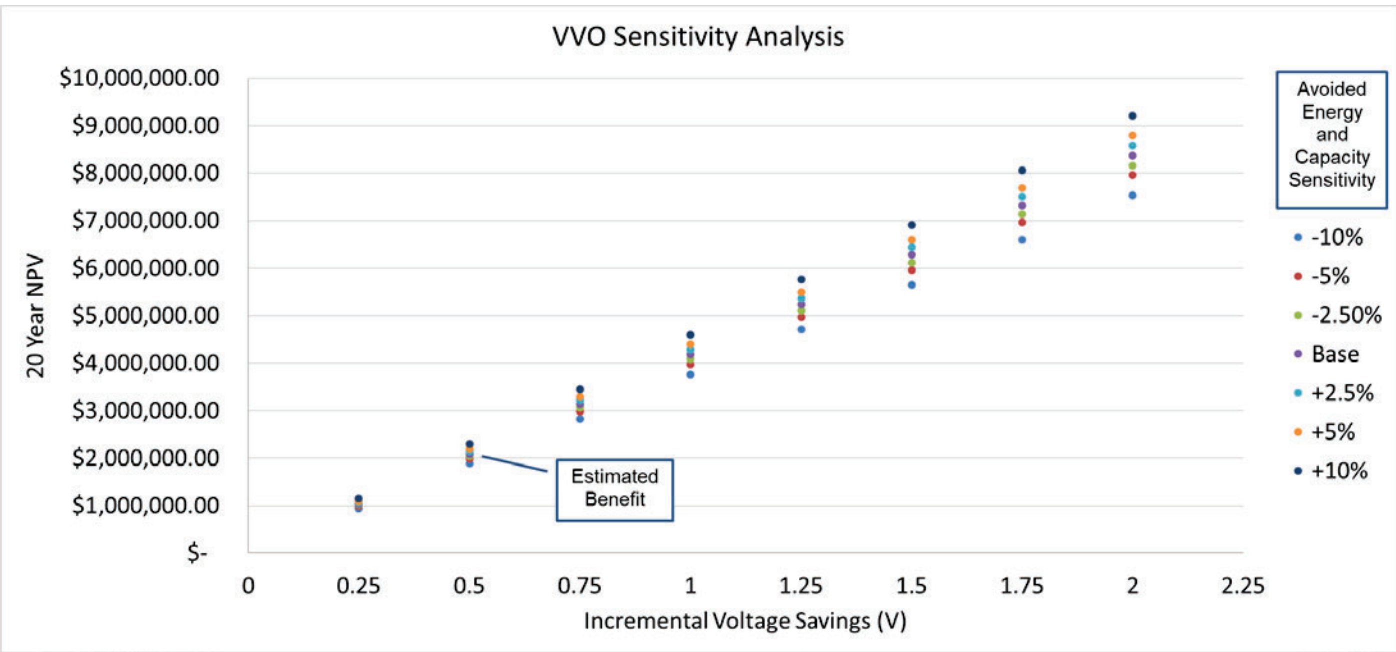


Figure 7.2 ADMS VVO Sensitivity Analysis

The estimated aggregate value of VO is roughly 2.7% for CVR, and an additional 0.2% energy savings from model-based VO enabled by the ADMS. However, this will be greatly influenced by future investment in distribution hardware. The maturity progression looks something like the image on the right. As the appropriate monitoring, measurement, analysis, communications, and control devices are inserted into the distribution grid over time, the value realized will increase.

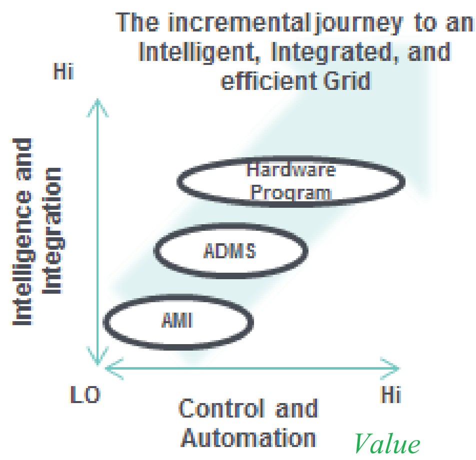


Figure 7.3 PSE Grid Modernization Journey

If PSE can reduce the average voltage at the substations by an additional incremental amount of 0.5 volts afforded from added ADMS dynamic capabilities around power flow analytics and control at the eligible substations, then we can realize a range of potential energy and capacity savings as shown in the below Figure 7.1. The chart illustrates how with every quarter volt reduction at the substation, we can expect an increasing amount of energy and capacity savings.

Avoided energy and capacity costs will also impact the value of this benefit. Figure 7.2 shows the sensitivity of this benefit across an incremental voltage reduction of 0.25-2.0V and changes in avoided energy and capacity costs +/-10%.

Category #2 - Cost Avoidance from system consolidation

PSE will realize cost avoidance by consolidating obsolete systems like OMS into a single advanced platform through ADMS, as well as consolidating other platforms like YFA, DMS, DERMS and others. A competitive environment demands that utilities continue to undertake cost-effective energy conservation actions (demanded by I-937). Advanced capabilities from the ADMS can allow PSE to drive continued reliability, efficiency and energy savings as the grid grows more complex.

One path is to maintain the status quo, but continue to devise new homegrown and/or stand-alone platforms to approximate the functionality of a fully integrated ADMS. With this option, PSE would also have to shoulder the increasing administrative burden of maintaining and integrating multiple systems, as well as replacement costs for the obsolete OMS.

Alternatively, PSE can avoid costs by integrating the functionality of interrelated systems into one system that will reduce complexity, provide a streamlined data configuration, and provide synergies afforded by a single system designed to integrate multiple bi-directional and dynamic data flows.

Assuming the avoidance of some of the systems' licensing, maintenance, and operational costs, it is estimated that PSE can realize a benefit of $34.9M (NPV) over 20 years.

As previously discussed in Section 3, there is a coherent connection between the potential benefits of implementing ADMS and the Objectives & Strategies of PSE. Figure 4.3 is a matrix illustrating where those benefits may align with the PSE integrated strategic plan. Although subjective, this goes to the foundational aspect of ADMS, which will enable all other Grid Modernization capabilities in the future.

Category #3: Reduce crew responses to single-customer false-positive outages

When a single customer on a blue sky day reports an outage, PSE will dispatch a first responder to validate the customer's report. The ADMS integrates data from several sources and can validate if the outages are on PSE's side of the meter or at the customer's premise. By doing so, PSE can reduce a portion of the single-customer blue sky outage that requires sending a first responder to the customer's premise. PSE operations staff can direct the customer to check if the breaker has tripped in the customer's panel or direct to the customer to call an electrician. The anticipated improvement is an initial reduction starting in 2023 of from 5-10%, which increases to between 10 -20% across the project's life

Category #4: Reduce outages for all classes of customers by sectionalizing and restoring all but the faulted section(s)

The ADMS in concert with distribution automation field devices such as sectionalizing switches and distance-to-fault relays can automatically restore some of the customer impacted by a fault. The processes are once a fault trips the feeder breaker the ADMS:

- Pinpoints the fault's location on the feeder
- Isolates the fault by opening the sectionalizing switches upstream of the fault (closer to the substation) and downstream (farther from the substation) of the fault
- Closes the feeder breaker thereby restoring those customers upstream of the faulted section
- Analyzes if those customers downstream of the faulted section can be supplied from another feeder.
- Calculates if the alternate supply can support those customers and if so closes a switch reconnecting that customer to the alternate supply

In this way, the scope of outages is reduced to those customers on the faulted section. PSE currently uses the YFA platform, which utilizes a rules-based approach to fault location, isolation and service restoration. The ADMS utilizes a model based approach which is significantly more flexible. The anticipated incremental benefit of the centralized model-based approach used by ADMS over the current rules-based approach used by YFA is 5-10%. Section 12.2 provide more information on types of FLISR implementation.

Category #5: Operational efficiency – Switching Order Management

The ADMS includes a switch-order application that automates the preparation and validation of switch orders for planned and unplanned work. The application simplifies the process of building switching steps, automating much of the process directly from the graphical model of the grid. Once the switching steps are completed, the ADMS will automatically analyze them to ensure the portion of the grid requiring isolation will be de-energized and grounded, making it safe for work to begin. The ADMS also identifies all the customers that will be without service. The ADMS both makes the work safer and alerts the operator before a switch error could cause an unplanned outage.

Also, once the Advanced Applications are implemented, switching takes the actual loading of the system into consideration instead of the static versions of this information. When implemented, the Advanced Applications can provide an automated switching scenario builder allowing the operator/dispatcher to build switching orders that are validated automatically. The net improvement anticipated is between .5% - 2.0% of unplanned outage costs and labor costs associated with errors beginning 2021 and continuing across the life of the project.

7.2. Non-Quantified Benefits

In addition to the quantified benefits identified in the previous section, the ADMS also provides for several benefits that are extremely relevant but not quantified. Some of them are listed below.

Table 7.2 ADMS Description of ADMS non-quantified benefits

Benefit Area	Benefit Description	Impact
Unbalanced Load Flow	• Currently, our system is limited to as-switched network state and only has connectivity and rated capacity information. Moving to the ADMS will allow for an "as operated" state of the network that leverages power flow,	• A single view of the distribution system leading to Improved situational awareness

Benefit Area	Benefit Description	Impact
	SCADA device locations, and tap changer positions. This will allow operators to have better switching abilities.	
Customer Satisfaction	• Shorter outages and more accurate information	• Customer perception of the quality of service and value received improves
Safety for the public, the workforce, and the assets	• Provides visibility and awareness of the whole distribution network to reduce the risk of accidental injury workers or to the public. • Protects the network assets from potentially damaging surges or sags in voltage or from short circuits. • More rapid and accurate switch order management to enable workers to address faults before potential injuries or damage is possible. • Better control room supervision to ensure lockouts and tags are effectively performed to ensure field safety.	• The safety of the workers and customers should be of paramount concern • Reduces inherent safety risks associated with many interfaces, bottlenecks and coordination handoffs between personnel and between multiple systems, by achieving increased awareness, visibility, velocity, simplification and control through the integrated ADMS system
	• Ensuring that voltage levels are within an acceptable range regardless of the load level and that DER safely integrated into the network.	• Customers not adversely affected by voltage variances, and assets are protected against voltage conditions out of the optimal range. Already doing this, but the ADMS should provide more advanced capability.
Dynamic usage of devices	• Smart grid devices such as capacitor banks and tap changers in VVO and reclosers and fault line indicators in FLISR can potentially be used dynamically with each other when considering solutions instead of completely independent from each other.	• Being able to better utilize the devices out in the field to its full capacity will allow us to reach the economic and functional potential of our devices better. • Devices about VVO, FLISR, and DERMS will no longer run on a static study basis or be triggered by a specific event. The operators/end users will have the ability to run studies and utilize these devices about the advanced ADMS technology on an as-needed basis.

Benefit Area	Benefit Description	Impact
Customer Satisfaction	• Customer satisfaction is a difficult metric to manage because it lags investment, has many factors beyond reliability such as cost and openness to customers ambitions to choose new opportunities to self-supply, develop microgrids, and to feed electricity back into the grid.	The ADMS provides a major step forward in enabling this future. Key ADMS aspects that deliver to increased customer satisfaction include • OMS module delivering improved understanding of the outages allowing field crews to prioritize their work. • FLISR module that allows PSE to move quickly to the self-healing grid by bringing power back on quickly to more people in an automated manner • Unbalanced load flow which provides a better situational awareness to the operator, thereby allowing them to manage the grid better.
Electricity always to be available and reliable – and as we move forward, "Green."	The move towards green (renewable) energy requires a system such as the ADMS to enable the grid to still function in a reliable and resilient manner. • Distributed energy • Electric transportation • Microgrids • Energy storage – utility or behind the meter	• An ADMS is central to provide both improved availability and reliability of electricity, and better information on the state of the grid.

8. Net Costs and Benefits

The potential net impact of adding ADMS as the foundation for future technology deployments to enable grid modernization on a 20yr NPV ranges from a low of ($18M) to a high of ($6M). The 20yr nominal totals range from a low of ($17.4M) to a high of $21.1M. The breadth of the range reflects conservativism at the low and possible upside based on improvements resulting from the number and depth of additional intelligent devices implemented at substations and selective feeders throughout the network.

	NPV 2018-2037	Nominal 2018-2037
Low	($14.1M)	($14.2M)
Base	($12.9M)	($10.3M)
High	($2.1M)	$24.2M

Figure 8.1 ADMS Net Costs and Benefits

9. Financials

Figure 9.1 shows the ADMS Net Benefits profile for both the low and high scenarios.

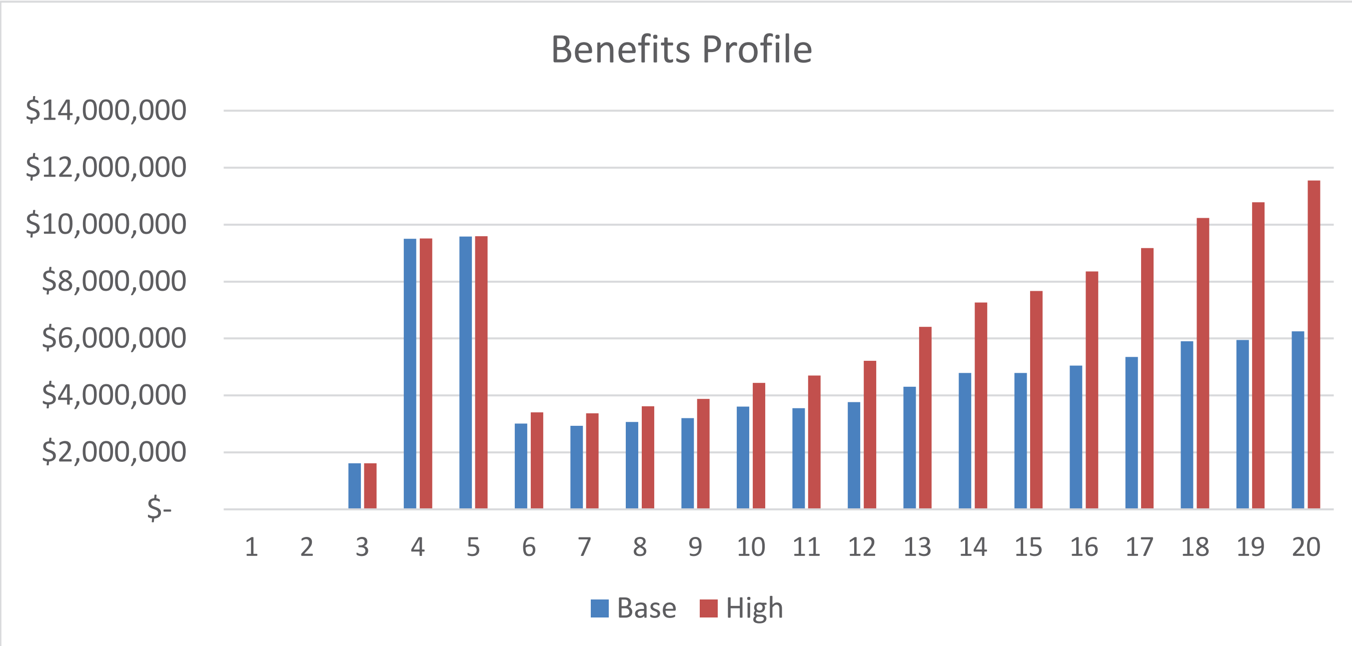
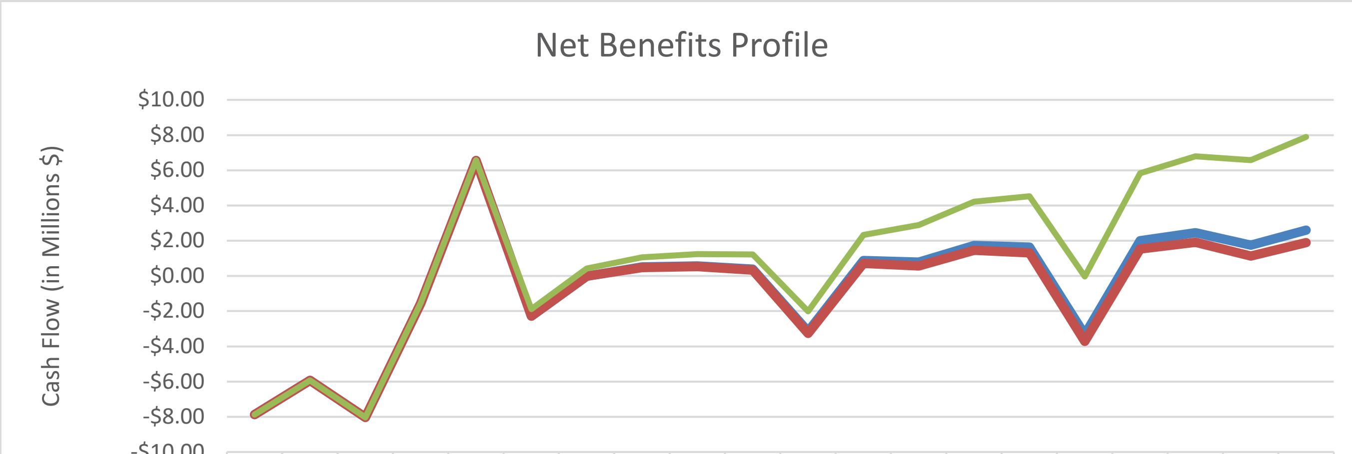


Figure 9.1 ADMS Benefits Profile

Figure 9.2 shows the cash-flow analysis for the same time period.



	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Base Benefits	-$7.8	-$5.9	-$8.0	-$1.5	$6.55	-$2.2	-$0.0	$0.51	$0.57	$0.39	-$3.1	$0.88	$0.78	$1.73	$1.64	-$3.3	$2.01	$2.46	$1.75	$2.59
Low Benefits	-$7.8	-$5.9	-$8.0	-$1.5	$6.55	-$2.2	-$0.0	$0.49	$0.53	$0.32	-$3.2	$0.72	$0.57	$1.46	$1.31	-$3.7	$1.54	$1.91	$1.12	$1.90
High Benefits	-$7.8	-$5.9	-$8.0	-$1.5	$6.57	-$1.8	$0.42	$1.05	$1.24	$1.22	-$2.0	$2.33	$2.89	$4.21	$4.52	-$0.0	$5.83	$6.79	$6.58	$7.89

Figure 9.2 ADMS Cash-Flow Analysis

10. ADMS Risks

The following tables, 10.1 and 10.2 contain tables representing the high-level project risks associated with implementing ADMS and with not implementing ADMS. As the project team is established, more detailed project risks and mitigations will be devised.

10.1. High-level ADMS deployment risks

Table 10.1 ADMS Deployment Risks

Risk Title *(List the high-level risk title)*	Risk Description *(List risks that could significantly impact funding and/or spend schedule)*	Mitigation Plan *(What are you doing to mitigate the risk? Are risk $s assigned?)*	Risk Date Horizon *(Date risk will no longer be a threat)*
1. Data Readiness *Impact = H* Probability = H	• The data model for GIS may be incomplete or have errors that prevent DMS functions from operating properly. Excessive cleanup could impact the schedule.	• In the pilot for advanced applications, focus on data for four feeders to understand the readiness and build a remediation plan. Bound the advanced application data work to a fixed dollar amount and go live with a limited but prioritized group of feeders in the ADMS	2021
2. Resource availability *Impact = M* *Probability = H*	• RFP activities are coinciding with data center activities and competing for same IT DMS resources	• Rely on IT architecture and BA for RFP support when IT ADMS team unavailable. ADMS manager is also looking for opportunities to make his team more available (e.g., pulling work earlier).	2021
3. Project Dependencies *Impact = M* Probability = M	• IWM, AMI has dependencies for integrating to legacy OMS that may result in throw-away interfaces.	• Closely monitor dates where Dev and QA environments are available for external systems to take advantage. Build interfaces to legacy OMS that can be partially reused in new OMS, limiting throw-away.	2020
4. ADMS vendor not being ready with the product for delivery *Impact = H* Probability = H	• Timely delivery of ADMS will be impacted resulted in increased costs and delayed benefits	• Work closely with the vendor to understand their constraints as well as impact to schedule (costs and benefits). Try to delay costs to synch up better with anticipated benefits • In parallel, speed up the GIS/model work to bring in some of the advanced applications such as power-flow to pull forward some of the benefits realizations.	

Risk Title *(List the high-level risk title)*	Risk Description *(List risks that could significantly impact funding and/or spend schedule)*	Mitigation Plan *(What are you doing to mitigate the risk? Are risk $s assigned?)*	Risk Date Horizon *(Date risk will no longer be a threat)*
5. Unknown integration issues *Impact = M* *Probability = H*	• Unknown systems integration issues that may arise, and drive schedule and cost to resolve.	• Proactively engage stakeholders to identify issues that would increase or decrease installation and deployment costs. • Identify cost savings opportunities such as work bundling and contracting strategy.	2021

10.2. Risk of not deploying ADMS

Table 10.2 Risks of Not Deploying ADMS

Title *(List the high-level risk title)*	Description *(List risks that could significantly impact funding and/or spend schedule)*	Mitigation Plan *(What are you doing to mitigate the risk? Are risk $s assigned?)*	Date Horizon *(Date risk will no longer be a threat)*
1. Software Obsolescence *Impact = H* *Probability = L*	• Delaying ADMS would result in PSE having to maintain obsolete systems at a premium cost with increased risk of failure between related stand-alone systems.	• Consolidate as many systems as possible into the ADMS to assure optimal integration, capability, and reliability. Also, to minimize complexity and escalating costs.	Forever, if not implemented
2. Diminished Competitive Advantage *Impact = H* *Probability = L*	• Delaying or failing to effectively execute and communicate the value of ADMS, which is a foundational component to assure the continued progress of the broader Smart Grid program, will diminish our competitive position	• Assure effective project management and program integration. • Assure effective communication mechanisms are in place to allow regulators and community stakeholders to understand how we are progressing in a way that aligns with both of their priorities and goals. • Ensure business case continues to stay relevant	Forever
3. Increasing complexity and administrative burden	• Failure to implement a core ADMS solution will result in increasing complexity of synchronizing data between	• Implementing core ADMS technology as soon as feasible, integrating systems	Forever, if not implemented

Title *(List the high-level risk title)*	Description *(List risks that could significantly impact funding and/or spend schedule)*	Mitigation Plan *(What are you doing to mitigate the risk? Are risk $s assigned?)*	Date Horizon *(Date risk will no longer be a threat)*
Impact = H *Probability = L*	multiple systems, which will create as increasing administrative burden as well as data maintenance issue.	with stakeholder involvement.	
4. EMS Constraints and increasing costs *Impact = H* *Probability = L*	• Reduced flexibility and ability to work with distribution points due to NERC requirements on an EMS. Distribution control points increased from 25% in 2014 to 44% of EMS in 2017. With the growing additional demand in EMS, the cost of NERC compliance increases.	• Transition as many distribution control points to ADMS, and make remaining Distribution control points in EMS read-only.	Forever, if not implemented
5. DER integration constrained if ADMS not deployed *Impact = M-H* *Probability = M-H*	• Less equipped for optimization of Distributed Energy Resource assets and growth having to share a platform with EMS.	• Ensure that all DERs are integrated properly with new ADMS system,	Forever, if not implemented
6. Not implementing ADMS may limit access to some distribution applications *Impact = L-M* *Probability = M*	• We'd have to deploy other distribution management software applications, and there is a strong possibility some applications don't exist as a standalone.	• Assure that all required modules/functions are included in ADMS deployment.	Forever, if not implemented

11.Conclusions

The ADMS is the foundation enabling the realization of broad synergies across multiple intelligent systems and devices. Further, the ADMS optimizes the collective technology portfolio, managing the electrical distribution network by supporting the monitoring, control, and analysis of distribution assets. Also, the ADMS provides decision support to aid the distribution operators, engineers, technicians, managers, and others in monitoring, controlling, optimizing performance, and protecting the electric distribution system, all without jeopardizing field workforce or public safety.

ADMS includes functions that further automate outage restoration and optimize the performance of the distribution grid. Deployment of ADMS at Puget Sound Energy will include enhanced fault location, isolation, and restoration; voltage optimization, i.e., voltage conservation through voltage reduction; peak demand management; enabling microgrids, electric vehicles, and distributed energy resources. Using these functions, the ADMS will support any of today's or future distributed energy resources, automation capabilities, power quality applications, as well as enabling operational security capabilities to support possible new NERC requirements, should these encroach beyond the traditional transmission domain and enter the distribution systems.

Distribution System Operations is one of the critical core functions of a utility because it drives a significant portion of customers' experience with the utility. This function entails having primary responsibility and authority for the reliable operation of the electric distribution system.

The ADMS will dramatically change PSE's operational effectiveness and become the primary tool of the future to enable the Distribution System Operator to manage their responsibilities. Its functionality will support monitoring and operating the grid, clearance coordination, switching order creation, and emergency and storm management.

- The future of ADMS points toward enhanced capabilities including increased automation, integration with AMI, edge devices, Internet of Things, and other modern grid technologies. If a utility has not deployed an ADMS or is not currently in the process of implementation, they run the risk of falling farther behind the rest of their peers in this transformed, highly demanding, and competitive market.
- The future of ADMS is to incorporate Distribution Automation, DA, components into its core product. Similar to the way SCADA is widely distributed within the grid today because of the efficiency it provides to the operators, DA components will provide even more in the way of automating the monitoring and control of field devices. This automation gives the operators an enhanced ability to pinpoint outage locations, restore customers, and reduce unplanned outage duration than what is possible without DA components.

As utilities integrate more technology to their ADMS, they begin making progress towards broad grid modernization. Field devices and end-of-line voltage sensing through AMI will monitor events on the grid and provide feedback to operators and engineers in real-time. In contrast to today's capabilities, operators will know when and precisely where an outage occurred before customers can call.

The ADMS aligns with several Integrated Strategic Plan objectives of PSE. Deployed incrementally over time, there is a continuum of strategic objectives addressed. The ADMS project strategy is to pursue an integrated platform for distribution system management and optimization. The ADMS solution will be implemented incrementally, starting with establishing a distribution model, aligning existing distribution SCADA points, replacing the legacy OMS, and implementing real-time load flow, state estimation, and operator training. PSE will then incrementally implement advanced capabilities including switching optimization, Volt/VAR optimization, situational awareness, self-healing, distributed energy resource integration, crew management integrated with IWM and outage management.

Delays caused by the ADMS vendor triggered this revision to the business case. The vendor had announced earlier this year about an approximately one-year delay in their product release which has also impacted how PSE is planning the release of ADMS functionality to production.

The shift in the schedule delays benefit realization. The cost avoidance benefits are also delayed, again aligning with the new schedule. With the revised schedule and further experience, PSE has identified additional benefits to the ADMS implementation. The following are areas where additional benefits lie:

- Significant customer saving from reduced outage scope and duration based on ICE calculation
- Reduction in false-positives outages and a corresponding reduction in truck-rolls
- Operational efficiency resulting from fewer switching errors resulting in less rework and unplanned outages.

The business case supports the investment in the ADMS based on the overall benefits. The benefits show greater than a 80-million-dollar gain in the pessimistic analysis, which rises to nearly 120 million in the optimistic analysis.

It must be noted that implementing a DMS involves a lot of work that goes into planning, building, and testing the new application. The implementation must also focus on GIS data quality, which is a key enabler.

12.Appendix A: Other Advanced Applications and modules

12.1. Volt-VAR Optimization

Volt-VAR Optimization (VVO) is a process that is intended to achieve efficient grid operation by reducing system losses, peak demand, and energy consumption. VVO uses power regulation equipment like load tap changers (on the transformer) and capacitor banks to improve the power quality, minimize losses and conserve energy. This process is a more sophisticated and extensive process than Conservation Voltage Reduction but relies on similar principles. ADMS will leverage AMI data at the end of the line, with its analytics and control intelligence to dynamically optimize power delivery within the distribution network, minimize losses and conserve energy.

On average, customer usage is lowered, leading to overall saving customers money on their bill. Generation resources are freed up by VVO, driving down power acquisition costs for the customer and potentially reducing carbon footprints. Power quality is actively monitored and managed, ensuring good power quality for customers.

The utility itself benefits by increasing efficiency, reducing losses, reduce our carbon footprint, and can more readily meet our customer's power quality and capacity needs. With the current demand and production, a 1-2% increase in efficiency can quickly add up, reducing annual costs.

12.2. FLISR

Fault Location Isolation and Service Restoration (FLISR) is a combination of field devices (fault locators) and sometimes supported by centrally located software that provides self-healing capabilities to key feeders in the system.

The FLISR application on the ADMS platform is more flexible than PSE's current DA implementation. Over the last few years, PSE has implemented FLISR as a part of its DA program in the field. PSE had procured and implemented a software platform known as YFA (Yukon Feeder Automation) to provide self-healing capabilities.

Terms such as FLISR are used for both applications that are distributed or centralized. For the sake of clarity, this document divides them into three main types. This section will attempt to define and explain them better.

- Distributed: In this option, utilities install devices in the field which monitor fault currents on specific feeders (where they are installed), and when a fault is detected, then it acts by opening and closing certain switches based on the settings built into the scheme.

  While they are aware of the switch statuses before acting on them, the settings are pre-defined and are generally not operated once the feeder is in a non-normal state.

- Centralized but rules-based: This mechanism is implemented at some utilities where the fault locators send their information to the central location. A good example of this is the YFA implementation at PSE. PSE has installed YFA devices in the field which monitor fault currents on specific feeders (where they are installed).

  At the central location, there is a rules-based engine which takes the fault information and through a series of rules, identifying the switches that need to be opened or closed to achieve the new end-state.

  This approach provided for greater flexibility to the utility in its ability to support a few off-nominal scenarios.

- Centralized and model-based: This approach is considered the most flexible and sustainable. The fault information comes into the ADMS, which through a Power Flow analysis identifies the location of the fault and then opens and closes the appropriate switches to restore as many of the customers as possible.

  This approach is considered to be the most flexible because it allows the FLISR process to continue operation under different switching configurations.

12.3. DERMS

As DERs get more and more prevalent, PSE will need to add tasks which allow it to (1) monitor and visualize DERs, and their interactions with the distribution grid (2) control the DERs and (3) dispatch them. To perform these tasks, the PSE operator/dispatcher will need a system that allows them to perform the tasks identified above. The system of record that is being developed by vendors to perform the tasks is called DERMS or Distributed Energy Resource Management System.

DERMS systems are still somewhat early in their stage of maturity, and so their exact capabilities vary from vendor to vendor. Also, the long-term outlook for this system is somewhat unknown – whether it will persist as an independent system integrated with the ADMS or will get fully subsumed into the ADMS as another module/application. Conventional wisdom says that the latter option may prevail.

PSE plans to implement Schneider's DERMS in the future.

13.Appendix B: Glossary & Acronyms

Term	Definition
AMI	Advanced Metering Infrastructure: Meter reading system with enhanced capabilities that include two-way communication and command and control capabilities.
CVR	Conservation Voltage Reduction: The act of reducing the voltage on a circuit to induce less power consumption by end-users. AMI meters are used to measure the voltage levels on the line to ensure that minimum levels are maintained.
DA	Distribution Automation: Real-time remote monitoring and control of distribution system assets. It also provides decision support tools and, in some cases, automated decision making to improve system performance. DA covers automation at the substation, feeder, and customer level. Key components of a typical DA system include distributed field sensors; remote-controlled switches such as feeder switches, reclosers, or capacitor switches; the SCADA system; a communication system for remote data acquisition; and a suite of advanced DMS applications as decision support systems.
DER	Distributed Energy Resource: Energy source such as a generator, battery, or controllable load located on the distribution system.
ADMS	Advanced Distribution Management System: A collection of applications designed to monitor and control the distribution network efficiently and reliably. These can include advanced functions such as distribution automation, power quality control, and DER management.
D-SCADA	Distribution Supervisory Control and Data Acquisition: Monitoring and control application for real-time operation of the grid
EMS	Energy Management System
FLISR	Fault Location, Isolation and Supply Restoration: A collection of tools used for detection, location, and isolation of faults and restoration of supply for de-energized customers
GIS	Geospatial Information System: A system designed to capture, store, manipulate, analyze, manage, and present spatial or geographic data about our electric and gas infrastructure.
IT	Information Technology: Systems used for data-centric computing such as back-office information systems that are used for conducting business-type transactions
OT	Operational Technology: Systems such as SCADA, two-way communication, and ADMS used to monitor events, processes, and devices and make adjustments.

Term	Definition
O&M	Operating and Maintenance
OMS	Outage Management System: PSE's control system for managing system outages and switching/clearances.
RTU	Remote Terminal Unit: An RTU is an electronic device that is controlled by a microprocessor. The device interfaces with physical objects to a Distributed Control System (DCS) or Supervisory Control and Data Acquisition (SCADA) system by transmitting telemetry data to the system
SaaS	Software as a Service: An acquisition model where software is licensed on a subscription basis and is centrally hosted by a third party.
SAIFI	System Average Interruption Frequency Index
SOM	Switch Order Management
VAR	Volt-Amps Reactive (Reactive Power)
VVO	Volt-VAR Optimization
YFA	Yukon Feeder Automation: A Fault Location, Isolation & Supply Restoration application.

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WILDFIRE MITIGATION

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

The Wildfire mitigation plan is a reliability and safety initiative to prevent wildfire ignition and reduce ignition risks associated with electricity delivery. It is already an element of our grid modernization efforts to enhance reliability, resiliency and safety. We are continuing that approach and wildfire is another layer with which we enhance those plans. Wildfire risks are used to help prioritize work in other reliability and resiliency efforts.

2. BACKGROUND

Historically, large wildfires have occurred predominantly in Eastern Washington and have impacted our neighboring utilities at a much higher rate than within PSE service territory. This scenario has changed in recent years due, in part, to the potential effects of climate change, past forest management practices, as well as the continued growth of population centers within the Wildland-Urban-Interface areas.

Between 1990 and 2010, populations classified as Wildland-Urban-Interface have expanded by 41%. These communities are at the highest risk for wildfire damage and some of these communities have limited egress paths to facilitate evacuation.

Wildfire risk drivers have traditionally been addressed by multiple reliability plans across the company. In 2018, following the catastrophic California fires, a Wildfire Task Force was convened in response to a growing need for coordinated and targeted wildfire efforts.

3. STATEMENT OF NEED

This plan targets the identification of fire risks, the reduction of outages that could also lead to ignition in fire-prone areas, improved situational awareness and increased communication with the public and agency partners.

PSE's electrical system consists of 23,000 miles of distribution and 2100 miles of transmission. Of this, only 55 miles of distribution and 38 miles of transmission transverse areas identified as high, or very high burn potential. Wildfire burn potential is an index that depicts the relative potential for wildfire that would be difficult for suppression resources to contain, based on wildfire simulation modeling by the USDA Forest Service, Fire Modeling Institute (current revision: 2020)[1]. This is a small percentage of the total system, however, wildfires can have severe consequences if they are able to spread uncontrolled. PSE prioritizes safety concerns and this plan will continue to improve public safety by reducing these risks.

[1] https://usfs.maps.arcgis.com/home/item.html?id=55226e8547f84aae8965210a9801c357

Initial efforts utilized publicly available datasets for weather, fire risk, populations and egress. These datasets are relatively static assessments and subject to the assumptions and criteria of external agencies which do not necessarily align with those of an electric utility.

3.1. Need Drivers

- **Grid Modernization –**
  - **Safety** – Wildfires endanger lives through fire and smoke, spreading quickly and causing massive damage. The electrical system serves as a possible ignition source and can also sustain damage which has the potential to block first responder access and community egress.
  - **Resiliency** – Modernizing PSE's aging infrastructure will harden and protect the system from failures and create operational flexibility that increases system availability. The resiliency efforts are focused on high-impact, low-frequency events, such as wildfires.
  - **Reliability** – System outages, predominantly vegetation-based, can ignite the surrounding brush. Therefore preventing outages is directly tied to reducing ignition risks. Some wildfire activities may have negative Reliability aspects as safety and ignition prevention supersedes immediate restoration. These small negatives expect to be less than reliability improvements associated with system hardening.
  - **Smart & Flexible** – The need for enhanced situational awareness to inform system operators of real-time field conditions allows for operational decisions to prevent PSE from energizing equipment into fault conditions in wildfire-prone areas.

3.2. Integrated Strategic Plan (ISP) Alignment

This plan aligns primarily with the Safety and the Processes & Tools categories of the ISP:

- **System Reliability and Integrity**: System outages and wildfires are interconnected. By reducing outages we reduce electrical discharges that can trigger ignition.
- **Enhance customer preparedness and safety:** Hardening activities decrease risk for customers and employees.

4. PLAN DETAIL

4.1. Plan Size/Population

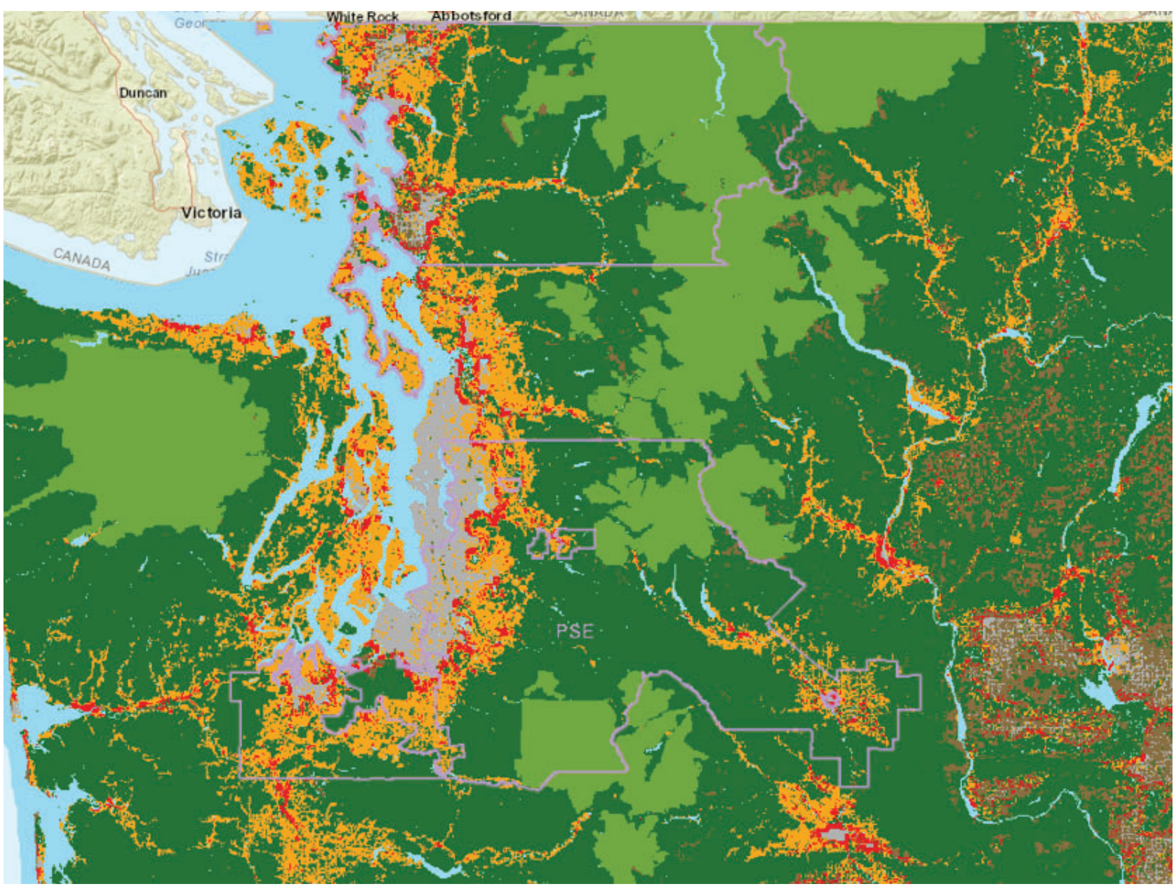
The proposal is to replace the high risk wires in both the very high and high burn potential areas. This amounts to 55 miles of small conductors being replaced with a current standard conductor. In the very high burn potential areas this wire and an additional 2 miles of medium-risk wire should be evaluated as to the benefit of insulated conductor or other low-risk conductor options.

Additionally 71 standard fuses and 139 overhead transformers are proposed to be replaced with low-arc, low-exhaust expulsion-type fuses and FR3-filled transformers. The fuses do not coordinate downstream, so additional fuses outside the very high risk areas may require change-out as well.

The initial focus is on the top ~20 Priority Circuits plus other specific areas of concern as identified by the Wildfire Risk analysis. This analysis undergoes constant feedback and updates as new information is incorporated into the risk assessments. A detailed assessment of wildfire risks and possible mitigation projects will be developed and optimized through use of IDOT. The lower-risk circuits will be monitored and evaluated for targeted risk reductions.

	Count per Burn Potential		
	Very High	High	Moderate
# Distribution poles	397	997	10175
# Transmission structures	74	145	914
# OH transformers	139	267	4108
# Padmount transformers	382	508	4522
# Fuses	71	177	2416
# Regulators	0	2	28
# Reclosers	1	6	34
# OH Capacitors	0	1	18
Low-risk wires (miles)	15.392	41.957	499.307
Medium-risk wires (miles)	1.946	6.905	44.265
High-risk wires (miles)	11.087	43.740	340.791

Figure 1: PSE Service Terrritory and Wildland Urban Interface



Enhanced Inspection and Assessment: Improved frequency and comparison considering cross country corridors which may limit truck travel. Currently exploring infrared and enhanced equipment inspection with future plans to explore drone-mounted LiDAR and Infrared. LiDAR can show vegetation grow-in and clearances between the energized line and nearby trees. Drone-based inspections will be cheaper and more frequent than currently performed and will be able to determine specific areas for vegetation treatment. PSE is also working on contracts with a satellite visualization company to provide vegetation analysis on satellite imagery to identify dying trees off right-of-way.

Aging infrastructure: By assessing wildfire risks associated with failing equipment and identifying old and obsolete equipment and structures, mitigation projects including line rebuilding and updating may be part of the mitigation solutions moving forward.

Improved Detection and Isolation: New technology for the detection and clearing of high-impedance faults, falling conductors, ground faults is under development. This plan proposes to explore and test this technology and incorporate this equipment into Grid Modernization with the goal of preventing wildfire ignition. The exact implementation is difficult to predict, however the 108 circuits within Fire Impact Areas is proposed as the target for this implementation with specific focus on the top ~20 Priority Circuits.

Situational Awareness Enhancements: One key benefit is through real-time situational Awareness through operator dashboards utilizing public risk and weather datasets. System Operators are able to use these dashboards to trigger operational decisions such as non-reclose operation of distribution circuits, staging first-response personnel, and required visual inspection during restoration efforts. These actions will significantly reduce the risk of ignition.

Future improvements involve improved risk and fire-spread modelling and localized weather stations along with digital data collection of spatial and condition assessments.

Enhanced Vegetation Management: This plan proposes to implement an enhanced vegetation management plan within the Fire Impact Areas. This would include expanding vegetation clearances, review of vegetation clearing frequency, enhanced visual and drone inspections, and an expanded off-right-of-way danger tree removal plan.

System Hardening: Targeted System Hardening by replacing aging and standard-built infrastructure with newer and upgraded equipment to prevent outages and ignition events. This may include insulator replacement and bonding, covered conductors, targeted undergrounding, spacers, splices, and conductor spacing.

Construction and Materials: This plan proposes to develop enhanced construction standards for Fire Impact Areas and implement replacing standard equipment based on a robust risk assessment. This can include low-expulsion fuses, service transformers filled with less flammable oils, and non-wood poles and cross-arms. Boric-acid expulsion-type fuses creates low arcing voltage and mild exhaust during fault interruption. FR3-filled transformers have a much higher smoke and flash point compared to standard mineral oil units and are less likely to lead to ignition. Fiberglass cross-arms provide additional insulating layers and prevent insulator tracking to the pole.

PSE is exploring falling line sensors, fast tripping mechanisms, and advanced fault detection schemes along with existing Distribution Automation that analyzes and segments line faults without reclosing into them.

Access and Evacuation Routes: Downed transmission conductors across roadways could block access for fire-fighting crews and impede evacuation efforts. This plan proposes to assess all roadway crossings in Fire Impact Areas and mitigate the risks as needed. Currently PSE has identified 650 transmission road crossings in scope of this plan.

4.2. Proposed Completion Date

The System Hardening efforts to be completed in Fire Impact Areas by 2026 includes oil-filled transformer replacement, fuse replacement, high-risk conductor replacement, and egress route protections.

Enhanced vegetation maintenance in Fire Impact Areas is an ongoing process as long as overhead conductors are employed. The proposal is to take a targeted approach to assess the effectiveness of existing vegetation management practices through inspections and performance measurement, along with dedicated removal of off- RoW danger trees.

Ongoing Research and Development efforts in relaying and protection to detect and mitigate high-impedance ground faults and fallen conductors.

Ongoing additional hardening prioritized based on annual risk assessments and coordination with reliability priorities.

4.3. Summary of Plan Benefits

PSE's primary benefit of the wildfire mitigation efforts is to reduce the likelihood and impact of large, destructive fires for customers and communities in PSE's service territory. This benefit is achieved by the specific wildfire plans discussed in this business case, but also by numerous existing plans. The wildfire risk scores associated with PSE circuits are used to provide relative risk levels in order to prioritize and justify system work that carries wildfire benefit.

Table 1, from the Wildfire Mitigation Plan provides a summary of how this plan and other PSE business plans contribute to the broader wildfire mitigation focus. The total investment across all plans towards wildfire areas is $129.5 million.

Table 1. Summary of wildfire mitigation contribution from all PSE business plans

Business Plan	Wildfire Impact			$ Millions	Relevant Investments
	High	Medium	Low		
Copper Conductor Replacement	X			$1.26	4.2 miles in wildfire impact zones
Distribution Automation		X		$33.25	Prevent reclosing into faults
Circuit Enablement - DERs and Migrogrids			X	$11.9	Enablement for microgrid to lessen impact of wildfire outages
Circuit Enablement - EV			X	$1.34	Prevent overloading the circuit due to EV use
Poles Inspection and Remediation	X			$20.37	Identify failing poles and inspect pole-mounted equipment
Underground Conversions		X		$3.23	Directly remove exposure and ignition source
Reclosers			X	$5.58	DA enablement, SCADA control for sectionalizing
Root Cause Analysis			X	$0.096	Framework for tracking and learning from failures
Resilience Enhancement			X	$0.216	Equipment drone inspection, radial feeder microgrid enablement to lessen impact
Targeted Reliability		X		$12.6	Capacity upgrades, tree-wire, UG Conversion, reliability improvements
Substation SCADA			X	$2.25	SCADA control for sectionalizing and DA enablement
Transmission Automation		X		$6.1	Prevent reclosing into faults
Worst Performing Circuits	X			$18.3	6 priority wildfire circuits, and 14 other wildfire circuits are WPC, direct reliability improvements
Wildfire Mitigation	X			$13	Fuse, Transformer, crossarms replacement, fast tripping, rebuilds

4.4. PRIMARY iDOT CATEGORIES

The primary iDOT Categories related to this plan are:

- Outage Concern
- Health & Safety
- Environmental
- Stakeholder Perception

Table 1: Summary of Plan Benefits, Population and iDOT B/C Score per Year

2022-2026	Budget ($M)[2]		NPV ($M)[3]	iDOT B/C Score[4]
	Capital	OMRC	Total Benefits	
Total	**13**	**0.5**	**229.9**	**21.23**

4.5. Estimated Total Costs

Over the 5 years, from 2022-2026, the Wildfire plan will cost approximately $13 million (Capital). OMRC Costs are estimated at 3% of the Capital cost. As the trial projects determine the efficacy of alternate materials, the scope and cost of the plan is subject to change.

Estimated costs are generated based off of historical costs on similar types of projects, allowing for variations in project scope, increase in project cost due to inflation, and added contingency to account for unforeseen conditions associated with the project.

Example, but not limited to, historical to support this business plan include:

Tree wire feeder - $650,000/mile
Tree wire lateral - $590,000/mile
UG Feeder Conversion $1.5M - $3M/mile

5. ALTERNATIVES

5.1. Solution alternatives

No Action – With no enhanced plan in place, PSE would only be able perform mitigation under existing plans. This alternative would not mitigate wildfire risk in the moderate, high and very high wildfire risk areas. Response to wildfires would continue on a reactive basis only versus the proposed proactive measures identified in this plan.

5.2. Funding alternatives

Increase Funding from Proposed – With increased annual funding, the goals and benefits of the plan could be achieved more quickly, reducing risk on the moderate, high and very

[2] Budget indicate are sum of future year budget as it is allocated for that specific year
[3] Benefits indicated are Net Present Value (NPV) sum of future year benefits allocated for that specific year
[4] B/C Score uses NPV of Benefits and Budget

high circuits more quickly than 2026. This would result in achieving the overall plan benefits sooner.

Decrease Funding from Proposed – With decreased annual funding less system hardening would be completed with the corresponding slow-down and decrease in risk abatement for wildfire circuits, Thus the moderate, high and very high wildfire risk circuits would not be addressed by 2026, leaving those in a reactive state for longer than recommended.

6. PLAN DOCUMENT HISTORY

The current version of the project summary supersedes all previous versions.

Date of Project Summary Revision	Reason(s) for Update	Summary of Significant Change(s)	Modified By
May 7, 2021	Business Case format update	Collection and distilling of wildfire program recommendations.	Josh Pelman
July 7, 2021	Used and Useful Policy guidance	Add alternatives and cost information	Josh Pelman
12/1/2021	Annual Review	Minor word and format changes	Josh Pelman

7. SUPPORTING DOCUMENTATION

Document Name
2021 WILDFIRE MITIGATION AND RESPONSE PLAN

8. APPENDIX – WILDFIRE RISK LINES (* PRIORITY CIRCUITS)

DISTRIBUTION CIRCUITS			
	Overbuild	Risk Weight	% of Risk
*CAS-16		4.07	4.64%
*CLE-11	TRUE	3.95	4.51%
*CLE-12		3.93	4.48%
*WOD-15	TRUE	3.6	4.11%
*ETN-15	TRUE	3.39	3.87%
*CLE-13	TRUE	3.22	3.67%
*KIT-26		3.04	3.47%
*THO-13		2.94	3.35%
*ETN-13	TRUE	2.69	3.07%
*GRI-16	TRUE	2.65	3.02%
*KIT-25		2.56	2.92%
*SPG-13	TRUE	2.48	2.83%
*BLU-16	TRUE	2.47	2.82%
*PRI-13	TRUE	2.45	2.79%
*CAS-15	TRUE	2.44	2.78%
*THO-04	TRUE	2.29	2.61%
*GRI-13	TRUE	2.29	2.61%
*ELD-25	TRUE	2.23	2.54%
*FRG-25	TRUE	2	2.28%
GRI-15	TRUE	1.97	2.25%
BLU-13	TRUE	1.86	2.12%
CLR-16		1.82	2.08%
PRI-23	TRUE	1.77	2.02%
ELD-23	TRUE	1.64	1.87%
AIR-22		1.54	1.76%
GWR-16		1.43	1.63%
ELD-27	TRUE	1.29	1.47%
PAT-15	TRUE	1.23	1.40%
PLG-13	TRUE	1.06	1.21%
MOT-14		1	1.14%
RAI-11	TRUE	0.95	1.08%
FRG-24		0.87	0.99%
AIR-23		0.76	0.87%
PLG-17	TRUE	0.74	0.84%

FRG-22	TRUE	0.7	0.80%
BLU-17	TRUE	0.62	0.71%
SPG-14	TRUE	0.57	0.65%
BAR-13		0.51	0.58%
MCA-15	TRUE	0.49	0.56%
MKI-17	TRUE	0.45	0.51%
PAT-17	TRUE	0.43	0.49%
WOL-25	TRUE	0.43	0.49%
WOD-13	TRUE	0.42	0.48%
SWI-17	TRUE	0.41	0.47%
CHA-15	TRUE	0.41	0.47%
CHA-13	TRUE	0.4	0.46%
ROC-16	TRUE	0.4	0.46%
FRG-23	TRUE	0.36	0.41%
THO-25		0.33	0.38%
AIR-26		0.32	0.36%
KIT-22	TRUE	0.29	0.33%
LAC-17	TRUE	0.29	0.33%
MCA-16	TRUE	0.25	0.29%
OBY-17	TRUE	0.23	0.26%
DEC-13		0.22	0.25%
PLG-16	TRUE	0.2	0.23%
PRI-24	TRUE	0.2	0.23%
PAT-13	TRUE	0.2	0.23%
MOT-15	TRUE	0.2	0.23%
RAI-14	TRUE	0.19	0.22%
BAR-15		0.18	0.21%
PAT-16	TRUE	0.18	0.21%
MKI-14	TRUE	0.17	0.19%
MKI-15	TRUE	0.16	0.18%
SPG-11	TRUE	0.16	0.18%
CLE-14		0.15	0.17%
CHA-16	TRUE	0.15	0.17%
TAN-16	TRUE	0.15	0.17%
CAS-14		0.15	0.17%
SWI-15	TRUE	0.13	0.15%
CLR-15	TRUE	0.13	0.15%
TAN-15	TRUE	0.12	0.14%
CAP-13	TRUE	0.12	0.14%
MKI-16	TRUE	0.12	0.14%

SWI-13	TRUE	0.12	0.14%
WOL-23	TRUE	0.12	0.14%
CHA-12	TRUE	0.11	0.13%
AIR-25		0.11	0.13%
SKY-25	TRUE	0.11	0.13%
WDH-11		0.08	0.09%
MCA-13	TRUE	0.08	0.09%
BAR-16		0.07	0.08%
DEC-17		0.06	0.07%
HAW-11		0.06	0.07%
PLG-15	TRUE	0.05	0.06%
SWI-21	TRUE	0.05	0.06%
RAI-12	TRUE	0.04	0.05%
TAN-13	TRUE	0.04	0.05%
MOT-17	TRUE	0.04	0.05%
JHO-12		0.04	0.05%
HAW-14		0.03	0.03%
SWI-16	TRUE	0.03	0.03%
HAW-12	TRUE	0.03	0.03%
GWR-13	TRUE	0.03	0.03%
ELD-26	TRUE	0.02	0.02%
OBY-16	TRUE	0.02	0.02%
BPE-39		0.02	0.02%
MOT-16	TRUE	0.02	0.02%
SKY-23	TRUE	0.02	0.02%
WOL-22	TRUE	0.01	0.01%
PRI-22	TRUE	0.01	0.01%
JHO-15	TRUE	0.01	0.01%
LAC-13	TRUE	0.01	0.01%
CUM-15	TRUE	0.01	0.01%
WLK-15	TRUE	0.01	0.01%
BRS-24		0.01	0.01%
BAR-17		0	0.00%
CLA-13		0	0.00%

Transmission Lines		
Name	**Risk Weight**	**% of Risk**
ROCKY REACH - CASCADE	9.172128	28.2%

CASCADE - WHITE RIVER	5.587016	17.2%
CLE ELUM - KITTITAS	3.688816	11.4%
CLE ELUM - HYAK	3.621966	11.2%
WANAPUM - WIND RIDGE 230kV	2.121642	6.5%
GREENWATER TAP	1.171125	3.6%
BLUMAER - SAINT CLAIR	0.899892	2.8%
BLUMAER - YELM	0.602156	1.9%
SCHNEBLY - POISON SPRING	0.570699	1.8%
TONO - PRINE	0.551074	1.7%
TWIN FALLS - HYAK	0.548665	1.7%
OLYMPIA - SAINT CLAIR #1	0.421101	1.3%
SUMMIT - SKYKOMISH	0.397788	1.2%
SAINT CLAIR - PLEASANT GLADE	0.366993	1.1%
WIND RIDGE - KITTITAS 115kV	0.348169	1.1%
OLYMPIA - AIRPORT	0.334519	1.0%
OLYMPIA - WEST OLYMPIA #2	0.264961	0.8%
BPA OLYMPIA - OLYMPIA #1	0.208449	0.6%
BPA OLYMPIA - OLYMPIA #2	0.200242	0.6%
TWIN FALLS TAP	0.188177	0.6%
OLYMPIA - SAINT CLAIR #2	0.171922	0.5%
SAINT CLAIR - GRAVELLY LAKE #2	0.154564	0.5%
SKYKOMISH - BEVERLY PARK	0.110841	0.3%
CASCADE - CLE ELUM	0.109098	0.3%
ROCHESTER - BLUMAER TIE	0.088015	0.3%
OLYMPIA - PLUM STREET	0.084719	0.3%
PLUM STREET - PLEASANT GLADE	0.069185	0.2%
PLEASANT GLADE TAP	0.064382	0.2%
TONO - OLYMPIA	0.062867	0.2%
TONO - BLUMAER	0.060695	0.2%
OLYMPIA - WEST OLYMPIA #1	0.049753	0.2%
CLE ELUM - CASCADE	0.044452	0.1%
SAINT CLAIR - GRAVELLY LAKE #1	0.040292	0.1%
OLYMPIA - PRINE	0.039527	0.1%
WIND RIDGE - KITTITAS	0.03309	0.1%
ELECTRON HEIGHTS - STEVENSON	0.018738	0.1%
CEDAR FALLS - SNOQUALMIE (SCL)	0.007949	0.0%

WORST PERFORMING CIRCUITS

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

The Worst Performing Circuits (WPC) plan addresses 135 circuits that historically had poor reliability performance year after year with high customer minutes interruptions (CMI) and high circuit SAIDI and SAIFI. PSE embarked on a multi-year effort to make targeted investments to improve the performance of these circuits.

Different reliability strategies are applied to the WPC circuits, including tree wire, underground conversions, overhead rebuilds and adding new feeder ties until the circuit improves by 50%. Distribution automation solutions implemented on WPC circuits are included in the Distribution Automation - FLISR business plan.

2. BACKGROUND

Prior to 2017, PSE had annually identified the 50 worst “area of concern” distribution circuits as those that had contributed the most customer minute interruptions to PSE’s “all-in” companywide annual Customer Minute Interruptions (CMI) performance based on a five-year average ranking. Realizing that a more holistic approach was needed to improve customer’s reliability, starting in 2017, PSE refined the definition of a worst performing circuit. The 135 circuits on the WPC list either meet the pre-2017 “area of concern” circuit criteria or the new criteria that was established in 2017.

In 2017, PSE reviewed circuits with high non-major event day (non-MED) CMI, non-MED SAIDI, and non-MED SAIFI to ensure the view of the worst performing circuits was holistic. Through that process, PSE identified high priority circuits that had more than 3 million CMI over three years, circuits with more than 750,000 CMI for at least two out of three years, circuits with SAIDI greater than 300 minutes (five hours) and circuits with SAIFI of two or more interruptions in two of three years as well[1].

The 135 circuits on the WPC list either meet the pre-2017 “area concern” circuit criteria or the new criteria that was established in 2017. See Table 1 below for a summary of the WPC triggers.

Table 1: Summary of triggers for reliability studies – non-MED

METRIC	STUDY TRIGGER
Circuit 3 year CMI	3,000,000 CMI over 3 years
Circuit Annual CMI	CMI > 750,000 for 2 out of 3 years
Circuit Annual SAIDI	SAIDI > 300 minutes for 2 out of 3 years
Circuit SAIFI	SAIFI > 2 for 2 out of 3 years

[1] Analysis based on 2013-2015 non-MED results and does not include transmission related outages or distribution circuits with less than 50 customers

While the WPC plan targets the worst performing circuits defined in 2017 by the reliability metric thresholds, PSE will also continue to target individual customers or smaller pockets experiencing a lower level of reliability on circuits outside of the WPC plan. PSE will continue to evaluate, explore and adopt new strategies to improve the reliability of the system.

3. STATEMENT OF NEED

Some PSE customers have experienced poor reliability performance year after year. Specifically the WPC customers experience high CMI and/or high circuit SAIDI and SAIFI. Despite reliability projects built in past years to improve the customer experience, only modest improvements of performance have been achieved.

3.1. Need Drivers

- **Grid Modernization**
  - **Reliability** – The main driver for the WPC plan is to improve reliability for those customers that continue to experience the worst performance each year.

3.2. Integrated Strategic Plan (ISP) Alignment

This plan aligns primarily with the Processes & Tools category of the ISP:

- **System Reliability and Integrity:** The main driver for this plan is to reduce the duration and frequency of outages and improve the customer experience. The improvements to reliability support operational excellence and customer satisfaction.
- **Streamline processes to drive effectiveness and efficiency** – This plan drives effectiveness and efficiencies by addressing multiple benefit streams within the same scope of work. For example, Tree Wire and Underground Conversion Projects address more than reliability. These projects may also help with improving data quality/information, capacity, aging infrastructure, DER integration and safety.
- **Extract and leverage value from existing technology and assets** – When appropriate, each reliability project scope will utilize existing equipment to optimize the costs to attain the plan's goal and benefits.

4. PLAN DETAIL

4.1. Plan Size/Population

The WPC plan targets 135 circuits defined in 2017. The list of circuits can be found in Section 9: Appendix of this document.

4.2. Proposed Completion Date

The first year of the WPC plan was 2017. The intent of the WPC plan targeting 135 circuits is to improve the reliability metric that put the circuit on the list by 50%, which is expected to be reached by 2024 based on recommended funding levels.

As noted in the Short Description, the distribution automation solutions are being implemented on WPC circuits. The reliability benefits of these distribution automation schemes are counted as part of the distribution automation plan but will be considered as solutions to the reliability improvements required by the WPC plan.

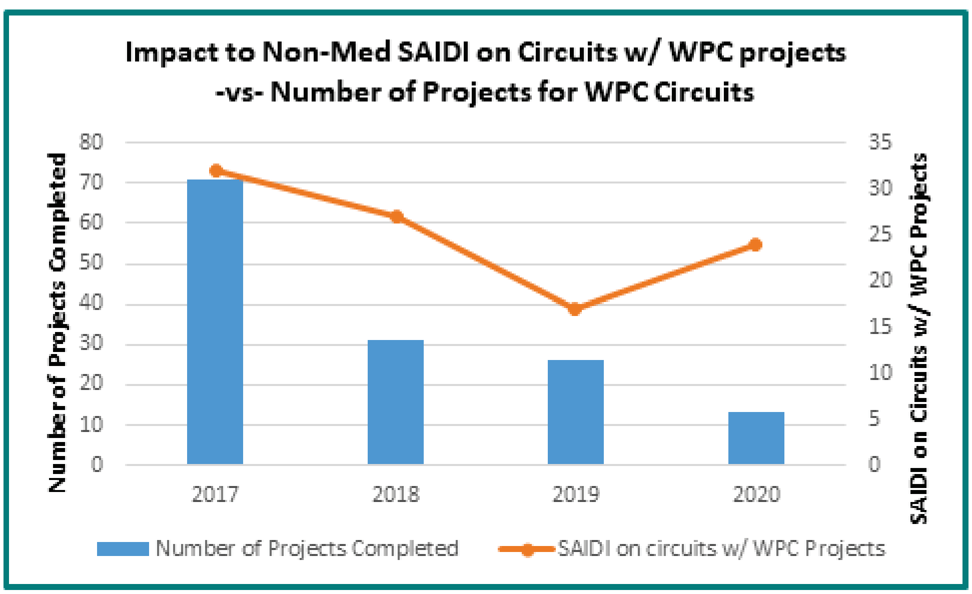
4.3. Summary of Plan Benefits

As stated earlier, the WPC plan aims to improve reliability for those customers that continue to experience the worst performance each year. This plan will reduce the reliability metrics, such as customer minute interruptions (CMI), customer interruptions (CI), number of outages, improving the customer experience. This will result in an improved performance in the two reliability SQI metrics, SAIDI and SAIFI.

In 2019, the performance for the first two years of the WPC plan was reviewed. For the 64 circuits for which work was completed, circuit SAIDI performance trended positive, with improvements on over 66 percent[1] of the circuits. Reliability performance has been evaluated for the 2017-2020 WPC projects. Figure 1 below compares the impact the 2017-2020 WPC projects made to the Non-Med SAIDI for those circuits with WPC projects. This accounts for 58% of the 135 WPC circuits. Between 2018 and 2020, the 135 Worst Performing Circuits with projects saw an average of nine-minute SAIDI reduction from 2017.

There are also some secondary benefits of the WPC plan. With the reduced number of outages experienced after the WPC projects are complete, there is anticipated to be less call outs for 1st and 2nd response crews. As well, some of the WPC projects permanently solve vegetation management issues.

Figure 1: SAIDI Results and Projects Completed on WPC



[1] PSE 2018 WPC Summary Report + 2019 and 2020 Actuals

4.4 Primary iDOT Categories

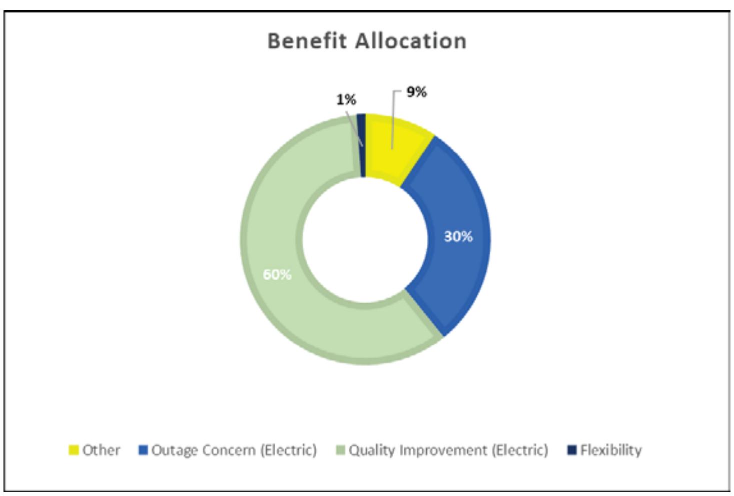
- Outage Concern - Preventing or reducing the number of future outages and outage duration experienced by customers.
- Energy Quality - Addressing specific customer inquiries regarding the customer's history of outage duration, outage frequency or power quality issues.
- Flexibility - Improving the flexibility to utilize the grid, either for immediate use or creating an opportunity for a future project.

Table 2: Summary of Plan Benefits, Population and iDOT B/C Score

2021-2024	Non-MED CMI Saved (M)	Number of Locations	Budget ($M)[2]		NPV ($M)[3]	iDOT B/C Score[4]
			Capital	OMRC	Total Benefits	
Total	**12.9**	**87**	**123.5**	**3.7**	**204.4**	**1.78**

**Assumes diminishing reliability benefit each year, per $1M (20% reduction in 2021, 30% in 2022, 40% in 2023, and 50% in 2024)*

Figure 2: Total Benefit Allocation[5]



[2] Budget indicate are sum of future year budget as it is allocated for that specific year
[3] Benefits indicated are Net Present Value (NPV) sum of future year benefits allocated for that specific year
[4] B/C Score uses NPV of Benefits and Budget
[5] Risk of not achieving budget and expected benefits is 4%

4.5 Estimated Costs

For Electric System Planning estimated costs are generated based off of historical costs on similar types of projects, allows for variations in project scope, increase in project cost due to inflation, and added contingency to account for unforeseen conditions associated with the project.

Total estimated cost are based on average historical cost which include the following:

Tree wire feeder - $650,000/mile
Tree wire lateral - $590,000/mile
UG Feeder Conversion $1.5M - $3M/mile
Reclosers - $75,000/per unit

Over the remaining 4 years, from 2021-2024, the WPC program will save a total of ~13 million non-MED CMI and cost approximately $123 million (Capital). OMRC Costs are estimated at 3% of the Capital cost.

5. FUNDING ALTERNATIVES

5.1. Solution alternatives

The risk of not pursuing a more aggressive approach is that existing plans alone will fail to adequately improve system performance enough to make any noticeable change in reliability indices. With the development of each individual project within the plan, alternative solutions are considered. These solutions can include both maintenance options and a variety of different capital construction options. Typical alternatives considered are: enhanced vegetation management, bird/animal guards, tree wire, underground conversion, feeder ties, fuse savers, reclosers, and distribution automation. The solution that provides the highest cost benefit ratio is submitted as part of the plan.

No Action - By not funding this targeted group of worst performing circuits, this will impact PSE's ability to meet the reliability SQIs. There will be lost opportunity to restore power to a variety of feeder and lateral outages. There is also risk of customer dissatisfaction in areas experiencing frequent outages that could be reasonably addressed by this plan.

5.2. Funding alternatives

Increased Funding - With increased funding, benefits of reducing sustained outages could be achieved in earlier years.

Decreased Funding - Decreased funding would result in fewer circuits seeing overall circuit improvement in a relatively short period of time. There is also potential risk of customer dissatisfaction in areas experiencing frequent outages that could be reasonably addressed by this plan.

6. PLAN DOCUMENT HISTORY

The current version of the project summary supersedes all previous versions.

Date of Project Summary Revision	Reason(s) for Update	Summary of Significant Change(s)	Created/Modified By
10/25/2019	Initial plan - New plan template	Initial document– Summarize historical plans	Karen Pavletich
4/21/2020	First Revision	Update iDOT Benefits and updated Program Plan Dollars and Metrics	Karen Pavletich
7/9/2021	Update with current information and Used and Useful Policy guidance	Update iDOT Benefits and updated Program Plan Dollars and Metrics. Add alternative and cost information	Karen Pavletich
12/1/2021	Annual Review	Minor word and format changes	Karen Pavletich

7. SUPPORTING DOCUMENTATION

Document Name
2018 Worst Performing Circuit Report
2017 and 2018 Reliability Plan

APPENDIX – 135 WORST PERFORMING CIRCUITS

Electric Reliability Plan Worst Performing Circuits	
1	Airport-23
2	Alger-12
3	Alger-15
4	Avondale-15
5	Baker River Sw-24
6	Belmore-26
7	Big Rock-15
8	Birch Bay-15
9	Black Diamond-13
10	Blaine-12
11	Blaine-13
12	Blumaer-16
13	Blumaer-17
14	Burrows Bay-13
15	Central Kitsap-14
16	Chambers-13
17	Chambers-15
18	Chico-12
19	Christensens Corner-22
20	Christensens Corner-23
21	Christopher-22
22	Cle Elum-11
23	Cottage Brook-13
24	Cottage Brook-15
25	Dieringer-15
26	Duvall-12
27	Duvall-15
28	Easton-13
29	Eld Inlet-25
30	Eld Inlet-27
31	Evergreen-13
32	Fall City-15
33	Fernwood-16
34	Fernwood-17
35	Four Corners-14

36	Fragaria-12
37	Fragaria-13
38	Fragaria-15
39	Fragaria-16
40	Freeland-12
41	Freeland-13
42	Freeland-15
43	Friendly Grove-24
44	Gardella-16
45	Goodes Corner-15
46	Gravelly Lake-15
47	Greenbank-13
48	Greenwater-13
49	Greenwater-16
50	Griffin-13
51	Griffin-16
52	Hamilton-15
53	Happy Valley-16
54	Hickox-16
55	Hobart-15
56	Hobart-16
57	Hyak-13
58	Inglewood-13
59	Inglewood-15
60	Kendall-12
61	Kenmore-23
62	Kenmore-26
63	Kingston-24
64	Knoble-11
65	Lake Leota-13
66	Lake Louise-17
67	Lake Meridian-15
68	Lake Tapps-17
69	Lake Tapps-18
70	Lake Wilderness-14
71	Langley-12
72	Langley-15
73	Langley-16
74	Lea Hill-17
75	Long Lake-21
76	Long Lake-23

77	Longmire-17
78	Longmire-25
79	Luhr Beach-14
80	Manchester-15
81	Marine View-13
82	Marine View-17
83	McAllister Springs-15
84	Mckinley-17
85	Miller Bay-17
86	Miller Bay-22
87	Miller Bay-23
88	Mottman-14
89	Norlum-15
90	Nugents Corner-26
91	Orchard-13
92	Orting-22
93	Patterson-15
94	Pickering-21
95	Point Roberts-14
96	Point Roberts-16
97	Port Gamble-12
98	Port Gamble-13
99	Port Gamble-16
100	Port Madison-12
101	Poulsbo-13
102	Poulsbo-15
103	Prine-13
104	Rainier View-13
105	Semiahmoo-13
106	Sequoia-16
107	Serwold-13
108	Sheridan-16
109	Sherwood-18
110	Silverdale-13
111	Silverdale-15
112	Silverdale-16
113	Sinclair Inlet-25
114	Skykomish-23
115	Skykomish-25
116	Slater-16
117	Snoqualmie-13
118	Snoqualmie-17

119	Soos Creek-25
120	South Keyport-22
121	South Mercer-12
122	Southwick-15
123	Summit Park-21
124	Tolt-15
125	Vashon-12
126	Vashon-13
127	Vashon-23
128	Wayne-15
129	West Olympia-23
130	Wilson-16
131	Winslow-12
132	Winslow-13
133	Winslow-15
134	Woburn-23
135	Yelm-27

TARGETED RELIABILITY

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

The Targeted Reliability Upgrades plan (formally Reliability Roadmap) supports distribution electric reliability needs that have been evaluated using project benefits and achieve positive benefit-cost ratios. This plan includes Overhead (OH) or Underground (UG) Rebuilds, Tree Wire Upgrades, UG Conversion, Feeder Ties, root cause analysis (RCA) identified improvements, mobile distributed generators to minimize planned outages and otherreliability improvements.

2. BACKGROUND

In 2017, PSE reviewed circuits with high non-major event day (non-MED) CMI, non-MED SAIDI, and non-MED SAIFI to ensure the view of the Worst Performing Circuits (WPC) was holistic. Through that process, PSE identified high priority circuits that had more than 3 million CMI over three years, circuits with more than 750,000 CMI for at least two out of three years, circuits with SAIDI greater than 300 minutes (five hours) and circuits with SAIFI of two or more interruptions in two of three years as well[1].

The 135 circuits on the WPC list either meet the pre-2017 "area concern" circuit criteria or the new criteria that was established in 2017. See Table 1 below for a summary of the WPC triggers.

Table 1: Summary of triggers for reliability studies – non-MED

METRIC	STUDY TRIGGER
Circuit 3 year CMI	3,000,000 CMI over 3 years
Circuit Annual CMI	CMI > 750,000 for 2 out of 3 years
Circuit Annual SAIDI	SAIDI > 300 minutes for 2 out of 3 years
Circuit SAIFI	SAIFI > 2 for 2 out of 3 years

While the WPC Plan targets the 135 worst performing circuits defined in 2017, outside of the WPC plan PSE also targets needs on the other 965 circuits outside of the 135 WPC defined in 2017. These needs are reliability and operational flexibility.

In past years, the Reliability Roadmap Plan included reclosers/gang operated switches, Trip Savers and Copper Replacement. These types of projects now have their own business plan.

The Reliability Roadmap plan also included capacity projects such as OH/UG upgrades, new feeders, new lateral ties and new feeder ties for N-1 flexibility.

[1] Analysis based on 2013-2015 non-MED results and does not include transmission related outages or distribution circuits with less than 50 customers

3. STATEMENT OF NEED

PSE planners identify system needs by screening reliability performance and getting input from the RCA process, Customer Complaints and Operations/Regional Engineering to target the needs of the of 965 circuits outside of the WPC plan. The scope of this plan are:

- Feeders or laterals experiencing a lower level of reliability resulting in customer complaints.
- Individual customers or smaller pockets of customers experiencing a lower level of reliability.
- Operational flexibility to better support customers during planned work and outages.

Examples of operational flexibility are distribution feeder ties, distribution lateral ties, SCADA and adding another phase.[2]

To screen potential reliability projects PSE Reliability Planners:[3]

- Performs Root Cause Analysis on all outages over 500,000 minutes and identify reliability needs.
- Reviews customer complaints and input from PSE Operations and Regional Engineers and identify reliability needs.
- Perform annual review of the 5 year average reliability circuit performance to identify risks.
- Performs 5 year average reliability circuit reviews for "at risk" circuits which include those targeted RCA, Customer Complaint and Operations/Regional Engineering Recommendations.

3.1. NEED DRIVERS

- **Grid Modernization –**
  - **Reliability** – This plan aims to improve reliability for those customers that experience poor performance.
  - **Resiliency –** System Upgrades can improve the ability of the electric system to withstand and recover from a major disruption, such as storm events, natural disasters, deliberate attacks, or accidents.
  - **Smart & Flexible** – System Upgrades support operational flexibility to allow for integration of Distributed Automation and other Grid Modernization plans.
  - **Safety** – System Upgrades improve reliability by upgrading aging or exposed equipment that can be considered a safety risk.

3.2. INTEGRATED STRATEGIC PLAN (ISP) ALIGNMENT

This plan aligns primarily with the Processes & Tools category of the ISP:

[2] PSE Distribution Planning Guidelines 2020 – Chapter 7 Capacity Planning: 7.3.3.1 Feeder Assessment

[3] PSE Distribution Planning Guidelines 2020 – Chapter 9 Reliability and Resiliency Planning: 9.2 Reliability Study Thresholds

- **System Reliability and Integrity:** The main drivers for this plan are to reduce the duration and frequency of outages, provide operational flexibility and overall improve the customer experience. The improvement to reliability supports operational excellence and customer satisfaction.
- **Streamline processes to drive effectiveness and efficiency** – This plan drives effectiveness and efficiencies by addressing multiple benefit streams within the same scope of work. For example, Feeder Ties, OH/UG Rebuilds, Tree Wire Upgrades and Underground Conversion Projects address more than just reliability needs. These projects may also help with improving data quality/information, aging infrastructure, DER integration and safety.
- **Extract and leverage value from existing technology and assets** – When appropriate, each reliability project scope will utilize existing equipment to optimize the costs to attain the plan's goal and benefits.

4. PLAN DETAIL

4.1. Plan Size/Population

There is not a finite population of circuits to target. Instead, this plan addresses emerging reliability needs across PSE's entire population of ~1100 distribution circuits outside of the 135 Worst Performing Circuits.

4.2. Proposed Completion Date

This plan is on-going and addresses emerging system needs. It is expected this plan will go on indefinitely to account for the continual changes with system performance, physical plant and customer needs which will account for PSE's highest distribution reliability system needs outside of the Worst Performing Circuits.

4.3. Summary of Plan Benefits

PSE's highest distribution reliability needs outside of the WPC plan will be targeted with this plan. As the benefits for the WPC plan are diminishing as it approaches its completion year of 2024, the Targeted Reliability Upgrades Plan will provide consistent average benefits. The reliability benefits align to and are being calculated based on the PSE plan pool benefits of "reliability overhead, underground and tree wire projects"[4].

4.4. Primary iDOT Categories

The primary iDOT Categories related to this plan are:

- Outage Concern: Preventing or reducing the number of future outages and outage duration experienced by customers.
- Energy Quality: Addressing specific customer inquiries regarding the customer's history of outage duration, outage frequency or power quality issues.

[4] http://team/sites/Reliability/Distribution%20Planning/Documents/ERP/Project%20Tracking.xlsx?csf=1&e=AYYF6W

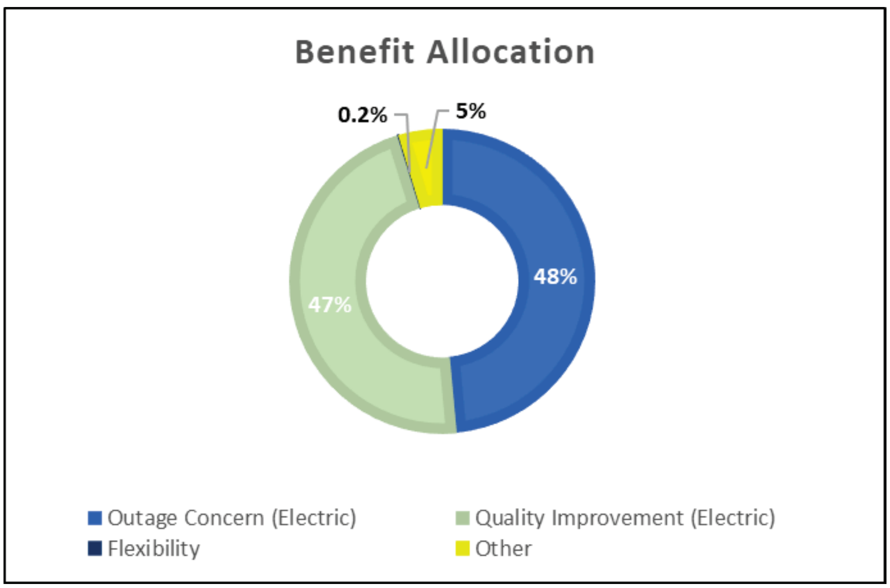
- Platform for Success – Flexibility: Improving the flexibility to utilize the grid, either for immediate use or creating an opportunity for a future project.

Table 2: Summary of Plan Benefits and Population

2022-2026	Non-MED CMI Saved (M)	Number of Locations	Budget ($M)[5]		NPV ($M)[6]	iDOT B/C Score[7]
			Capital	OMRC	Total Benefits	
Total	**34.1**	**480**	**284.2**	**8.5**	**1127.8**	**4.93**

- Plan Dollars =based on May 2021 Five Year Budget Plan
- B/C Score, NPVs and % OMRC based on 2020 Reliability Roadmap
- MED CMI and Customers Impacted based on OH/UG reliability/Treewire plan pool

Figure 1: Cumulative Annual Benefit [8]



4.5. Estimated Total Costs

For Electric System Planning estimated costs are generated based off of historical costs on similar types of projects, allows for variations in project scope, increase in project cost due to

[5] Budget indicate are sum of future year budget as it is allocated for that specific year
[6] Benefits indicated are Net Present Value (NPV) sum of future year benefits allocated for that specific year
[7] B/C Score uses NPV of Benefits and Budget
[8] Risk of not achieving budget and expected benefits is 16%

inflation, and added contingency to account for unforeseen conditions associated with the project.

Costs will vary widely and some circuits may need more improvements than others due to variability of the type of improvements needed. For example, a specific project might require treewire reconductor, pole replacements, adding reclosers and partial underground conversion to name a few.

Plan Years	# of Circuits	Capital Cost ($M)
Actual 2018 to 2021	90	67.1
Estimated 2022 to 2026	446	284.2

5. ALTERNATIVES

5.1. Solution alternatives

The risk of not pursuing a more aggressive approach is that existing plans alone will fail to adequately improve system performance enough to make any noticeable impact to the targeted customer's quality of service. With the development of each individual project within the plan, alternative solutions are considered. These solutions can include both maintenance options and a variety of different capital construction options. Typical alternatives considered are: enhanced vegetation management, bird/animal guards, tree wire, underground conversion, feeder ties, fuse savers, reclosers, and distribution automation. The solution that provides the highest cost benefit ratio is submitted as part of the plan.

5.2. No Action

There is also risk of customer dissatisfaction in areas experiencing frequent outages that could be reasonably addressed by this plan. There is also the lost opportunity to restore power to a variety of feeder and lateral outages. This also includes customers impacted by certain types of planned outages related to construction. **FUNDING ALTERNATIVES**

Increased Funding from proposed - With increased funding, the triggers for identifying customer's reliability could be expanded to accommodate the needs of more customers.

Decreased Funding from proposed - Decreased funding would result in fewer circuits seeing overall circuit improvement in a relatively short period of time. There is also potential risk of customer dissatisfaction in areas experiencing frequent outages that could be reasonably addressed by this plan.

6. PLAN DOCUMENT HISTORY

The current version of the project summary supersedes all previous versions.

Date of Project Summary Revision	Reason(s) for Update	Summary of Significant Change(s)	Modified By
5/18/2020	Original Program Documentation - New plan template	Initial Plan Document – Summarize historical plans	Karen Pavletich
4/2/2021	2021 Updates	Data updated to reflect most recent 5 Year Plan Dollars	Karen Pavletich
5/6/2021	Addt'l 2021 Updates	Data updated to reflect additional updates to the 5 Year Plan Dollars	Karen Pavletich
5/7/2021	OMRC Update	Budget plan reflects latest estimate from Project Management	Karen Pavletich
12/15/2021	RevisionUpdate with current information and Used and Useful Policy guidance	Addition of RCA, CBD and remote DG to the plan. Update iDOT Benefits and updated Program Plan Dollars and Metrics. Add alternative and cost information	Karen Pavletich
12/1/2021	Annual Review	Minor word and format changes	Karen Pavletich

7. SUPPORTING DOCUMENTATION

Document Name
2019 SERVICE QUALITY PROGRAM AND ELECTRIC SERVICE RELIABILITY FILING
HTTP://TEAM/SITES/PLANNINGMGT/IDOT/IDOT%20REFRESH/PROJECTS%20AND%20PROGRAMS.XLSX?CSF=1&E=SQGQIR http://team/sites/Reliability/Distribution%20Planning/Documents/ERP/Project%20Tracking.xlsx?csf=1&e=AYYF6W
PSE DISTRIBUTION PLANNING GUIDELINES 2020

DISTRIBUTION AUTOMATION - FLISR

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

The Distribution Automation Fault Location, Isolation, and Service Restoration (DA FLISR) plan will expand automation capabilities to PSE distribution circuits, through the installation and/or upgrade of equipment and other system components as required.

2. BACKGROUND

According to a US DOE study, implementation of DA FLISR is expected to provide a 17.5% reduction in annual SAIFI, SAIDI minutes and CMI minutes on associated circuits.

DA FLISR automates outage restoration on PSE's distribution grid by using sensors to locate faults, remotely operate switches to isolate faulted sections and to restore power to the non-faulted sections. The DA FLISR system collects information from grid devices and determines the optimal switching to restore power to the largest number of customers in less than five minutes. The faulted section will still remain without power until crews can repair the damage.

DA FLISR has existed within PSE's system in different forms since the 1990s for customer funded targeted applications. GE's Prologic controller software was utilized, but became obsolete and required heavy manual maintenance for system updates and reconfigurations.

In 2016, a pilot was fully tested, proven and launched to replace the obsolete GE Prologic controller with a new computer control system, called Yukon Feeder Automation (YFA), to help orchestrate the self-healing automation. The first automated circuits under this plan were enabled in 2016 and new automated circuits continue to be implemented using the same control system. PSE's Advanced Distribution Management System (ADMS,) currently in development, may replace YFA as the FLISR control logic in the future.
As of the end of 2020, 94 circuits have DA FLISR capabilities enabled.

Since 2018 there have been 120 DA FLISR scheme operations on PSE's distribution system with the potential to save 15.4 million CMI. Of the 120 operations, 74 were considered totally successful with an additional 7 being partially successful. Due primarily to communications failures and modeling errors, actual CMI savings were approximately 60% of the total possible savings. In 2020 - 34 successful DA FLISR operations saved approximately 2.97 SAIDI minutes. Thus far in 2021 successful DA FLISR operations have saved approximately 2.03 SAIDI minutes. As experience is gained with the deployment and operation of this technology, the successful operation percentage will rise as shown by an increasing operation success rate since 2018.

3. STATEMENT OF NEED

PSE is committed to providing safe, reliable service to our customers. PSE is also integrating initiatives to modernize the grid. Grid modernization includes implementation of new technologies and devices that, when strategically deployed, can reduce customer outage minutes, through automated fault location, isolation and service restoration.

3.1. Need Drivers

- **Grid Modernization –**
  - **Reliability** – Strategic deployment of the DA FLISR schemes will reduce CMI, SAIDI and SAIFI by reducing the number of customers experiencing a sustained service interruption from any one outage event. Distribution SCADA reclosers, deployed by this plan, provide an increased ability of the distribution system to quickly and automatically respond to and switch around an outage event.
  - **Resiliency** - The ability to automatically and remotely operate reclosers provides PSE with the capability to quickly respond to and restore outages during extreme weather events and other emergencies.
  - **Smart and Flexible -** The addition of smart devices on the distribution system, such as the SCADA reclosers and voltage support devices, deployed by this plan, provide increased grid visibility and control to support grid modernization initiatives and the planning and management of an increasingly complex distribution system.
  - **Safety -** The increased ability to monitor and control the distribution system, provided by this plan, improves safety through the ability to remotely set HLWS, and to quickly locate and isolate faults and roll trucks directly to the identified location.

3.2. Integrated Strategic Plan (ISP) Alignment

- Processes & Tools:
  - **System Reliability and Integrity:** The implementation of DA FLISR schemes will reduce outage duration and limit the number of customers experiencing an outage. The distribution SCADA devices used in DA FLISR schemes also give System Operators remote monitoring and operational capabilities including setting reclosers for HLWS when work is being performed on a circuit.
  - **Streamline processes to drive effectiveness and efficiency:**
    - Adding DA FLISR to circuits increases efficiency of field personnel by auto locating the fault and dispatching more directly to the area of the problem
    - DA FLISR implementation, whether through YFA or ADMS, furthers the successful operation of PSE's grid by increasing the availability of quality data and information.
  - **Extract and Leverage Value from Existing Technology and Assets:** When appropriate, each DA FLISR scheme will utilize existing equipment to optimize the costs to attain the plan's goals and benefits. This includes:
    - Existing SCADA capability and smart relays at substations
    - AMI network will be used for the communication network needed to monitor and control the DA FLISR equipment.
- Safety:

- The increased ability to monitor and control the distribution system, provided by this plan, improves safety through the ability to remotely set HLWS, quickly locates and isolates faults and send service trucks directly to the identified location and maintains adequate voltage for customers.

4. PLAN DETAIL

4.1. Plan Size/Population

There are approximately 1120 distribution circuits in PSE's electric system. At the end of 2020, there were ~94 circuits with DA FLISR enabled. This plan proposes to install DA FLISR on an additional 532 circuits. At the end of the plan, there will be ~626 circuits with DA FLISR enabled, or approximately 56% of all PSE circuits.

480 PSE circuits have been identified as "High CMI" circuits. These circuits have >150K average annual, all-in CMI (2015-2019), from outages originating on the feeder and can derive the highest benefit from DA FLISR implementation.

Of the 480 high CMI circuits, 113 circuits are on the Worst Performing Circuit (WPC) list and are part of the WPC Plan. Reliability benefits of DA FLISR schemes on these circuits are counted as part of the DA FLISR plan benefits but will be considered as solutions to meet the reliability improvements required by the WPC Plan.

Based on a review of completed DA FLISR projects it was found that approximately 1/2 of the circuits used within the DA FLISR schemes were not categorized as high CMI. This is because a high CMI circuit may not have available ties to other high CMI circuits and so must be backed up by a circuit(s) not in the high CMI group. This plan assumes that 1/3 of the circuits used in DA FLISR schemes will not be high CMI circuits.

Remaining DA FLISR Plan Circuit Population	
Total PSE circuits	1120
High CMI circuits *(defined as: PSE circuits with > 150K average annual, all-in CMI (2015-2019) from outages originating on the feeder)*	480
High CMI circuits that have/will have existing DA FLISR by end 2020	*(48)*
Remaining High CMI circuits with no exist DA as of 2021	**432**
Remaining High CMI circuits without a viable circuit tie (does not exist or violates N-1 capacity guidelines)	(33)
Remaining Eligible High CMI circuit population for 2021-2027 DA FLISR plan	**399**
Additional tie circuits necessary to implement DA on eligible High CMI circuit population (assumes 33% of plan circuits will need to tie to circuit not already within the plan)	133
Total Circuits included in the 2021-2030 DA FLISR plan	**532**

4.2. Proposed Completion Date

The plan is proposed to run for 7 years, 2021 through 2030. Monitoring of performance of the initial population of devices as well as re-analysis of circuit and system capabilities and needs will drive decisions on the deployment of DA FLISR schemes both within and beyond the 7 year plan.

4.3. Summary of Plan Benefits

The primary benefit of the DA FLISR plan is improved reliability for PSE customers. Significant reliability benefits, as shown in Section 4.4, will come from installing DA FLISR across our system. Annual non-MED CMI and SAIDI savings during the plan will vary depending on the make-up of the project portfolio for that year.

In addition, this plan expects to improve resiliency during major weather events or during the loss of a transmission line or substation that are not included in the figures below. This benefit was not quantified, as the benefit for reliability substantially outweighed the benefit for resiliency for this plan.

Implementation of DA FLISR schemes will result in decreased travel times and improved situational awareness for PSE service personnel. This is achieved by better identifying and isolating the predicted fault location, providing the ability to remotely operate and control settings (i.e. HLWS during line work), further sectionalizing feeders and increasing system monitoring capability. This benefit was not quantified, as the benefit for reliability substantially outweighed the benefit of Operational efficiency and awareness for this plan.

4.4. Primary iDOT Categories

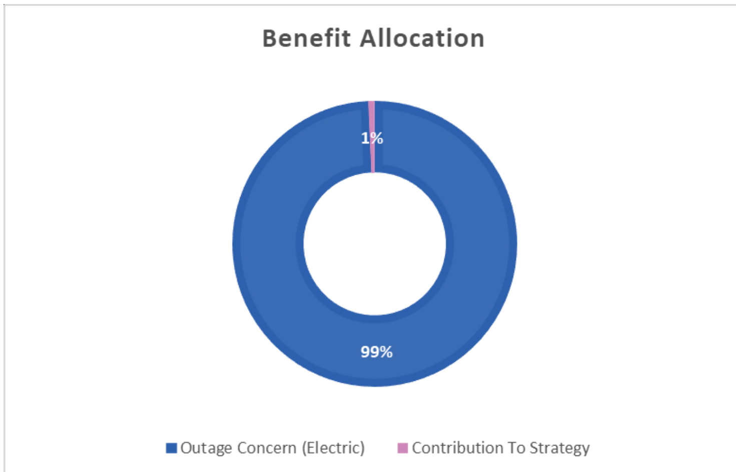
- Outage Concern: Preventing or reducing the number of future outages and outage duration experienced by customers.
- Contribution to Strategy: Creating an opportunity to make improvements to elements of specific corporate strategies.

Table 1. Summary of Plan Benefits, Population and iDOT B/C Score

2021-2037	Non-MED CMI Savings (M)	Number of Circuits	Budget ($M)[1]		NPV ($M)[2]	iDOT B/C Score[3]
			Capital	OMRC	Total Benefits	
Total	**21.65**	**532**	**133**	**18.62**	**701.58**	**6.67**

[1] Budget indicate are sum of future year budget as it is allocated for that specific year
[2] Benefits indicated are Net Present Value (NPV) sum of future year benefits allocated for that specific year
[3] B/C Score uses NPV of Benefits and Budget

Figure 1: Benefit Allocation[4]



4.5 Estimated Costs

For Electric System Planning estimated costs are generated based off of historical costs on similar types of projects, allows for variations in project scope, increase in project cost due to inflation, and added contingency to account for unforeseen conditions associated with the project.

Historical actual cost are $206k per circuit, future estimated cost are $250k per circuit.

DA FLISR project costs vary based on scope but average $250K per circuit. Total cost for the estimated 532 circuits included in this program would be approximately $133 million. OMRC is estimated to be 1.4% of project capital costs.

5. ALTERNATIVES

5.1. Solution alternatives

No Action/Other Action - If DA FLISR is not implemented, PSE customers will experience outages that could have been prevented or shortened by DA FLISR schemes. PSE will need to improve reliability through other, possibly more costly means such:

- Reliability solutions such as tree wire (WPC business case $9.57/Non-MED CMI saved, Targeted Reliability business case $8.33/Non-MED CMI saved) and underground conversion ($114/Non-MED CMI saved) can improve reliability by preventing some outages totally but at a greater cost.
- Installing additional traditional reclosers (increased circuit sectionalization) would also help to decrease the number of customers affected by any one event but does not have the ability to quickly restore customers through automated switching.
- Limiting the number of customers served per circuit (adding more circuits) would also help to limit the number of customers impacted by any one circuit outage.

[4] Risk of not achieving budget and expected benefits is 6.0%

5.2. FUNDING ALTERNATIVES

Increased Funding - With increased funding, benefits of reducing sustained interruptions for our customers could be achieved in earlier years. This is an evolving technology on PSE's system, so risks of accelerating deployment include potential for future costs associated with the need to convert more DA FLISR schemes from the current Yukon system to the ADMS system. Additionally, accelerated deployment could outpace the Substation SCADA plan implementation resulting in a lack of eligible circuits for the DA FLISR plan. Proper pacing of construction allows time to make adjustments to construction standards or deployment strategies as soon as issues become apparent, and allows for incorporation of new learning into our reliability improvement strategy.

Decreased Funding - Decreased funding would result in fewer DA FLISR schemes being implemented. PSE would see fewer outage reduction benefits and overall the corporate outage reduction metrics would see less improvement.

6. PLAN DOCUMENT HISTORY

Date	Reason(s) for Update	Summary of Significant Change(s)	Created/Modified By
10/25/2019	Initial Document - New plan template	Initial Document – Summarize historical plans	Sue Cagampang
4/22/2020	Revision	Updated scope, added budget and IDOT details	Sue Cagampang
5/5/2021	Revision	Update of program population and program timeframe	Sue Cagampang
7/13/2021	Used and Useful Policy guidance	Add alternative and cost information	Sue Cagampang
12/1/2021	Annual Review	Minor word and format changes	Sue Cagampang

7. SUPPORTING DOCUMENTATION

Document Name
FLISR Program Development Analysis, 2018, Jeff Kensok

TRANSMISSION AUTOMATION

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

The Transmission Automation plan provides automatic sensing and control to PSE's transmission lines to improve resiliency following transmission line faults. Transmission Automation uses sensors to identify and isolate the faulted section of transmission line and automatically performs switching to restore the non-faulted sections.

2. BACKGROUND

This plan builds on the Transmission SCADA plan of the past that used programmable logic controllers and traditional automatic switching schemes to restore as many substations as possible following a transmission line fault. While most customers are restored using traditional automatic switching following a transmission line fault, if the fault is in the wrong location on the transmission line, one or more substations may be left without power. Transmission Automation sensors monitor each line segment to intelligently sectionalize a faulted line section and restore the customers on the remainder of the transmission line.

The Transmission Automation plan began as a pilot plan out of the Smart Grid Technology Planning and Analysis Group in System Planning. Beginning in 2017, the project team set up the pilot, which included identifying the equipment to use, building a simulator in PSE's Snoqualmie Engineering Lab, and installing sensors in the field on two transmission lines.

More recently, PSE has developed the second generation of Fault Location, Isolation, and System Restoration (FLISR) for the transmission system which is called Transmission Line Automated Switching (TLAS). The overall goals of the second generation system are to have full coverage of each transmission line regardless of the number of distribution substations and to reduce the quantity of reclose-test actions needed to locate the fault. There are other benefits but these two are the highest priority.

In 2018, Horstmann Navigator Faulted Circuit Indicators (shown right) were installed on the two pilot transmission lines. These indicators send information that is used to determine fault directionality and location. Since installation, the Transmission Automation scheme on the two pilot transmission lines has been running in data gathering mode. This data has shown that the scheme correctly identified all faults, the availability of the system is greater than 98%, and that none of the components failed.

During this pilot period, the Substation Controls group has configured a duplicate Transmission Automation scheme in Snoqualmie Engineering Lab. In order to determine the durability of components used in Transmission Automation, the duplicate test scheme was subjected to over 15,000 faults. Following this successful trial, the Transmission

Automation Project Team can confidently say that the system is ready for real-world control.

The plan is to turn on Transmission Automation controls for the two pilot lines in 2021. Prior to enabling the scheme, the Substation Controls group will complete proper documentation, commissioning plans, SCADA maps, SCADA screens, switch diagrams, training, and modifications to the Switching & Clearances Handbook.

3. STATEMENT OF NEED

3.1 Need Drivers

- **Grid Modernization –** PSE's Automatic Switching methodology has not changed since implementation in the 1970s. On transmission lines with more than one substation, this dated technique can only restore all distribution substations automatically for a subset of possible outage scenarios. If a fault occurs outside this subset of scenarios, one or more substations would have to be restored by supervisory or manual action.

  After a permanent fault on a transmission line, Power Dispatchers sometimes have a difficult time determining the line section with a fault. Dispatchers must send Servicemen to patrol lines to identify the cause and location of the fault, leading to longer sustained outages.

- **Reliability –** Currently, traditional automatic switching schemes are installed on 95% of PSE transmission lines with at least one distribution substation. A traditional automatic switching scheme consists of motor-operated circuit switchers or disconnect switches that automatically open or close (without operator action) based on a loss of voltage or re-energization of a line section. There is no communication between switches, so each switch acts independently according to its local operating settings.

  Traditional automatic switching is most effective on lines with one or two distribution substations. Because each switch operates independently, the full scheme must be coordinated based on timing. Thus, it is only possible to coordinate a few switches per scheme. For lines with more than two distributions substations, this means that some substations will experience an outage for faults in certain line sections not covered by the traditional automatic switching scheme.

  Transmission Automation schemes rely on communication between switches and breakers, not time coordination. Transmission lines with substations not previously covered by traditional schemes will see a benefit from a new TA scheme.

- **Resiliency –** Transmission Automation contributes to resiliency during storm restoration through fault location and isolation. Transmission Automation sensors have LEDs that show which line section contains the fault. This can greatly assist crews in identifying which line section to patrol during a storm.

  When substations are tripped out of service during storms, all of their distribution circuit breakers are opened to prevent accidentally energizing grounded distribution lines following the transmission fault. Servicemen must patrol and re-energize each of the distribution circuits after the substation is energized. Transmission Automation schemes coordinate all switches and breakers on a line to restore as many non-faulted sections as possible, leading to fewer substation outages.

One way to determine how effective automatic switching schemes are at restoration is to look at the Transmission Reliability Index (TRI). This index measures the probability of restoring substations along a transmission line following a fault.

The average TRI for transmission lines with at least two substations is 0.731 (73.1% probability of restoration following a fault). Due to intelligent identification and isolation of faults employed by Transmission Automation schemes, transmission lines with TA have a TRI of 1.0 (100% probability of restoration following a fault). Improving TRI is a major driver in reducing both frequency and duration of sustained outages.

- **Smart & Flexible** – Traditional automatic switching schemes rely on trial and error to determine which transmission line section contains a permanent fault. By closing into a permanent fault, the transmission line and connected equipment are exposed to high levels of damaging fault current. This can drastically reduce the lifespan and capability of the equipment.

  Transmission Automation schemes perform fault sectionalizing while the transmission line is de-energized. Only sections without a fault are re-energized, saving the equipment from exposure to another round of high fault current.

3.2 Integrated Strategic Plan (ISP) Alignment

This plan aligns primarily with the Processes & Tools category of the ISP:

- **System Reliability and Integrity:** The main drivers for this plan are to reduce the duration and frequency of outages, provide resiliency and improve the customer experience. The improvement to reliability supports operational excellence and customer satisfaction.
- **Extract and leverage value from existing technology and assets** – When appropriate, each reliability project scope will use existing equipment to reduce project costs.

4 PLAN DETAIL

4.1 Plan Size/Population

PSE has 173 transmission lines at 115kV and 55kV. Of these, 115 transmission lines serve at least one distribution substation. 109 of those lines have a traditional automatic switching scheme (95%). Further, 68 transmission lines serve at least two distribution substation and are candidates for improvement through Transmission Automation.

4.2 Proposed Completion Date

It is proposed that the Transmission Automation plan be funded to complete the upgrade from traditional automatic switching over the next 15 years. It is estimated that each line will cost an average of $500,000 to provide Transmission Automation to all substations on the line. An additional 2-3% per year is planned for OMRC.

It is expected to ramp up to the full spending level over the next three years.

4.3 Summary of Plan Benefits

This plan will improve reliability by using new technology to restore substations following a single transmission fault. The greatest benefits will be seen in the early years of the plan, when the highest priority lines will be addressed. Priority factors include the number of substations between breakers, the annual customer outage impact (customers between breakers multiplied by annual sustained outages) and the line's Transmission Reliability Index (TRI).

Transmission Automation benefits can be quantified by the following:

- Total CMI Saved: 31,220,000
    - Non-Major Event Day CMI Saved: 14,860,000
- For lines with at least two substations, TRI average will increase from 0.731 to nearly 1.0. (Factors associated with upgrading transmission line switches may prevent some transmission lines from having a TRI of 1.0)

4.4 Primary iDOT Categories

The primary iDOT Categories related to this plan are:

- Outage Concern: Preventing or reducing the number of future outages and outage duration experienced by customers.
- Flexibility-- Improving the flexibility to utilize the grid, either for immediate use or creating an opportunity for a future project.
- Avoided Maintenance Cost – less maintenance due to switch operations.

To calculate iDOT metrics, the following assumptions were used (includes lines with two or more distribution substations):

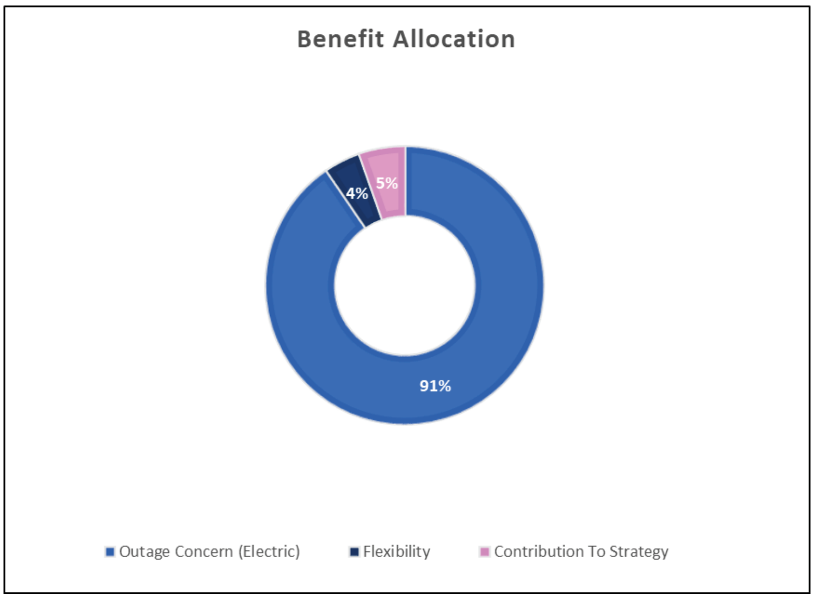
- Average line length is 13.2 miles.
- Each line has 2.6 substations, 1 radial and 1.6 looped.
- Assuming one substation is out for each transmission line outage and that TLAS would restore that substation if installed.
- The average customers per non-industrial substation is 4,071 according to 2020 Customer Data.
- Each outage takes 2 hours to patrol and restore for a single event.
- On average, each line will cost $760,000 to install TLAS.
- TLAS will not be installed on radial lines and lines with zero distribution substations.
- Lines with one distribution substation were not included in this analysis, but may be included in the future on a case-by-case basis.
- Note: Fiber is not required for TLAS implementation. Other methods of communication, like cellular and radio, are sufficient for TLAS. Installation of

fiber is covered by the IP-SCADA plan, and may be included in Transmission Automation projects where applicable.

Table 1: Summary of Plan Benefits, Population and iDOT B/C Score

2021-2036	CMI Saved (M)		Number of Lines Automated	Budget ($M)[1]		NPV ($M)[2]	iDOT B/C Score[3]
	Non-MED	All-In		Capital	OMRC	Total Benefits	
Total	**14.9**	**31.2**	**75**	**57**	**1.19**	**83.5**	**6.67**

Figure 1: Benefit Allocation[4]



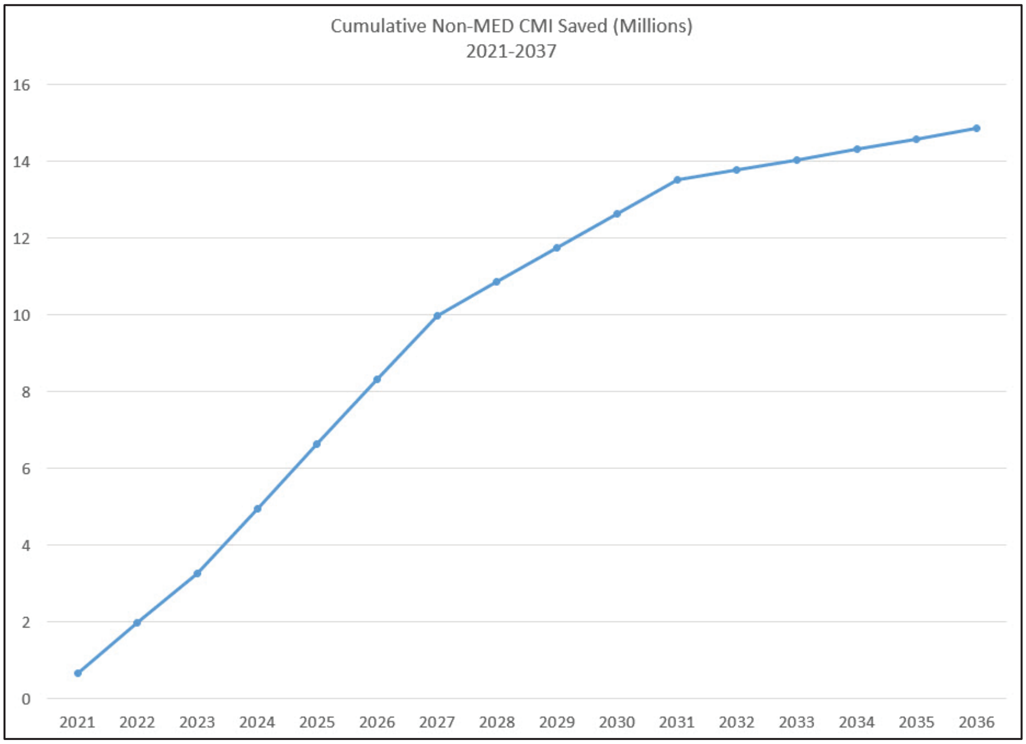
[1] Budget indicate are sum of future year budget as it is allocated for that specific year

[2] Benefits indicated are Net Present Value (NPV) sum of future year benefits allocated for that specific year

[3] B/C Score uses NPV of Benefits and Budget

[4] Risk of not achieving budget and expected benefits is 0.5%

Figure 2: Cumulative Non-MED CMI Saved by Transmission Automation 2021-2036



4.5 Estimated Total Costs

Baseline for future year cost estimate is $760k per line, which allows for variations in project scope, total number of substation devices per line, increase in project cost due to inflation, and added contingency to account for unforeseen conditions associated with the project.

5. ALTERNATIVES

5.1 Solution alternatives

No Action – By not implementing the Transmission Automation Program, PSE would continue to rely on an outdated method of automatic switching which has shown limitations in its’ ability to restore substations following a single transmission line fault.

Other alternatives include enhanced vegetation management, widening transmission corridors, building new transmission lines or installing transmission breakers within substations, which all have much higher costs and complexities in attaining the desired results. Easement acquisition and substation footprint increases are some of the complexities that prevent some of these alternatives from becoming cost effective and implementable.

5.2 FUNDING ALTERNATIVES

Increase Funding – An increase in funding would increase the number of TLAS schemes installed and move the program closer to completion. The program benefits increase with the number of active TLAS schemes. Increasing funding would lead to an earlier realization of these program benefits and an immediate reduction in CMI.

Decrease Funding – A decrease in funding would results in fewer active TLAS schemes and would increase the number of years required to install TLAS schemes on all applicable transmission lines. Program benefits would take several years to realize. PSE would continue to rely on an outdated method of automatic switching which has shown limitations in its' ability to restore substations following a single transmission line fault.

The proposal is to install Transmission Automation schemes on PSE transmission lines, with more than one substation, over 15 years. This will reduce substation outages following a single transmission line fault.

Relying on traditional automatic switching is a failure to realize the reliability benefits of this new technology. In addition to the reliability benefits, transmission conductor and substation equipment are spared the repeated exposure to damaging fault current.

The question of how long it will take to fully implement the plan is one of benefits versus budget. Simply, the more money spent on this plan, the greater the benefits.

6. PLAN DOCUMENT HISTORY

The current version of the project summary supersedes all previous versions.

Date	Reason(s) for Update	Summary of Significant Change(s)	Modified By
6/23/2020	Initial Program Documentation - New plan template	Initial Program Document – Summarize historical plans	Carol Jaeger
3/31/2021	2021 Business Case Update	Revised language throughout. Updated program summary, budget and cost estimates	Ben Walborn
7/12/2021	Used and Useful Policy guidance	Add alternative and cost information	Ben Walborn
12/1/2021	Annual Review	Minor word and format changes	Ben Walborn

7. SUPPORTING DOCUMENTATION

Transmission Line Priority Spreadsheet: X:\#1 T PLAN\7 System Wide\Transmission Automation\Prioritization.xlsx

RECLOSERS

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

This plan will address the addition of new reclosers for reliability/sectionalizing purposes on a subset of PSE's 1124 feeder circuits company-wide. Also, there are some aging/obsolete (oil filled and Joslyn/SEL-351J) reclosers and sectionalizers planned for replacement. These specialized protective devices sectionalize and reduce the number of customers impacted by a permanent fault on the main line feeder.

2. BACKGROUND

In 2008, PSE commissioned a study by Quanta Technologies to prepare a 10 Year Distribution Reliability Improvement Roadmap. Quanta's final report in June 2008, presented a reliability roadmap that predicted the number of customer interruption minutes on the system could be reduced by approximately 50%. Among the numerous reliability improvement projects in the roadmap, was the highly cost effective plan of installing new 3-phase line reclosers on circuits throughout the system. In 2016, PSE requested a study update in order to reflect the progress that PSE had already made and to identify potential improvements to the distribution reliability improvement strategy for the next several years. The 2016 update was focused on distribution reliability improvement strategies with particular emphasis on identifying ways to reduce SAIDI and SAIFI and to identify improvement solutions to improve PSE reliability indices. The 2016 updated study again emphasized that overcurrent protection options have a dramatic impact on reliability, and are critical to consider within a reliability improvement project. Equipment considered within this category are fuses and reclosers.

A recloser is a three phase reclosing device that, when sensing fault current, will quickly trip open. After an adjustable period of time (usually 10 seconds) the device will reclose (close again). If the cause of the fault remains, the recloser will trip open and lock open with a minimum disturbance to the upstream customers on the feeder. If the cause of the fault cleared itself (temporary fault), then the recloser would remain closed, then power would be restored to all customers initially affected.

Most utilities pursuing significant reliability improvement rely heavily on the installation of new 3-phase reclosers. These devices dramatically reduce the impact of sustained faults on the main trunk line by not requiring the substation circuit breaker to lock out and interrupt all of the customers on the entire circuit, which results in an improved customer experience.

3. STATEMENT OF NEED

During PSE's more than 145-year history, one thing has remained constant: PSE's commitment to safe, reliable, affordable energy service. While focusing on reliability, PSE is also integrating initiatives to modernize the grid. This grid modernization includes implementation of new technologies and devices that, when strategically deployed, can reduce outages through fault clearing and reclosing (a form of automation). Smarter devices out on the system, such as reclosers which record operations, can further assist planning analytics to develop a clearer understanding of the benefits of and the need for temporary fault clearing.

3.1. Need Drivers

- **Grid Modernization -**
  - **Reliability** – Strategic deployment of reclosers will reduce CMI, SAIDI, and SAIFI by reducing the magnitude/exposure of some outages and shortening some outages from sustained outages to momentary outages.
  - **Smart & Flexible** – It can be difficult to assess which outages of unknown cause are the result of a temporary fault. Reclosers can provide fault, indication and loading data that can be used to validate planning analytics around the impacts of temporary faults on PSE reliability metrics, and inform future planning decisions. Also, with the installation of SCADA capable reclosers across the distribution system, PSE will be able to enable SCADA in the future and utilize the reclosers for distribution automation which will provide a level of control and visibility for system operators for improved awareness via ADMS.

3.2. Integrated Strategic Plan (ISP) Alignment

- Processes and Tools –
  - **System Reliability and Integrity**: Execution of reliability work, these devices will significantly increase reliability.
- Safety
  - **Replace/upgrade aging infrastructure**: Removal of aging/obsolete (oil filled and Joslyn/SEL-351J) reclosers will reduce the risk of environmental damage from oil leaks and reduce the potential for employee injuries while working on or troubleshooting older equipment. Also, upgrading old controllers with new controllers which provide HLWS, and are ready for possible future DA-FLISR deployment, will provide increased safety and reliability.

4. PLAN DETAIL

4.1. Plan Size/Population

This plan proposes to install ~558 reclosers over ~14 years by applying planning criteria for prioritizing the most suitable sites for a new recloser installation or upgrade of an old/obsolete recloser. Priority will be given to areas with highest CMI which is determined from the highest number of customers' benefitted and highest numbers of outage events.

4.2. Proposed Completion Date

The plan is currently proposed to run for ~14 years, 2021 through 2034. There are a limited number of locations where reclosers are either feasible or beneficial. Initial planning assessments indicate that ~433 circuits will likely receive a new recloser. Replacing obsolete or oil filled reclosers and sectionalizers will account for another ~125 reclosers for a total of ~558 reclosers.

4.3. Summary of Plan Benefits

Improved Customer Reliability -The primary benefit of this plan is improved reliability for PSE customers. Completion of the ~433 new recloser locations is expected to result in the non-storm (non-MED) and storm (All-In) related reliability benefits indicated below. The added benefit of more data points in the field will provide increased situational awareness for PSE's operators and enable faster outage restoration.

Improved Customer Satisfaction/Experience - Improved reliability for customers will result in an improved customer perception of PSE as well as provide the value to customers of avoided outages. Increased reliability also has an overall public benefit when critical and public services are not disrupted and commercial businesses can operate normally.

4.4. Primary iDOT Categories

Primary iDOT categories addressed:

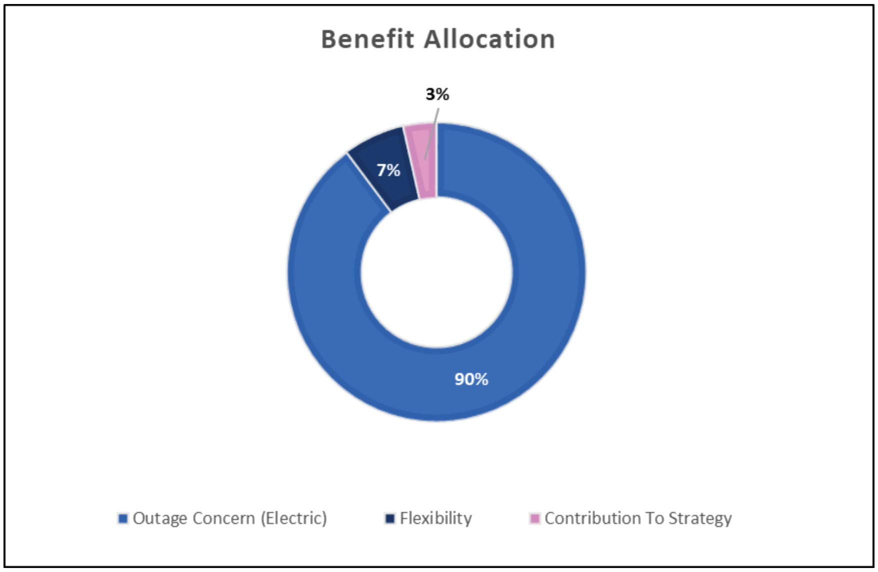
- Outage – Preventing or reducing the number of future outages and outage duration experienced by customers
- Flexibility – Improving the flexibility to utilize the grid, either for immediate use or creating an opportunity for a future project.

Table 1: Summary of Plan Benefits, Population and iDOT B/C Score

2021-2036	CMI Saved (M)		Number of Reclosers	Budget ($M)[1]		NPV ($M)[2]	iDOT B/C Score[3]
	Non-MED	All-In		Capital	OMRC	Total Benefits	
Total	**4.15**	**12.87**	**558**	**45.6**	**1.82**	**116.4**	**4.01**

[1] Budget indicate are sum of future year budget as it is allocated for that specific year
[2] Benefits indicated are Net Present Value (NPV) sum of future year benefits allocated for that specific year
[3] B/C Score uses NPV of Benefits and Budget

Figure 1: Benefit Allocation[4]



4.5. Estimated Costs

Electric System Planning estimated costs are generated based off of historical costs on similar types of projects, allowing for variations in project scope, increase in project cost due to inflation, and added contingency to account for unforeseen conditions associated with the project.

Total estimated cost are based on average historical cost of $75k per installation.

There are currently ~433 circuits identified as possible candidates for new recloser installations. The average cost per installation is:

Capital: $75K per recloser

OMRC: $ 3K per recloser (OMRC = 4% of CAP)

Capital costs assume a 50 ft. pole is used for any new pole installation.

Total cost for ~558 installations (~433 new + replacement of ~125 obsolete) would be ~$47.4 million over ~14 years.

5. ALTERNATIVES

5.1 Solution alternatives

No Action: If the recloser plan is not implemented:

- The system will not see the benefits of reduced outage exposure (SAIDI) resulting from improved sectionalization for permanent faults.

[4] Risk of not achieving budget and expected benefits is 0.5%

- There is also the potential risk of customer dissatisfaction in areas experiencing outages due to breaker operations with unknown causes that could be reasonably addressed by this plan.
- More costly solution alternatives like the installation of tree wire or underground conversions may be required.

5.2 FUNDING ALTERNATIVES

Increased Funding: With increased funding, benefits of reducing sustained outages could be achieved in earlier years. Pacing construction, however, allows time to make new installations part of a well thought out DA-FLISR implementation/deployment.

Decreased Funding: Decreased funding would result in fewer locations with recloser installations. Only areas with new installations would see outage reduction benefits and overall the corporate outage reduction metrics would see less improvement.

6. PLAN DOCUMENT HISTORY

Date	Reason(s) for Update	Summary of Significant Change(s)	Created/Modified By
6/18/2020	Initial plan- New plan template	Initial Document– Summarize historical plans	Sam Di Re, PE
5/5/2021	Revised Funding	Revised Funding	Sam Di Re, PE
12/1/2021	Annual Review	Minor word and format changes	Sam Di Re, PE

7. SUPPORTING DOCUMENTATION

Document Name
RELIABILITY IMPROVEMENT ROADMAP: FINAL REPORT - PREPARED BY QUANTA TECHNOLOGY, JUNE 24, 2008
RECLOSER PRIORITIZATION
UPDATE OF 10-YR DISTRIBUTION RELIABILITY IMPROVEMENT ROADMAP: DRAFT REPORT - PREPARED BY QUANTA TECHNOLOGY, DECEMBER 20, 2016
APPLICATION OF OH DISTRIBUTION SECTIONALIZING DEVICES - PSE STANDARD 6300.0500

FUSESAVERS

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

The Fusesaver plan will replace existing fuses (100T) on the electric distribution system with specialized protection devices. These devices work to reduce the frequency of sustained power interruptions by quickly tripping to clear temporary faults and restore power following a momentary outage.

2. BACKGROUND

Industry research suggests that 80% of all outages industry wide are caused by faults that are temporary in nature. PSE analysis indicates that value to be closer to 60% on PSE's overhead system. Addition of devices that will clear temporary faults automatically should improve PSE's reliability metrics.

A Fusesaver is a single phase reclosing device that can be installed in series with overhead fuses that, when sensing fault current, will quickly trip open prior to downstream fuses blowing. After an adjustable period of time (PSE has selected 5 seconds) the device will reclose and stay closed. If the cause of the fault remains, the appropriate downstream fuse will blow just like it typically would without the Fusesaver present. With these devices, temporary faults would be cleared and power restored before customers have the chance to call PSE. With the automatic restoration of power, PSE Electric First Response servicemen will not be called to the outage, saving the deployment of resources for temporary faults.

3. STATEMENT OF NEED

PSE is committed to providing safe, reliable, affordable energy service to our customers. PSE is also integrating initiatives to modernize the grid. This grid modernization includes implementation of new technologies and devices that, when strategically deployed, can reduce outages through fault clearing and reclosing (a form of automation). Analysis of outage data combined with some assumptions has allowed planning to develop estimates for the impacts of temporary faults on PSE's reliability indices. "Smarter" devices out on the system, such as Fusesavers which record operations, can further assist planning analytics to develop a clearer understanding of the benefits of and the need for temporary fault clearing.

3.1. Need Drivers

- **Grid Modernization -**
  - **Reliability** – Strategic deployment of Fusesavers will reduce CMI, SAIDI, SAIFI, and CEMI by shortening some outages from sustained outages that require serviceman deployment to momentary outages with no personnel dispatch required. Reliability improvement metrics will vary by location.

- **Smart & Flexible** – It can be difficult to assess which outages of unknown cause are the result of a temporary fault. Fusesavers can provide trip data that can be used to validate planning analytics around the impacts of temporary faults on PSE reliability metrics, and inform future planning decisions.

3.2. Integrated Strategic Plan (ISP) Alignment

- Processes and Tools –
  - **System Reliability and Integrity**: Execution of reliability work, these devices will significantly increase reliability, particularly in small CEMI pockets
- Safety
  - **Reduce injuries in the workplace**: While not a driver of the plan, implementation of automatic fault clearing could potentially improve the MVI metric by decreasing the number of hours spent driving for EFR personnel by preventing need to respond to temporary faults.

4. PLANDETAIL

4.1. Plan Size/Population

There are approximately 1400 100T fuses on PSE's system. This plan proposes to install 600 Fusesavers over the next 5 years by applying planning criteria for prioritizing the most suitable sites for retrofit with Fusesavers. Priority will be given to areas with high numbers of outage events of unknown cause or known to be temporary in nature. Ahead of to 2022, roughly 4% of 100T fuses are to be retrofit under this plan. Over the next five years, the plan as proposed will automate an additional 43% of the highest priority 100T fuse locations for a total of roughly 47% of the 100T fuse population.

4.2. Proposed Completion Date

The plan is currently proposed to run through 2026. There are a limited number of locations where Fusesavers are either feasible or beneficial. Initial planning assessments indicate that retrofitting fuses beyond the initial priority fuse population would return diminishing results. Monitoring of performance of this initial population of devices will drive future decisions on deployment of additional fusesavers beyond the next five years, and absent future retrofit plans, the device could remain as a tool to address specific reliability issues in the future.

4.3. Summary of Plan Benefits

Improved Customer Reliability -The primary benefit of this plan is improved reliability for PSE customers. Completion of the 600 locations is expected to result in the non-MED reliability benefits indicated below. Similar additional reliability benefits are anticipated during major weather events that are not accounted for in the table. Momentary outage data collection will improve PSE understanding of how temporary faults impact PSE reliability.

Improved Customer Satisfaction/Experience - Improved reliability for customers will result in an improved customer perception of PSE as well as provide the value to customers of avoided outages. Increased reliability also has an overall public benefit when critical and public services are not disrupted and commercial businesses can operate normally.

4.4. Primary iDOT Categories

Primary iDOT categories addressed:

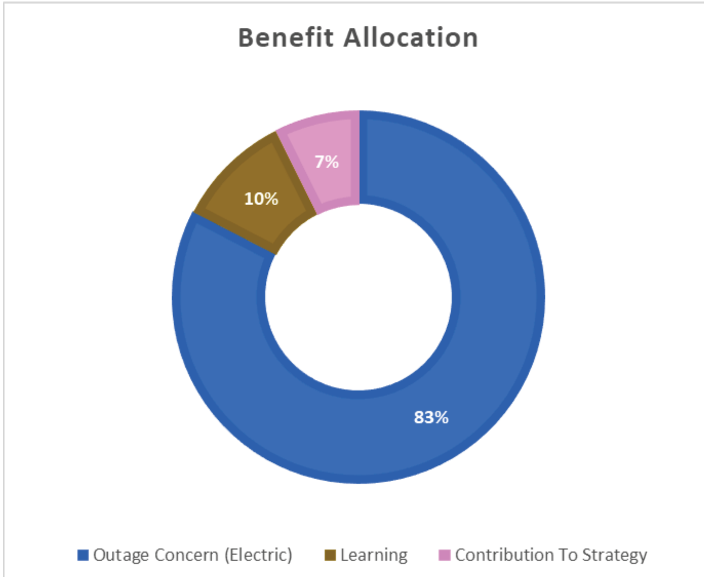
- **Outage Concern** - Preventing or reducing the number of future outages and outage duration experienced by customers.
- **Learning** - Providing an opportunity to introduce a new technology and create a learning experience.
- **Contribution to Strategy** - Creating an opportunity to make improvements to elements of specific corporate strategies.

Table 1. Summary of Plan Benefits, Population and iDOT B/C Score

2021-2024	Non-MED CMI Savings (M)	Number of Locations	Budget ($M)[1]		NPV ($M)[2]	iDOT B/C Score[3]
			Capital	OMRC	Total Benefits	
Total	**5.3**	**600**	**15**	**0.75**	**24.4**	**1.89**

[1] Budget indicate are sum of future year budget as it is allocated for that specific year
[2] Benefits indicated are Net Present Value (NPV) sum of future year benefits allocated for that specific year
[3] B/C Score uses NPV of Benefits and Budget

Figure 1. Benefit Allocation[4]



4.5. Estimated Costs

For Electric System Planning estimated costs are generated based off of historical costs on similar types of projects, allows for variations in project scope, increase in project cost due to inflation, and added contingency to account for unforeseen conditions associated with the project.

Total estimated cost are based on average historical cost of $25k per location.

The average costs is $25K per set of 3-phase Fusesavers. Total cost for remaining 600 Fusesavers would be $15 million, approximately $3 million/year. OMRC is estimated to be 5% of project capital costs.

5. ALERNATIVES

5.1 SOLUTION ALTERNATIVES

No Action - The alternative to a fuse saving protective scheme is fuse blowing. If this fuse saving plan is not implemented, fuse blowing scheme would continue to be used to clear both permanent and temporary faults beyond 100T fuses, requiring a serviceman response even when faults are temporary. There is also potential risk of customer dissatisfaction in areas experiencing frequent outages due to blown fuses with unknown causes that could be reasonably be addressed by this plan. Other more costly plans such as tree wire may be implemented for high outage locations, but may

[4] Risk of not achieving budget and expected benefits is 0.35%

be ineffective or less effective due to the difficulty in identifying location of temporary faults.

Other Options - Other options for clearing temporary faults were considered. Substation breakers and line reclosers can also be set to clear temporary faults with a fuse saving setting. These options were rejected as they would cause nuisance momentary outages to more customers on the circuits that implement fuse saving. Tripsaver devices are similar devices from a different manufacturer that offer the same benefit as fusesavers and were also considered as an option for clearing temporary faults and was piloted. Following the pilot, this option was also rejected due to operational concerns, and Fusesavers was the preferred device. Other reliability solutions such as tree wire, underground conversions and vegetation management practices are all considered as alternatives but Fusesavers are an extremely cost effective solution and much timely to install and gain benefits, in comparison to these other options.

5.2 FUNDING ALTERNATIVES

Increased Funding - There is a finite population of fuses to retrofit. A subset of the population should not be retrofit due to presence of tree wire, underground cable, or other constructability issues. Areas with particular outage characteristics should also be avoided and overfunding runs the risk of degraded service in some areas with increased momentary outages. There are diminishing returns on this investment over time as the highest priority locations will be addressed earliest in the plan. There is not expected to be additional benefit with increased funding of this plan.

Decreased Funding - Decreased funding would result in fewer locations retrofitted. Only retrofitted areas would see outage reduction benefits and overall the corporate outage reduction metrics would see less improvement overall.

6. PLAN DOCUMENT HISTORY

Date of Project Summary Revision	**Reason(s) for Update**	**Summary of Significant Change(s)**	**Created/Modified By**
10/25/2019	Initial Plan – New plan template	Initial document – Summarize historical plans	Kit Maret
4/14/2020	Revision	Added budget and IDOT Details	Kit Maret
4/5/2021	Revision	Funding increase, increasing population	Kit Maret
5/5/2021	Revision	Funding decrease	Kit Maret
6/10/2021	Revision – Used and Useful Policy guidance	Director comments – add alternative and cost information	Kit Maret
12/1/2021	Annual Review	Minor word and format changes	Kit Maret

7. SUPPORTING DOCUMENTATION

Document Name
FUSE SAVING VS. FUSE BLOWING – ANALYSIS OF POTENTIAL IMPACTS ON THE PSE DISTRIBUTION SYSTEM (5/15/2018)
PSE ELECTRIC DISTRIBUTION LINE CONSTRUCTION STANDARD 6022.1060 – FUSESAVER INSTALLATION

UNDERGROUND CONVERSIONS

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

This plan will proactively convert to underground a targeted subset of PSE's backbone electric distribution feeder system. The purpose of this plan is to improve system reliability by reducing exposure to hazards and to substantially impact the resiliency of the distribution system during major events.

2. BACKGROUND

Sustained feeder outages where overhead conductor is identified as the affected equipment account for roughly 4% of all outages by outage count, yet they contribute roughly 36% of the total (All-in) CMI due to the larger number of customers typically impacted by a feeder outage. From 2017 through 2019, feeder outages (identified where the protective device was a substation circuit breaker or recloser and the affected equipment was overhead conductor) totaled 2.5 billion all-in customer minutes and 478 million non-MED minutes. Feeder routes that follow high speed traffic corridors may also be vulnerable to car pole accidents. From 2017 through 2019, an average of 33 car pole accidents per year involved poles on the feeder system.

A proactive approach to reduction of feeder outages and corresponding CMI would take into account not only past performance at specific locations, but specifically future anticipated performance based on risk assessments by planners.

3. STATEMENT OF NEED

PSE is committed to providing safe, reliable, affordable energy service to our customers. PSE is also integrating initiatives to modernize the grid. Underground systems are more modern and resilient to storms than overhead systems. This is an aggressive, forward thinking effort to gain significant reliability and resiliency benefits by reinforcing the electric distribution system backbone.

3.1. NEED DRIVERS

- **Grid Modernization –**
  - **Reliability** – Conversion of exposed feeders to underground eliminates outages caused by vegetation, car pole accidents, wildlife, and phase slapping. Due to the high CMI of feeder outages, a reduction of feeder outages will result in a reduction in SAIDI.
  - **Resiliency –** Underground systems have shown resiliency during major or minor storms and wind events that the Pacific Northwest is susceptible to.
  - **Safety** – Underground systems remove pole hazards from the right-of-way resulting in a decrease of car pole accidents.

3.2. Integrated Strategic Plan (ISP) Alignment

- Processes and Tools –
    - **System Reliability and Integrity**: This plan proactively and systematically reduces risks of high CMI outages by eliminating exposure for highly loaded sections of the electric distribution system.
    - **Streamline processes to drive effectiveness and efficiency**: This plan is proactive instead of strictly reactive as many reliability projects are. Since there is a significant degree of randomness with outages, targeting a population of the system instead of just reacting to outages after they happen should yield the most effective results in outage reduction over the long run.
- Safety
    - **Reduce risks to the Public**: While public risk is low, this plan further decreases public exposure to pole hazards in the right-of-way and overhead conductors. Underground conversions completely eliminate the risk of downed lines or conductor tree contact. If feeders are converted in areas with wildfire risk, this is a potential benefit, although this is not a plan driver.

4. PLAN DETAIL

4.1. Plan Size/Population

There are an estimated 2,900 miles total of overhead feeder conductor, divided among 1124 distribution circuits on PSE's distribution system. This effort would have roughly 86 miles of overhead feeder converted to underground at the end of 10 years. This is roughly 3% of the feeder population.

An analysis of company-wide outage data over a three year period (2017-2019) finds the following system averages:

Feeder outages: 0.25 outages/mile/year ALL-IN

Feeder outages: 0.10 outages/mile/year NON-MED

Average CMI per feeder outage: 400K per outage ALL-IN

Average CMI per feeder outage: 127K per outage NON-MED

A feeder failure rate of 0.25 outages per mile per year (or 1 outage every 4 years per mile) assumes that outages are evenly distributed across the system, which clearly they are not. Sections of feeders with more exposure to hazards will experience higher failure rates, while some feeder sections see virtually no outages. This plan assumes that feeder sections with expected failure rates that are at least double the company average (or 0.5 failures per mile per year) will be identified.

4.2. Proposed Completion Date

This plan is open-ended due to the extensive amount of overhead feeder on the distribution system. While the RRM and WPC plans have converted feeders based on past performance only, this proactive effort would convert roughly 86 miles of overhead feeder to underground over the first 10 years of the plan (starting in year 2). This is roughly 3% of the feeder population. For this proactive plan it is anticipated that by prioritizing conductor by customer counts, exposure risks, and lack of redundancy, after 10 to 20% of the population is completed, diminishing returns may end the plan. Since only 3% will be completed in 10 years, this plan will continue beyond 10 years.

4.3. Summary of Plan Benefits

Improved Customer Reliability -The primary benefit of the plan is improved reliability for PSE customers. Significant additional reliability and resiliency benefits are anticipated during major weather events. Annual non-MED CMI and SAIDI savings during the plan will vary depending on the make-up of the project portfolio for that year. While feeder outages are less frequent, they are a significant contributor to overall company SAIDI, so decreasing feeder outages will have a measurable impact at the overall system level.

Improved Customer Satisfaction/Experience - Improved reliability for customers will result in an improved customer perception of PSE as well as provide the value to customers of avoided outages. Increased reliability also has an overall public benefit when critical and public services are not disrupted and commercial businesses can operate normally.

Improved PSE Operations – All customers benefit where crews are freed up from major feeder restoration work during major events to focus on other smaller outages.

4.4. Primary iDOT Categories

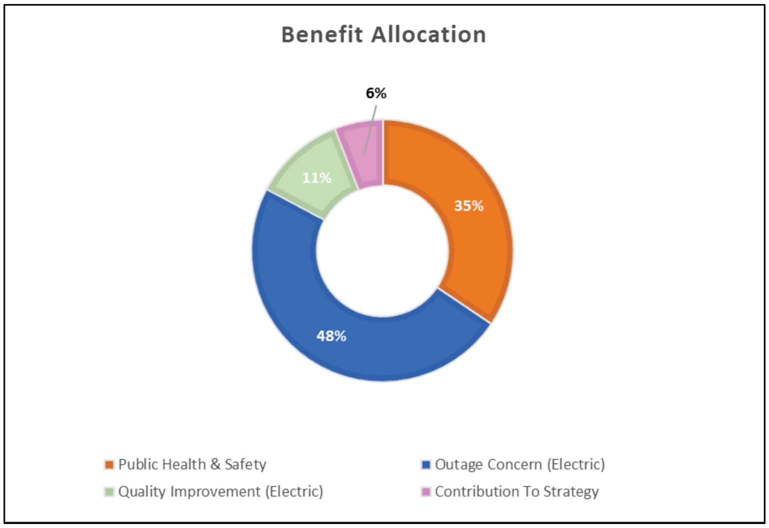
The primary iDOT Categories related to this plan are:

- **Outage Concern** - Preventing or reducing the number of future outages and outage duration experienced by customers.
- **Energy Quality** - Addressing specific customer inquiries regarding the customer's history of outage duration, outage frequency or power quality issues.
- **Public Health and Safety** - Addressing a potential hazard that has a chance of causing harm to the public or field personnel. The potential hazards do not include imminent threats to the public or field personnel, those are resolved immediately.

Table 1: Summary of Plan Benefits, Population and iDOT B/C Score

2023-2031	CMI Saved (M)		Number of Miles	Budget ($M)[1]		NPV ($M)[2]	iDOT B/C Score[3]
	Non-MED	All-In		Capital	OMRC	Total Benefits	
Total	**1.881**	**14.7**	**86**	**215**	**6.261**	**88.5**	**0.60**

Figure 1: Benefit Allocation[4]



4.5. Estimated Total Costs

Electric System Planning estimated costs are generated based off of historical costs on similar types of projects, allowing for variations in project scope, increase in project cost due to inflation, and added contingency to account for unforeseen conditions associated with the project. Average historical cost have a range of $1.5M - $3.0M per mile due to the variability in the complexity of the project. For the purpose of this business plan we're using $2.57M per mile to estimate cost.

The estimated capital cost is $215M to complete a targeted proactive population of overhead feeder.

[1] Budget indicate are sum of future year budget as it is allocated for that specific year
[2] Benefits indicated are Net Present Value (NPV) sum of future year benefits allocated for that specific year
[3] B/C Score uses NPV of Benefits and Budget
[4] Risk of not achieving budget and expected benefits is 2%

5. ALTERNATIVES

5.1. Solution alternatives

No Action - Feeder outages have a substantial impact to Company-wide SAIDI (particularly All-in SAIDI). Costs would be borne by other proactive plans, such as vegetation management or reactive plans, such as Targeted Reliability Upgrades (tree wire reconductor) after performance degrades on feeder sections. These alternatives may not see benefits, such as car-pole accident prevention. Alternatively, WSDOT driven control zone work may remove poles from risk of car pole accidents, but increase vegetation risks as pole lines are pushed off of state right-of-ways.

With the development of each individual project within the plan, alternative solutions are considered. Since this plan proactively converts overhead system to underground, alternative solutions such as reconductor to overhead feeder tree wire would be evaluated under the Targeted Reliability Upgrades business plan, for example. The Targeted Reliability Upgrades solutions can include both wired and non-wired solutions. Typical alternatives considered are: switching, energy efficiency, rebuild or extend existing facilities, new feeders and distributed energy resources. The solution that provides the highest cost benefit ratio is submitted as part of the portfolio.

5.2. Funding alternatives

Increase Funding from Proposed: With increased funding, benefits of outage reduction could be achieved in earlier years. This is complex work, however, and it is heavily impacted by permitting issues, so risks of accelerating too much funding include externally caused delays.

Decrease Funding from Proposed: Decreased funding would result in fewer locations converted. Only converted areas would see some outage reduction benefits and the company-wide outage reduction metrics would see less improvement overall.

6. PLAN DOCUMENT HISTORY

The current version of the project summary supersedes all previous versions.

Date	Reason(s) for Update	Summary of Significant Change(s)	Modified By
June 1, 2020	Initial Document	Initial Document	Kit Maret
12/1/2021	Annual Review	Minor word and format changes	Kit Maret

7. SUPPORTING DOCUMENTATION

Document Name
N/A

CEF3 Living Lab
Corporate Spending Authorization (CSA) – Infrastructure & Facilities

Date Submitted:	2/10/2020
Officer Sponsor:	Booga Gilbertson
Completed By:	Nick Coulson
Phase Gate:	**Initiation**

I. Project Overview

Problem Statement:

PSE has made a commitment to provide affordable and reliable service to all customers while working towards a carbon-free generation portfolio by 2045 in compliance with the Clean Energy Transformation Act. One of the initiatives to achieve this aggressive goal is to make strategic investments in new products and renewable resource development to allow higher renewable penetration in the form of Distributed Energy Resources (DER).

In recent years, increasing customer requests for DER and microgrid interconnections have brought to light the need for a DER interconnection process that is transparent and efficient while taking into consideration the impacts on PSE's distribution system. A more robust interconnection process requires the results of demonstration projects of new technologies to analyze real world impacts to our electric system. Currently, the review of interconnection requests for DERs is more reactive than proactive, and as such, focuses most immediately on system limitations and reliability rather than enabling DER integration that could be beneficial to the distribution system moving forward.

Telecommunication and internet technology have evolved to make available real-time data that could be harvested and utilized to deliver power more efficiently, reliably, and affordably. Technologies offer immediate benefits in planning, operations and asset management, and a fully modernized grid can support more renewable integrations and more dynamic interactions with customers/energy providers. On the other hand, grid modernization, especially for a major utility like PSE, is going to be costly, so the challenge lies in determining the suitability and cost-effectiveness of a variety of technologies with many possible application schemes corresponding to PSE's system characteristics. A comprehensive demonstration project, or "Living Lab", would allow PSE to gain first-hand knowledge of the benefits of smart grid technologies, understand the steps and costs required for implementation, and align with PSE's Integrated Strategic Plan (ISP).

Future Vision:

It is PSE's vision to develop a comprehensive Smart Grid Living Lab to test technologies and to provide learning opportunities for utility staff, future generation workforce for the modern grid, and community members alike. The Living Lab will be a region of coordinated and co-located technology demonstrations. Future technology demonstrations could include volt-var optimization, demand response, and DER assets in various configurations.

The Smart Capacity Analysis, Learning and Engagement (SCALE) project, co-funded by the Department of Commerce (DOC) Clean Energy Fund 3 Grant (CEF 3), is a foundational step for the Smart Grid Living Lab development. SCALE will start with a confined area with a limited number of circuits for modeling and program testing. As soon as the models are validated and lessons are learned from hosting capacity analysis and DER asset demonstrations, it opens the door to a broad range of research topics and demonstrations of innovative technologies for new products and services, continuous improvement in carbon reduction, service quality, renewable integration, and system planning that can be applied across the grid.

Tenino was selected as the project site for several reasons. With the local community, a non-profit organization developed a vision for a holistic community engagement, education, and grid modernization project in 2018-2019. In coordination with the non-profit, PSE developed a grid modernization project scope that would enable technical advancement, serve the community, and go hand-in-hand with broader educational initiatives that are now being led by the Centralia College Center of Excellence for Clean Energy. The Tenino community is very supportive of this project and PSE's investment in the region. Like many areas of PSE's service territory, Tenino is a rural community. The decision to site the Living Lab in Tenino is consistent with DOC's mission to support rural and underserved communities, and also gives PSE experience in a project that could be replicated in other rural communities in our service territory in the future.

Proposed Solution:

Through the implementation of a tool called Hosting Capacity Analysis (HCA), PSE could speed the interconnection process for third parties while creating opportunity for PSE planners to meet system needs and build a modern grid using DERs. Given that each utility has unique system characteristics and different objectives for the types and penetration levels of DERs, utilities must define their own requirements for DER interconnection and develop a methodology to address relevant impact factors. As the first step of the technology-enabling Living Lab, SCALE can bring all the technologies, such as HCA and DER interconnecting as system assets, microgrid interconnection and optimal operations, at one location with live circuits, and the associated technical and financial evaluations are essential for PSE to define cost-effective use cases and application guidelines before system-wide deployment. The SCALE project will implement a microgrid consisting of a 1MW/2MWh Battery Energy Storage System (BESS) and corresponding 150kW solar array at the Blumaer substation to support the adjacent high school that currently has existing rooftop solar. The project will also implement a 300kW/60kWh battery energy storage system near a neighborhood at the end of a feeder in order to test use cases such as reliability and voltage management. The major components of this project will consist of the following:

- Battery Energy Storage System
- Solar Array
- Reclosers

- Microgrid control system in combination with a battery control system
- Balance of Plant
- Substation upgrade (if applicable)
- Hosting Capacity Analysis Tool

CEF 3 will provide a matching investment of up to $2,746,240, which substantially increases the cost-effectiveness of PSE's investment on this project. The Living Lab will be PSE's ongoing center of innovations and experiments as technology evolves and new solutions become available for improving system performance and customer service.

Project Complexity:	☐Straightforward and well understood ☐Complex and well understood ☒Complex and not well articulated
Cost Estimate Maturity Score:	**Class 4 - Concept Evaluation / Preliminary Budget** >>Review the Cost Estimates references here for scoring
Expected Start Date If Funded:	**01/30/2020**
Expected Project Duration:	4 Years, 3 Months

II. Phase Gate Change Summary

Scope:	Not applicable
Budget - Initial Estimate:	CAP: $12,000,000 OMRC: $20,000
Budget - Net of Changes:	Not applicable
Schedule:	Scheduled completion is April, 2024
Risk Profile:	Not applicable

III. Key Schedule and Financial Information

Estimated Five Year Allocation:

Category:	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Total
Capital (incl. contingency)	$1,500,000	$4,200,000	$4,300,000	$1,700,000	$300,000	$0	$12,000,000
Project-related O&M	$0	$0	$0	$0	$0	$0	$0
OMRC	$0	$0	$0	$20,000	$0	$0	$20,000
Ongoing O&M	$0	$0	$0	$0	$0	$50,000	$50,000

***The numbers in this table have been rounded. The detailed cost estimate is linked to this CSA in section VII Supporting Documentation**

Expected Grant Reimbursement:

Category:	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Reimbursement	$494,323	$933,721	$439,398	$823,873	$54,925	$2,746,239

***The expected grant reimbursement values correspond to the activity periods listed in “Attachment B – Budget” in the contract.**

Incremental Ongoing Annual O&M:

Category	Annual Amount
Maintenance	$50,000

Non-Cash Benefits / Future Cost Avoidance:

1. A long-term technology testbed with public support that consists of a large enough variety of PSE’s system elements for piloting novel grid technologies targeting higher DER and renewable accommodation/integration, reliability, resiliency, power quality, customer flexibility, maximization of grid capacity, and new tariff structure
2. DER as a viable non-wire alternative (NWA) for potential future deferral of traditional system upgrades with tools for active distribution planning driven by locational benefits
3. Capability to enhance and manage system hosting capacity
4. Expedited process for DER and microgrid interconnections and avoided cost and time saved for proposed DER/microgrid projects that are infeasible
5. Environmental benefits with potential for higher renewable penetration
6. Field data of reduced SAIDI and SAIFI and other system benefits with support by energy storage
7. In-house expertise development for grid modernization and DER/microgrid interconnections, operating strategies, and planning
8. Employee development and retention
9. Community outreach to increase public awareness of integrating clean energy, assessing non-wires solutions, and improving power quality in PSE’s system

High-Level Schedule

Tenino Living Lab			2019				2020				2021				2022				2023				2024			
Lifecycle Phase	Start	Finish	Q 1	Q 2	Q 3	Q 4	Q 1	Q 2	Q 3	Q 4	Q 1	Q 2	Q 3	Q 4	Q 1	Q 2	Q 3	Q 4	Q 1	Q 2	Q 3	Q 4	Q 1	Q 2	Q 3	Q 4
Initiation																										
Planning																										
Design																										
Execution																										
Closeout																										

IV. Project Benefits & ISP Alignment

ISP Objectives, Mandatory and/or Corporate Risk	**Strategy** Abbreviated ***ISP strategy descriptions***	**Benefit Description** *Benefit, measurement and/or scorecard affected*
Financial	☐ Five-Year Strategic Plan ☒ Maximize long-term value ☒ Grow core business ☒ Grow new business	DER/microgrid interconnection with potential system upgrades as a service to DER/microgrid owners; potential earning opportunities with new rate structure; avoided costs for system upgrades by identifying locational benefits of DERs and directing DERs to more cost-effective interconnection points; centralized testbed set up for piloting various technologies and sharing learnings across the utility organization in a coordinated fashion
Customer	☒ Execute the Customer Experience Intent Statement ☒ Recognition of PSE role in community ☒ Customer preparedness & safety ☐ Ideal customer behaviors ☒ Listen & dialogue with customers	New DER assets can improve power quality and reliability for some customers (reduced SAIDI and SAIFI) if controlled properly. First demonstration of a microgrid that includes customer asset. Both PSE and customer objectives need to be satisfied harmoniously through active customer engagement, collaboration, and proper control scheme design. Sets up a framework for customer-owned or partially-owned DER assets to be controlled by PSE. Formalized interconnection process and control standards for microgrids to facilitate efficient response to microgrid-related customer service requests and hosting capacity enhancement. Highlight PSE's commitment to applying new technologies for grid modernization and renewable integration. Promoting green energy jobs and providing training opportunities through Living Lab demonstration to the public.

ISP Objectives, Mandatory and/or Corporate Risk	**Strategy** *Abbreviated* ***ISP strategy descriptions***	**Benefit Description** *Benefit, measurement and/or scorecard affected*
Process and Tools	☒ Streamline processes to drive effectiveness and efficiency ☒ System reliability and integrity ☐ Safety and security of systems, information and assets ☐ Extract and leverage value from existing technology and assets ☒ Optimize product/service portfolio consistent with long-term strategy	HCA can offer great value in streamlining the DER interconnecting process by providing transparency of the hosting capacity data on distribution lines to DER developer's feasible locations for interconnection per the generation capacity. Hosting capacity data typically are published in the form of a "heat map," which will be set up and tested in this project. Another process improvement by HCA is the planning for system-wide DER adoption based on hosting capacity limitations, DER locational benefits, and NWA facilitation for capacity upgrades. Readily available visibility to circuit hosting capacity along with forecasts, when incorporated in the planning process, allows System Planning team to take a proactive approach for optimizing solutions for system improvements (including reliability) and for customer DER adoption. This will become an integrated step in System Planning's Grid Modernization Capability Development Project. PSE currently does not have microgrid interconnection procedures and operation strategies in place, for both utility- and customer-owned microgrids. Interconnecting procedures will be developed for microgrids with utility- and customer-owned components to illustrate the interconnection condition requirements, steps and parties involved from defining microgrid operation objectives, equipment selection and sizing, to installation and commissioning. This pilot will enable microgrid related service to become part of PSE's future service portfolio and a non-wired solution for System Planning.
People	☒ Develop/Retain best employees ☒ Ownership, innovation and continuous improvement	The Living Lab is a grid-scale testbed that offers first-hand experience to PSE employees on state-of-the-art power system technologies. Employees have the opportunities to work with top industry experts on system modeling, operation strategy research, financial analysis, Engineer, Procure, Construct (EPC) project execution, protection/control optimization and O&M practices for various kinds of DERs all tailored for PSE's system characteristics. Employees with aptitude for learning new technologies and new ways of running business, solving problems without cookbook solutions will have the opportunity to demonstrate talents and interests in innovation through direct contributions to the project.
Safety	☒ Educate and train employees on effective safety and wellness strategies	Develop safety measures with stakeholders for battery application and stay current with industry practices and standards

V. Project Alternatives Summary

Alternative	Pros	Cons	Cost	Duration
Do not apply to CEF 3; continue with existing DER interconnecting process and operation strategy	Funding could be spent on other high-priority projects	1. Possibility of UTC questioning why PSE did not pursue a grant program with a 50% matching fund. 2. Potential political fallout for not applying to a high priority issue for elected officials 3. PSE to shoulder 100% in the future for piloting new tools that can advance clean energy technologies and increase renewables in PSE's energy source portfolio 4. Increasing backlog of DER interconnection applications and customer complaints 5. Overly conservative system planning due to lack of visibility of hosting capacity and locational benefits for DERs 6. Possible duplication of technology pilots due to the lack of a common testbed to be shared across the organization	To PSE: loss of opportunity for enhancing system performance and enabling novel technology that could have been completed by 2024. System upgrade spending that could have been deferred, avoided, or reduced with system-wide analytic tools that enable DER integration for both customer and grid benefits. To customers: delay in or cancellation of DER interconnection projects due to lack of transparency of system's hosting capacity that imposes more technical challenges and higher costs in identifying proper interconnection points; up to $15,000 wasted per customer if a chosen interconnection point turns out infeasible	N/A

VI. Risk Management Summary

Risk	Likelihood	Impact of Occurrence	How Monitored	Mitigation
Environmental and Land Use issues	Medium	High	Environmental review and land use permitting	Work proactively with local jurisdictions to mitigate potential issues/delays
Finding Vendors with good performance/cost balance, aftersales service, and ability to meet project milestones	Medium	High	Pre-qualify vendors, Quality control process, RFP, Contracting, Project management	- Minimize dependence on outside engineering services by development of in-house expertise through training and self-learning - Extensive vendor search with shop visits and reference checking - Seek lessons learned from other utilities with experience executing similar work scope - Leverage DOC's experience from CEF 1 and CEF 2 - Detail contract review with consultants' support RFP development, bid evaluation to ensure technical needs are met and sufficient aftersales support is part of contract with proper payment structure - Shop visits for quality/schedule control during manufacturing and prior to approval for delivery

Risk	**Likelihood**	**Impact of Occurrence**	**How Monitored**	**Mitigation**
Going Live and Operating new PSE asset	Low	Medium	Prepare Organizational Change Management (OCM) Plan and engage with key stakeholders including Electric Operations, Engineering, etc.	- Engagement with Operations starting in early project phase - Work with Operations for support during testing phase - Collaborate with Operations in designing control strategies and test plans
Service interruptions in test area(s)	High	Medium	Outage report in test area(s)	- Well thought out test plans with mitigations for potential interruptions, look for ways to minimize possible service interruptions - Thorough communication between test planner and Operations
System constraints that would require high-cost infrastructure upgrades	Medium	High	Engineering review	- Avoid DER locations that would require extensive infrastructure upgrades causing budget increases by engaging Engineering in the scoping stage to identify system constraints
Public Scrutiny	Medium	High	Communication	- Justifications for costs and timeliness for PSE's efforts in new technologies, choices of technologies, choice of test locations, use cases and benefits

VII. Supporting Documentation

Cost Estimating and Budget:	H:\~ T&D Project Folders\Other Projects\CEF3\102 PIP - Scope\CSA\CSA January 2020
Business Needs and Alternatives:	Business Needs and Alternatives shown above and in the grant application
Risk Register*:	Risks are shown above
Department of Commerce Final Contract:	H:\~ T&D Project Folders\Other Projects\CEF3\102 PIP - Scope\CSA\CSA January 2020\19-92201-003 CEF 3 Contract Final 1-15.docx
CEF3 Original Grant Application:	H:\~ T&D Project Folders\Other Projects\CEF3\102 PIP - Scope\CSA\CSA January 2020

VIII. CSA Approvals

Prepared By	Title	Role	Date	Signature
Nick Coulson	Project Manager	Project Manager	2/11/2020	DocuSigned by: Nick Coulson 18F90E075A784D3...
Kincheiu Wei	Sr. Engineer – Smart Grid Technology Planning and Analysis	Smart Grid Technology Planning and Analysis	2/11/2020	DocuSigned by: 4DCFF01ABCDB47B...

Approved By	Title	Role	Date	Signature
Elaine Markham	Manager – Smart Grid Technology Planning and Analysis	Sponsor	2/11/2020	DocuSigned by: Elaine Markham 9D0C63E133DF452...
Roque Bamba	Director Project Delivery	Director	2/12/2020	DocuSigned by: Roque Bamba BC203E4E58BB426...
Cathy Koch	Director Planning	Director	2/14/2020	DocuSigned by: Catherine Koch
Booga Gilbertson	Sr. VP Operations	Officer	2/14/2020	DocuSigned by: Booga Gilbertson C34688A34AF5492...

Please direct any questions to either:
1. The Capital Budget team at CSA-TeamMail@pse.com, or
2. The Enterprise Project and Performance Project Practices team at EPP-ProjectPracticesTeam@pse.com

Clean Energy Fund 3 / Clean Energy Transformation 4
Grid Modernization Program (GRID2021)
Track 1 Application

Directions:

1. Please complete the application below. Cells will expand to accommodate longer responses.
   - Questions regarding the application process may be emailed to cef@commerce.wa.gov.

2. Save the document with this file name structure:
   - <Name of Submitting Entity>_GRID2021 TRACK 1 APP

3. Complete all application attachments requirements listed in the Attachments list below, and save the documents using the naming conventions listed in that section.

4. Print Attachment 4, "Certifications and Assurances", then read, sign, and scan, then save using the naming conventions listed in the Attachments list below.

   Upon the completion of steps 1 – 4, email the application and all attachments to cef@commerce.wa.gov, using the subject line: "<Name of Submitting Entity> GRID2021 Track 1 Application"
   - *The Application must be received by 5:00 PM (PST) on Tuesday, ~~May 18, 2021~~ June 15, 2020. Successful Applicants are expected to be notified on ~~June 30, 2021~~ August 2, 2021.*

Section 1: Application Summary (**MANDATORY, SCORED**)				
1.01	Application Title:		Tenino Alternative Renewable Backup Generator	
1.02	Dollar Amount of Funding Requested (The maximum request must not exceed the maximum award amount specified for Track 1 projects in RFA SECTION 1.4 FUNDING to be considered responsive to this RFA.)		$150,000	
1.03	Organization Name:		PUGET SOUND ENERGY	
1.04	Legal status of the Applicant (sole proprietorship, partnership, corporation, etc.)		Corporation	
1.05	The year the entity was organized to do business as the entity now substantially exists		1997	
1.06	Organization Mailing Address:		355 110th ave NE Bellevue, WA 98004 Click or tap here to enter text.	
1.07	Email #1:	Kincheiu.wei@pse.com	Email #2:	dana.kaul@pse.com
1.08	Phone #1:	425-625-9742	Phone #2:	206-396-1084
1.09	Organization Official's Name:		Elaine Markham	

	(Signatory to Certifications and Assurances)			
	Official's Title:		Manager of Grid Modernization Strategy and Enablement	
1.10	Email:	Elaine.markham@pse.com	Phone:	425-698-3587
1.11	Additional Contacts (Please provide name, email, and phone)		Cathy Koch cathy.koch@pse.com 206-396-2375	
1.12	Name, address, and telephone number of each principal officer (President, Vice President, Treasurer, Chairperson of the Board of Directors, etc.)		Address: 355 110th Ave NE, Bellevue WA 98004 President: Mary Kipp (425) 462-3930 Sr. VP & COO: Booga Gilbertson (425) 462-3843 Sr. VP & CFO: Daniel Doyle (425) 462-3193 Chairperson of BoD: Steven Hooper 425-462-9892	
1.13	The applicant is a utility serving retail electric customers in Washington State? (See RFA Section 1.3 MINIMUM QUALIFICATIONS)			
	☒ Yes			
	☐ No			
1.14	Which category of technology does your project primarily address? Select all that apply. (See RFA Section 1.3 MINIMUM QUALIFICATIONS)			
	☐ Battery energy storage			
	☐ Demand management			
	☒ Distribution protection and automation for integration of renewable energy and/or distributed energy resources			
	☒ Microgrids using renewable energy or other renewable distributed energy resources			
	☐ Transactive controls			
	☐ Building thermal or district energy systems			
	☐ Reduce transmission or distribution congestion issues limiting renewable energy resources			
	☒ Other clean, distributed energy resources (must not be conventional and commercially available technology such as solar PV systems, smart meters, etc., unless there is an inherent innovative application)			
1.15	Would capital assets to be deployed have a lifespan of greater than 13 years and be located in the State of Washington? (See RFA Section 1.3 MINIMUM QUALIFICATIONS)			
	☒ Yes			
	☐ No			
1.16	At the conclusion of the project's performance period, would the activities included under the Track 1 Minimum Scope of Work (listed below) be completed? (See RFA Section 1.3 MINIMUM QUALIFICATIONS) • Procure consulting and/or other services necessary to completing Track 1 activities • Complete commercial and financial feasibility analysis. • Form project team and preliminary contractual relationships between partners, as well as preliminary commercial terms of the project • Assess site, including constraints and opportunities • Assess legal and environmental suitability			

	• Complete preliminary (10%) system technical design (technology assessment and selection, configuration) • Complete preliminary project management and operations plan, budget and schedule
	☒ Yes
	☐ No

1.17	Statewide Vendor Number (SWV)	SWV0058840
	Applicant Universal Business Identifier (UBI)	179-010-055
	Applicant Tax Identification Number (TIN)	91-0374630

Section 2: Technical and Management Proposal

2.01 **Project Concept (MANDATORY, SCORED):** Include a complete description of the Applicant's core concept for the capital project for which predesign activities are being contemplated. This section should convey Applicant's understanding of the high-level objectives and minimum qualifications of the RFA and how their project relates to these objectives. This response may:

a. Choose to highlight how this project is innovative and why this innovation is important in the broader context of grid modernization in the state, including as a result of technology selection, project development, engagement, implementation, or operation.
b. Describe how the capital project would be designed to provide direct and/or indirect benefits to Federally Recognized Tribal Governments, Tribal Communities and/or Vulnerable Populations, in particular those in the community where the project is sited. Direct benefits may include but are not limited to: improved electric grid reliability in ways that primarily benefit Federally Recognized Tribal Governments, Tribal Communities and/or Vulnerable Populations; and improved resilience for critical loads and community resources in the face of adverse events (for example, power outages, fires, earthquake, etc). Indirect benefits may include but are not limited to: job or training opportunities.
c. Discuss ways in which the project has, or will, meaningfully engage communities as part of project development. Meaningful engagement includes but is not limited to community input to inform project development (co-creation). *Priority will be given to projects demonstrating meaningful co-creation of project design and outcomes.*
d. Briefly describe other high-level impacts/outcomes the Applicant proposes to achieve as a result of the capital project, including benefits to the host utility and to Washington communities.

Washington state's 100% clean energy policy and goal has driven, and will continue to drive, the proliferation of renewable distributed energy sources (DER) recognized as the top candidates for replacing fossil-based energy sources in our current energy portfolio. The most currently mature DER technologies, such as photovoltaics and battery energy storage, have been popular amongst earlier stage demonstration projects. While PV+storage has formed several successful microgrids across the industry, their inherent technical limitations render prolonged outage support impossible in areas where seasonal weather impacts on PV generation is significant, such as in the Pacific Northwest (PNW). During the winter months (Jan. – Mar.) when the PNW typically experiences low sunlight coinciding with harsh weather conditions, PV+Storage microgrids have difficulty in providing backup power beyond 24 consecutive hours. This presents opportunities for alternatively fueled backup generations to improve resilience for critical loads and community resources – particularly, those that serve vulnerable populations during prolonged, adverse events.

	The "PV + storage" microgrid that PSE is planning to build in collaboration with the Tenino High School (THS) in the CEF 3 program presents an opportunity for PSE and its partners to continue to innovate and demonstrate how rising technologies can advance the integration and energy source options of renewable energy for utility customers. While the new microgrid to be installed in CEF 3's scope will offer great potential for energy independence most of the year, detailed feasibility studies show that the PV's energy created during the winter months and the characteristics of Lithium-ion batteries are not the optimal solution to meet the THS studied emergency shelter load requirements. A fuel-based backup generator is a natural solution to close the resiliency gap throughout the school year and during winter storm season when the potential for prolonged outages is greater. This also aligns with the City of Tenino's vision to enhance community services by utilizing the THS as an emergency shelter. According to the Electric Power Research Institute (ERPI)'s study on "Low Carbon Backup Generators," hydrogen fuel cell and spark ignition engine powered by 100% hydrogen or renewable natural gas plus 15% hydrogen mix are viable candidates for this project in that 1) their low or zero-carbon emission and/or renewable characteristics align with the State's clean energy goal, 2) they are non-conventional DERs and their commercial applications are scarce, 3) the integration of these technologies in addition to PV+storage adds a new dimension of challenge to DER optimization planning and operations, and to microgrid/distribution control systems, 4) they widen PSE's customer energy choice by enabling PSE to offer low or zero carbon renewable gas service as an alternative to 100% electrification in achieving the clean energy goal, 5) they will help to be catalyst for local producers of clean hydrogen or renewable natural gas to promote a "local energy ecosystem" when opportunities present themselves. Overall, it will broaden the engagement of grid modernization beyond the typical participants in the previous rounds of the CEF program, as vendors of new forms of technology, energy source providers, and PSE's Gas Division will be joining this effort. PSE is currently in the process of engaging the City of Tenino to see if there is synergy between this expanded scope and the City's energy and community service goals. This includes engaging with a wastewater treatment plant near THS to review its methane production capacity and availability for RNG supply, which could be part of the preliminary or future design considerations. As this is a new product for both PSE and its customers, successful implementation of this project will provide a test bed to 1) demonstrate the current industry technology on hydrogen fuel cell and hydrogen/RNG generators, 2) to determine the modifications required, and 3) to address issues with hydrogen and RNG handling, creation, storage, sourcing, transportation, system reliability, safety protocol, and other regulations and economics. ***(1250 word maximum)***
2.02	**Project Methodology and Work Plan (MANDATORY, SCORED):** Include all grant project requirements and the proposed tasks, services, activities, etc. necessary to complete the required Track 1 activities listed in RFA Section 1.2 OBJECTIVES AND SCOPE OF WORK, and any additional objectives of the scope of work that would be funded under this solicitation. This section of the technical proposal must contain sufficient detail to convey to members of the evaluation team the Applicant's knowledge of the subjects and skills necessary to successfully complete the grant scope of work. Include any required involvement of COMMERCE staff or third parties.

PSE will perform feasibility on two possible forms of backup generation in the project: a 100% hydrogen fuel cell and Renewable Natural Gas blended with hydrogen (15% minimum target). A breakdown of the tasks are proposed as follow:

- Determine feasibility and cost of creating green hydrogen off site and storing.
- Determine feasibility of purchasing green hydrogen for local storage.
- Determine feasibility and cost for purchasing 100% RNG. (consultant support required)
- Determine feasibility for mixing 15% or higher green hydrogen with 85% or less renewable natural gas (equipment manufacturer's recommendations on mix)
- Determine feasibility of transporting hydrogen to site and transferring to stationary tanks or using the transportation tankers as permanent storage.
- Determine rough tanker costs.
- Determine permit issues (PSE Permitting people and/or permitting consultant required)
- Determine high-level code issues for project (including requirements for storage of 100% hydrogen and RNG/HYDROGEN on site to be used as a backup fuel). (PSE permitting, project management and possible permitting consultants)
- Determine the feasibility of existing hydrogen fuel cell and RNG/HYDROGEN power generators in the 150kW size. (consultants or other support required)
- Confirm startup time for fuel cell generator is acceptable for need. (consultants or other support required)
- Conduct preliminary research on the control system necessary for the generator (consultant or other support required)
- Obtain rough capacity of hydrogen needed for 48 hour run time for generator. (consultant or vendor support required)
- Determine the rough, size, pressure and footprint of hydrogen and RNG/HYDROGEN storage needed.
- Confirm suitable property size for fuel cell and RNG/HYDROGEN generator and storage.
- Determine the rough costs for fuel cell generator. (consultant support required)
- Determine rough costs for electrical system, microgrid control expansion, and generator controls. (consultant or other support required)
- Determine project install costs. (PSE PM or consultant or other support required)
- Determine final rough overall cost and schedule for project. (PSE PM or consultant or other support required)
- Determine on-going maintenance requirements and cost. (consultant and vendor support required)
- Make overall recommendation on project technical, commercial, and financial feasibility. (PSE with consultant or other support required)
- Assess candidate sites, including constraints and opportunities (PSE with consultant or other support as needed):
    - Check property ownership and title for easement and encumbrances
    - Obtain property owner written permission to enter the property for studies and analysis
    - Acquire property operating rights for the PSE's portion of work
- Assess legal and environmental suitability (PSE with consultant or other support as needed)
- Prepare preliminary budget and schedule for EPC implementation

(500 word maximum)

2.03	**Project Management (MANDATORY, SCORED):** Provide a description of the proposed project team structure and internal controls to be used during the course of the project. If the project includes partnership with Federally Recognized Tribal Governments or Non-Profit Organizations serving Tribal Communities or Vulnerable Populations, please describe the structure of the partnership and relationship between project partners. As applicable, describe lines of authority for personnel involved in performance of this potential contract and relationships of this staff to other programs or functions of the Applicant's organization or partner organizations. Include who within the firm will have prime responsibility and final authority for the work.
	The proposed project team for implementation will consist of PSE's existing Clean Energy Fund 3 team members (a cross-functional group generally composed of grid mod engineers, planners, permitting, real estate, procurement, communications/outreach, and IT staff) as well as some additional consulting technical support from the gas organization. External consulting will be available upon necessity to help support the project. A project manager, usually from our major project division, will be assigned to lead the team through PSE's typical project lifecycle from initiation through commissioning/closeout and will use best practices including cost control, scheduling, resource planning, and scope management to effectively execute the project. Scoping support will come from our internal Grid Modernization Strategy and Enablement and Gas System Integrity departments, as well as any external consulting entities. The project sponsor will be the manager of the Grid Modernization Strategy and Enablement department (Elaine Markham) and will have prime responsibility and final authority for the work. ***(300 word maximum)***
2.04	**Experience of the Applicant (MANDATORY, SCORED):** Identify relevant experience that indicates the qualifications of the Applicant (including specific staff assigned to the project), and any subcontractors, for the performance of the potential contract. Indicate where supplemental expertise will be needed for the performance of the potential contract (such as from consultants, equipment vendors and contractors).
	PSE is the largest utility in Washington State and in the forefront of clean energy implementation and grid modernization. PSE was awarded $3.1 million and $2.7 million of grant fund from CEF 1 and 3, respectively, successfully implemented the Glacier Battery, and is currently in strong partnership with EPRI in advancing DER technologies through novel application planning, and with a reputable, experienced Owner's Engineer (Power Engineers) to work on knowledge transfer for DER technology implementation, BESS in particular. The growth of the Grid Modernization Team at PSE and funding allocated for CEF projects demonstrates strong executive support and commitment to a clean, reliable energy future. PSE's Grid Modernization Team will continue to lead the effort of the CEF 4 if grant fund is awarded along with the execution of CEF 3. Key staff in the CEF team are as follow: *Elaine Markham, P.E. (PSE CEF Program Sponsor)* *Manager, Grid Modernization Strategy and Enablement* *Kincheiu Wei, P.E. (PSE CEF Project Lead)* *Technology Planner, Grid Modernization Strategy and Enablement* *Sue Cagampang (PSE CEF Lead Planner)* *Electric Distribution Planner, System Planning* *Dana Kaul, PE*

	GSI Gas System Integrity, Gas System Planning, Consulting Engineer *Nick Coulson, P.E.* *Grid Modernization Program Manager, Infrastructure Program Management* *Robert Zimmerman* *Project Manager, Major Projects* *Trudi Webster* Communication Initiatives Consultant PSE has identified EPRI as one of the potential subcontractors to provide consulting services as indicated in items from the response in Section 2.02. Vendor consultation will be essential and EPRI will facilitate the initial conversations as part of their potential contract scope. PSE will also leverage its membership in the "Renewable Hydrogen Alliance" to reach out to manufacturers of hydrogen electrolyzers and fuel cells for more information to deepen our understanding in this study. ***(300 word maximum)***
2.05	If the Applicant or any subcontractor contracted with the state of Washington during the past 24 months, indicate the name of the agency, the contract number and project description and/or other information available to identify the contract. (**MANDATORY)**
	Schedule 139 Voluntary Long Term Renewable Energy Service Agreement
2.06	If the Applicant's staff or subcontractor's staff, or a member of either's governing board, was an employee of the state of Washington during the past 24 months, or is currently a Washington State employee, identify the individual by name, the agency previously or currently employed by, job title or position held and separation date. If following a review of this information, it is determined by COMMERCE that a conflict of interest exists, the Applicant may be disqualified from further consideration for the award of a contract.(**MANDATORY**)
	PSE does not track this information company-wide. No listed members of the project team are currently employed by or have been employed by Washington state within the past 24 months.
2.07	If the Applicant has had a contract terminated for default in the last five years, describe such incident. Termination for default is defined as notice to stop performance due to the Applicant's non-performance or poor performance and the issue of performance was either (a) not litigated due to inaction on the part of the Proposer, or (b) litigated and such litigation determined that the Proposer was in default. (**MANDATORY**)
	No
2.08	Submit full details of the terms for default including the other party's name, address, and phone number. Present the Applicant's position on the matter. COMMERCE will evaluate the facts and may, at its sole discretion, reject the application on the grounds of the past experience. If no such termination for default has been experienced by the Applicant in the past five years, so indicate. (**MANDATORY**)
	NA

Section 3: Cost Proposal (**MANDATORY**, **SCORED**)		
3.01	**Match**: Identify the total eligible grant project costs to be funded by the Applicant. *(Note: In-kind or cash claimed as*	$258,513

	match for this program cannot be claimed as match for any other funding sources.)	
3.02	Indicate what proportion of this funding has already been secured and which is subject to pending applications.	0%

3.03	**Identification of Costs:** Identify all costs in U.S. dollars including expenses to be charged for performing the services necessary to accomplish the objectives of the grant project. Applicants are required to collect and pay Washington state sales and use taxes, as applicable. Costs for subcontractors are to be broken out separately. Please note if any subcontractors are certified by the Office of Minority and Women's Business Enterprises.	
	$ 0	Equipment
	$221,375	Salaries & Benefits
	$150,000	Contractor/Consultant Services
	$12,998	Indirect/Overhead
	$24,139	Other 1 If dollar amount entered is greater than zero, please list major costs: **Administration**
	$	Other 2 If dollar amount entered is greater than zero, please list major costs: **Click or tap here to enter text.**
	$408,512	Total
3.04	Please provide a clear and concise budget narrative to identify what costs are planned to be funded through this grant.	
	Part of the consultant's fee and PSE's labor will be funded through this grant for up to $150,000. ***(200 word maximum)***	

Attachments		
#	**Description**	**Attachment Naming Convention**
4	**CERTIFICATIONS AND ASSURANCES (MANDATORY)** The Certifications and Assurances form (Exhibit A to the RFA) must be completed, signed and dated by a person authorized to legally bind the Applicant to a contractual relationship, e.g., the	**4_PUGET SOUND ENERGY_GRID CERTIFICATIONS AND ASSURANCES**

	President or Executive Director if a corporation, the managing partner if a partnership, or the proprietor if a sole proprietorship.	
5	**SITE INFORMATION DATA SHEET (MANDATORY, SCORED)** The site information data sheet (template provided at the website listed in RFA SECTION 2.1 RFA COORDINATOR) must be completed for all project sites included in the application. A. **Street Address** of the capital project site. **B. Median Income:** ACS 2018 5-year household median income levels for the city or town where the site is located i. Go to https://data.census.gov/cedsci/. ii. Enter the name of your city or town and the word "income" in the search bar. iii. Click on the first search result under the heading "Explore Data" near the top of the page. iv. Near the top of the page, use the "Product:" dropdown menu to select the "2018: ACS 5-Year Estimates Subject Tables" data set. v. Scroll down to learn your municipality's Estimate for Median Income (dollars) for Households. *vi. Note: If an Applicant's city- or town-level data is unavailable from the source provided above, an Applicant is permitted to substitute county-level ACS 5-Year Estimates instead. If city- or town-level data is available, the Applicant must use that data to determine eligibility for this reduced match option.* **C. Environmental Health Disparities:** Environmental Health Disparities v1.1 rank for the census tract where the site is located i. Based on the Washington Department of Health's Washington Tracking Network tool ii. https://fortress.wa.gov/doh/wtn/wtnibl/ iii. Click "Environmental Health Disparities V 1.1" on the left-hand column iv. Locate the exact location of the project's site(s) and click that tract (optionally use the location tool to search for the site's physical address) v. The rank is shown in the left-hand column adjacent to "Environmental Health Disparities V 1.1" **D. Rural Status:** Whether the proposed site is in an area identified as "non-entitlement" according to information provided by COMMERCE's Community Development Block Grant program. i. Based on http://www.commerce.wa.gov/wp-content/uploads/2016/06/CDBG-2014-Map-of-Local-Governments-Served.pdf	**5_PUGET SOUND ENERGY _GRID SITE INFORMATION**

	ii.Note that some cities in Non-Entitlement Counties are identified as Entitlement Cities and will count as entitlement areas for the purposes of this program	
6	**DIVERSE BUSINESS INCLUSION PLAN (MANDATORY)** The Diverse Business Inclusion Plan form (Exhibit B to the RFA) must be completed and submitted as a component of the application. See RFA SECTION 2.7 DIVERSE BUSINESS INCLUSION PLAN for more information.	**6_PUGET SOUND ENERGY_GRID DIVERSE BUSINESS INCLUSION**
7	**WORKERS' RIGHTS CERTIFICATION (MANDATORY, SCORED)** The Workers' Rights Certification form (Exhibit C to the RFA) must be completed, signed and dated by a person authorized to legally bind the Applicant to a contractual relationship, e.g., the President or Executive Director if a corporation, the managing partner if a partnership, or the proprietor if a sole proprietorship.	**7_PUGET SOUND ENERGY_GRID WORKERS RIGHTS CERTIFICATION**
8	**PARTNER LETTERS OF SUPPORT (OPTIONAL, SCORED)** The applicant may optionally submit letters of support from project partners demonstrating their support for and commitment to carrying out the project as written. Letters of Support may also describe the partner's relationship to the Applicant, as well as any anticipated involvement of the partner in the project. Letters of support should be compiled into a single PDF. If the Applicant is not a Federally Recognized Tribal Government (nor a subdivision of a Federally Recognized Tribal Government) and the capital project would benefit community(ies) located in census tracts that are fully or partially on "Indian country" as defined in 18 U.S.C. Sec. 1151, the presence or absence of a Letter of Support from a Federally Recognized Tribal Government will contribute to a portion of the Applicant's Equity & Community Benefits score in addition to other scoring impacts described in Section 4.2.	**8_TENINO HIGH SCHOOL_GRID PARTNER LETTERS OF SUPPORT** **8_CITY OF TENINO_GRID PARTNER LETTERS OF SUPPORT**
9	**OMWBE Certification (OPTIONAL AND NOT SCORED)** Include proof of certification issued by the Washington State Office of Minority and Women's Business Enterprises (OMWBE) if certified minority-, women-, or veteran-owned firm(s) will be participating on this project. For more information please visit: http://www.omwbe.wa.gov.	**NA**

End of Application
See following page for Application Process Survey

Section 6: APPLICATION PROCESS SURVEY

Survey Questions

The following questions are intended to help us improve our application process. Please indicate your agreement/disagreement with the following statements.

Your responses will not impact the evaluation of your application in any way.

1: Strongly Disagree

2: Disagree

3: Neither Agree nor Disagree

4: Agree

5: Strongly Agree

Name of Applicant: PUGET SOUND ENERGY	
Application Survey Questions	Responses
1. The guidelines provided enough information on the program.	5
2. The Pre-Application Conference was helpful introducing the application process	5
3. The Request For Applications (RFA) application instructions were clear.	5
4. The RFA application process was easy to follow.	5
5. I was able to receive the assistance I needed from Commerce to complete the application.	5
6. Commerce staff was timely in responding to process related inquiries.	5
7. I had adequate time to prepare the application prior to the deadline.	4
8. Given program requirements, the application process was reasonable.	5

CIRCUIT ENABLEMENT - ELECTRIC VEHICLE IMPACT

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

The Circuit Enablement – Electric Vehicle (EV) Impact plan anticipates the demands that widespread EV adoption will have on PSE's transmission and distribution system and proactively addresses system concerns to ensure continued reliability.

2. BACKGROUND

PSE'S region is expecting to see a growth in EV utilization in both Light-Duty Vehicles (LDV) and Medium and Heavy-Duty Vehicles (MHDV) driven by industry and government mandates like the Zero-Emission Vehicles bill. LDV classes include passenger cars and light trucks. MHDV classes include delivery trucks, school buses, semi-trucks, and transit buses. Under this 2020 law, WA must reduce its overall greenhouse emissions by 45% by 2030, 70% by 2040, and 95% by 2050. As nearly 45% of Washington's annual greenhouse gas emissions come from transportation, cleaner LDV and MHDVs are essential to reaching those targets. The PSE EV Market Analysis performed by Guidehouse predicts the population of EVs in our territory growing as shown below:

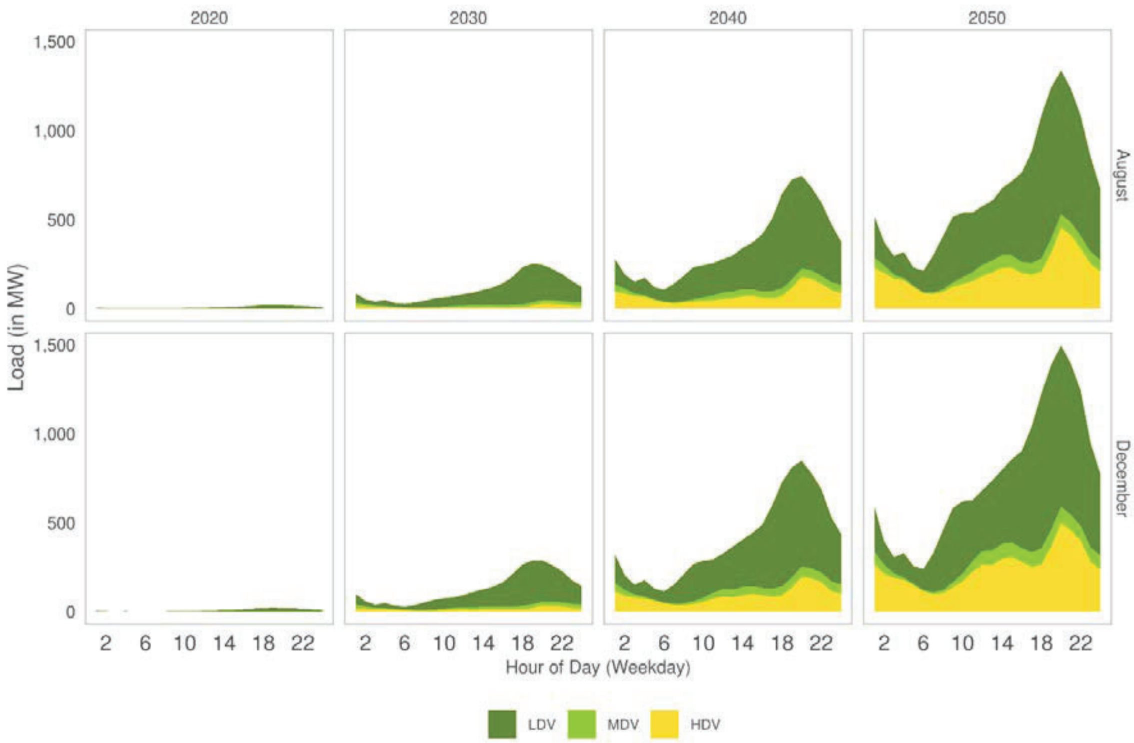
Table 1: Cumulative EV Population in PSE Territory (number of vehicles, in thousands)

Duty	2020	2025	2030	2035	2040	2045	2050
LDV	36	135	321	586	894	1,204	1,476
MHDV	0	2	11	24	40	59	83

Source: Guidehouse

This plan seeks to use existing market studies, asset and customer data to better plan how to accommodate this growth in demand. PSE is ramping up programs to encourage customer EV adoption, incentivizing off-peak charging to limit grid demand, and establishing an EV charging network. However, the pace of EV demand will quickly exacerbate system constraints. To counter this PSE, is implementing the LoadSEER tool coupled with AMI data with the objective of aligning forecast load growth all the way down to the local customer level. By doing this, PSE can gain a better understanding of customer load growth and offer a suite of solutions including but not limited to distribution circuit upgrades and local battery storage as appropriate. Until that information is available in 2022, the study assumed the worst-case scenario – that all EV load is added to the forecasted distribution system peak demand.

Figure 1: August and December Weekday Peak Load Impacts by Duty

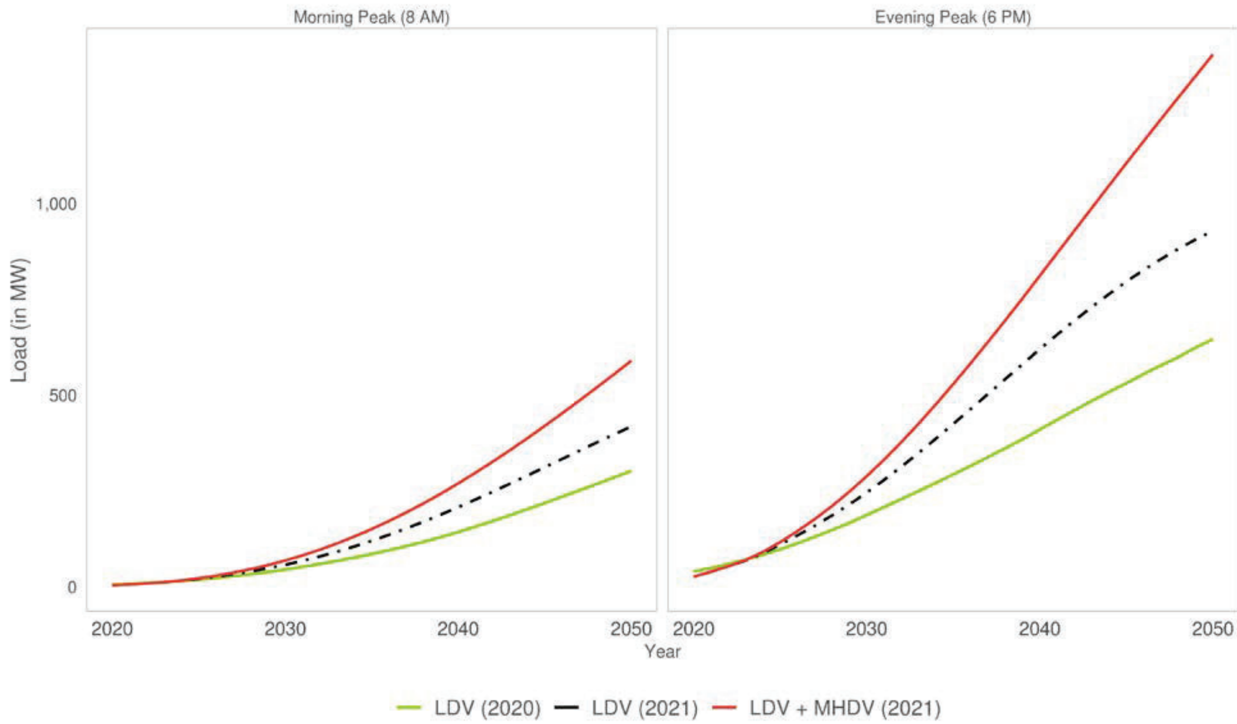


Source: Guidehouse

2.1. Data Analytics Fleet Demand

PSE is anticipating a total of 14 MW of load increase due to fleet electrification by 2026. Reference Figure 2 for the predicted daily peak demand increase. PSE is also working with multiple customers to enable the connection of new fleet charging facilities. Significant existing distribution capacity impact is expected from one of the large PSE customers proposing EV fleet charging in (6) different locations served by PSE. The impact from this customer's fleet electrification is not captured by the load forecast and studied as an addition to the overall forecasted load peak resulting in a total 50.6 MW of load by 2026. Total distribution capacity impacts would necessitate the addition of (4) four new distribution transformer banks and (15) feeders. Funds associated with constructing new substations are included in the project initiation program and not captured under the EV enablement plan. The EV fleet impacts for this plan include distribution circuits and existing substation upgrades needed to connect the new load. The estimated cost of enabling EV fleet can increase as more major customers shift their fleet conversions to EV.

Figure 2: Daily Peaks by Study and Duty



2.2. Data Analytics Residential Demand

Widespread LDV adoption in residential areas significant impacts our existing distribution infrastructure, specifically service transformers. PSE has approximately 223k single service transformers, 136k currently have visible loading data from AMI (advanced metering infrastructure) enabled.

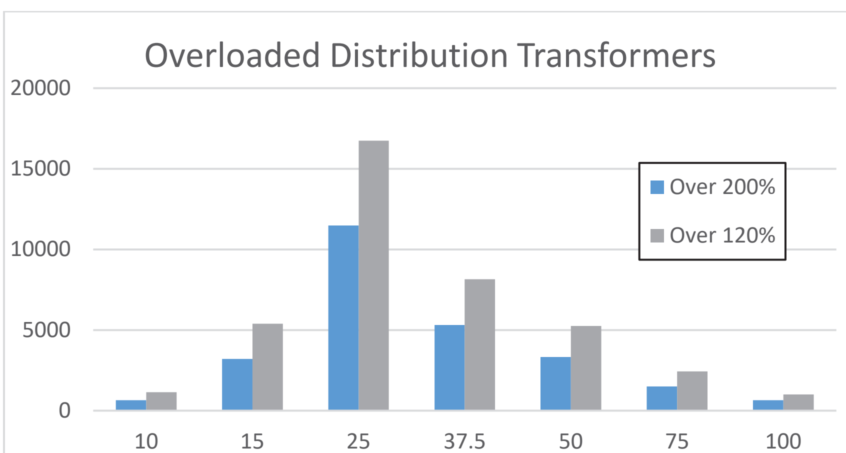


Figure 3: Service Transformers Loaded more than 120% over Nameplate

Based on current AMI data, over 40k distribution transformers are over 120% loaded with ~26K of those over 200%. While these units are designed to be overloaded, prolonged heavy loading reduces the life of the equipment and leads to more frequent failures and customer outages. Assuming that the increase in residential EV load will be evenly distributed across the exiting transformer population, between 10-20% of the currently overloaded transformers will need to be upgraded within the next 5 years as more residents install EV chargers to their existing household panels. Using this Asset Health information, we can proactively target specific circuits and service areas to improve residential capacity.

3. STATEMENT OF NEED

PSE is committed to providing safe, reliable, affordable energy service to our customers and working with them to act on climate change. Load forecasts predict a 120 MW increase in incremental peak demand by 2026 – which prompts circuit enablement actions. The existing distribution system requires upgrades so meet the increasing EV load demand.

3.1. NEED DRIVERS

Grid Modernization –

- **Reliability** – New EV load demand overloading transformers will lead to earlier and more frequent outages, with reduced capacity limiting switching flexibility and extending outage times.
- **Smart & Flexible** –Proactively planning system upgrades using forecast and granular customer/feeder data to anticipate customer needs as well as system constraints.
- **Capacity**- According to the Load Forecast, a 120 MW peak demand increase is expected for the entire PSE system by 2026, solely from EVs.

3.2. INTEGRATED STRATEGIC PLAN (ISP) ALIGNMENT

This plan aligns primarily with the Processes & Tools category of the ISP:

System Reliability and Integrity: Targeted improvements to address local system capacity enabling EV loading will support operational excellence and major commercial and residential customer satisfaction as well as improve customer reliability.

Streamline processes to drive effectiveness and efficiency: This plan shall serve as a feedback loop to mature forecast models and other various PSE plans tackling constraints on the system. Ultimately, the assets upgraded are able to address several needs throughout the system.

Extract and leverage value from existing technology and assets: The use of AMI data to identify specific customer transformer loading and usage pattern changes is critical to proactively identifying stressed equipment. That AMI usage data combined with improved local load forecast systems using LoadSEER will allow real time and future load flow studies to plan for localized EV implementation.

4. PLAN DETAIL

4.1. Plan Size/Population

The plan can be split into residential/ LDVs and fleet/ MHDVs. This plan addresses emerging capacity needs across PSE's entire region, focusing specifically on known customer fleet projects and distribution transformers that are already overloaded and would need to be upgraded to meet increased loading. As more major customers develop EV fleet conversion projects, the areas of concern will increase.

PSE is working to incentivize off-peak loading for residential customers (as commercial customers have a more consistent demand profile.) As more is learned about the results of such efforts, system-wide load forecasts may be reduced, but until that information is learned PSE must plan for the worst-case scenario.

4.2. Proposed Completion Date

This plan is ongoing to match load forecasts as EVs begin to dominate the market. Current plans are through 2026.

4.3. Summary of Plan Benefits

Proactively address system infrastructure constraints for electric vehicles which reduces outages due to overloaded transformers.

Increase DER data knowledge through EV demands, increase granularity of evolving customer loads through LoadSEER to implement system-wide solutions.

4.4. Primary iDot Categories

The primary iDOT Categories related to this plan are:

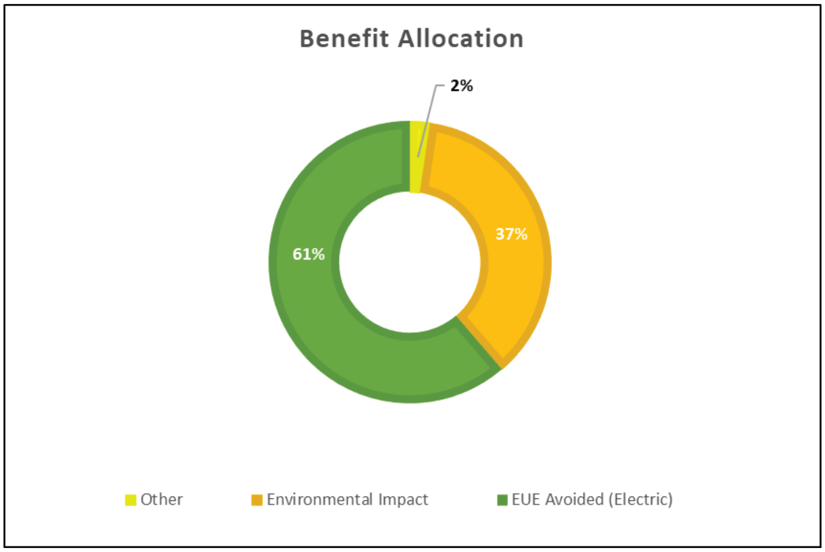
- Expected Unserved Energy: Addressing the need to have sufficient capacity to serve the increasing energy needs of customers.

Table 3: Summary of Plan Benefits and Population

2022-2026	Non-MED CMI Saved (M)	Number of Locations	Budget ($M)[1]		NPV ($M)[2]	iDOT B/C Score[3]
			Capital	OMRC	Total Benefits	
Total	**8.6**	**4,000**	**56.6**	**N/A**	**1,287.48**	**24.29**

[1] Budget indicate are sum of future year budget as it is allocated for that specific year
[2] Benefits indicated are Net Present Value (NPV) sum of future year benefits allocated for that specific year
[3] B/C Score uses NPV of Benefits and Budget

Figure 1: Benefit Allocation[4]



4.5. Estimated Total Costs

Estimates are based on available fleet costs from planned partner projects. At least $51M by 2026. The cost of upgrading all heavily overloaded service transformers based on current upgrade estimates by size is shown in Table 4. While all overloaded transformers are eventually replaced, for the time scale of this project, estimates assume that only 20% will need to be upgraded or replaced by 2026. That makes the residential portion of the budget $33.4 million.

Table 4: Upgrade Cost Estimate by Service Transformer Size

Size kVA	# Over 200%	Upgrade Cost
10	656	$5,000
15	3200	$5,000
25	11489	$5,500
37.5	5319	$6,500
50	3328	$8,500
75	1512	$10,000
100	647	$10,000
Total Population Cost		**~$167,000,000**
2022-2026 Estimated 20% Replacement		**$33,400,000**

[4] Risk of not achieving budget and expected benefits is 48.0%

The final expected cost of adding charging infrastructure associated with the fleet (MDV+HDV) is $23,203,749. Per year expected fleet cost can be found in Table 5.

Table 5: Fleet Expenditures by Year

EV Plan Spending/Year	Fleet $ Load Forecast Only	Fleet $ With Major Customers Block Loads
$3,350,000	$35,805	$6,035,805
$7,600,000	$196,073	$3,996,073
$12,000,000	$576,656	$5,276,656
$14,000,000	$995,021	$6,495,021
$14,350,000	$1,400,193	$1,400,193
$51,300,000	$3,203,748	$23,203,748

New circuit costs associated with fleet infrastructure upgrades are:

1. New distribution substation circuit breaker installation - $0.1M
2. Upgrades to existing distribution substation enabling new circuit breaker - $0.3M
3. New feeder cost per mile – $0.5M

5. ALTERNATIVES

5.1. Solution alternatives

No Action – Reduced reliability and increased outages as growing demand taxes existing infrastructure. Heavily overloaded transformers will fail at a higher rate, causing unplanned outages and increasing CMI. Unplanned work has a higher cost than planned worked. Reduced distribution capacity also makes it more difficult to connect new customers. For fleet, no funding would mean not planning proactively and preventing industrial partners from quickly/efficiently roll out their EV plans, prolonging environmental impacts from non-EV vehicles.

5.2. Funding alternatives

Increase Funding from Proposed – Reach out to more customers, plan further than 2026, and more rapidly invest in better modeling tools and AMI expansion to better identity impacted areas. This could include incorporating satellite images of industrial areas to estimate fleet density and locations.

Decrease Funding from Proposed – If the funding is decreased below the level needed to support fleet demand, then we would see an associated decrease in reliability and capacity, similar to No Action being taken.

6. PLAN DOCUMENT HISTORY

Date	Reason(s) for Update	Summary of Significant Change(s)	Modified By
5/1/2021	Initial Plan	Initial document	Vic Eder, Alex Karptsov, Joseph Do
12/1/2021	Review	Minor word and format changes	Vic Eder, Alex Karptsov, Joseph Do

7. SUPPORTING DOCUMENTATION

Document Name
GUIDEHOUSE STUDY
F21 FINAL LOAD FORECAST_072321
ASSET HEALTH DASHBOARD

SUBSTATION SCADA

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

This plan will bring Supervisory Control and Data Acquisition (SCADA) capabilities to PSE's distribution circuits through equipment upgrades and improvements. SCADA implementation includes installation of controllers, relays, sensors, software and IT (Information Technology) upgrades for communication. These upgrades typically apply to the substation breakers on the 12.5kV distribution system and enable data collection and communication between equipment in order to function automatically or controlled remotely if needed.

2. BACKGROUND

PSE has approximately 268 distribution substations. These substations transform transmission level voltage (typically 115kV) to a distribution level voltage (typically 12.5kV) to safely deliver power to residential and commercial neighborhoods. These distribution substations are important electrical hubs and there are many different pieces of substation equipment, e.g. Breakers, Transformers, Relays that send status updates, alarms and diagnostics data for Operators to monitor and control the system, in real-time. In addition, this information allows planners to identify short and long-term deficiencies and propose system improvements to ensure a reliable and safe electrical grid.

SCADA is a communication system used to remotely monitor and control substation or field equipment. Key information, such as circuit breaker status and transformer loading, can be obtained almost instantly and transmitted to PSE's Control Area operations center.
To enable SCADA capability at all PSE substations, it will be required to replace much of the aging equipment directly affected. The remaining vacuum type breakers will be replaced with new smart breakers which include micro-processor relays. This in turn drives the replacement of aging control cables and older type RTU (Remote Terminal Units), amongst other distribution related equipment in the substation.

2.1. Plan History

Late 1980's - PSE invested in an Energy Management System (EMS), which allowed Operators to visualize substation data. At the time, this was a new technology in the industry that many other utilities started to adopt. As the company gained familiarity with EMS, an early Distribution SCADA plan was initiated to add SCADA equipment to substations to provide transformer MW, MVAR, MVA, and single-phase distribution feeder amps back into EMS for visualization.

1990's – As PSE learned more about communication needs and additional benefits were evaluated, the Distribution SCADA Plan scope was revised to include three-phase feeder amps, as well as, feeder breaker status (Open/Close). Some breakers were retrofitted with new SATEC meters, while others were replaced with new circuit breakers with the meters built-in.

2000's – In the early 2000's, the Distribution SCADA plan was accelerated to upgrade approximately 10 substations a year, to bring these benefits to the remaining distribution substations. In the late 2000's, distribution circuit breaker supervisory control was added to the scope of the plan. Some breakers were retrofitted with remote control switches, while others were replaced with new circuit breakers with the remote control capability.

2016 – In 2016, all distribution substations were planned to be upgraded to meet the intent of the original Distribution SCADA plan (feeder breaker three-phase amps and status, & transformer loading data). At this time, it was determined to continue the Distribution SCADA plan renamed as the Substation SCADA program. This included focus on adding supervisory control to the remaining distribution substations and feeder breakers while also enhancing SCADA equipment in the control house.

As of the end of 2020, approximately 123 of the 268 substations have SCADA capabilities on all distribution substation breakers. The plan aligns with the internet protocol (IP) SCADA plan as PSE extends its fiber network and upgrades communication panels in each substation control house to support the installation of new relays and SCADA enabled equipment. At the current rate of implementation, PSE will complete the implementation of SCADA on remaining 145 substations by 2035.

2021 - The 2021 IRP recommends a substantial addition of DERs in order for PSE to meet compliance with the Clean Energy Transformation Act. Substation SCADA also facilitates increasing use of distribution automation for improved reliability and resiliency, a customer benefit indicator desired by CETA, and also the ability to operate and respond effectively to DER operations and the complexity that increases as more are added to a particular circuit or substation. Substation SCADA also is needed to advance the combination of these two benefits in the deployment of microgrids. These capabilities are not possible without Substation SCADA. PSE can wait until each DER interconnects at which time address SCADA and other enhancement needs. This approach will slow down operationalizing DERs and limit DER potential to offers that can afford higher interconnection costs. However, since PSE's plan is to ensure all substations have SCADA capabilities for reliability reasons, timing this programmatic plan to CEIP pace provides additional benefits of making more substations DER ready. PSE's plan is to accelerate Substation SCADA deployment from 2035 to 2029 mid-way through PSE's second CEIP.

3. STATEMENT OF NEED

The lack of supervisory control at distribution substations reduces the ability of system operators from operating the system in a timely manner to effectively reduce outage time during an event, and the restoration of service to customers. In addition, there can be multiple substation equipment that is at the end of its life, which can lead to additional reliability concerns. As Distribution Automation (DA) becomes a wide-spread solution, there are necessary upgrades needed to provide SCADA capability to substation equipment which allows us to implement the automation solution successfully. SCADA enabled breakers will allow for improved fault detection and provide the ability to restore power to customers faster. In order for the DA plan to be effective and provide reliability benefits to the customers, it is necessary to have SCADA enabled breakers and equipment on the relative circuits being upgraded under the DA plan.

3.1. Need Drivers

- **Grid Modernization –**
    - **Reliability** - The primary benefit of the Substation SCADA plan is improved reliability for Distribution circuits. The ability to remotely monitor and operate circuit breakers will allow System Operators to restore customers faster and reduce overall outage durations.
    - **Smart & Flexible** - Adding new smart breakers will provide the foundation of sensing and control for new advanced technologies, such as ADMS, DA FLISR and VVO, which will support System Operators to provide added flexibility to the system, improve reliability and enable customers to connect DERs.
    - **Resiliency –** Smart breakers combined with DA systems help detect and locate faults faster. Through new effective switching and protection schemes in place, PSE can restore power to customers faster and remotely. This improves resiliency by protecting the infrastructure from further damage and maintain service to our customers.

3.2. Integrated Strategic Plan (ISP) Alignment

This plan aligns primarily with the Processes & Tools category of the ISP:

- **System Reliability and Integrity**: The main driver for this plan is to reduce the duration of outages, giving System Operators the remote monitoring and remote capability to restore customers faster.
- **Streamline processes to drive effectiveness and efficiency:** This plan drives effectiveness and efficiencies by addressing multiple benefit streams within the same scope of work. For example, adding supervisory control improves customers' reliability, replacement of aging infrastructure addresses reliability and safety concerns, and improved data quality/information provides ability to easily execute on other reliability plans and smart grid efforts successfully, such as distribution automation and CVR/VVO.
- **Extract and leverage value from existing technology and assets:** When appropriate, each reliability project scope will utilize existing equipment to optimize project costs.

4. PLAN DETAIL

4.1. Plan Size/Population

As of the end of 2020, there are approximately **145 substations** requiring supervisory control for some or all breakers. This plan will ensure all PSE owned feeder breakers have supervisory control. Substation SCADA projects are prioritized based on multiple factors including failure history and number of customers impacted to provide benefit.

4.2. Proposed Completion Date

This plan has been accelerated to complete SCADA improvements on the remaining substations by 2029 in alignment with 2030 CETA requirements. Delivery of this plan is based on crew availability per region and capacity to complete projects on time. Major challenges include being able to obtain multiple substation outages and the ability to pick up customers on the affected circuits, this could lead the grid to be less reliable while multiple substations are being picked up by neighboring substations.

4.3. Summary of Plan Benefits

Supervisory Control at the feeder breaker level provides reliability, operational flexibility and safety benefits.

- **Reliability** - The main driver for this plan is to reduce the duration of outages, giving System Operators the remote capability to restore customers faster.
- **Operational Flexibility** - Provides added operational flexibility to System Operators to operate breakers, turn on/off reclosing, and toggle HLWS remotely, when field personnel are not available. Substation inspectors do not need to be on site to obtain information or operate equipment.
- **Safety** – Supervisory control of individual feeder breakers allow operators to de-energize or isolate circuits, rather than entire substations, quickly in case of any safety issues in the field.

SMART breakers allows for enhanced planning analysis and post-fault evaluation.

- **Data Integrity** - Ability to acquire MW & MVAR data points at the feeder level to evaluate feeder-level power quality for optimal Capacitor Placement and future CVR/VVO prioritization.
- Microprocessor relays can estimate the location of faults, giving operators additional real-time information to quickly send servicemen to isolate trouble areas. The relays also provide post-fault recording data for use in Root Cause Analysis, to resolve unknown or other unique fault events.

Replacement of Communication Remote Terminal Unit (RTU) at the end of life.

- **Situational Awareness**- RTU failures can lead to a loss of visibility and control, leading to immediate unplanned use of field personnel to repair/replace the equipment, and 1-2 weeks of loss visibility and control. Updated Remote terminal units under the SCADA plan will provide improved situational awareness.
- **Data Quality & Integrity** - The upgrade to IP SCADA allows for faster and improved data transfers, as well as higher data accuracy and granularity.

- **Communication Quality** - The replacement of RTU will allow for a higher reliability of communication and an increased confidence in the success rate of Distribution Automation.
- **Operational Flexibility** - In addition, upgrading to IP SCADA provides the ability for remote engineering access to breaker relays.

4.4. PRIMARY IDOT CATEGORIES

The top primary iDOT Categories this plan addresses are:

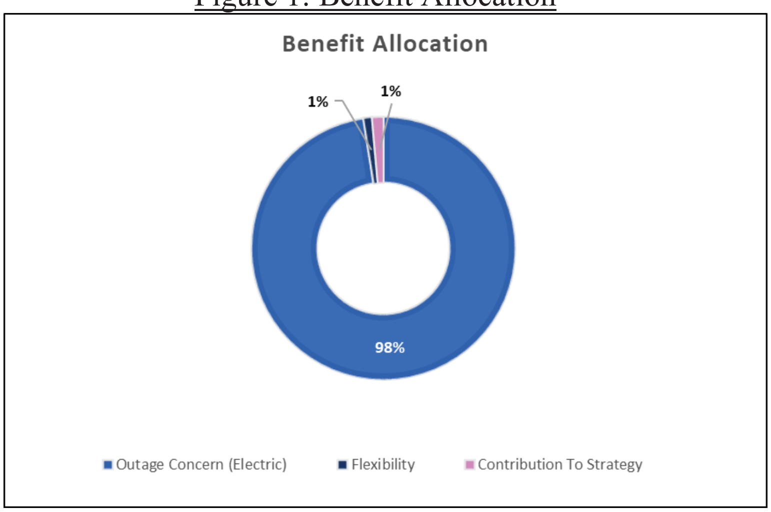
- Outage Concern - per impacted customer with the project
- Flexibility – improved operational flexibility benefits due to project upgrades

Sub SCADA plans are entered into iDOT at a plan level based on available funding and portfolio project count. Each project has a certain amount of customers which impacts the final CMI (Customer Minute Interruptions) benefits that can be achieved at that substation.

Table 1: Summary of Plan Benefits, Population and iDOT B/C

2021-2026	Non-MED CMI Saved (M)	Number of Substations	Budget ($M)[1]		NPV ($M)[2]	iDOT B/C Score[3]
			Capital	OMRC	Total Benefits	
Total	**32.5**	**115**	**93.75**	**0**	**258.6**	**3.73**

Figure 1: Benefit Allocation[4]



[1] Budget indicate are sum of future year budget as it is allocated for that specific year

[2] Benefits indicated are Net Present Value (NPV) sum of future year benefits allocated for that specific year

[3] B/C Score uses NPV of Benefits and Budget

[4] Risk of not achieving budget and expected benefits is 3%

4.5. Estimated Costs

Average historical cost are not applicable to future projects due to the wide variability and complexity of improvements needed within each substation. We've used $500k as a baseline starting point to estimate future projects. That amount was increased to $781k per substation to allow for variations in increase in the project scope, increase in project cost due to inflation, and added contingency to account for unforeseen conditions associated with each substation.

Starting in 2021, over an 8-year period, the projected total estimated cost for this program is approximately $105M, an annual funding level of $20 million per year from 2024 through 2026.

5. ALTERNATIVES

5.1. Solution alternatives

No Action – Lost opportunity to improve customer reliability and drive forward on Grid Modernization in a strategic and programmatic manner. Will not provide PSE the control to restore power quicker to customers and improve overall reliability.

One alternative to this proactive plan is replace assets with SCADA enabled devices as they fail leading to impacts to customer reliability during fault events.

Another alternative is to add SCADA enabled breakers without Supervisory control which would still provide visualized load data in the EMS (Energy Management System) at a lower cost, but with no Supervisory control, the equipment could not be remotely operated to restore power to customers faster. This slows restoration time and reduces operational flexibility while also not improving safety by requiring substation personnel to directly operate the equipment.

5.2. Funding alternatives

Increased Funding – Increasing funding will allow for increased circuit eligibility for Distribution Automation-FLISR to be added. It will also increase System Operations' ability to control field equipment and improve situational awareness.

Decreased Funding – Decreasing funding will mean some of the coordinated circuits aligned with Distribution Automation-FLISR would need to be deferred. It will also slow down System Operations' ability to control field equipment and provide situational awareness on more of the PSE circuits.

6. PLAN DOCUMENT HISTORY

The current version of the project summary supersedes all previous versions.

Date	Reason(s) for Update	Summary of Significant Change(s)	Modified By
10/25/2019	Substation SCADA Business Case - New plan template	Document history and development of the plan	Colin O'Brien
04/17/2020	Format Update	Addition of IDOT Benefit Summary	Reid Shibata
03/25/2021	Change of Ownership	Annual Program updates based on budget adjustments	Stephen Hartnett
07/08/2021	Used and Useful Policy guidance	Add alternative and cost information	Stephen Hartnett
12/1/2021	Annual Review	Minor words and format changes	Stephen Hartnett

7. SUPPORTING DOCUMENTATION

Document Name
N/A

VEGETATION VIRTUAL RIGHT OF WAY PROGRAM

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

This is a proposal for a program to remove trees at risk of falling into PSE's electric system resulting in an interruption of service to customers. The focus will primarily be on removing dead and dying trees from off right-of-way (ROW) as well as any trees in the ROW that grow fast enough to risk damage to the system between normal tree trimming cycles.

In order to optimize funding to focus on removing trees where the benefit to cost ratio is greatest, the project also includes evaluating new tools, including satellite, LIDAR and machine learning solutions that can help to evaluate risks and benefits and to prioritize work.

Puget Sound Energy is requesting that the cost for the program be deferred and amortized over 10 years, which is the expected length of the growth cycle of replacement trees.

2. BACKGROUND

In 1998, a Virtual Right-of-Way (VROW) tree removal program, known as Tree Watch, was approved (see docket No UE-980877) which removed trees along 6,430 miles of the electric system on 323 distribution circuits. The purpose of the program was to identify and remove trees whose structural integrity had been compromised. Rather than purchasing additional ROW before removing trees, PSE worked with landowners to remove high risk trees to achieve the same benefits at a greatly reduced cost. The program began in 1999 and ended in 2005 costing approximately $44,000,000. The program expected to see a 15% decrease in non-storm outages that lasted 20 – 25 years. Analysis in 2005 showed an average yearly savings of 22%

PSE's current tree removal program consists primarily of removing trees within the 12 ft. ROW, prioritized based on circuits identified as having poor reliability performance with respect to vegetation caused interruptions or based on recommendation from employees working in the field identifying high risk areas. This work has an average annual budget of $2,000,000 and removes an average of 5,000 trees per year.

Though PSE has a robust process for evaluating the root cause of tree failures affecting large numbers of customers, which helps in understanding the impacts of tree failures on the system, it has not had sophisticated tools to help identify and prioritize high risk areas system-wide, especially with respect to trees off of ROW. This is primarily because it is difficult to track the millions of trees in PSE's territory that are constantly changing and identify which ones are at highest risk of failing and impacting PSE customers.

The new tree removal program proposal is an update of the original VROW tree removal program whose benefits have ended and expands current vegetation management practices to include tree risks outside the normal scope of vegetation work. Additionally it seeks to evaluate and implement advanced tools to better identify risks and prioritize work.

3. STATEMENT OF NEED

PSE Roughly 32% of outages and 77% of SAIDI minutes on PSE's electric transmission and distribution systems are caused by vegetation. Of the vegetation caused outages, PSE estimates more than 80% are caused by trees outside the ROW. Additionally, vegetation caused outages may be increasing. The number of non-Major Event Day (MED) vegetation caused outages increased by about 140 per year from 2014 through 2020 (see Figure 1). The impacts of a continued drought are likely to increase the number of dead and dying trees and may accelerate vegetation caused outages in the near term.

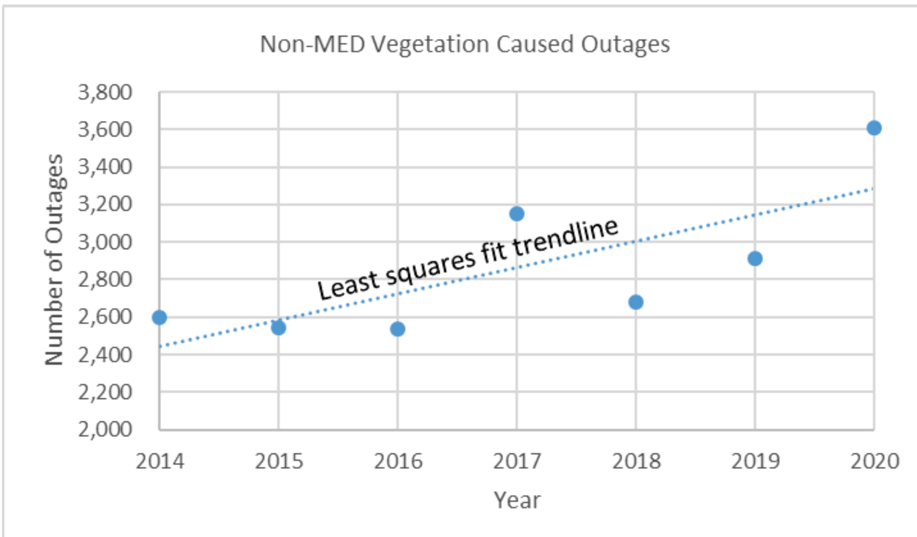


Figure 1. The number of vegetation caused outages has been increasing.

PSE has a goal to push SAIDI performance from the third quartile of the annual IEEE PES DRWG benchmarking survey into the second quartile. As vegetation caused outages are such a large component of SAIDI, a cost effective method for achieving this improvement in reliability will not be possible without addressing dead and dying off ROW trees. Though it is difficult to estimate the exact impact, a tree removal program is expected to reduce the average number of vegetation caused outages by 20% on a given circuit with the benefit lasting for an average of 10 years.

The alternatives are to implement capital projects that prevent outages such as underground conversions or that mitigate outage impacts such as automated fault location, isolation and restoration projects. In many areas these solutions are more expensive to implement or provide fewer benefits than removing high risk trees.

4. PROGRAM DETAIL

4.1. SCOPE

The long term scope for the program could affect 1/3, or more, of circuits within PSE's territory and could improve reliability for about 1/3 of PSE customers. The work would target dead and dying trees from drought or disease, problem tree species and other trees with high risk factors that result in tree failures. The program also includes improved tracking of when and where trees are removed for accurate benefit validation and improved benefit prediction over time.

4.2. Implementation Plan

The program would be implemented using a phased approach. The first phase would be the 3 year period from 2023 – 2025 and would be focused on building the capabilities to best prioritize work and measuring results of the program on approximately 120 circuits. Depending on the results of the first phase, the second phase would increase the amount of work performed and modify components of the implementation to achieve better results or discontinue the program if the program cannot provide a reasonable benefit to cost ratio. The second phase would continue the work for another 3 – 5 years.

The program will initially prioritize areas to implement the program based on the potential reliability improvement benefits, which includes factors such as predicted outages saved, number of customers impacted and average outage duration. PSE built a machine learning model using historical outage, weather and vegetation program data to produce a preliminary prediction of savings at the circuit level, but more accurate results can be obtained with greater amounts and quality of data. Improvements to data collection and the use of advanced tools and data sets, such as satellite, LIDAR and machine learning, will allow prediction models to improve over time, resulting in a more efficient optimization of resources.

4.3. Customer Engagement

PSE's Vegetation Management Service Provider (Asplundh Tree Expert LLC) uses utility arborists to identify and target trees for removal. These contract arborists contact the owner of the property and ask for permission to remove the vegetation targeted for removal. The contract arborists are trained to explain the reasons for the tree removal and the benefits to customers. Additionally, communication via social media and other channels can be implemented to support awareness of the program and the benefits of a hazard tree removal program as well as "Right Tree, Right Place" messaging to help improve what types of trees are planted and where to prevent future issues.

An expanded hazard tree removal program will require additional contract arborists to negotiate tree removals with property owners. This labor resource is somewhat constrained in today's market, and may require some time to add the appropriate level of resources depending on the scope of the program. For this reason, and to accommodate other constraints, the amount of work will increase gradually over a 3 year period.

4.4. Regulatory Considerations

An expanded hazard tree removal program will require a significant amount of tree planting in order to mitigate the impacts of tree removal. This mitigation may occur due to several reasons:

- Most jurisdictions in PSE service territory require replacement trees to be planted to compensate for the ecological and aesthetic loss of trees that are removed. This may take the form of planting tall growing native vegetation in a site away from the location of the tree removals. Sometimes jurisdictions require trees to be replaced in the same area as the removed trees, which require lower growing ornamental trees to be planted.
- Outside of jurisdictional requirements, tree replacements are also sometimes necessary to compensate a property owner for the loss of their hazard trees. This may take the form of replacement trees or other compensation that mitigates for the ecological and aesthetic contributions of the removed tree to the property

4.5 Program Management

PSE's Vegetation Management department will perform the program management, contractor oversight, and overall implementation for an expanded hazard tree removal program. PSE's Vegetation Management Service Provider (Asplundh Tree Expert, LLC) would perform the day to day management of the tree removal planning and execution, along with data collection and reporting.

4.6 Benefits

Better management of off-right-of-way trees presents a valuable opportunity to reduce both storm and non-storm related outages for PSE, which will have a positive impact on the customer experience as well as on PSE SAIDI and SAIFI service quality indicators.

PSE estimates that the program can prevent approximately 20% of vegetation related outages on all impacted circuits. This estimate is taken from results from the previous Tree Watch program, in which vegetation related outages on impacted circuits were reduced by 22%, and by a predictive model developed by PSE in which an estimated savings of 24% were forecasted for a subset of potential circuits. This reduction in outages will provide 2 main benefits:

1. Reliability improvement – reduced number of customer interruptions and the associated reduction in SAIDI and SAIFI
2. Reduced O&M costs – reduction in restoration costs associated with damage caused by trees falling into system infrastructure

PSE estimates that the program can prevent approximately 20% of vegetation related outages

4.7 Reliability Improvement

To calculate SAIDI, SAIFI, and overall outage savings for the first 3 year phase of the program, a 20% reduction in vegetation caused outages was applied to a portion of the system and averaged for a typical reliability improvement per circuit. These were calculated to be:

- Predicted % reduction in outages: 20% reduction in outages/circuit
- Associated total SAIDI savings: 0.08 SAIDI savings/circuit
- Associated total SAIFI savings: 0.0005 SAIFI savings/circuit

Decreased funding would result in fewer DA FLISR schemes being implemented. PSE would see fewer outage reduction benefits and overall the corporate outage reduction metrics would see less improvement.

The initial phase will be focused on the 120 circuits that will benefit most from the program, which will result in an estimated:

- 390 fewer interruptions/year
- 9.6 minutes total SAIDI savings
- 0.06 total SAIFI savings

4.8 Reduced O&M Costs

On average, each vegetation caused outage costs approximately $5k to repair the system and restore power to customers. At this cost, 390 fewer interruption per year results in a savings of nearly $2M per year in restoration costs.

4.9 COSTS

The first phase of the program is expected to cost approximately $27 million and the remainder of the work to cost approximately $60 million, the majority of which is directly related to tree removals. Approximately $1,000,000 would be dedicated to developing new tools to optimize tree removal work as well as improve prioritization of other vegetation management activities. Table 1 shows the estimated yearly project costs.

Table 1. Estimated yearly program costs by Phase

Phase 1				
Year	**# Circuits**	**Tree Removal Cost**	**Tool Development**	**Tool Maintenance**
2023	25	$5,000,000	$1,000,000	$100,000
2024	40	$8,240,000		$103,000
2025	55	$11,669,900		$106,090
Total	120	$24,909,900	$1,000,000	$309,090
Phase 2				
Year	**# Circuits**	**Tree Removal Cost**	**Tool Development**	**Tool Maintenance**
2026	50	$10,927,270		$109,273
2027	50	$11,255,088		$112,551
2028	50	$11,592,741		$115,927
2029	50	$11,940,523		$119,405
2030	50	$12,298,739		$122,987
Total	250	$58,014,360	$0	$580,144

When entered into PSE's investment decision optimization tool (iDOT), the calculated benefit to cost ratio for Phase 1 is 4.7. This is generally considered a good score and is better than many other funded reliability focused projects and programs.

5 FUNDING ALTERNATIVES

Multiple alternatives to this project were considered. These include:

- No action
- Buying ROW
- Increased funding scenario – 50% additional funding for program
- Decreased funding scenario – 50% less funding for program

5.1 No action

If no action is taken, neither the predicted customer outage minute savings nor the O&M savings will be realized. As a result, achieving reliability targets will become less cost effective.

5.2 Buying ROW

Purchasing ROW was estimated to cost greater than $2 billion in 1998. At 2022 prices, we estimate a similar cost of over $3.1 billion to purchase additional right of way. As these costs are much higher than, and the benefits similar to, those for a virtual ROW vegetation program, a virtual ROW vegetation program is the better option.

5.3 Increased Funding Scenario – 50% additional funding

Although this scenario might further improve SAIDI and SAIFI, diminishing returns may result in unjustified costs to achieve those improvements. The current scope is an estimate of the amount of work that is most cost effective. As more information is gathered from the program and better predictions of costs and benefits can be made, the scope may be adjusted.

5.4 Decreased Funding Scenario – 50% less funding

Decreasing funding by 50% may reduce the reliability and O&M savings benefit by less than 50% as the program is focused on addressing areas that have the largest benefit first. However, in order to achieve the same overall benefit, less cost effective alternatives, such as underground conversions, would need to be implemented.

6 SUPPORTING DOCUMENTATION

Reference 1988 Tree Watch Proposal – docket UE-040926?
Reference wildfire mitigation plan – docket #??
Reference reliability report – docket #??