2021 PSE Integrated Resource Plan

M Delivery System 10-Year Plan

This appendix presents the 10-year electric and gas PSE-owned delivery infrastructure plans.

Contents

1. OVERVIEW

The PSE electric and natural gas delivery systems are planned to deliver energy through pipes and wires, safely, reliably and on demand; to fully meet all regulatory requirements, including NERC standards that govern the bulk electric system and PHMSA regulations that govern pipeline safety; and to be prepared to meet customers' future energy needs. The systems must be flexible enough to adapt to growing changes in customer uses, include more diverse clean resources, and manage increased complexity.

Modernizing the delivery system is a priority in both plans, as is aligning those plans with resource planning results. This includes a range of key foundational technology investments, specific asset hardening to improve reliability and resiliency to major events, intelligent demand-side management systems to optimize energy use, and backbone major infrastructure improvements.

2. ELECTRIC DELIVERY SYSTEM

Existing Electric Delivery System

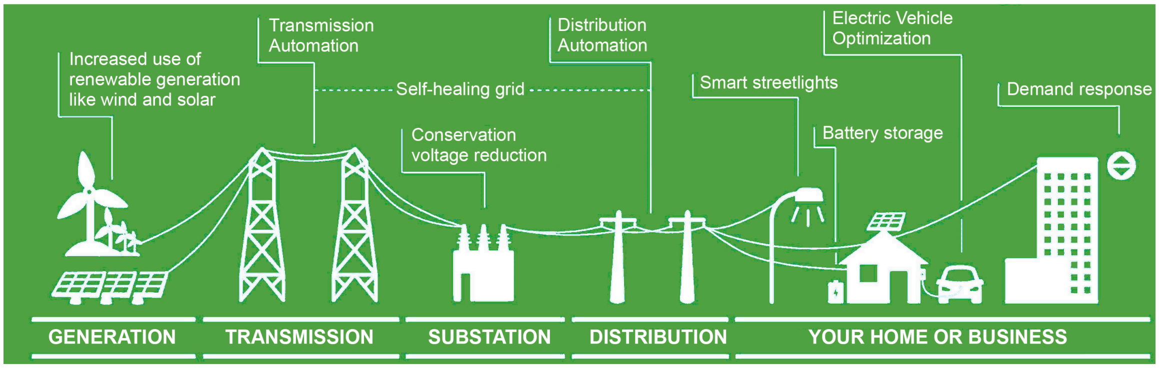
The table below summarizes PSE's existing electric delivery infrastructure as of December 31, 2020. Electric delivery is accomplished through wires, cables, substations and transformers.

Figure M-1: PSE-owned Transmission and Distribution System as of December 31, 2020

PSE-OWNED ELECTRIC DELIVERY SYSTEM AS OF 12/31/20
Customers: **1,189,754**
Service area: 4,500 square miles
Substations: 353
Miles of transmission line: 2,743
Miles of overhead distribution line: 9,823
Miles of underground distribution line: 13,898
Transmission line voltage: 55-500 kV
Distribution line voltage: 4-34.5 kV
Customer site voltage: less than 600 V

How the Electric Delivery System Works

Figure M-2: Illustration of Electric Delivery System



Electricity is transported from power generators to consumers over wires and cables, using a wide range of voltages and capacities. The voltage at the generation site must be stepped up to high levels for efficient transmission over long distances (generally 55 kV to 500 kV).

Substations receive this power and reduce the voltage in stages to levels appropriate for travel over local distribution lines (between 4 kV and 34.5 kV). Finally, transformers at the customer's site reduce the voltage to levels suitable for the operation of lights and appliances (under 600 volts). Wires and cables carry electricity from one place to another. Substations and transformers change voltage to the appropriate level. Circuit breakers prevent overloads, and meters measure how much power is used. Distributed energy resources such as wind, solar and biodigesters are being added to the distribution system.

The electric grid, first built 1889, expanded in a highly radial, one-way flow design. Over time, the transmission system was looped in a network manner as outages across the nation drove voluntary standards and eventually regulations requiring operations with one or more elements out of service. In urban areas, a distribution system with looped feeders became common practice to improve reliability. It still operated in a radial, one-way flow manner, but as automation and protection devices mature, some parts of the distribution system are able to automatically switch to a different source.

Nearly 100 percent of the transmission system is networked and over 80 percent of PSE's distribution system is looped.

10-Year Electric Delivery System Plan

Increasing amounts of distributed energy resources like rooftop solar, growing electric vehicle loads, greater emphasis on demand-side resources and the clean energy transformation are changing the demands on the electric delivery system. The 10-year electric delivery system plan is designed to maintain safe, reliable energy delivery to customers, meet NERC compliance requirements and evolving regulations related to integration of distributed energy resources, and support the clean energy transformation and maximize its benefits. To meet these goals, in the next 10 years, PSE will:

- modernize the grid to ensure visibility, analysis, and control through investments in technology, analysis tools and infrastructure.
- ensure reliability and resiliency by leveraging technology capabilities and infrastructure.
- modernize the distributed energy resource (DER) integration processes to improve opportunities to optimize value
- maintain focus on cyber security and privacy
- address location-specific capacity, reliability and resiliency needs with major backbone infrastructure projects as needed

As discussed in Chapter 4, Planning Environment, integrated resource planning (IRP) and delivery system planning (DSP) are converging as delivery system solutions like distributed energy and demand-side resources play a larger role in meeting resource needs and deferring investment in traditional generating resources. The public engagement process for DSP planning will also be expanded and aligned with the IRP process as discussed in Appendix A, Public Participation.

This is an iterative process, and as integration proceeds, the sharing of data and results between the IRP and DSP processes will better inform future cycles and enable PSE to create more specific alignments between the IRP, the Clean Energy Action Plan and the Clean Energy Implementation Plan. As distributed energy connections grow in both numbers and total MWs, this integration is increasingly important. The 10-year electric delivery plan will continue to mature to fulfill the full intent of RCW 19.280.100 (2) (e) over the next several IRP cycles as new data, market research and cost/benefit studies are used to further develop the plan. Finally, PSE will continue to build on its robust delivery system planning and optimization process, leveraging strong cost/benefit analysis and rigor to inform scenario constructs while furthering integration with IRP processes.

PSE's active involvement in many expert and science-based research organizations such as the Western Energy Institute, Edison Electric Institute (EEI), Electric Power Research Institute (EPRI), and in distribution planning, distributed energy and resiliency groups, will support and enhance our efforts to meet our goal of maximizing the clean energy transformation benefits.

The 10-year electric infrastructure plan includes key investments in the areas of grid visibility, analysis and control; grid reliability and resiliency; cyber security and privacy; integrating distributed energy resources; and addressing backbone infrastructure needs. Figure M-3 summarizes the major elements of the plan. Discussion of the key investment areas in the following pages highlights the fact that these investment areas are interrelated. The 10-year plan addresses needs that are either existing or predicted based on the processes described in Chapter 8, Electric Analysis. Delivery system studies including NERC Planning Studies are performed every year, and these studies will surface new needs or constraints in future 10-year plans. In addition, the outer years of the plan may change substantially during this time of grid and load evolution. Like the IRP, the 10-year plan provides overall direction to inform decisions about specifically funded actions and plans.

Figure M-3: Summary of 10-Year Electric Delivery System Plan

10-YEAR ELECTRIC DELIVERY SYSTEM PLAN SUMMARY	
VISIBILITY, ANALYSIS AND CONTROL	
Foundational Technology	Advance Metering Infrastructure (AMI) Advanced Distribution Management System (ADMS) Distributed Energy Resource Management System (DERMS) / Virtual Power Plant (VPP)
Smart Equipment	SCADA devices GIS enhancements Geospatial Econometric Forecasting
RELIABILITY AND RESILIENCY	
System health replacements and upgrades to system components to address aging infrastructure	Upgraded transmission and distribution lines, transmission and distribution substations, cable replacement, worst performing circuits, pole replacement, and investments to ensure reliable "backyard sources."
As needed for integration of DERs and EV public charging.	Transformer upgrades, substation upgrades and circuit improvements

Reduce outage duration and enable DER effectiveness	Fault Location Isolation and Service Restoration (FLISR) and distributed automation
Manage increasing loads effectively and reliably	Demand response and time-of-use possibilities Reliable conservation New transmission lines, distribution lines and substations
Pilot projects to grow scalable technologies that solve delivery system challenges and build resiliency of communities and infrastructure	Microgrids
DER INTEGRATION PROCESSES	
Process maturity for efficient DER integration	Interconnection process refresh and customer engagement portal Hosting capacity capability and power flow tools Billing and administration process changes Non-wires solutions analysis process DER operating skills and procedures
SECURITY, CYBERSECURITY AND PRIVACY	
Ongoing security measures	Physical security of key assets Industry standards, protocols and requirements of technologies and vendors
ADDRESSING MAJOR BACKBONE INFRASTRUCTURE NEEDS	
Major backbone infrastructure projects are driven by capacity and reliability needs. These are discussed in detail starting on page M-14.	

Improving Visibility, Analysis and Control

Proactive investments in the foundational technologies that modernize the grid are critical to support the clean energy transition and maximize its benefits. The data availability, integrity and granularity they provide are essential to planning for and operating DERs, managing EV loads, and taking advantage of demand-side resources and non-wires delivery system solutions. These foundational technologies are described below.

ADVANCED METERING INFRASTRUCTURE (AMI). PSE is in year four of replacing the current aging and obsolete Automated Meter Reading (AMR) system and electric customer meters with Advanced Metering Infrastructure technology. AMI is an integrated system of smart meters, communications networks, and data management systems that gives both PSE and its customers greater visibility into customer use and load information and enables two-way metering between PSE and its customers.

In addition to ensuring reliable and accurate billing, the granularity of AMI data will allow PSE to respond to system needs quicker, support DER integration, offer advanced customer energy management tools and develop new rate structures to incent beneficial usage patterns. PSE has identified 38 unique use cases that could be implemented using AMI data, and time-of-use pricing pilots are currently under development.

ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (ADMS). PSE is also replacing the obsolete Outage Management System with Advanced Distribution Management System technology. ADMS is a computer-based, integrated platform that provides the tools to monitor and control the distribution network in real time. In addition to outage management capabilities, ADMS provides visibility and control to SCADA devices, distribution system management and advanced applications.

The implementation of ADMS is expected to be completed by 2023. This will enable advanced operational capabilities for DERs, including an integrated Distributed Energy Resource Management System (DERMS). As DERs become more prevalent, PSE will need to (1) monitor and visualize DERs and their interactions with the distribution grid, (2) control the DERs and (3) dispatch them. DERMS allows us to perform these tasks. DERMS is in an early stage of maturity in the industry, so exact capabilities vary across technology vendors. When DERMS is integrated with ADMS, it will allow full visibility to the system operator and allow for safe and optimal dispatch coordinated with other operations activities. Prior to a fully integrated ADMS DERMS, PSE expects that acquisition of a Virtual Power Plant (VPP) will be required to monitor and dispatch DERs. While the VPP will not have full visibility to the distribution system, it will enable aggregation, forecasting and management of DERs to meet resource capacity needs.

SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA). PSE anticipates completion of the Supervisory Control and Data Acquisition program at all substations by 2025 to provide real-time visibility and remote control of distribution equipment to reduce duration of outages, improve operational flexibility, and enhance overall reliability of the distribution system.

GEOGRAPHIC INFORMATION SYSTEM (GIS). DERs and transportation electrification are changing load patterns, but not evenly across the system. As a result, system planners require greater insight to the expected locations of DERs and EVs. Maintaining and augmenting PSE's GIS data will be increasingly central to developing the location-specific load information needed to plan for and manage these loads. PSE is working to evolve GIS processes so that changes in the field can be quickly incorporated and data such as DER asset information is collected and displayed.

GEOSPATIAL ECONOMETRIC FORECAST. PSE is also investing in a geospatial and econometric load forecasting tool to predict load and power changes, where on the grid the new loads will occur, how distributed generation (DG) changes the load shape, and when DG must be supplied. The tool will utilize GIS, SCADA, and AMI data along with customer and weather information to perform analyses that address both short-term circuit trends and long-term grid expansion. The resulting forecast provides system planners with substation, circuit and small-area resolution time-series load growth and load shape changes, including predicting asset replacement needs before failure as DERs are added to the grid. This tool provides key functionality that makes it possible to avoid reactive investments from DER integration and transportation electrification.

Improving Reliability and Resiliency

Improving reliability and resiliency involves both replacing aging infrastructure and upgrading it to meet load increases and prevent outages, but also leveraging technology to improve access to grid management strategies.

ENSURING A HEALTHY SYSTEM. To improve overall reliability, ensure DER effectiveness, and enable more opportunities for DER siting, PSE expects to replace or upgrade the following system components in the next 10 years. These programs will help to avoid reactive investments as a result of increasing loads and DERs, further enabling the opportunities to enable technologies for all communities.

- Replace the remaining approximately 1,300 miles of underground high molecular weight, failure-prone distribution cable by 2031.
- Address pole and pole cross arm health with completion of system inspection on 10-year cycle and remediation of poor health poles as well as programmatically addressing jurisdictional clear zone relocation requirements and upgrades to support internet and telecommunication infrastructure additions jointly located on PSE poles.
- Complete reliability improvement work on 135 worst performing circuits (WPC) with a 50 percent improvement sought by 2027 and continue targeting additional circuits that are underperforming PSE reliability metrics per PSE's reliability report.

- Install additional equipment protective devices to minimize large impacts due to outages, such as 200 fuse savers by 2025.
- Replace major substation components as a result of ongoing inspection and diagnostics.
- Invest in increasing reliability infrastructure to address the growing expectations of customers with energy sources in their “backyards.”
- Evaluate infrastructure that hardens PSE’s electric grid, such as spacer cable that is more resilient to tree fall-ins, and new pole components, such as steel cross arms to withstand wildfires.

MANAGING DERs AND EV CHARGING. PSE anticipates the need to proactively and programmatically address customer transformers, substation and circuit improvements to support the increase in DERs, electric vehicle charging and public charging sites. The specific delivery system investments needed will be identified as energy resources (whether centralized or DERs) are sited through established interconnection processes. Preparing the grid and customers for DER integration will decrease the cost of interconnection and increase the number of viable locations for DERs.

ENABLING FASTER SYSTEM OUTAGE RESTORATION. ADMS will enable enhancement of PSE’s current Distribution Automation (DA) program. Over the last few years, PSE has implemented Fault Location Isolation and Service Restoration (FLISR) as a part of a DA program that will be rolled out to about half of PSE’s circuits. FLISR is a combination of smart field devices controlled by centrally located software that provides self-healing capabilities to key feeders in the system. Currently PSE implements DA using a centralized, rules-based approach with stand-alone software. ADMS will enable a more flexible centralized, model-based approach that is considered more sustainable and flexible than the rules-based approach because it allows the FLISR process to continue operation under different switching configurations. This is especially important as the grid becomes more complex and customer expectations for reliability grow.

MANAGE INCREASING LOADS. With increasing EVs and movement toward electrification, PSE’s load will continue to increase, requiring greater emphasis on relieving local capacity constraints. Lowering energy use through increased access to demand-side resources is a useful grid management tool that PSE can utilize to improve reliability and resiliency. Leveraging AMI and ADMS, PSE will be able to pursue additional demand-side resources through local programmatic reliable energy efficiency, conservation voltage reduction (CVR), volt-var optimization (VVO) and demand response. These measures lower customers’ energy use through reduction in supply voltage. The AMI project allows PSE to more broadly implement the CVR program for circuits fed from approximately 164 substations. When ADMS is fully installed, the CVR program will mature to volt-var optimization which uses end-of-line voltage information from AMI meters to optimally manage system-wide voltage levels and reactive power flow to achieve efficient distribution grid operation. This dynamic voltage management approach will also support the integration of intermittent renewables and new transportation electrification loads. PSE will continue to build on its demand response experience using AMI data and modeling tools to help solve projected needs. As PSE pursues its time-of-use pilot, lessons will benefit local applications to manage loads and defer infrastructure investments.

PSE anticipates that leveraging energy-saving technologies will help address some local delivery system capacity constraints, but not all, due to the local characteristics of a circuit or area. In addition to the major electric backbone infrastructure projects described below, approximately eight new distribution substations will be needed to serve load beyond what the existing substation capacity can serve, and approximately four existing substations will need to be upgraded to replace aging infrastructure. This will also require building out or reconfiguring the associated distribution lines.

BUILDING RESILIENT COMMUNITIES. DERs can play a part in increasing resiliency in specific locations through microgrids or by supporting local reliability. PSE is conducting two pilot projects involving microgrids and DER integration to test how these strategies can improve reliability and resiliency in places such as highly impacted communities, transportation hubs, emergency shelters and areas at risk for isolation during significant weather events or wildfires. This allows PSE to test use cases and develop technical capabilities, and the learnings from both pilots (described below) will be used to inform future planning in areas where PSE seeks to provide additional reliability, resiliency and integrate DERs for highly impacted communities. PSE continues to review lessons from pilot projects such as Glacier Battery, Bainbridge behind-the-meter batteries, and a commercial-scale battery installed at our Poulsbo office.

The Samish Island Community Demonstration serves a fire station and nearby homes on Samish Island in Skagit County. This project deploys a front-of-the-meter battery with roof-top solar panels and other smart equipment, switches and controls and will test a community battery's ability to manage solar integration, form a microgrid to 'island' the fire station for emergencies and provide temporary backup power.

The Tenino Microgrid project, partially funded through a Clean Energy Fund Grant from the Washington State Department of Commerce, will install an approximately 1 MW/2 MWh lithium-ion battery at PSE's Blumaer substation and solar array on adjacent land, complementing existing solar panels at nearby Tenino High School. Combined, the system will form a microgrid capable of providing temporary backup power to the school during an outage. Installation of a second battery in the Tenino area is planned to enhance local reliability.

Modernizing DER Integration Processes

In addition to the enabling technologies, analytical capabilities and system component upgrades PSE is implementing to support the growing role of DERs (discussed above), PSE is investigating options and requirements for an enhanced web-based interconnection portal that would streamline the interconnection process for both customers and developers by prescreening applications. The portal would make use of geospatial load forecasts, hosting capacity analysis and power flow modeling. Additional customer tools, such as modifications to billing systems and program administration and design, may be needed as PSE's operating model moves from traditional one-way power flow to two-way energy flow and delivery.

PURSUING NON-WIRES SOLUTIONS. As part of integrating the delivery system and energy resource planning processes, PSE has been expanding its technical skill and processes relative to non-wire alternative analysis and valuation of DERs that have the potential to defer traditional wire solutions, where effective. The four non-wire alternatives analyses PSE performed in Bainbridge Island, Lynden, Seabeck and West Kitsap are described in detail in the sections on major infrastructure projects. As noted in Chapter 2, Clean Energy Action Plan, and Chapter 5, Key Analytical Assumptions, when PSE's non-wire alternative analysis determines DERs are part of viable cost-effective solutions, they are included in the electric portfolio modeling and embedded in the preferred portfolio. Pursuing these solutions will require training program enhancements, process and procedure modification, and potentially additional workforce requirements. PSE will continue to screen new needs for non-wire alternative potential in support of this forecast and refine data and tools as more is learned.

Maintaining Strong Security, Cyber Security and Privacy

As critical infrastructure becomes more technologically complex, it is even more crucial for PSE to adapt and mature the physical security of key assets and cybersecurity practices and programs that make it possible to take advantage of new technology opportunities such as Internet of Things devices. To ensure risks are consistently addressed and mitigated in alignment with the rapidly changing security landscape, PSE utilizes a variety of industry standards to measure maturity as each standard approaches security from a different perspective. In addition, we foster strong working relationships with technology vendors to ensure their approach to cybersecurity matches PSE's expectations and needs. PSE's telecommunications strategy will evolve to support required security and reliability, leveraging existing communication networks such as the AMI communication mesh network.

Major Backbone Infrastructure Projects

Major infrastructure projects are driven by increasing loads and reliability needs and proceed in two phases. The **initiation phase** includes the development of the need and evaluation of alternatives and identification of a proposed solution. The **implementation phase** includes project planning for which the need and proposed solution is tested, followed by design, permitting and construction. Once a project is in implementation, location specific activities begin, including the engagement with the local community. Informational updates are provided through the IRP process for projects in this phase. PSE is working to develop more detailed engagement with the IRP stakeholders when a project is in the initiation phase.

Chapter 5, Key Analytical Assumptions, includes a discussion relative to the forecast of non-wire alternatives that may result in cost-effective DER solutions. The IRP results expect to harvest those solutions to support resource needs. PSE will deploy identified, project-specific non-wires solutions to support the near-term integration of 22 MW of DERs and continue to validate the DER forecast to realize predicted solutions to meet resource needs. The 22 MW DER forecast includes a combination of specific major backbone infrastructure projects and additional projects necessary to address specific growth areas over the next 10 years as detailed in the sections below. The projects identified as NWA candidates were specifically identified as those which were suitable for non-wire alternatives.

The specific project descriptions in the following pages are divided into the two phases described above. They include summaries of the need and solution identified for each project, as well as detailed descriptions of recently completed non-wire alternative analysis for four projects.

Major Electric Projects in Implementation Phase

Figure M-4 summarizes the planned projects in the project implementation phase, which includes design, permitting, construction and close-out. Learnings from the non-wires analysis pilots for the Bainbridge Island and Lynden projects will be applied to future projects in the initiation phase.

Figure M-4: Summary of Major Electric Projects in Implementation

SUMMARY OF MAJOR ELECTRIC PROJECTS IN IMPLEMENTATION	ESTIMATED IN-SERVICE YEAR
1. Sammamish – Juanita New 115 kV Line	2023
2. Eastside 230 kV Transformer Addition and Sammamish-Lakeside-Talbot 115kV Rebuilds (Energize Eastside)	2022
3. Electron Heights – Enumclaw 55-115 kV Conversion	2024
4. Sedro Woolley - Bellingham #4 115 kV Rebuild and Reconductor	2024
5. Bainbridge Island (NWA Analysis Pilot)	2024
6. Lynden Substation Rebuild and Install Circuit Breaker (NWA Analysis Pilot)	2024

1. Sammamish – Juanita New 115 kV Line[1]

Estimated Date of Operation: 2023

PROJECT NEED. Improvements must be made to increase transmission capacity and reliability in the Moorlands area. The existing system serves 56,000 customers in 5 cities from 12 substations with three transmission lines built more than 50 years ago using small wire. PSE's annual transmission system assessment to meet NERC reliability standards indicates multiple contingency (N-1-1) overload issues in the Moorlands area. Both winter and summer seasons are impacted. Interim operating plans have been developed to sectionalize lines and drop load if necessary to prevent overloads and meet NERC requirements, but this reduces customer reliability. PSE Planning Guidelines call for a fourth line when serving a commercial area in which load exceeds 150 MW. Credible outage scenarios could force one of the three lines to serve the entire 12-substation area.

1 / *https://www.pse.com/pages/pse-projects/sammamish-juanita-transmission-line*

SOLUTION IMPLEMENTED. Install 4.65 miles of new 115 kV transmission line, reconductor 0.15 miles of existing 115 kV transmission line between NE 124th St. and Juanita Substation, loop the Totem Lake Substation, and install supervisory control and automatic switching on switches on either side of Crestwood Substation.

CURRENT STATUS. The project is in design and permitting.

2. Eastside 230 kV Transformer Addition and Sammamish – Lakeside – Talbot 115 kV Rebuilds (The Energize Eastside Transmission Capacity Project)[2]

Estimated Date of Operation: 2022

PROJECT NEED. The backbone of the Eastside electrical system has not had a voltage upgrade since the 1960s. Since then, Eastside's population has grown from approximately 50,000 to nearly 400,000, and growth is expected to continue. Currently, electricity is delivered to the area through two 230 kV/115 kV bulk electric substations – Sammamish substation in Redmond and Talbot Hill substation in Renton – and distributed to neighborhood distribution substations using the many 115 kV transmission lines located throughout the area. PSE's annual transmission system assessment to meet NERC reliability standards completed in 2013 and 2015 demonstrated PSE could not meet federal reliability requirements in the area by the winter of 2017-18 and the summer of 2018 without the addition of 230 kV/115 kV transformer capacity. Overloads will impact the reliable delivery of power to PSE customers and communities in and around Redmond, Kirkland, Bellevue, Clyde Hill, Medina, Mercer Island, Newcastle, Renton, and the towns of Yarrow Point, Hunts Point and Beaux Arts among others. The supply issue focuses on the two 230 kV supply injections into central King County at Sammamish substation in the north and Talbot Hill substation in the south. The winter load level was expected to exceed capacity around the winter of 2017-18, and the summer load level was expected to exceed capacity in the summer of 2017. PSE's annual assessment also identified that primary driver of need was the forecasted summer overload. These possible overloads would result in operating conditions that put thousands of Eastside customers at risk of outages.

SOLUTION IMPLEMENTED. Install a 230 kV/115 kV transformer substation in the center of the Eastside load area and a rebuild of the 115 kV Sammamish – Lakeside – Talbot #1 & #2 lines to 230 kV to provide additional transmission capacity to serve projected load growth.

CURRENT STATUS. This project is in permitting with approval of the Environmental Impact Statement, and Bellevue Conditional Use Permit (CUP). The Bellevue CUP is currently being appealed.

2 / *https://www.energizeeastside.com*

3. Electron Heights – Enumclaw 55-115 kV Conversion[3, 4]

Estimated Date of Operation: 2024

PROJECT NEED. NERC reliability requirements for multiple contingencies identify this project as needed to prevent transmission system voltage collapse, overloading of the 115/55 kV transformers at Krain Corner, Electron Heights and White River, and overloading of the White River-Krain Corner 55 kV line. The project provides additional 115 kV support at Krain Corner and Electron Heights substations. It also provides the needed 115 kV supply for the new Buckley substation as well as needed improvement to the reliability of both the Electron Heights-Stevenson, and Krain Corner-Stevenson transmission lines through protection improvements and creation of the 115 kV loop.

SOLUTION IMPLEMENTED. Convert 22 miles of transmission line between Electron Heights and Stevenson substations from 55 kV to 115 kV operation, including the conversion of Wilkeson Substation and construction of a new Buckley 115 kV substation. The 55 kV equipment at Electron Heights Substation will be converted to 115 kV. The transmission line will connect through the Enumclaw Substation creating a complete 115 kV transmission loop from Electron Heights to Krain Corner substations; this will allow for the removal of Stevenson Substation, which will be a great benefit to the local community. One and one-quarter miles of the transmission line will be reconductored, and a short section of new 115 kV line will be built to maintain 55 kV service to the Greenwater Tap.

CURRENT STATUS. This project is in final design, permitting and property acquisition.

4. Sedro Woolley – Bellingham #4 115 kV Rebuild and Reconductor

Estimated Date of Operation: 2024

PROJECT NEED. There are several needs for this project. First, the low-capacity line ratings could cause the line to exceed its allowable ratings for several contingencies and limit generation capacity in Whatcom and Skagit Counties. The small copper wires could also cause high line losses, and the aging infrastructure could lead to extended outages. Second, the low capacity of the Bellingham-Sedro Woolley #4 line has caused constraints on regional power flows for over twenty years due to the parallel higher-voltage transmission line which requires PSE to protect the line from loading above its allowable limits by automatically opening the Sedro Woolley substation circuit breaker. Opening this breaker (and subsequently the line) reduces system reliability in both Whatcom and Skagit Counties, including the Norlum and Alger substations. The

3 / *https://www.pse.com/pages/pse-projects/electron-heights-enumclaw-transmission-line-and-substation-upgrades*
4 / *https://www.pse.com/pages/pse-projects/buckley-substation*

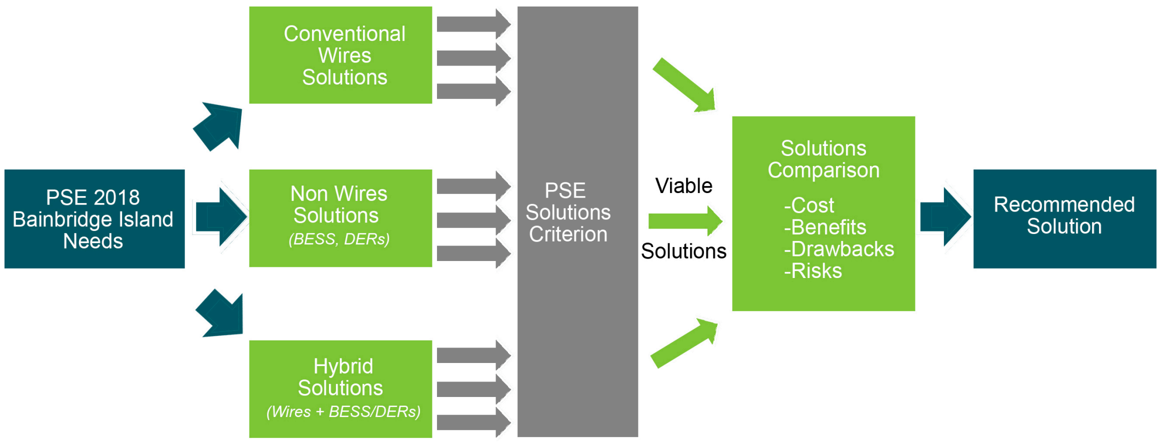
6,240 customers served from the Norlum and Alger substations are at an increased risk of outage during such time as each substation has only one transmission source. Finally, the line's aged equipment has contributed to 27 momentary outages and 4 sustained outages in the five years prior.

SOLUTION IMPLEMENTED. Rebuild and reconductor the existing 24-mile Sedro Woolley-Bellingham #4 115 kV line which connects the Skagit County and Whatcom County 115 kV systems and directly feeds two distribution substations, Alger and Norlum. To coordinate concurrent distribution system upgrades, this project is being constructed in five phases: Phase A includes approximately 4 miles of the line in Skagit County; Phase B includes approximately 7.5 miles of the line in Skagit County; Phase C includes approximately 6 miles of the line in Skagit and Whatcom Counties; Phase D includes approximately 6 miles of the line in Whatcom County; and Phase E rebuilds the final 0.5 miles of the line in Skagit County.

CURRENT STATUS. This project was initiated in 2010. Phase A was placed in service February 2018; Phase B was placed in service December 2018. Phase C, D and E are in design and permitting.

PSE has selected four areas of future needs to test, enhance and develop the planning process for integrating non-wires solutions: Bainbridge Island, Lynden, Seabeck and Kitsap. Bainbridge Island and Lynden have completed the planning process and are now in the implementation phase of project development. The following project descriptions provide insight into the process, initial findings and challenges in these areas. Seabeck and Kitsap are still in the planning phase and follow in the next section. In each area, PSE performed an electrical system needs assessment and identified key needs for grid investment. Next, solutions criteria for system performance were developed for the key needs. Alternative solutions were considered in three categories: 1) conventional wire solutions, 2) non-wire solutions consisting of battery storage and distributed energy resources (DER), and 3) hybrid solutions involving a combination of wires and non-wires components. Solutions were considered viable if they met all identified system needs and the performance standards set in the solutions criteria. Finally, a solutions alternatives analysis was conducted in order compare the costs for all viable solutions, and a solution was selected based on cost, benefits, drawbacks, risks and benefit-to-cost ratio. A diagram of the solutions process is shown below in Figure M-5.

Figure M-5: Solutions Process Overview



PSE engaged the services of two consulting firms, Navigant and Quanta, to assist in preparing the four non-wire analysis (NWA) and the combined teams worked for well over a year. The Bainbridge and Lynden project analyses are complete. The Seabeck and West Kitsap analyses are under review, and PSE is identifying solutions that will satisfy the needs assessment for each of the projects.

5. Bainbridge Island (NWA Analysis Pilot)[5]

Estimated Date of Operation: 2024

The Bainbridge Island transmission and distribution system serves 12,450 customers in Kitsap County from 3 substations and two 115kV transmission lines. The island is served by two parallel transmission lines via one water crossing from Suquamish.

NEED ASSESSMENT. PSE begins studying an area when certain study triggers occur based on the system health, operations, load growth projections and other information that surfaces. Data is gathered and assumptions are made as follows.

<u>Planning Study Triggers</u>

- Transmission reliability
- Aging infrastructure on the Winslow Tap transmission line
- Load forecasted to exceed 85 percent of substation group capacity in 2019

5 / *https://www.pse.com/pages/pse-projects/bainbridge-island-electrical-system-improvements*

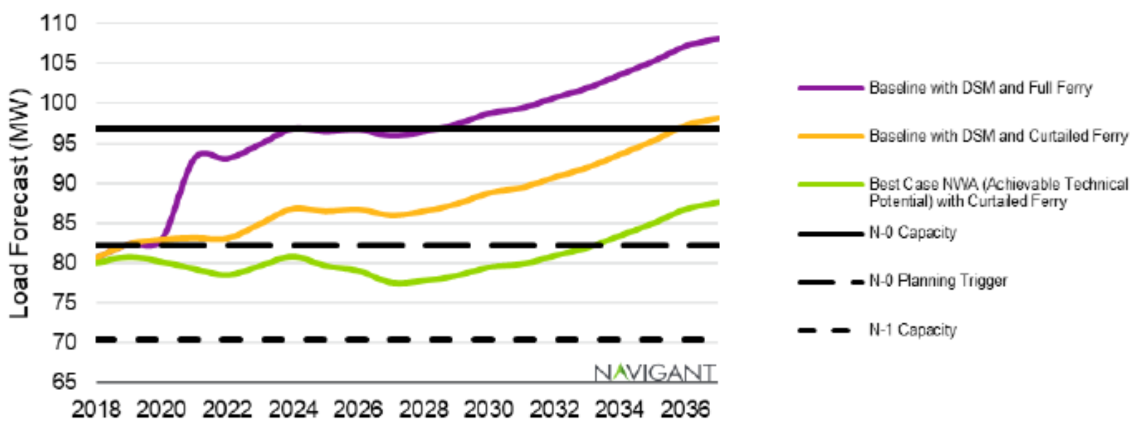
Data and Assumptions

- PSE's system load forecast net of conservation and known block load additions
- Current substation loading
- Outage data from 2013 through 2017

NEEDS IDENTIFIED. These include capacity, reliability, aging infrastructure and operational flexibility.

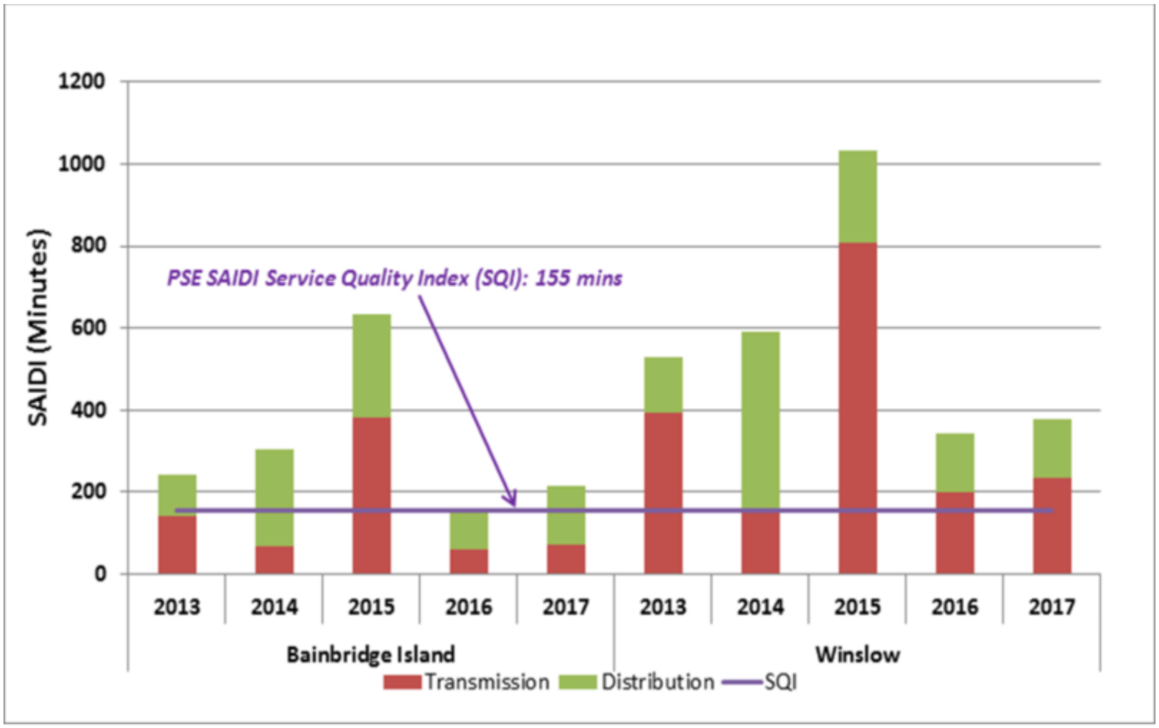
Capacity: Additional capacity will be required to meet projected load growth on the island over the next 10 years and the potential electric ferry charging facility as early as 2021.

Figure M-6: Bainbridge Island Potential Non-wires Forecast Scenarios



Reliability: Performance of the transmission source feeding the Winslow substation needs to be improved. Forty-seven percent of the total customer minutes of interruption to Bainbridge Island between 2013 and 2017 were caused by transmission outages. Nearly 70 percent of the 5-year total customer minutes of interruption were caused by Winslow transmission outages.

Figure M-7: Comparison of Bainbridge Island and Winslow SAIDI Performance



Aging Infrastructure: PSE's 2019 field inspection determined that 50 percent of the Winslow transmission tap wishbone-type crossarms will require replacement in the next one to three years.

Operational Flexibility: There was an operational flexibility concern related to the ability to transfer load to support routine maintenance and outage management. Winslow and Murden Cove substations are on radial transmission taps and have no operating flexibility at the transmission level.

SOLUTION ASSESSMENT. Solution criteria includes technical criteria and non-technical criteria as follows.

Technical Solution Criteria

- Must meet normal winter peak load forecast with 100 percent conservation
- Must be ≤ 85 percent of substation group utilization
- Must not re-trigger any of the needs identified in the Needs Assessment for 10 years or more after the project is in service

Non-technical Solution Criteria

- Feasible permitting
- Reasonable project cost
- Uses proven technology that may be adopted at a system level
- Constructible within reasonable timeframe

Evaluation of Solution Alternatives

PSE conducted a solutions alternatives analysis to determine a cost-effective solution that meets all identified system needs for Bainbridge Island over a planning horizon of ten years (2018-2027). A solution was considered viable if it met all identified system needs and the performance standards set in the solutions criteria.

Alternative solutions were considered in three categories.

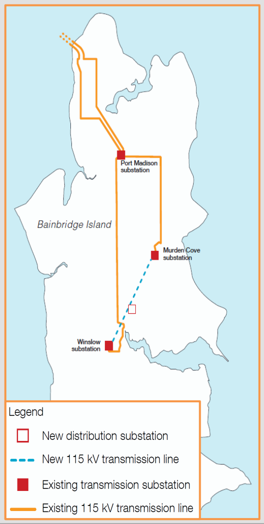
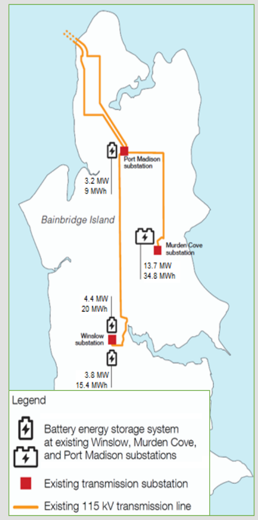
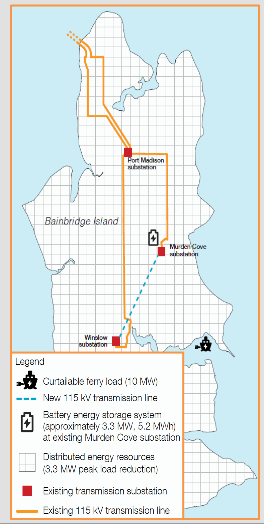
1. Conventional wire solutions
2. Non-wire solutions consisting of battery storage and distributed energy resources
3. Hybrid solutions involving a combination of wires and non-wire components

Eight alternatives were evaluated. These included three variations of traditional transmission line and substations alternatives, one alternative using all battery storage to meet need and five hybrid alternatives. Three alternatives were determined to be viable as a result of the analysis.

PSE concluded that a non-wires-only solution appeared technically feasible but that it would result in a higher cost than the wires solution, a lower benefit/cost ratio, involve significant disruption to Bainbridge Island, and likely not be ready in time to meet the projected load of the new electric ferry charging station.

Given these drawbacks, PSE considered potential hybrid solutions that included both conventional wired components and non-wired components. The technical potential and economic analysis concluded that a non-wires portfolio of energy efficiency, energy storage, renewable distributed generation and the option of demand response had the potential to cost-effectively defer the wired alternative of a distribution substation for capacity need until 2030 given current load forecasts. The consultants recommended sizing the energy storage to meet 50 percent of capacity needs in 2030; their analysis indicated that a 3.3 MW/5 MWh battery would provide sufficient flexibility for PSE to study and pilot targeted demand response and energy efficiency programs to meet the other 3.3 MW of need before other delivery system measures become absolutely necessary.

Figure M-8: Viable Alternatives for Bainbridge Solution

	Wired Alternative	Non-Wired Alternative	Hybrid Alternative
Solution Overview			
Primary Need: Winslow Tap Transmission Reliability	Transmission Loop	Total BESS: 25.1 MW/79.2 MWh MUR: 13.7 MW/34.8 MWh MUR-14, MUR-15, PMA-13: 7 MW/24.4 MWh WIN-13: 4.4 MW/20 MWh	Transmission Loop
Primary Need: Substation Group Capacity	New Dist. Substation		Ferry Curtailment: 10 MW up to 182 hr. 50% BESS @MUR: 3.3 MW/5 MWh 50% DER: 3.3 MW
Primary Need: Winslow Tap Aging Infrastructure	Replace Aging Poles; Improve Corridor Access and Veg Mgmt; Perfect Rights	Replace Aging Poles; Improve Corridor Access and Veg Mgmt; Perfect Rights	Replace Aging Poles; Improve Corridor Access and Veg Mgmt; Perfect Rights
Decision Factors	- Expertise - Long term solution - No ferry impact - High reliability	- New technology - 10 year solution - Ferry impact - Add with growth - New operations	- New technology - 10 year solution - Ferry impact - Add with growth - New operations - Local EE and DR
Benefit/Cost Ratio * Preliminary and subject to change	3.73	1.82	4.47

The hybrid solution has an estimated baseline cost of $24.3M compared to an estimated baseline cost of $28.7M for the wired solution. The hybrid solution also presents the opportunity to increase learning about adoption of energy storage and distributed energy resources as a method for deferral of electric system needs.

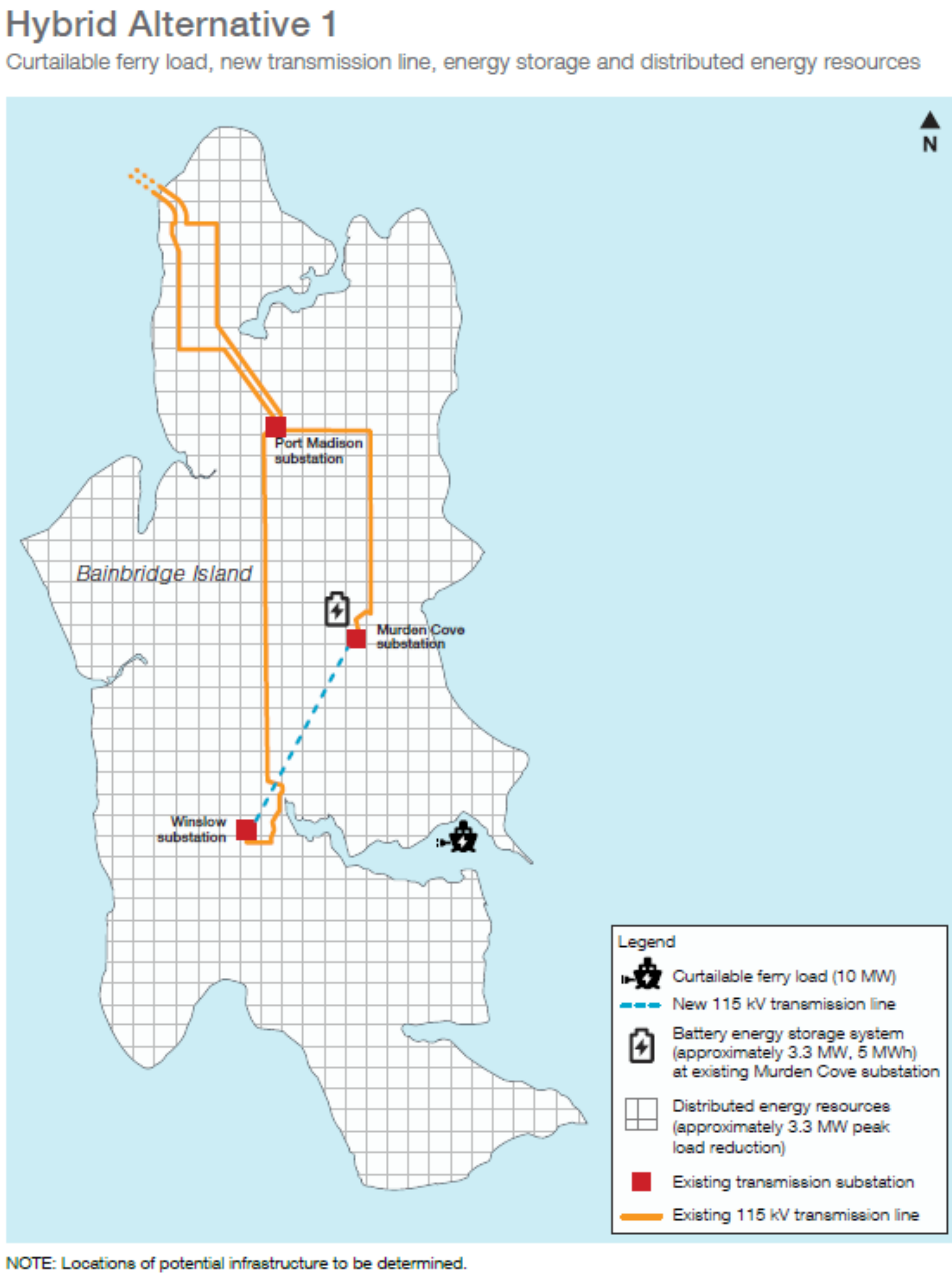
Preferred Solution

The preferred solution to further evaluate is the hybrid solution using traditional wired investment for the transmission and distribution reliability needs and a combination of energy storage and DERs for the distribution capacity need and reliability improvement.

The primary components of this solution are:

- An approximately 3.3 MW energy portfolio including energy efficiency, renewable distributed generation and the potential for demand response
- An approximately 3.3 MW/5 MWh battery located at Murden Cove substation
- 3.5 miles of new overhead 115kV line between Murden Cove and Winslow substations to create a transmission loop
- Replacement of 50 percent of poles and crossarms and improvement of the corridor for maintainability and operability of the Winslow transmission tap
- Connection of the 10 MW ferry load as a curtailable resource

Figure M-9: Bainbridge Island Hybrid Solution



CURRENT STATUS. This solution is in the development stage with an energy storage team and a DER team performing initial scoping strategy.

6. Lynden Substation Rebuild and Install Circuit Breaker (NWA Analysis Pilot)

Estimated Date of Operation: 2024

The Lynden substation serves 6,300 customers in Whatcom County, PSE's most northern area. The equipment is aging, and due to the site configuration, performing necessary maintenance and repair work is difficult. This in turn limits operational flexibility. One of the substation transformers is nearing end of its life based on the substation's health report and needs replacement by 2021. The existing substation yard and equipment configuration will not support replacement with a standard transformer.

NEED ASSESSMENT. PSE begins studying an area when certain study triggers occur based on the system health, operations, load growth projections and other information that surfaces. Data is gathered and assumptions are made as followed.

Planning Study Triggers

- Equipment age and condition
- Lack of transmission line circuit breaker
- Possibility of Remedial Action Scheme (RAS)
- Substation operational concerns
- Distribution reliability and operation concerns including capacity triggers

Data and Assumptions

- Assessment horizon – the ten-year period from 2018 to 2027
- Whatcom County local area demand forecast from PSE's F2017 Load Forecast, which estimated average annual demand growth of 0.66 percent over 10 years
- Assume the 2018 feeder extension project enables Lynden Circuit 26 to tie to Lynden Circuit 23, thereby enabling some load transfer to delay further feeder capacity upgrades
- Current substation loading
- Outage data from 2013-2017
- Asset health information from pole inspection data (2019 and previous years)
- Maintenance and operating history
- Power flow analysis consistent with North American Electric Reliability Corporation (NERC) TPL-001-4 requirements
- Assessment is in compliance with PSE's Transmission Planning Guidelines and Distribution Planning Guidelines

NEEDS IDENTIFIED. Aging infrastructure, reliability and operational needs exist presently and over the next 10 years. The next substation upgrade is recommended by 2021 for aging equipment replacement and may be needed by 2023 for load growth.

Aging Infrastructure. The Lynden Bank 2 transformer, rated 12/16/20 MVA, 115 -13.09 kV Y-Δ-Y, was installed in 1967. Its 2.0 MVA regulator was manufactured in 1965. A condition assessment of the Bank #2 transformer and regulator was performed by PSE's Technical Field Services (TFS) group in April 2018. The TFS Condition Assessment Report recommended that Bank 2 (XFR0196 and REG0277) be removed from service and replaced with a new LTC transformer within the next three years. PSE's Asset Management Group has planned to replace the transformer by 2026, based on economic life, by which time it would be 59 years old.

Reliability. One of the three transmission lines at the substation does not have a circuit breaker where the line connects to the 115 kV bus. This causes reliability impacts to all 6,300 Lynden Substation customers and risks momentary outages to another 15,700 customers in northern Whatcom County. A fault on this line also triggers a generation Remedial Action Scheme (RAS) at Sumas generating plant, removing 160 MW of generation from PSE's system twice as often as would be required if the transmission line had a circuit breaker. Additionally, during the five-year period from 2013 through 2017, the main contributor to high customer minutes of interruption (CMI) in the Lynden area was a wind storm on August 29, 2015. This storm significantly impacted Whatcom County. All three transmission lines to Lynden were out of service between 12:45 p.m. and 7:46 p.m. Each line had multiple outages during the storm, some of which were restored automatically prior to a permanent fault event.

Figure M-10 : Lynden Transmission Interruptions 2013-2017

CMI TRANSMISSION INTERRUPTIONS, 2013-2017			
Full Line Name	**Line Number**	**Total No. of Faults**	**CMI**
BPA Bellingham - Lynden (115 kV)	77	1	4,470,730
Portal Way – Lynden (115 kV)	264	2	576,928
Sumas – Lynden (115 kV)	167	2	279,162
Sumas – Bellingham (115 kV)	2	9	1,855,415
PSE Average 115 kV Line		4.5	3,071,838

Studies indicate there are areas of potential low voltage (< 113 volts) on LYN circuits that are could occur under N-0 conditions. Finally, there is one distribution circuit, LYN-14, that is above the system average for CMI with a value of 125,631 minutes (105 percent of system average).

The annual CMI reliability performance data for all LYN circuits from 2013 through 2015 is summarized in Figure M-11.

Figure M-11: Annual CMI Reliability Performance Data for 2013-2015

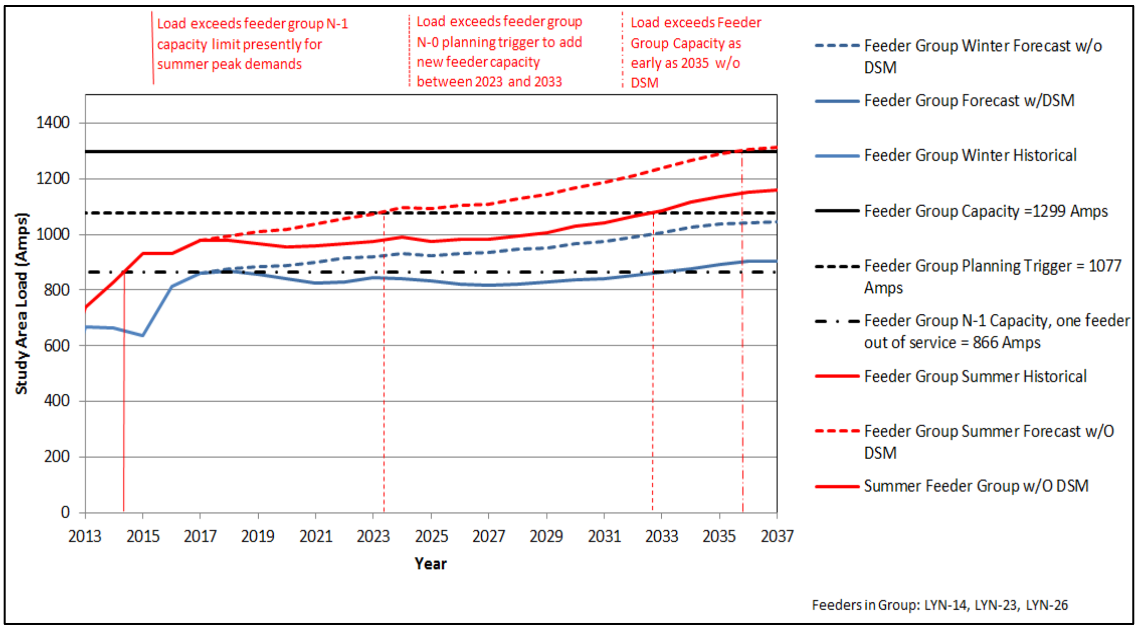
Non-MED CMI (IEEE, T_{MED} adj for catastrophic storm), Minutes				
Circuit	2013	2014	2015	Average (2013-2015)
LYN-13	53,774	47,035	13,464	38,091
LYN-14	46,226	325,861	4,806	125,631
LYN-16	787	-	278	355
LYN-17	46,596	47,058	6,352	33,335
LYN-23	219	711	7,657	2,862
LYN-24	27,460	102,883	211,164	113,836
LYN-26	39,556	130,062	27,900	65,839

Operational Flexibility. The existing layout affects reliability, future growth, and the ability to move workers and equipment in the substation to perform work.

- The crowded substation has more equipment than is usually found in a substation of this size, challenging crew ability to work efficiently and safely.
- There is not enough space in the substation for the upgrades required to replace the Bank 2 transformer. These upgrades include improvements to the control house and the Bank 2 feeder structure.
- Substation controls are spread among three control houses and a battery structure, with no room for more control equipment.
- Most double-banked substations have a bus tie switch between feeder structures; however, the Lynden substation does not. Without the bus tie switch, extensive field switching is required when taking a substation transformer out of service. Unplanned bank outages are longer in duration due to multiple distribution switching steps.

Capacity. Load growth within Whatcom County is uneven and Lynden Substation includes only a portion of the county, so the project team developed local load growth forecasts considered reasonable based on historical load growth and known load additions. Figure M-12 illustrates historical and projected demand for the 20-year F2017 load forecast for the LYN-14, 23, 26 Feeder Group. This figure also illustrates the N-1 planning trigger and capacity limits of the station group. Projected demand is shown both with and without adjustment for demand-side measure (DSM) effects. The planning trigger to add N-0 station capacity to this study grouping could be reached in 2037 without DSM.

Figure M-12: Projected Demand for LYN-14, 23, 26 Feeder Group



SOLUTION ASSESSMENT. Solution criteria includes technical and non-technical criteria as follows.

Technical Solution Criteria

- Must meet all performance criteria for transmission and distribution
- Address all relevant PSE equipment violations identified in the Needs Assessment
- Address all relevant needs identified in the Needs Assessment Report
- Must cause no adverse impacts to the reliability or operating characteristics of PSE's or surrounding systems
- Must not re-trigger any of the needs identified in the Needs Assessment for 10 years or more after the project is in service
- Must not increase non-MED SAIDI and non-MED SAIFI
- Address key infrastructure impacted by replacements to aging infrastructure

Non-technical Solution Criteria

- Feasible permitting
- Reasonable project cost
- Uses proven technology that may be adopted at a system level
- Constructible within reasonable timeframe

Evaluation of Solution Alternatives

Determining which parts of Lynden's needs could be met with non-wires components was more complicated than in the other three areas where PSE is piloting non-wires analysis. The interdependent needs presented an opportunity to further develop a framework for the initial assessment of project needs that takes place prior to investigation of non-wires alternatives.

The potential to solve Lynden needs using non-wires alternatives, including a combination of energy efficiency, demand response, solar photovoltaic, and distributed generation was evaluated. PSE concluded that a non-wires-only solution did not appear to be technically feasible. It was determined that critical upgrades needed to meet operational flexibility concerns and transmission reliability could not be solved by a non-wires solution, so any scenario analyzed to solve all of the identified needs would need to be a hybrid solution. In considering the type of needs that might be met with NWAs, Navigant noted that "NWAs are typically developed to address needs that tie directly to capacity constraints, and less typically to address other types of needs." For this reason the team investigated whether any of the needs were connected to capacity constraints. An alternative was considered that would utilize DERs and energy storage to remove rather than replace the aging transformer. This alternative would include critical substation upgrades only and would not include transformer replacement and associated metal clad feeders and substation expansion. Ultimately six solutions were considered to solve the needs identified at Lynden.

Figure M-13 shows the traditional wired solutions and hybrid solution that were developed. PSE conducted a solutions alternatives analysis for these alternatives to determine the most cost-effective solution that meets all identified system needs for Lynden over a planning horizon of ten years (2018-2027). The analysis identified Alternative 3 to have the greatest benefit for cost to improve the substation.

Figure M-13: Six Lynden Substation Alternatives
Benefits and Benefit vs. Cost Summary

Lynden Substation Project Benefits														
Alternative	Description	Benefits												Cost
		New Bank #2 Trf	New 115 kV Breaker	Bank #1 Ckt Switcher	Substation Expansion	New Control House	Bank #1 Metalclad	Bank #2 Metalclad	Transformer Differential	Remote 12.5 kV Breaker Control	Improved Driveway Access	12.5 kV Bus Section Switch or Breaker	115 kV Aux Bus or Better	Estimated Cost:
1	Replace Bank #2 in place when required.	✓												N/A
2	Expanded substation with 115 kV Main Bus and 1 Metalclad Feeder	✓	✓	✓	✓	✓		✓		✓	✓	✓		$7-14 million
3	Expanded substation with 115 kV Main Bus and 2 Metalclad Feeders	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		$8-17 million
4	Expanded substation with 115 kV Ring Bus and 2 Metalclad Feeders	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	$12-27 million
5	New substation at new site with 115 kV Ring Bus and 2 Metalclad Feeders	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	$11-43 million
6	Hybrid: Remove transformer, perform DER measures and do reduced scope of work in existing substation fence.	Not Needed	✓	✓	Not Needed	✓	✓	✓	✓	✓		Not Needed		$20-42 million

<u>Preferred Solution</u>

Even though the initial non-wires analysis suggested that there was an opportunity for cost-effective non-wires solution options for Lynden, a more detailed analysis indicated that a non-wires alternative will not be lower net cost than the traditional wires solution. The distinct characteristic of Lynden – a long-duration summer peak – meant that there were few incremental cost-effective DER available in PSE's portfolio that can address this peak. Without much capacity reduction from DER, the solution relies on a large-capacity battery, which is expensive relative to the traditional solution.

A staged approach can be used to make substation improvements efficiently. The preferred solution is for the substation be expanded within four years to address the aging infrastructure and operability issues before they affect customer reliability. At this point, the wired Alternative #3 would expand the substation, install a 115 kV circuit breaker for the BPA Bellingham-Lynden line, consolidate the control houses into one new control house, replace transformer Bank 2, replace both feeder structures to improve function, capacity and reliability, and improve operability by spreading out the equipment and relocating the driveway.

Alternatives will also be considered that would employ "non-wires" features that may be able to avoid some of the investment in traditional infrastructure. The hybrid options being developed would address both the N-0 capacity at the Lynden Substation and the N-1 capacity for the three-substation group that includes Lynden, Berthusen and Hannegan with only one transformer bank installed at the Lynden Substation. This three-substation group tends to achieve peak load in the summer due to agricultural operations in the region, which presents the opportunity to consider solar photovoltaics as part of the hybrid alternative in addition to energy storage and distributed energy resources.

CURRENT STATUS. This solution is in the final approval stage. Once approved it will move to the implementation phase for detailed design and permitting.

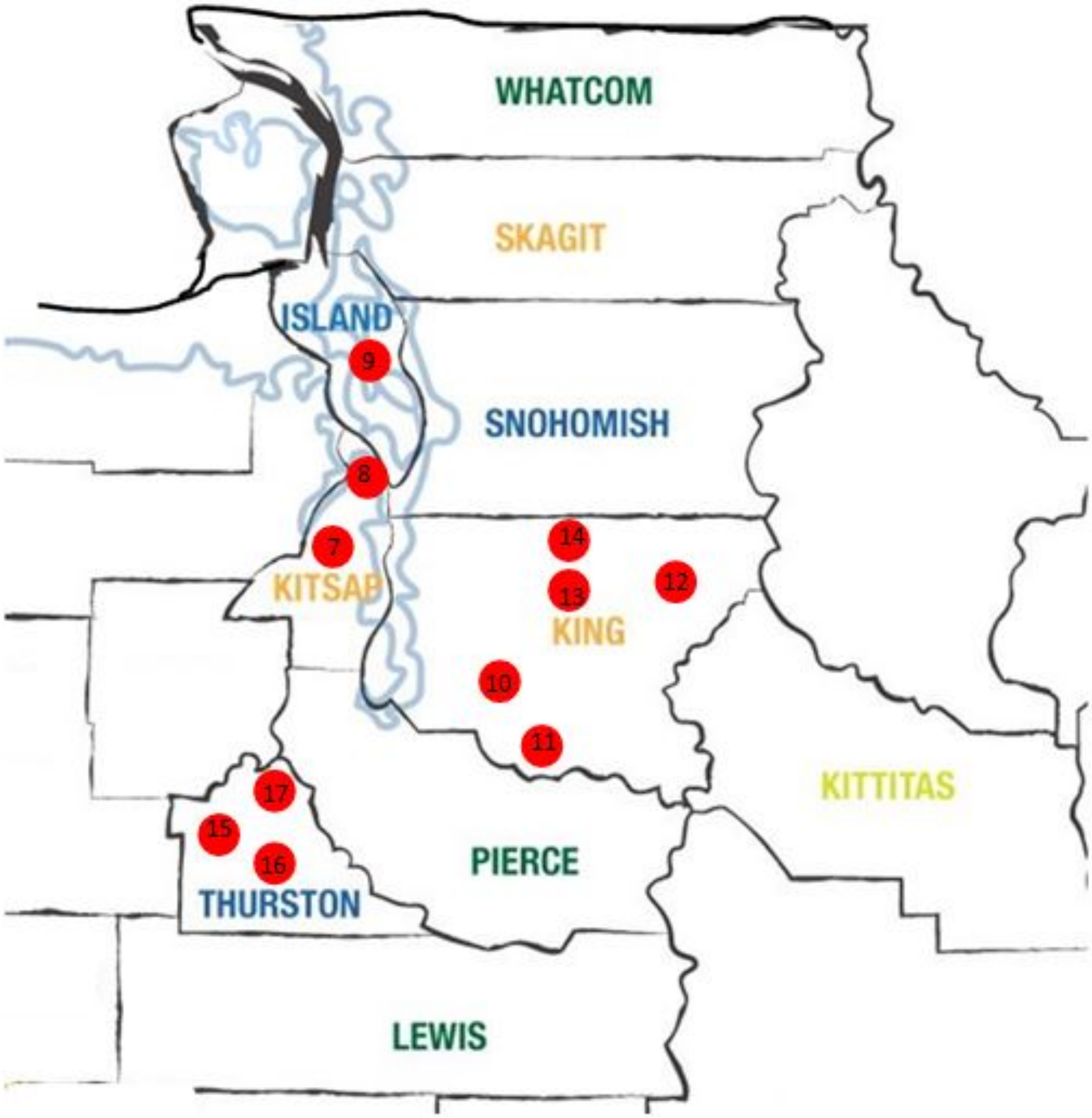
Major Electric Projects in Initiation Phase

The following projects are in the initiation phase, which includes determining need, identifying alternatives and proposing and selecting solutions. Among them are the Seabeck and West Kitsap projects, the remaining two projects being used to test, enhance and develop the planning process for integrating non-wires solutions. Based on learnings from the Bainbridge Island and Lynden assessments described in the project implementation section, as well as the Seabeck and West Kitsap projects, the non-wires analysis process has been initiated on additional projects, and a comprehensive study plan has been created to address known system needs going forward using the same approach. Based on the non-wire analysis screening criteria specific projects have been identified as suitable NWA candidates to further evaluate non-wire alternatives.

Figure M-14: Summary of 10-Year Major Electric Initiation Projects

SUMMARY OF MAJOR ELECTRIC PROJECTS IN INITIATION	DATE NEEDED	NEED DRIVER
7. Seabeck (NWA Pilot)	Existing	Capacity & Reliability
8. West Kitsap Transmission Project (NWA Pilot)	Existing	Capacity, Operational Flexibility & Aging Infrastructure
9. Whidbey Island Transmission Improvements	Existing	Aging Infrastructure, Reliability, Capacity, and Operational Concerns
10. Kent / Tukwila New Substation (NWA Candidate)	2020	Capacity & Aging Infrastructure
11. Black Diamond Area New Substation	2020	Capacity & Reliability
12. Issaquah Area New Substation (NWA Candidate)	Existing	Capacity
13. Bellevue Area New Substation	2021	Capacity & Reliability
14. Inglewood – Juanita Capacity Project (NWA Candidate)	2024	Capacity & Reliability
15. Spurgeon Creek Transmission Substation Development (Phase 2) (NWA Candidate)	Existing	Capacity & Reliability
16. Electron Heights - Yelm Transmission Project	2024	Capacity & Aging Infrastructure
17. Lacey Hawks Prairie (NWA Candidate)	2021	Capacity & Reliability

Figure M-15: Electric Planned Projects in Initiation Phase



7. Seabeck (NWA Analysis Pilot)

Estimated Need Date: Existing Need

Date Need Identified: 2019

The Seabeck area in Kitsap County serves 4,700 customers from two feeders through two substations and two transmission lines.

NEED ASSESSMENT. PSE begins studying an area when certain study triggers occur based on the system health, operations, load growth projections and other information that surfaces. Data is gathered and assumptions are made as followed.

Planning Study Triggers

- Feeder Capacity – When the loads in an area reach approximately 83 percent of existing capacity for both overhead (OH) and underground (UG) feeder sections under N-0 system operating conditions.
- Substation Capacity – When the loads in an area reach approximately 85 percent of existing station capacity for a study group of three or more substations to maintain operational flexibility.

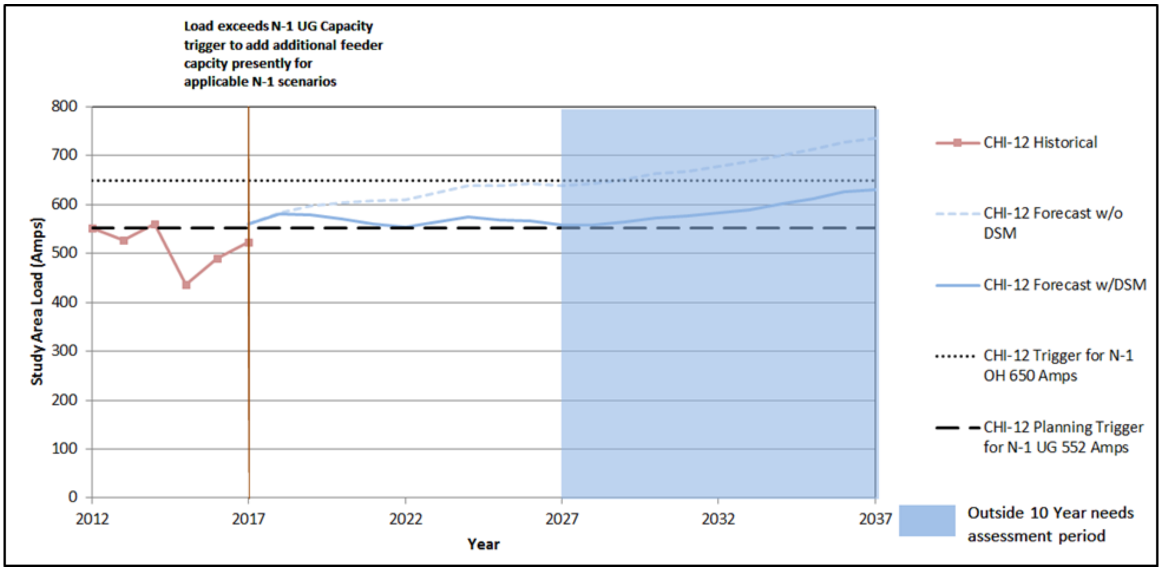
Data and Assumptions

- The assessment horizon selected was the ten-year period from 2018 through 2037.
- Historical five-year outage data are used in the assessment.
- There are no PSE DERs (distributed energy resources) on the feeders.
- There is 134 kW of interconnected net metering generation capacity on Chico substation on feeders CHI-12 79 kW, CHI-13 32 kW, CHI-15 5 kW, CHI-16 18 kW.
- There is 248 kW of interconnected net metering generation capacity on Silverdale substation on feeders SIL-13 73 kW, SIL-15 106 kW, SIL-16 69 kW.
- Normal Winter F2018 load forecast with 100 percent conservation.

NEEDS IDENTIFIED. The needs drivers identified are capacity and reliability.

Capacity: There are feeder capacity needs for distribution circuits CHI-12 and SIL-15. Both circuits are above the Distribution Planning Guidelines of 83 percent utilization of capacity under normal system configuration for current peak loading levels. CHI-12 is over 100 percent utilization under the contingent loading event of a step-up transformer failure for current peak loading levels. Figure M-16 illustrates historical demand, projected demand and the N-1 anticipated capacity need during the 10-year study period for CHI-12.

Figure M-16: CHI-12 N-1 Feeder Loading and Capacity



Feeder circuit CHI-12 has also experienced large phase imbalances at system peak during the past five years that are greater than planning guidelines allow (100 amps between any two phases). In 2017, at system peak, the difference between A and B phases was above 100 Amps for 60 hours with a peak imbalance of 124 Amps: Phase A averaged 657 Amps, B averaged 443 Amps and C averaged 401 Amps. In early January 2017, some single phase laterals were transferred from phase A to C. Year 2017 hourly PI data showed a maximum of 126 Amps imbalance between A and C. The resulting 126 Amp imbalance is above planning criteria of 100 Amps.

Reliability: There are also reliability concerns with circuits CHI-12 and SIL-15. Both are on PSE's worst-performing circuit list. These two circuits serve the entire load in this area and continue to have SAIDI and SAIFI scores significantly worse than average.

- Reduction of 220,000 CMI is needed on CHI-12 after completion of planned Distribution Automation (DA) project CMI Performance (2013-2015). The primary driver for CHI-12 is the 3-year non-MED CMI greater than 3 million minutes.
- Figure M-17 illustrates the CMI reliability metric for the Seabeck area which shows for both circuits well more than an average of 500,000 CMI minutes per year which is an indicator of poor performance.

Figure M-17: Seabeck Area Reliability Performance

Non-MED CMI (IEEE, T_{MED} adj for catastrophic storm), Minutes				
Circuit	**2013**	**2014**	**2015**	**Total (2013-2015)**
CHI-12	390,482	4,647,138	2,183,190	7,220,810
SIL-15	553,718	505,098	2,104,432	3,163,248

SOLUTION ASSESSMENT. Solution criteria includes technical and non-technical criteria as follows. PSE developed solutions criteria for system performance in the areas of capacity, reliability, asset life and constructability.

Technical Solution Criteria

- Must meet normal Winter 2018 load forecast with 100 percent conservation
- Must meet distribution planning standards and guidelines
- Must result in ≤ 100 percent of individual substation utilization
- Must result in ≤ 100 percent of overhead individual feeder limits for N-0 and applicable N-1 scenarios
- Must result in ≤ 100 percent of underground individual feeder limits for N-0 and applicable N-1 scenarios
- Must address all relevant PSE equipment violations
- Must not cause adverse impacts to the reliability or operating characteristics of PSE's or surrounding systems
- Must meet performance criteria for 10 years or more after construction

Non-technical Solution Criteria

- Environmentally acceptable to PSE and the communities it serves
- Constructible by the winter of 2021
- Utilize proven technology that can be controlled and operated using existing systems

Evaluation of Solution Alternatives

PSE studied conventional wires alternatives and determined the top wires alternatives to include (as shown in Figure M-18):

- WA-1: Build a new 115kV-12kV distribution substation near Seabeck.
- WA-2: Build a new 35kV-12kV distribution substation near Seabeck.
- WA-3: Install a third parallel step-up transformer at Chico substation.
- WA-4: Install a new express feeder from Chico substation to segment the existing feeder.

Figure M-18: Four Seabeck Wires Alternatives

		WA-1 Scope	WA-2 Scope	WA-3 Scope	WA-4 Scope
Needs	CHI-12 N-1 Capacity	Solved through new substation	New 35kV substation	Third parallel step-up transformer	New CHI-14 circuit taking
	CHI-12 Distribution Feeder Reliability	Improved through transmission restoration priority and spreading customers to multiple feeders	Improved through sub transmission restoration priority and spreading customers to multiple feeders	Improved through protection to multiple sub feeders. Mainline is hardened with tree wire	Improved through express underground feeder and creating sub feeders. Some customers transferred to new circuit
	SIL-15 Distribution Feeder Reliability	Improves SIL-15 CMI by placing some customers on a new circuit	Improves SIL-15 CMI by placing some customers on a new circuit	Does not reduce SIL-15 CMI	Improves SIL-15 CMI by placing some customers on new circuit
	Low Voltage	Solved through shorter feeders and more balanced circuits	Solved through LTC at new 35kV substation and sub placed closer to load center	Solved through addition of regulators and reduced load imbalance	Solved through reduction of load on CHI-12 and SIL-15 and reduced load imbalance
	CHI-12 Phase Balance	Phase imbalance will be reduced to less than 100 Amps per feeder. More opportunities to balance load.	Phase imbalance will be reduced to less than 100 Amps per feeder. More opportunities to balance load.	Phase balancing will need to be performed	Phase imbalance will be reduced to less than 100 Amps per feeder. More opportunities to balance load.
Decision Factors	Additional Costs - Land (ROW, Property)	Sub. property available, Public ROW	Public ROW	Public ROW	Public ROW + CHI-14 getaway route, New step-up transformer location
	Total Baseline Cost Estimate	$29.8 M	$19.5M	$12.5 M	$11.3M
	Reliability Benefits	High	Moderate	Moderate	High
	Benefits	Highest reliability improvement, eliminates most 35kV, increases operational flexibility	Improves reliability, increases operational flexibility	Improves reliability, increases operational flexibility	Improves reliability, eliminates 35kV exposure, increases operational flexibility
	Drawbacks	High Cost	High Cost	35 KV remains, no improvement to SIL-15 CMI	Some 35kV remains
	Risks	Public opposition to new substation and T-Line	Public opposition to new substation	Permitting challenges	Permitting challenges
	B/C Ratio	1.22	2.02	2.36	3.27
	Overall Preference	Lowest due to cost	3rd	2nd	1st - Highest benefit/cost ratio

After PSE developed conventional wires alternatives, Navigant was contracted to review these alternatives, analyze non-wire alternatives, and analyze hybrid solutions consisting of both wires and non-wires alternatives. The goal of this analysis was to consider the technical and economic feasibility of potential alternatives that could meet the Seabeck area needs. It was found that phase balancing would be best addressed using conventional methods, so a non-wires solution was not feasible. A hybrid solution composed of both wires and non-wires elements is a cost-effective and technically feasible solution. Ultimately two solutions were considered, a wired solution and a hybrid solution, as outlined in Figure M-19 below. As noted in the table, the non-wires solution did not meet the needs of the area.

Figure M-19: Three Seabeck Solution Alternatives

		Top Wires Alternative	Top Non-Wires Alternative	Top Hybrid Alternative
Needs	CHI-12 N-1 Capacity	Solved through new feeder	Solved through energy storage and DER	Solved through energy storage and DER
	Distribution Feeder Reliability	Improved by reduced tree/vegetation outage exposure and allowing more effective automation, while reducing the number of customers exposed to each outage	Distribution reliability is not addressed in the full non-wire alternative	Improved by reduced tree/vegetation outage exposure and allowing more effective automation
	CHI-12 Phase Balance	Phase imbalance will be spread throughout feeders, reducing to less than 100 Amps per feeder. More opportunities to balance load.	Phase Balance is not addressed in full non-wires alternative	Phase imbalance will be spread throughout feeders, reducing to less than 100 Amps per feeder. More opportunities to balance load.
	Low Voltage	Reduced loading and express 35kV circuit solves low voltage areas	Reduced loading solves voltage issues	Reduced loading and UG conversion solves voltage issues
Decision Factors	Total Cost Estimate Range (Base to High)	$11.3 million to $14 million	$4.6 million to $6.5 million	$16.1 million to $19.6 million
	Benefits	10-year solution. Highest reliability benefit. Added capacity. Increased operational flexibility.	10 year solution. Local EE and DR	10-year solution. Improved reliability.[6] Local EE and DR.
	Risks	Easement and permitting challenges for new construction	No reliability improvement. Easement and permitting challenges for BESS site. New operational strategies needed. Need additional improvements with growth	Easement and permitting challenges for BESS site. New operational strategies needed. Need additional improvements with growth

CURRENT STATUS. PSE has performed a cost comparison for all viable solutions. The preferred solution is the top wired alternative which was selected based on cost, benefits, drawbacks, risks and benefit-to-cost ratio.

6 / Navigant has identified islanding as a potential additional reliability benefit of the hybrid alternative, however this would require additional studies and operational changes within PSE.

8. West Kitsap Transmission Improvement (NWA Analysis Pilot)

Estimated Need Date: Existing Need

Date Need Identified: 2018

The West Kitsap area includes Port Orchard, Bremerton, Poulsbo and Bainbridge Island and serves 122,000 customers from 28 substations and 18 transmission lines.

NEED ASSESSMENT. PSE begins studying an area when certain study triggers occur based on the system health, operations, load growth projections and other information that surfaces. Data is gathered and assumptions are made as followed.

Planning Study Triggers

- Capacity need
- Voltage collapse conditions
- Transmission reliability
- Aging infrastructure

Data and Assumptions

- The study analyzed the Kitsap Peninsula transmission system over a planning horizon of 10 years (2018 to 2027).
- The 2017 PSE Load Forecast was utilized to project native PSE load in Kitsap County – with 100 percent conservation.
- There are two non-PSE major loads on the Kitsap Peninsula – U.S. Naval Base Kitsap and the U.S. Navy Puget Sound Naval Shipyard (PSNS). The load levels for these two non-PSE major loads were taken from the WECC power flow models.
- The transmission system assessment was conducted in accordance with the NERC and WECC Transmission Planning Standards (TPL-001-4, TPL-001-WECC-CRT-3) and PSE Transmission Planning Guidelines.
- Transmission contingency studies focused on the BPA transmission supply system out of BPA's Shelton substation and PSE's transmission facilities located within Kitsap County.
- Generation dispatch patterns and Northern Intertie transfers were maintained the same as in the WECC base cases, as they have no significant impact on the Kitsap Peninsula transmission system.
- There are no utility-scale generation resources within Kitsap County. There are distributed energy resources connected behind the meter, and those are included in the loads.

- There are no transportation loads for PSE in Kitsap County; however, the study model includes transportation loads in other counties. The power flow base cases modeled PSE transportation load as observed during 2017, i.e., summer transportation load of 238 MW and winter transportation load of 262 MW.

NEEDS IDENTIFIED. The analysis determined that there are capacity, thermal and voltage needs over the next 10 years on the transmission system, plus operating flexibility, aging infrastructure and reliability concerns.

Capacity. The existing 230 kV supply system to Kitsap Peninsula lacks capacity under multiple contingency scenarios (N-1-1, N-2 or bus contingencies) in supplying the forecasted Kitsap Peninsula load over the 10-year planning horizon (2018-2027). Certain multiple contingencies result in a voltage collapse on the peninsula. In 2018, eight 115 kV transmission lines located in central and northern Kitsap Peninsula exceeded their emergency limits for N-1-1 conditions during the winter and summer peak conditions.

Operating Flexibility. The 115 kV transmission system on Kitsap Peninsula is capacity constrained under N-1-1 scenarios during winter. This creates operating flexibility concerns while scheduling outages for planned and unplanned maintenance on the transmission system during winter. Typical corrective action to prevent N-1-1 overloads includes opening the transmission network to make transmission lines radial, which reduces reliability and increases the risk of the transmission outages.

Aging Infrastructure. BPA's two 230 kV bulk transformers feeding PSE's Kitsap Peninsula load are nearing the end of their useful life at 40 and 56 years of age. Loss of a bulk transformer and the long time-frame required to replace it with a spare (approximately a month) puts PSE's Kitsap load at risk of a large outage or voltage collapse for the next major contingency during peak winter conditions. PSE's 115 kV Vashon submarine cables are 56 years of age and have had numerous operational issues.

SOLUTION ASSESSMENT. Solution criteria includes technical and non-technical criteria as follows. PSE developed solutions criteria for system performance in the areas of capacity, reliability, asset life and constructability.

Technical Solution Criteria

- Must meet all performance criteria for transmission and distribution
- Must address all relevant PSE equipment violations identified in the Needs Assessment
- Must address all relevant needs identified in the Needs Assessment Report
- Must not cause any adverse impacts to the reliability or operating characteristics of PSE's or surrounding systems
- Must not re-trigger any of the needs identified in the Needs Assessment for 10 years or more after the project is in service

Non-technical Solution Criteria

- Environmentally acceptable to PSE and the communities it serves
- Constructible by the winter of 2029
- Utilize proven technology which can be controlled and operated using existing systems
- Reasonable project cost

Evaluation of Solution Alternatives

PSE planners are developing multiple wires solutions to solve the area's needs in order to compare them with non-wires solutions comprised of distributed energy resources and utility-scale energy storage systems. At this time, one of the wired alternatives is being used as a reference for the non-wires analysis. Additional wired alternatives are being developed, and a final proposed solution is yet to be determined.

The Kitsap Peninsula needs are so great that the peninsula load would need to be reduced by more than 30 percent in the near term to reduce all N-1-1 thermal overload and voltage collapse conditions. As a result, an energy storage system comparable to the largest ever built would be required to entirely eliminate the need for a conventional wires solution. In addition, the non-wires expert consultants on the project team estimated that a full non-wires alternative would be many times more expensive than the wires solution. Once it was determined that a full non-wires solution was not practical technically or economically, hybrid solutions were considered.

The wired components considered in the hybrid solutions varied slightly, but consistently included the bulk system elements necessary to prevent voltage collapse. Energy storage and distributed energy resources were analyzed for their ability to prevent overloads. To meet portions of the capacity needs, alternatives including exclusively energy storage or combinations of energy storage and distributed energy resources were considered. However, while there is some potential to reduce the size of the energy storage for hybrid solutions (compared to a full non-wires solution), the net costs are still much higher than the estimated conventional solution costs. There are many winter hours that exceed the capacity threshold, and these longer duration needs are more expensive to meet with battery storage or distributed energy.

Preferred Solution: The preferred solution is to continue development of a full wires solution. Given the complexity of the wires solutions, work will continue on refining the preferred solution developed initially that involves the installation of multiple segments of 115 kV transmission lines between BPA Kitsap/South Bremerton and Valley Junction. The final step of the multi-year plan is to add a 230-115 kV transformer capacity in Kitsap County. The non-wires studies prepared for PSE by the consultants will be referenced as the wires solution is finalized, but at this time the overall conclusion is not expected to shift materially. Deconstructing the needs and potential solutions for a complex transmission system with significant needs required a very high level of effort by the project team (both PSE staff and the consultants), and the experience provided PSE with a sense of the demanding analysis required and the feasibility of meeting such transmission needs with non-wires alternatives.

CURRENT STATUS. Completion of the wired alternatives analysis is expected by Q1 of 2021. Stakeholder engagement will be determined after the recommended solution becomes available.

9. Whidbey Island Transmission Improvements

Estimated Need Date: Existing
Date need identified: 2018

Whidbey Island serves 38,000 customers out of 12 substations and two transmission lines.

PROJECT NEED. The need drivers for this area are aging infrastructure, reliability, capacity and operational concerns.

Aging Infrastructure: Replacement of aging infrastructure is an immediate need. Two 115 kV oil-filled circuit breakers need to be replaced at Whidbey Substation due to age and outdated technology. The distribution transformer at Faber Substation was installed in 1968 and is being monitored due to the presence of water in the oil. Plans are under way to replace this transformer with a 25 MVA load tap changing transformer in the future.

Reliability: The main bus design at Whidbey Substation does not allow for breaker maintenance without a line outage and has a possibility of substation outages south of Whidbey due to a bus or breaker fault.

Capacity: A capacity concern beginning in 2026 includes transmission line ratings that are significantly limited due to low ratings of the older circuit breaker CTs.

Operational Concerns: There are over and under voltage concerns outside the standard range of 116 V – 126 V on certain sections of the feeders on the island.

CURRENT STATUS. The needs assessment has been completed and the study process for both traditional wires solutions and non-wire alternatives will be undertaken in 2021.

10. Kent/Tukwila New Substation (NWA Candidate)

Estimated Need Date: 2020
Date need identified: 2018

The Kent-Tukwila area serves 20,300 customers from 12 substations and four 115 kV transmission lines. The area is expected to experience heavy growth in the next 20 years.

PROJECT NEED. The need drivers for this area are capacity and aging infrastructure.

Capacity: 2018 NERC TPL studies showed that different combinations of P6 contingencies (N-1-1) resulted in the potential for thermal overloads during summer and winter peak conditions starting in 2024. Additional development occurring in the area (including redevelopment of industrial areas) has resulted in the need for additional substation and distribution system capacity to serve growing demand. The additional loads also exacerbate the NERC Compliance issues listed above.

Aging Infrastructure: Replacement of aging infrastructure is an immediate need. The 115 kV underground transmission line that provides transmission service in the area was installed in 1974 and is currently beyond its expected service lifetime. Loss of transmission support from the cable would negatively impact reliable service to customers in the area.

CURRENT STATUS. The study process for traditional solutions is underway. The study has not progressed enough to propose solutions. Project initiation to review alternatives is expected to be finalized in 2021.

11. Black Diamond Area New Substation

Estimated Need Date: 2020
Date Need Identified: 2019

The Covington/Black Diamond area serves 17,500 customers from six substations and one 115 kV transmission line. The area is expected to experience heavy load growth in the next 20 years.

PROJECT NEED. The need drivers for this area are capacity and reliability.

Capacity: Several large developments in the area will result in the need for additional distribution capacity. This capacity will need to come from additional transmission substations in order to serve the load reliably and meet future needs.

Reliability**:** A single 115 kV transmission line serves this area. The transmission system will need additional reinforcements to ensure that reliability is not reduced if additional substations and distribution transformers are added to the existing equipment.

CURRENT STATUS. The study process for traditional solutions is underway. The study has not progressed enough to propose solutions. Project initiation for review of alternatives is expected to be finalized in 2021.

12. Issaquah Area New Substation (NWA Candidate)

Estimated Need Date: 2021
Date Need Identified: 2019

The Issaquah area distribution feeders serve 23,000 customers in downtown Issaquah, Klahanie and the Highlands area from four substations with four transmission lines. The area is expected to experience more growth in the near future.

PROJECT NEED. The need driver for this area is capacity.

Capacity. Between 2020 and 2021, the predicted load increases will reduce operational flexibility for the feeder group in the Issaquah Highlands area and exceed the planning trigger for adding additional feeder capacity. Between 2023 and 2025, the area will have insufficient feeder capacity to serve additional load. In 2018, with the operating scenario of having one feeder out of service (N-1), capacity was already exceeded. This has resulted in lengthier outages, as the ability to pick up customers during a feeder outage contingency is limited.

CURRENT STATUS. Preferred wires solutions are expected to be identified at end of 2020. The two expected options are expanding Pickering substation to two banks (requires an additional transmission line) or interconnect a new 230 kV at Grandridge site to BPA. The traditional solutions should be identified by end of 2020 and non-wires solutions by the end of March 2021. Then project initiation will be able to review the alternatives.

13. Bellevue Area New Substation

Estimated Need Date: 2021

Date Need Identified: 2018

The downtown Bellevue, Redmond and Kirkland area serves 21,000 customers from 8 substations and three 115 kV transmission lines. The area is expected to experience more growth in the near future.

PROJECT NEED. The need drivers for this project are reliability and distribution capacity.

Reliability: Bellevue and Kirkland have a high percentage of commercial, industrial and high-rise residential customers in the downtown core. For a planned outage followed by an unplanned outage during peak summer or winter loading on either of these lines, a significant amount of residential and commercial load will be at risk.

Capacity**:** Load growth from the new Sound Transit and Spring District exceeds the capacity of the distribution system.

CURRENT STATUS. The detailed Needs Assessment is complete. The study process for traditional solutions will start in 2020. Traditional solutions should be identified by the end of March 2021 and non-wires solutions by the end of June 2021. At that time, project initiation will be able to review the alternatives.

14. Inglewood – Juanita Capacity Project (NWA Candidate)

Estimated Need Date: 2024

Date Need Identified: 2019

With the completion of the Sammamish – Juanita project (Project 1 in the Planned Projects discussion above), the Inglewood – Juanita line will be one of three transmission lines that serves 40,000 customers from eight substations in the Kirkland, Kenmore and Bothell areas.

PROJECT NEED. The need drivers for this area are capacity and reliability.

Capacity: 2018 NERC TPL studies indicate thermal overloads for P6 contingencies (N-1-1) during the summer 2024 time period. The same overload is predicted during both the winter and summer 2028 time periods.

Reliability**:** The potential increased load along with the potential for additional distribution transformation and capacity requires transmission infrastructure upgrades to maintain reliability for customers.

CURRENT STATUS. Project initiation to review alternatives is expected in 2022.

15. Spurgeon Creek Transmission Substation Development (Phase 2) – (NWA Candidate)

Estimated Need Date: Existing Need

Date Need Identified: 2019

The Thurston County South region is primarily served by one extra high voltage source and one 115 kV transmission line connecting to the Pierce County grid. The cities of Tenino and Yelm, which are in the South region, have approximately 19,000 customers served by five substations and two transmission line sources.

PROJECT NEED. The need drivers for this area are capacity and reliability.

Capacity: A transmission capacity need currently exists under certain N-1-1 transmission contingencies that result in thermal overloads of the bulk power supply source into the Olympia area. A distribution capacity need may also be present at a substation due to estimated load growth, and an additional distribution transformer bank will require the transmission line to be looped into the radially fed substation, providing a second source to the station.

Reliability: Two reliability improvements are required: 1) a new bulk power source supply into South Thurston County, and 2) additional transmission lines to interconnect the North and South regions of Thurston County.

CURRENT STATUS. The detailed Needs Assessment is underway. The transmission and distribution needs are identified. The study process for traditional solutions will start in 2021. Project initiation to review alternatives is expected in 2021.

16. Electron Heights - Yelm Transmission

Estimated Need Date: 2024

Date Need Identified: 2019

The Tenino/Yelm area serves approximately 19,000 customers from five substations and two transmission sources.

PROJECT NEED. The need drivers for this area are capacity, reliability and aging infrastructure.

Capacity. Greater transmission capacity is needed to resolve line overloads on the Electron Heights-Yelm 115 kV line and low voltage conditions under multiple contingencies (N-1-1) in the area. A significant portion of the line is 4/0 Cu low-capacity conductor, which limits the throughput of the line.

Reliability. Customers are at risk of outages under N-1-1 conditions. The need will be met by the Electron Heights – Enumclaw 55-115 kV Conversion that is expected to be complete in 2022, which may delay the need for this project past the 10-year planning horizon.

Aging Infrastructure. The wishbone cross-arm construction has reached the end of its useful life and poses an outage risk due to failure.

CURRENT STATUS. The detailed Needs Assessment and project initiation to review alternatives is expected to start in 2022.

17. Lacey Hawks Prairie Capacity (NWA Candidate)

Estimated Need Date: 2022
Date Need Identified: 2018

The Lacey Hawks Prairie area serves approximately 13,000 customers from three substations and six transmission sources.

PROJECT NEED. The need driver for this area is capacity

Capacity. Greater distribution substation and feeder capacity is needed to maintain operational flexibility and serve developing load.

Reliability. The customer base is at risk of outages under N-1-1 conditions.

CURRENT STATUS. The detailed Needs Assessment and Project initiation to review alternatives is expected to start in 2021.

Additional Capacity Growth Areas in Initiation Phase

Additional growth areas throughout PSE's service territory are being tracked and studied. These areas experience local growth that will exceed our transmission and distribution capacity limits within a 10-year timeframe. All of these are expected to pass the non-wire alternative screening criteria and be considered candidates for non-wire alternatives.

Figure M-20: Additional 10-Year Capacity Growth Areas

ADDITIONAL CAPACITY GROWTH AREA NEEDS IN INITIATION	DATE NEEDED	NEED DRIVER
Sumner Valley Area (NWA Candidate)	2024	Capacity
Federal Way Area (NWA Candidate)	2024	Capacity & Reliability
Covington Area (NWA Candidate)	2027	Capacity
East Whatcom Area (NWA Candidate)	2026	Capacity
Redmond/Duvall Area (NWA Candidate)	2028	Capacity
Kent/Auburn Area (NWA Candidate)	2030	Capacity
Skagit County Area (Potential NWA Candidate)	2030+	Capacity
Puyallup Area (Potential NWA Candidate)	2030+	Capacity

3. NATURAL GAS DELIVERY SYSTEM

Existing Natural Gas Delivery System

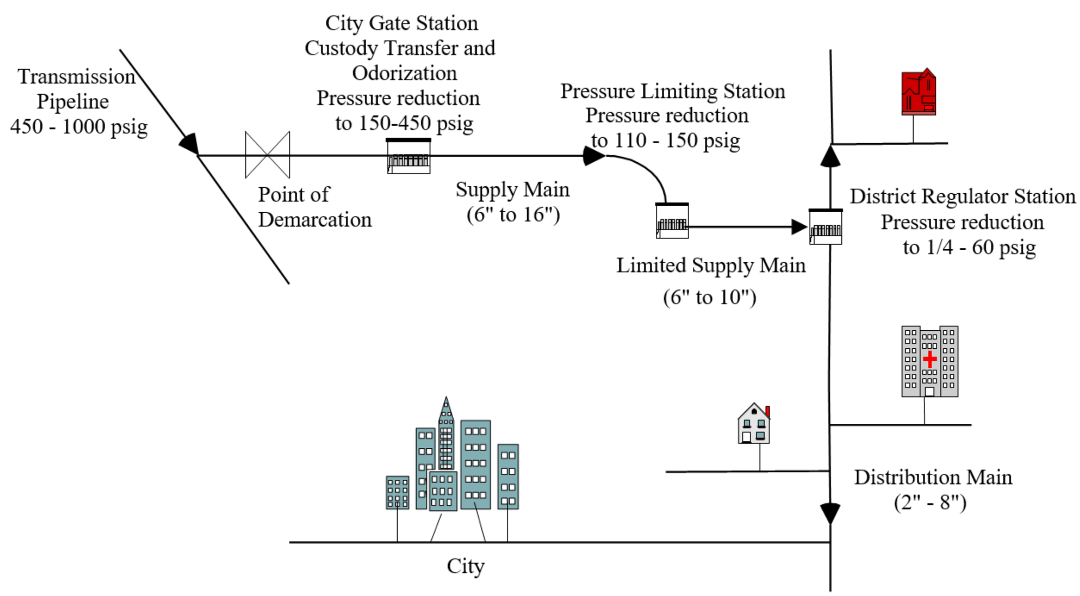
The table below summarizes PSE's existing gas delivery infrastructure as of December 31, 2020. Natural gas delivery is accomplished by means of pipes and pressure regulating stations.

Figure M-21: PSE-owned Natural Gas Distribution System as of December 31, 2020

PSE – OWNED NATURAL GAS DISTRIBUTION SYSTEM AT 12/31/20
Customers: 866,788
Service area: 2,520 square miles
City gate stations: 42
Pressure regulating stations: 560
Miles of pipeline: 13,282
Supply system pressure: 150–550 psig
Distribution pipeline pressure: 45–60 psig
Customer meter pressure: 0.25 psig

How the Natural Gas Delivery System Works

Figure M-22: Illustration of Natural Gas Delivery System



Natural gas is transported at a variety of pressures through pipes of various sizes. Interstate transmission pipelines deliver gas under high pressures (generally 450 to 1,000 pounds per square inch gauge [psig]) to city gate stations. City gate stations reduce pressure to between 150 and 450 psig for travel through supply main pipelines. Then district regulator stations reduce pressure to less than 60 psig. From this point gas flows through a network of piping (mains and services) to a meter assembly at the customer's site where pressure is reduced to what is appropriate for the operation of the customer's equipment (0.25 psig for a stove or furnace), and the gas is metered to determine how much is used.

The natural gas system was first built in the late 1800s, expanding in a networked, two-way flow design. Pipeline materials and operating pressures have changed over time. Natural gas was introduced to the Puget Sound region in 1956, allowing for higher pressures and smaller diameter pipes. Where older cast iron pipe was used, new plastic pipe is inserted into it as a way of cost effectively renewing existing infrastructure in urban areas. While the energy qualities and pipeline materials have changed, the technology used to operate the system has not. Because natural gas pipelines are often located within increasingly congested rights-of-way, protecting pipelines from damage is even more important.

10-Year Natural Gas Delivery System Plan

The natural gas resource planning process focuses on conservation and demand-side resources and the future of low-carbon alternative fuels. In the next decade, PSE will modernize the natural gas system to:

- reduce greenhouse gas emissions
- ensure pipeline safety
- address major backbone infrastructure needs

The modernization of the natural gas system and focus on pipeline safety will provide more opportunities for programs such as demand response and position the pipeline system to become agnostic to fuel type over time as alternative fuel supply chains mature, supply increases and costs decrease.

The 10-year natural gas infrastructure plan includes key investments in the areas of visibility, analysis and control; reducing greenhouse gas emissions; pipeline safety and reliability; and addressing backbone infrastructure needs. Figure M-23 summarizes the major elements of the plan. Discussion of the key investment areas in the following pages highlights the fact that these investment areas are interrelated. The 10-year plan addresses needs that are either existing or predicted based on the processes described in Chapter 9, Natural Gas Analysis. Delivery system studies are performed every year which will surface new needs or constraints in future 10-year plans. In addition, the outer years of the plan may change substantially in this time of energy and load evolution. Like the IRP, this 10-year plan provides overall direction to inform decisions about specifically funded action and plans.

Figure M-23: Summary of 10-Year Natural Gas Delivery System Plan

10-YEAR NATURAL GAS DELIVERY SYSTEM PLAN SUMMARY	
VISIBILITY, ANALYSIS AND CONTROL	
Foundational Technology	Advance Metering Infrastructure (AMI)
Smart Equipment	Data and control technologies such as automated values and SCADA devices
REDUCE GREEN HOUSE GAS EMISSIONS	

Ongoing programmatic leak repair and operation practice modifications	New tools and operating procedures Upgraded high pressure and intermediate pressure distribution lines
Pilot Projects enable PSE to test the feasibility and effectiveness of new solutions to delivery system challenges.	Hydrogen and other lower carbon blending fuels
PIPELINE SAFETY AND RELIABILITY	
Ongoing programmatic replacements and upgrades to system components to address aging infrastructure and load increases to ensure reliable energy delivery.	Demand response, conservations, and time-of-use Upgraded high pressure and intermediate pressure distribution lines and regulation equipment 34 risk mitigation programs that include inspections and upgraded lines and equipment
SECURITY. CYBERSECURITY AND PRIVACY	
Ongoing security measures	Physical security of key assets Industry standards, protocols and requirements for technologies and vendors
ADDRESSING MAJOR BACKBONE INFRASTRUCTURE NEEDS	
Major backbone infrastructure projects are driven by capacity and reliability needs. These are discussed in detail starting on page M-57.	

Improving Visibility, Analysis and Control

ADVANCED METERING INFRASTRUCTURE (AMI). PSE is in year four of replacing the current aging and obsolete Automated Meter Reading (AMR) system and gas customer modules with Advanced Metering Infrastructure technology. AMI is an integrated system of smart modules, communications networks and data management systems that gives both PSE and its customers greater visibility into customer use and load information and enables two-way metering between PSE and its customers.

DATA AND CONTROL. PSE has modernized its monitoring tools, replacing manual field charts with digital equipment, and will continue to evaluate greater use of automated valves to provide control where needed.

Reducing Greenhouse Gas Emissions

ELIMINATING LEAKS AND METHANE RELEASE. PSE will continue to eliminate leaks from the natural gas system, eliminating all non-hazardous[7] leaks by 2022. PSE will evaluate operating practices and methods to further minimize methane releases, for example, by increasing contractor awareness when working around pipelines to prevent damage during construction, repairing leaks more quickly than regulations require, or capturing natural gas when construction work requires pipelines to be depressurized and purged.

CLEANER FUELS. PSE already integrates some renewable natural gas (RNG) into the delivery system to decrease carbon emissions, and PSE will continue to look for innovative ways to harvest more RNG. PSE has also begun to evaluate opportunities to partner in testing and learning how hydrogen can be blended into the natural gas system to reduce carbon emissions in ways that are similar to how bio-methane or waste-based renewable natural gas are blended with natural gas. This will prepare PSE to leverage the technology as supply increases, cost decreases and the technology matures.

Ensuring Pipeline Safety and Reliability

ENSURING A HEALTHY SYSTEM. To ensure overall reliability and safe operations, PSE expects to replace or upgrade the following system components in the next 10 years.

- Replace 200 to 300 miles of gas main (for example, DuPont pipelines that are prone to catastrophic failure).
- Continue PSE's industry leadership in mitigating sewer cross bores,[8]
- Remediate customer meter set equipment that has been buried.
- Deploy 34 programs to address pipeline safety risks associated with pipelines, pressure regulation equipment and meters.
- Invest more in risk mitigation programs pursuant to the recent passage of the Pipeline Reauthorization Act Rules.

7 / Hazardous leaks require immediate repair or repair within defined timeframes.
8 / Sewer cross bores occur when gas pipe, installed by bore technologies, crosses through unlocatable sewer pipes.

MANAGING INCREASING LOADS. With real possibilities to reduce carbon emissions by increasing use of renewable natural gas and blending alternative fuels such as hydrogen with natural gas, PSE will continue to address growth areas to meet customer choice expectations. PSE will also continue investigating demand response technologies that help offset increased loads as a result of customer growth**.** In 2018-2019, PSE piloted a natural gas demand response program to determine the potential for peak capacity reductions using smart thermostats. These pilot results will allow PSE to evaluate the potential for using gas demand response as a non-pipes alternative to delay supply and distribution investments. PSE will continue to build on its demand response experience to help determine what role this new tool can play in alternatives to pipeline infrastructure. Additionally, PSE will leverage demand-side resources through local programmatic reliable energy efficiency. As PSE pursues its time-of-use pilot, lessons will benefit local applications to manage loads and defer infrastructure investments.

PSE anticipates that leveraging energy-saving technologies will help address some local delivery system capacity constraints, but not all, due to the local characteristics of each area. In addition to the major natural gas backbone infrastructure described below, new or upgraded high pressure and intermediate pressure systems will be needed, along with upgrades to approximately 31 pressure regulation stations to serve load beyond what the existing stations capacity can serve.

Maintaining Strong Security, Cyber Security and Privacy

As critical infrastructure becomes more technologically complex, it is even more crucial for PSE to adapt and mature the physical security of key assets and cybersecurity practices and programs to make it possible to take advantage of new technical opportunities such as Internet of Things devices. To ensure risks are consistently addressed and mitigated in alignment with the rapidly changing security landscape, PSE utilizes a variety of industry standards to measure maturity as each standard approaches security from a different perspective. In addition, PSE fosters strong working relationships with technology vendors to ensure their approach to cybersecurity matches PSE's expectations and needs. PSE's telecommunications strategy will evolve to support required security and reliability, leveraging existing communication networks such as the AMI communication mesh network.

Major Backbone Infrastructure Projects

Major infrastructure projects are driven by increasing loads and reliability needs and proceed in two phases. The **initiation phase** includes the development of the need, evaluation of alternatives and identification of a proposed solution. The **implementation phase** includes project planning for which the need and proposed solution is tested, and then design, permitting and construction begins. Once a project is in implementation, location specific activities begin, including engagement with the local community. Informational updates are provided through the IRP process for projects in this phase. PSE is working to develop more detail and engagement with the IRP stakeholders when a project is in the initiation phase.

Lessons learned from the PSE demand response pilot support the IRP preferred portfolio that identifies the opportunity to meet increasing resource needs using conservation and demand-side management programs. Chapter 9, Natural Gas Analysis, discusses PSE’s non-pipe alternative analysis process, and PSE will continue to screen new needs for non-pipe alternative potential in support of this forecast and refine data and tools as more is learned.

The specific project descriptions in the following pages are divided into the two phases described above. They include summaries of the need and solution identified for each project, as well as highlights for upcoming non-pipe alternative (NPA) analysis for two projects.

Major Natural Gas Projects in Implementation Phase

Figure M-24: Summary of 10-year Major Natural Gas Implementation Projects

SUMMARY OF MAJOR NATURAL GAS PROJECTS IN IMPLEMENTATION	EST. In SVC
1. Bonney Lake Reinforcement	VARIES
2. North Lacey Reinforcement	2022
3. Tolt Pipeline	2026

1. Bonney Lake Reinforcement

Estimated Need Date: Existing

Date Need Identified: 2019

The Bonney Lake area includes the Lake Tapps and South Prairie areas and a particularly large and growing customer development.

PROJECT NEED. Demand on PSE's natural gas supply system serving the Lake Tapps and Bonney Lake areas exceeded its capacity in 2017. Additionally, a large development being built in the southern end of the system, the Tehaleh development. The combination of existing demand, projected area growth and this new development exceeds the capacity of the existing high pressure lateral. For several years, PSE's ten-year plans have documented the necessary system improvements for the Bonney Lake area. PSE performs manual adjustments in two locations during cold weather along with 100 percent curtailments in order to maintain service at the end of the system. These actions will soon be insufficient to address the reliability concerns.

Figure M-25: Bonney Lake Area Capacity Need

Year Number	Winter Year Need	Total Additional Capacity Necessary in scfh (Cumulative)*	Yearly Capacity Increase (or decrease) Necessary in scfh*
1	2019-20	104,200	104,200
2	2020-21	139,900	35,700
3	2021-22	171,100	31,200
5	2023-24	234,100	63,000
10	2028-29	406,900	172,800
15	2033-34	571,500	164,600
20	2038-39	732,400	160,900

SOLUTION IMPLEMENTED. PSE is installing 12-inch high pressure pipeline parallel to the existing 6-inch high pressure pipeline for which capacity has been exceeded and a Gate Station to reinforce the natural gas supply to the Bonney Lake and Lake Tapps areas.

CURRENT STATUS. Phase 1 was completed in 2017, which included two miles of 12-inch line parallel to the existing 6-inch line. Phase 2 will be completed in 2022, which includes an additional two miles of new 12-inch line parallel to the existing 6-inch line. Future phases include additional high pressure pipeline and a new gate station.

2. North Lacey Reinforcement

Estimated Need Date: Existing
Date Need Identified: 2009

The North Lacey area includes Lacey and the north and east Olympia areas and serves approximately 21,000 customers. The project is intended to reinforce the Olympia system.

PROJECT NEED. Overall customer growth is increasing the demand on the existing system. The supply system needs reinforcement in order to serve recent and projected customer loads. The models are showing significant low pressure issues when pipeline restrictions are taken into account. The supply system is unable to meet minimum design requirements without manual operations. The downstream distribution system cannot maintain adequate system reliability when the upstream supply system is unable to maintain system reliability itself. Two cold weather actions (CWAs) are scheduled for this area along with 100 percent curtailments, and these actions will soon be insufficient to address the reliability concerns.

SOLUTION IMPLEMENTED. The preferred solution is a pipeline solution for the current and near-term need. It includes high pressure pipeline and may also include a limit station and a pressure increase. These projects will solve the capacity, pressure, CWA and reliability concerns and still allow for future expansion when and if it occurs.

CURRENT STATUS. Final completion of the long-term alternatives analysis is expected to be completed by the end of 2022.

3. Tolt Pipeline

Estimated Need Date: 2024

Date Need Identified: 2009

The greater Eastside area, from Bothell/Woodinville to Bellevue in King and Snohomish counties serves approximately 80,000 customers from the Duvall Gate Station.

PROJECT NEED. Growth will exceed the current Duvall gate station capacity in the winter of 2024-25, at which time a total station rebuild of Duvall gate station is required. The Duvall Lateral, which delivers gas from the Williams Interstate Pipeline at the Duvall gate station to the Woodinville, Bothell, Kenmore and Kirkland areas, will experience low pressures for 40 percent of its length during extreme cold weather events. On a design day, the area experiences a shortfall of 127,000 scfh.

SOLUTION IMPLEMENTED. Install 1.3 miles of 16-inch high pressure pipeline and a new gate station to loop and reinforce the existing supply system.

CURRENT STATUS. PSE completed Phase 1 of this project, installing 2.7 miles of 16-inch high pressure pipeline in 2015. Phase 2 will be completed in 2026, which includes a new gate station.

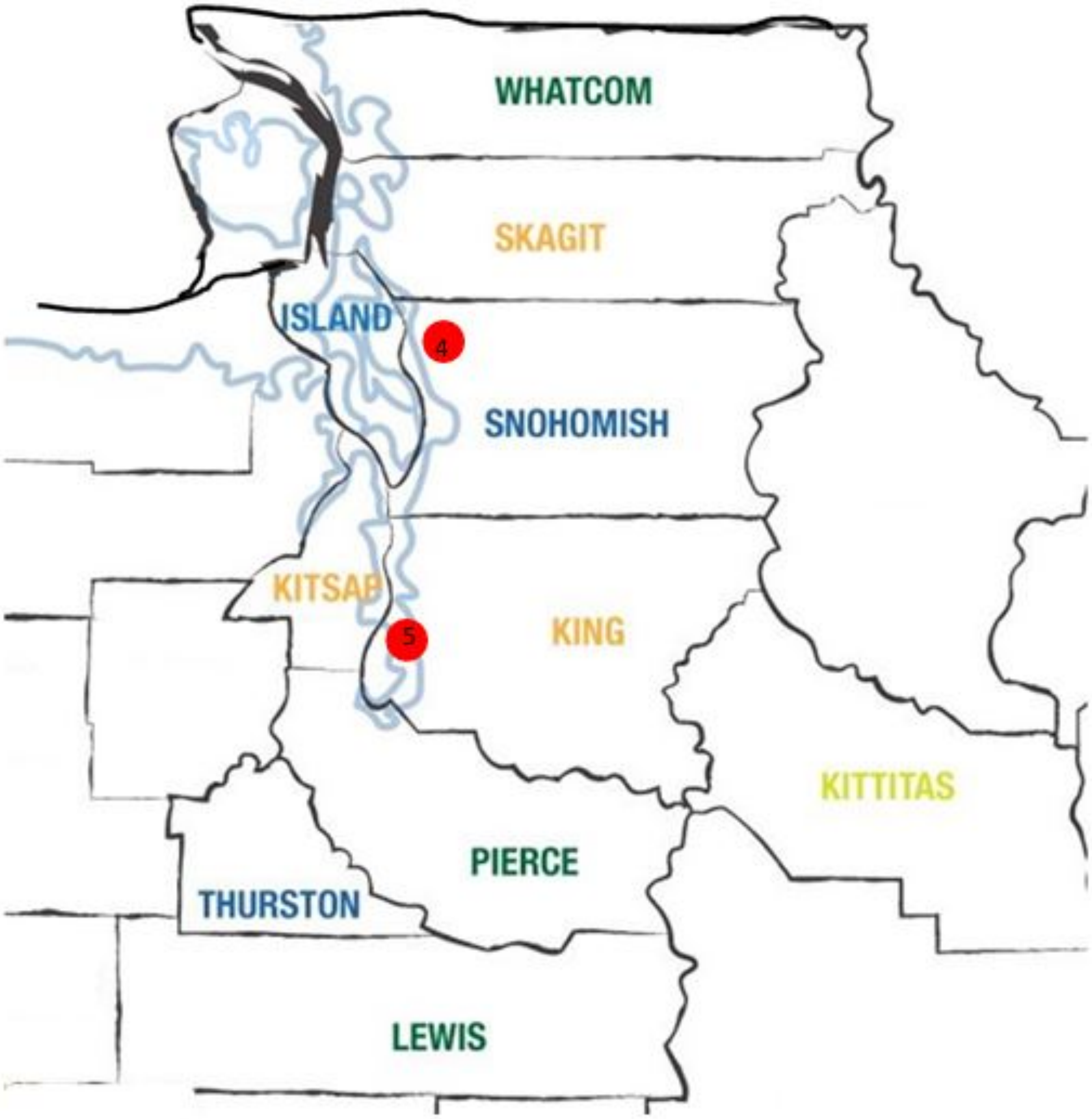
Major Natural Gas Projects in Initiation Phase

Figure M-26 summarizes the planned projects in the project initiation phase which includes determining need, identifying alternatives and proposing and selecting solutions.

Figure M-26: Summary of 10-year Major Natural Gas Initiation Projects

SUMMARY OF MAJOR NATURAL GAS PROJECTS IN INITIATION	DATE NEEDED	NEED DRIVER
4. Sno-King Reinforcement Projects (NPA Analysis Pilot)	Existing	Capacity, Reliability, Operational Flexibility and Aging Infrastructure
5. Gas Reliability Marine Crossing (NPA Analysis Pilot)	Existing	Reliability, Operational Flexibility and Aging Infrastructure

Figure M-27: Natural Gas Planned Projects in Initiation Phase



4. Sno-King Reinforcement Projects (NPA Analysis Pilot)

Estimated Need Date: Existing

Date Need Identified: 2009

The Sno-King area includes the south Snohomish county area and the Central/Northern King county areas and includes approximately 200,000 gas customers.

NEED ASSESSMENT. PSE begins studying an area when certain study triggers occur that affect system reliability including critical natural gas pipeline pressures and flows, load/customer growth projections, gas supply contracts, excessive cold weather actions (CWAs), and other information that surfaces. Data is gathered and assumptions are made as follows.

<u>Planning Study Triggers</u>

- Minimum pressure guidelines have been crossed
- Maximum flow guidelines have been reached
- Load and customer growth
- Increased CWAs
- Natural gas customer outages

<u>Data and Assumptions</u>

- This study analyzed the Southern Snohomish county area and the Central/Northern King county areas over a planning horizon of 10 years during multiple timeframes, and has extended this timeframe to 25+ years multiple times to ensure solutions were also optimized for the long term.
- Individual load growth of specific areas was completed in detail where needed for these studies. This includes the review of over 5,000 building permits in the Seattle area to help determine commercial gas load growth in this area in the next five years.
- The latest PSE load forecasts were coordinated with detailed planner knowledge of localized growth to determine the final yearly predicted load growth.
- The latest PSE gas models were used that contain all pipes down to the service level and the latest natural gas load files. Natural gas loads are calculated for every gas customer on our system based on their history and then this is temperature-compensated and applied to the models.
- All models are baselined against actual flows, loads and pressures to ensure accuracy.
- The loads in the model contain no interruptible loads for these studies.

NEEDS IDENTIFIED. The analysis determined that there are operational reliability concerns created by increased load growth resulting in low pressure issues, operational flexibility concerns due to limitations caused by excessive Cold Weather Actions, and aging infrastructure concerns.

Capacity. Some of the fastest growing zip codes are contained in the Sno-King area, which are contributing to significant load growth over many years. Both the supply and distribution systems need reinforcement in order to serve recently added and projected customer loads.

Reliability. The supply system is unable to meet minimum design requirements without manual operations (see "operational flexibility" below). The downstream supply and distribution systems cannot maintain adequate system pressures when the upstream supply system is unable to maintain its system pressure.

Operational Flexibility. Six Cold Weather Actions are scheduled for this area along with 100 percent curtailments, and these actions are markedly insufficient to address the reliability concerns. Manual operations carry an inherent operational risk that an action may not be able to be implemented when needed due to weather and road conditions and/or equipment and personnel issues. There are limitations to manual operations based on location and availability of sufficient equipment and trained personnel. As demand continues to increase, manual operations are insufficient to support the system.

Aging infrastructure: Critical pieces of the pipeline infrastructure have maintenance concerns in addition to a need to be increased in size for capacity reasons. Both of these issues contribute to reliability concerns.

SOLUTION ASSESSMENT. Solution criteria includes technical and non-technical criteria as follows that must be met. PSE developed solutions criteria for system performance in the areas of capacity, reliability, cost and constructability.

Technical Solution Criteria

- Must meet all performance criteria for supply and distribution system requirements, including reliability
- Must address all relevant needs identified in the Needs Assessment Report
- Must not cause any adverse impacts to the reliability or operating characteristics of PSE's system
- Must be able to meet a 25-year planning horizon – staging (phased approach) is acceptable
- Must be safe

Non-technical Solution Criteria

- Meet environmentally impacts and permitting requirements
- Constructible to meet capacity need dates, both current and future
- Utilize proven/mature technology
- Reasonable, prudent project costs
- Must assess and account for community and transportation impacts

Evaluation of Solution Alternatives. PSE is completing a thorough alternative analysis that includes analyzing pipeline and non-pipeline solutions (including LNG, CNG, energy efficiency and demand response) to determine the most cost-effective solution for this area's need.

CURRENT STATUS. Final completion of the long-term alternatives analysis is expected to be completed by the end of 2022.

5. Natural Gas Reliability Marine Crossing (NPA Analysis Pilot)

Estimated Need Date: Current

Date Need Identified: 2019

The marine crossing in King County serves roughly 13,000 customers on the Gig Harbor peninsula and Vashon/Maury Island.

NEEDS ASSESSMENT. A high pressure natural gas supply system needs assessment was performed for the Gig Harbor peninsula, Vashon Island and Maury Island area. Based on results of this needs assessment, it has been determined a long-term supply solution should be developed, while also developing a backup supply solution for the area.

NEEDS IDENTIFIED. The dynamic marine environment in which this crossing has operated for more than 50 years has resulted in the need for reinforcement or replacement of parallel 8-inch undersea high pressure laterals. Seafloor movement and fatigue induced by ocean currents have resulted in the crossing nearing end of its service life.

Reliability. The supply system is unable to meet minimum design requirements should the lateral exceed fatigue limitations. As a result, the downstream supply and distribution systems cannot maintain adequate system pressures when the upstream supply system is unable to maintain its system pressure.

Operational Flexibility. The existing marine crossing is the only pipeline supply of natural gas to roughly 13,000 customers on the Gig Harbor peninsula and Vashon/Maury Island. While the supply is augmented by PSE's Gig Harbor LNG facility to meet system peak loads, a pipeline connection is required to maintain natural gas service to all customers in the area.

Aging infrastructure: Segments of the undersea pipeline infrastructure have maintenance concerns requiring mitigation.

SOLUTION ASSESSMENT. PSE developed solutions criteria that must be met in the areas of capacity, reliability, cost, constructability and customer impact.

Solution Criteria

- Must meet all technical criteria
- Must be able to be constructed and permitted within a reasonable timeframe
- Must have reasonable project costs
- Must use mature technology
- Must have the least customer impact

Evaluation of Solution Alternatives. PSE is completing a thorough alternative analysis that includes analyzing pipeline and non-pipeline solutions to determine the most cost effective solution for this area's need.

CURRENT STATUS. Project initiation to review alternative solutions has begun and is expected to be completed in 2021. Limited system modifications are planned in 2021 to enable operation of an emergency backup supply plan should the marine crossing experience a failure prior to completion of the project.