PSE REPORT TO COMMUNITY

PUGET SOUND ENERGY
The Energy To Do Great Things

October 8, 2010

Resident or Business Owner
Address
City, State Zip

Community input helps shape Bainbridge Island's energy future

Dear PSE Bainbridge Island customer,

Thank you for taking the time to learn more about Puget Sound Energy's plans to address the electric system capacity and reliability issues facing your community. We received input from several hundred people attending our three public meetings this past spring on Bainbridge Island and more than 900 customers who offered input via comment cards, e-mail messages and phone calls. The thoughtful feedback was used to further develop our future plans to ensure you and all of our customers on the island have adequate and reliable power now and in the future.

Community feedback

In our conversations with customers and community leaders, we heard several recurring themes:

- Saving energy, minimizing the number and length of outages and restoring power quickly after an outage are top concerns. More than half of the written comments mentioned energy conservation and three-quarters mentioned electric reliability.
- Many responses suggested that PSE delay construction of electric infrastructure to see if islanders could mount an energy conservation campaign that would eliminate or postpone the need for additional electric capacity.
- Another common theme was a desire for PSE to concentrate efforts on improving reliability on our electric distribution system.
- Other themes included minimizing project costs, limiting the footprint of electric system infrastructure, and ensuring our existing infrastructure is as efficient as possible.

PSE took the input we received from our customers and community leaders on the island and used it as a guide to refine our integrated multi-year plan to serve the community. The result: a Community Plan that incorporates the desires of islanders while also ensuring our system is protected from being over strained and maintains electric capacity and reliability for our customers.

Community Plan

Focus on energy efficiency initiatives

PSE will postpone submitting planned substation and transmission infrastructure project-related permit applications for a minimum of the next three winters, allowing the community time to put energy efficiency measures to work to reduce energy usage on the island. (If substation or transmission components fail, construction permits to replace failed equipment would be pursued.)

These energy efficiency efforts include the Bainbridge Island energy challenge campaign (formerly known as the Community Energy Task Force), that is set to kick off next month following a grant of $4.88 million dollars from the U.S. Department of Energy. PSE, in close collaboration with the community challenge, will carefully monitor and report the island's energy usage. If enough islanders participate in the "energy challenge" to make their homes and businesses more energy efficient and reduce the island's peak demand, PSE may be able to defer installing additional electric capacity infrastructure beyond spring 2013.

If the community is successful in reducing its peak load and holds peak demand below 58 megawatts during the next three winters, PSE will not expand our substation or build a transmission loop unless disasters necessitate.

Continue vegetation management and distribution improvements

PSE will maintain our ongoing program of trimming trees that threaten our electric transmission and distribution system on the island. This year, PSE is working to trim 83 miles of distribution circuits on the island as part of our normal distribution trimming cycle. Your help in getting this work completed is much appreciated.

PSE will also continue to identify and improve the segments of our distribution lines that are most prone to outages, with investments in several projects over the next few years.

Ensure continued electric capacity and reliability on the island

As we look into the future, we can expect the island population to grow, with more homes, more businesses and more PSE customers. In addition, the coming of electric vehicles may also provide an opportunity for low-carbon transportation, but with additional demands on our electric infrastructure. We will continue to monitor the load growth, as well as the system constraints. If after three years of monitoring the community peak load reaches 58 MW, a level too risky for our system to tolerate (similar to overloading a circuit in your house), PSE will need to move forward with plans to expand substation capacity at our 50-year-old Winslow substation on Bucklin Hill Road.

At that time, in addition to expanding our substation, we will move forward with plans to install a new transmission line connecting our Winslow substation to our Murden Cove substation. In the event of an outage, the new loop will provide a second source of power to customers served from this substation and increase reliability to the approximately 8,000 customers on the lower half of the island, providing an anticipated savings of 1.15 million customer power outage minutes per year.

It's important to know we will not implement expansion or construction plans unless the 58 MW threshold is crossed following the three-year monitoring period or if disasters like an unusual storm necessitate; however, by developing plans in advance, we will be ready to initiate the permitting process and make necessary upgrades in a timely manner, should we reach the point where the system continues to be overloaded.

We look forward to your support of our multi-phased and integrated community approach to address the capacity and reliability issues on the island. Our Community Plan focuses on strengthening energy efficiency and our electric system, including distribution, vegetation management, and, if triggered by island electricity use or disasters, substation and transmission infrastructure.

For more information, please visit our Web page at www.PSE.com/Bainbridge. Look for the launch of the Bainbridge Island energy challenge in November. We will continue to update you on the success of the island's energy efficiency programs, as well as any developments in our Community Plan project timeline. Again, thank you for your continued interest in and valuable feedback on the energy future for you and all of our customers on Bainbridge Island.

Sincerely,

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Bainbridge Island Electric System Needs Assessment

Bainbridge Island, WA

Strategic System Planning
July 2019

PUGET SOUND ENERGY

Bainbridge Island Electric System Needs Assessment

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Strategic System Planning
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Executive Summary

A transmission and distribution system needs assessment was performed for Bainbridge Island. The detailed technical analysis determined that there are reliability, system capacity and aging infrastructure needs during the 10-year planning horizon.

Bainbridge Island is home to a population of 24,400 residents and Washington State Ferries Eagle Harbor Maintenance Facility and Ferry Terminal. Puget Sound Regional Council has identified Bainbridge Island as an urban area for the Growth Management Act.

Bainbridge Island receives electric power via two 115,000 volt (115 kV) transmission lines extending south onto the island. Approximately 12,400 island electric customers are served from three distribution substations – Port Madison, Murden Cove and Winslow. The two supply transmission lines connect at Port Madison, and then split into single radial transmission lines, also referred to as “taps”, to bring power to Murden Cove and Winslow substations. From the three substations, distribution lines deliver power to island homes and businesses.

Transmission Needs and Concerns

Transmission Reliability Need

Key findings from the reliability assessment for the five year period (2013 to 2017) identified reliability needs on Bainbridge Island.

Customers on Bainbridge Island, in particular those served by the Winslow substation, experienced longer and more frequent outages in comparison to Kitsap County and PSE company-wide. Excluding storm related outages, Bainbridge Island 5-year average SAIDI[1] was 2 times PSE service quality index of 155 customer minutes of service interruption a year. Bainbridge Island 5-year average SAIFI[2] was 75 percent higher than PSE service quality index of 1.3 customer service interruptions a year.

Transmission outages contributed to nearly 50 percent of the total customer minutes of service interruption to Bainbridge Island over the past 5 years. In comparison, across PSE’s service territory, transmission outages contributed an average of 10 percent to the total customer minutes of service interruption.

Nearly 70 percent of the transmission customer minutes of service interruption on Bainbridge Island were from outages to the Winslow Tap transmission line. The remaining transmission customer minutes of service interruption were caused by island-wide outages due to loss of both transmission supply lines outside of the island.

The Winslow Tap transmission corridor has cross country sections with limited access and difficult terrain for patrol, which results in prolonged restoration times for many of the Winslow tap outages.

Winslow substation experienced a significant number of outages, 21 over the five-year period, averaging 4 outages a year, primarily caused by loss of Winslow Tap transmission line from tree related events.

[1] SAIDI (System Average Interruption Duration Index): Reliability metric calculated for an area or PSE company-wide to measure average outage duration impacting customers in minutes per year. Outages longer than 5 minutes are considered.

[2] SAIFI (System Average Interruption Frequency Index): Reliability metric calculated for an area or PSE company-wide to measure average outage frequency impacting customers in interruptions per year. Interruptions longer than 1 minute are considered.

Transmission Aging Infrastructure Need

The Winslow Tap transmission line was built in 1960 with wishbone crossarm construction. PSE has started to see wishbone crossarms of similar vintage failing in other parts of PSE service area and considers this type of construction to be a reliability risk. An inspection of this transmission line in early 2019 indicated that nearly half of the wishbone crossarms will require replacement.

Transmission Operating Flexibility Concern

Operational flexibility is related to the ability to transfer load to support routine maintenance and outage management. Winslow and Murden Cove substations are on radial transmission taps with no operating flexibility at the transmission level, meaning there is no transmission backup supply to power these substations. In absence of transmission backup, for managing a transmission outage to a substation, PSE switches customers of the affected substation to adjacent substations over distribution ties. Such switching can be time taking and complex dependent on the area loading. During winter when customer demand is highest, some customers on the affected transmission line and its substation may not be transferred and can experience an outage[3].

Transmission Service Concern - Load shedding, Low Voltage and Island-wide Outage Events[4]

Bainbridge Island and the North Kitsap County substations are at the end of the transmission system serving Kitsap Peninsula. PSE transmission planners studied various contingencies in compliance with federal reliability requirements and found that certain multiple contingencies on the transmission system off-island on Kitsap peninsula may cause low voltage or overloading of the transmission lines on the peninsula. Under such contingencies, PSE may be forced to shed load by de-energizing some or all of Bainbridge Island substations. These concerns will be addressed separately under PSE's solution for Kitsap Transmission System Needs. PSE rebuilt the 2 transmission supply lines in North Kitsap in 2016 and expects the line upgrades to improve reliability of the two supply lines and mitigate possibilities of island-wide outages.

Distribution Needs and Concerns

Distribution Substation Group Capacity Need

An additional substation group capacity of 14.6 MW is needed on Bainbridge Island over the next 10 years starting in 2019/20 to support general load growth and the planned 10 MW load addition of WSDOT electric ferry, and keep the island's projected load within PSE's distribution planning guidelines.

Distribution Feeder Group Capacity Concern

The distribution feeder capacity needs are for distribution circuit group of five feeders supplying the Downtown Winslow area. With the electrification of Bainbridge to Seattle Ferry currently planned by Washington State Ferries, load would exceed N-1 (one element out of service) feeder capacity in the area leaving some customers in this commercial area at risk for long duration outages. A dedicated new feeder will be required to supply the ferry load under their tentative rate schedule. This additional dedicated feeder will eliminate the feeder group capacity concern in the Downtown Winslow area.

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[3] PSE limits routine equipment maintenance to summer months when loading is light and backup is available from the distribution system. An unplanned or emergency transmission repair situation in winter can lead to outages for some customers due to lack of operating flexibility.

[4] For this document, the definition of Island wide outage is the simultaneous loss of electric service to all customers on Bainbridge Island.

Distribution Reliability Concern

There are reliability needs with Port Madison and Winslow substations feeders - PMA-12 and WIN-13 feeders respectively. These two circuits continue to have SAIDI and SAIFI scores significantly worse than PSE's average values. However, reliability projects are currently planned to eliminate these reliability needs.

Conclusion

The system needs and concerns identified for Bainbridge Island are summarized below. Potential solutions must address all of the system needs identified in this study, while also considering the identified concerns. The system needs and concerns for Bainbridge Island are:

- **Transmission Reliability need:** A reliability improvement need was identified to improve the performance of transmission service to Winslow substation.
- **Transmission Aging Infrastructure need:** An infrastructure replacement need was identified for the Winslow Tap transmission line support structures that are nearing end of useful life and could potentially fail leading to unplanned outages and emergency repairs.
- **Substation Capacity need:** A distribution substation group capacity need of 14.6 MW was identified on Bainbridge Island within the 10 year planning horizon (2018-2027) to support general load growth of 4.6 MW and planned 10 MW load addition of WSDOT electric ferry.
- **Transmission Operating Flexibility concern:** Concerns related to ability to transfer load to support routine maintenance and outage management on the radial transmission lines feeding Winslow and Murden Cove substations.

1 Introduction

This document reports the results of a needs assessment performed for the transmission and distribution systems serving Bainbridge Island to identify current and future needs of the electric systems.

1.1 Study Objective

The study objective was to assess the capability of existing transmission and distribution infrastructure within Puget Sound Energy's (PSE's) Bainbridge Island service area. (See Figure 1-1 for study area)

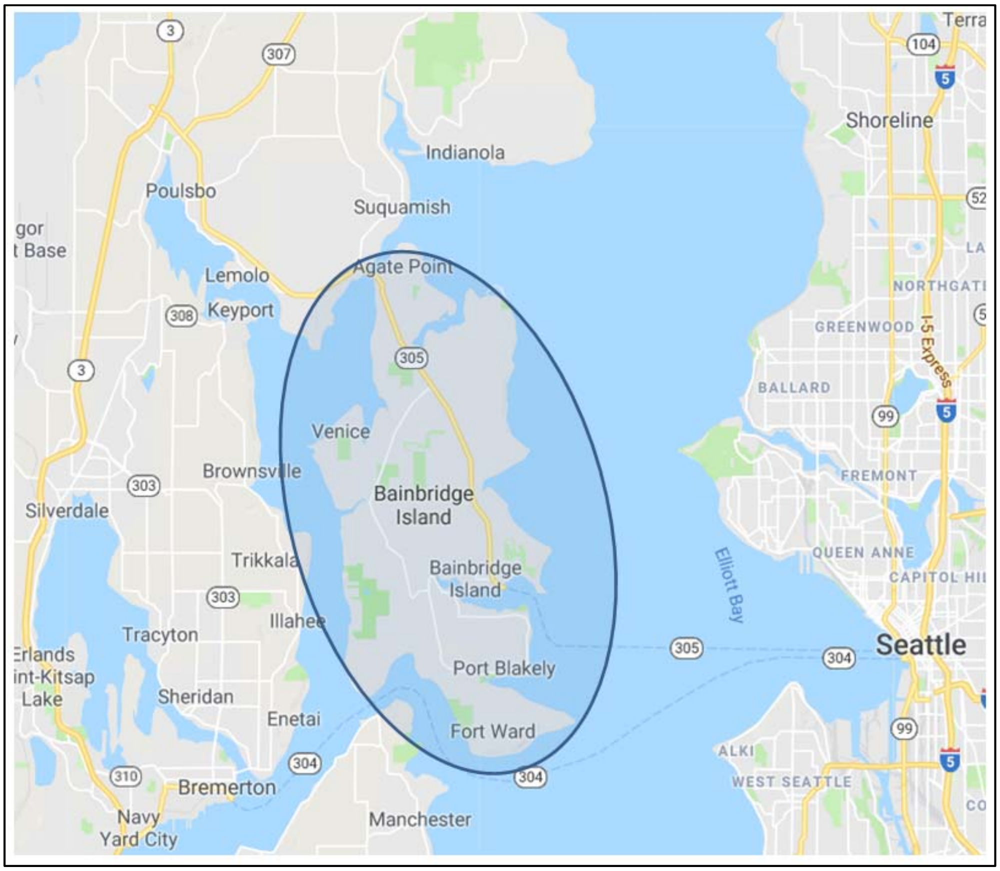


Figure 1-1: Bainbridge Island Study Area

Transmission Assessment includes:

- Analysis of transmission capacity to serve Bainbridge Island load over the next 10 years (2018-2027), as forecasted under the F2017 PSE Load Forecast (See Appendix A-1). The transmission system was analyzed for a range of planning contingencies as per the North American Electric Reliability Corporation (NERC) Transmission Planning Standard (TPL-001-4).
- Reliability assessment of the transmission lines serving Bainbridge Island
- Analysis of operational concerns of the transmission system serving Bainbridge Island.

Distribution Assessment includes:

- Analysis of distribution capacity to serve Bainbridge Island load over the next 10 years (2018-2027). Analysis includes all elements in service (N-0) and one element out of service (N-1) contingencies.
- Review of historical reliability performance
- Analysis of operational concerns for all the circuits and substations on Bainbridge Island.

2 Background

2.1 Background Information

Reliability issues were first identified for Bainbridge Island in 1993. At the time, PSE proposed to construct a new parallel 115 kV transmission line via Bainbridge Island from Bremerton to Foss Corner switching station in Poulsbo. The proposed West Sound Transmission Reliability project was later revised to implement one of the alternate solutions: to improve tree trimming and to re-build Port Madison (PMA) substation with four 115 kV breakers. This project was completed in 2000.

In 2006, PSE completed a reliability and capacity study of the Island, which resulted in proposed infrastructure solutions and community conversations about the proposed solutions from 2008-2010. After input from the community, PSE agreed to a three-year “stay out” period where the community would attempt to reduce its energy demand; any load growth above 58 MW peak demand (Winslow and Murden Cove combined) would require additional substation capacity. PSE also clarified that providing the community with a three-year window to reduce its energy demand would only address the capacity challenges – reliability problems would not be addressed. A peak combined demand of 54.8 MW was experienced on February 7, 2014. Ferry electrification would require a 10 MW load connection to either Winslow or Murden resulting in exceeding the 58 MW.

PSE conducted a residential Demand Reduction Pilot (DRP) project from October 2009 through September 2011, as part of an effort to work with the residents of Bainbridge Island to reduce their load in an attempt to defer a need for additional substation capacity. During the pilot, PSE used special equipment to monitor and reduce residential household energy use on peak load days. One of the goals of the pilot project was to determine the potential peak electric demand reduction achievable on Bainbridge Island through the control of residential space and water heating equipment. Approximately 8% of the target customers participated in the pilot and an average aggregate demand reduction of 683 kW were realized in the target area.

With growing reliability challenges and expected increases in demand, PSE initiated this needs analysis in 2017.

2.2 Area Description

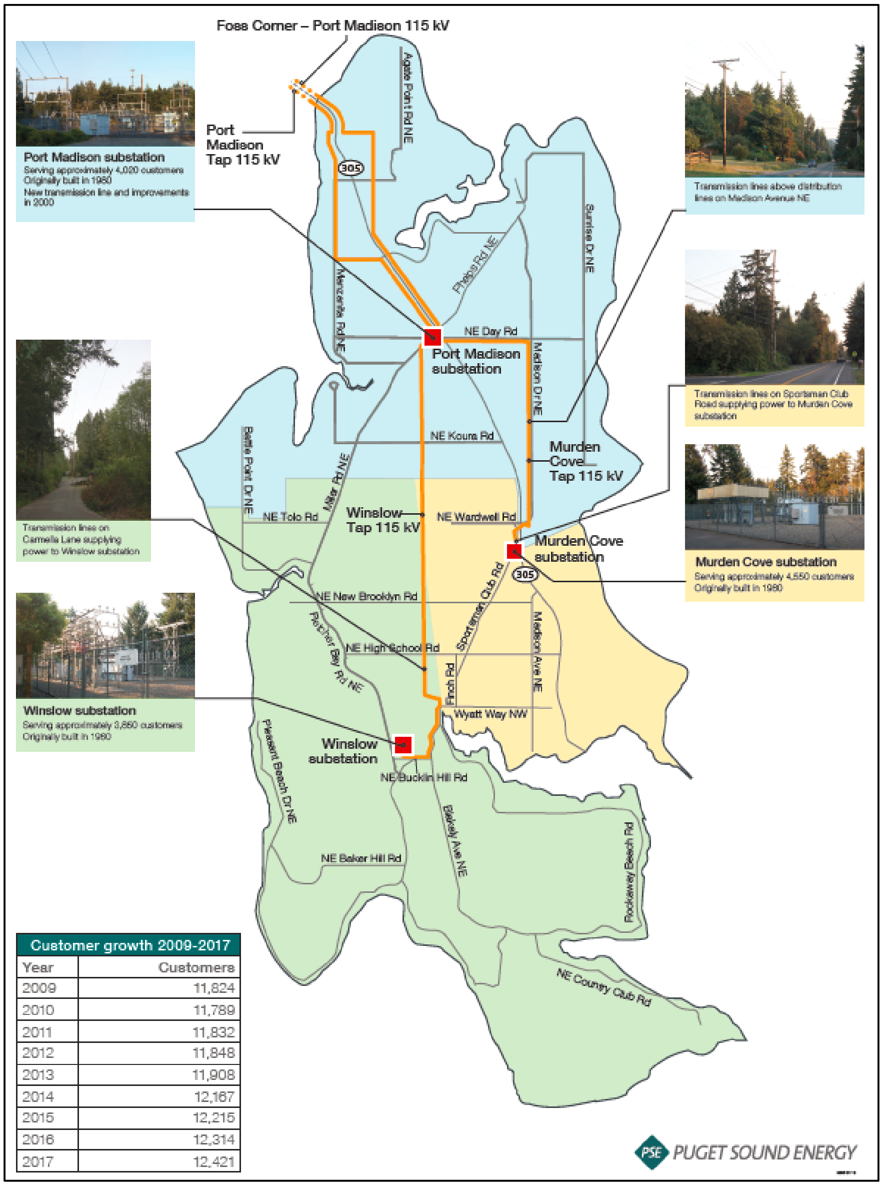
The City of Bainbridge Island is an urban growth area separated from the Kitsap Peninsula by the Agate Pass waterway and bridge and is home to a population of 24,400 residents, a unique downtown area, and Washington State Ferries Eagle Harbor Maintenance Facility and Ferry Terminal. In 2017, an average customer meter count of 12,400. Two-thirds of the population is located at the south end of the island.

Bainbridge Island customers are served from three distribution substations, Port Madison, Murden Cove and Winslow, with an aggregate peak winter 2016/17 electric load of 77 megawatts (MW) and a peak summer 2017 of 26 MW[5]. Two 115 kilovolt (kV) transmission supply lines bring power to the Port Madison substation on Bainbridge Island. From Port Madison, there are two separate radial 115 kV transmission lines that serve Murden Cove and Winslow substations respectively.

[5] Peak winter and summer loads coincident with system peak

The Bainbridge Island study area is served primarily by electric energy as there is no natural gas service to the island, though some customers use propane gas for heating. In winter, electricity usage is higher than is typical in other PSE service areas, due to a large amount of electric heating loads. Bainbridge Island has mainly residential electric customers and relatively few commercial and industrial customers. The peak load occurs in the winter and is typically 2.5 to 3 times the summer peak load.

Figure 2-1 illustrates the Transmission System and Distribution Substations serving Bainbridge Island.



Customer growth 2009-2017	
Year	Customers
2009	11,824
2010	11,789
2011	11,832
2012	11,848
2013	11,908
2014	12,167
2015	12,215
2016	12,314
2017	12,421

Figure 2-1: 115 kV Transmission System and Distribution Substations Serving Bainbridge Island

2.3 Existing Transmission System

As shown in Figure 2-1, Bainbridge Island receives power from 2-115 kV lines, the Foss Corner-Port Madison 115 kV line and the Port Madison Tap of the Foss Corner-Keyport 115 kV line. The two 115 kV transmission lines terminate at Port Madison 115 kV switching station. Two separate 115 kV radial transmission lines – the Winslow Tap 115 kV and Murden Cove Tap 115 kV, tap off the Port Madison 115 kV bus and serve Murden Cove and Winslow distribution substations.

The Murden Cove Tap 115 kV transmission line is 3 miles long and consists of 795 ACSR Tern conductor. The Winslow Tap 115 kV transmission line is 4.5 miles long and consists of 4/0 ACSR conductor. Both transmission lines are radial from the Port Madison transmission bus. This means if there's an outage anywhere on the transmission line, the substation at the end of the line has an outage (either Winslow or Murden Cove). If the substation is out, then all customers served by it have an outage, too.

2.4 Existing Distribution System

Bainbridge Island is generally served from four feeders from the Port Madison substation (PMA-12, PMA-13, PMA-15, PMA-16), four feeders from the Murden Cove substation (MUR-13, MUR-15, MUR-16, MUR-17), and four feeders from the Winslow substation (WIN-12, WIN-13, WIN-15, WIN-16). All three substations utilize the PSE standard 115-12 kV 25 MVA distribution transformers.

Table 2-1 summarizes the customer count and feeder system conductor type for each circuit on Bainbridge Island during normal system configuration (N-0).

Table 2-1: Study Area Feeder System Conductor Type by Mile

Circuit	2017 Average Customer Count	Overhead Bare	Overhead Tree Wire	Underground
PMA-12	993	3.8	-	.1
PMA-13	893	.4	2.3	.5
PMA-15	1290	3.0	.9	.5
PMA-16	843	1.3	.9	.1
PMA Total	**4019**	**8.5**	**4.1**	**1.2**
WIN-12	1158	1.7	3.1	.1
WIN-13	1247	1.2	2.0	.3
WIN-15	727	.8	3.2	1.5
WIN-16	720	.1	-	1.1
WIN Total	**3852**	**3.8**	**8.3**	**3**
MUR-13	1493	1.7	2.5	2.0
MUR-15	751	1.0	-	1.9
MUR-16	601	2.4	-	.1
MUR-17	1705	1.4	.3	2.2
MUR Total	**4550**	**6.5**	**2.8**	**6.2**
Total (Study Area)	**12421**	**18.8**	**15.2**	**10.4**

3 Forecasted Load

The PSE F2017 Kitsap County area load forecast was utilized for modeling of PSE's Kitsap peninsula load outside of Bainbridge Island. The Bainbridge Island Load Forecast was used for modeling loads for analysis of transmission and distribution system on Bainbridge Island.

3.1 Kitsap County Corporate Load Forecast

PSE's F2017 Corporate Load Forecast shows a slightly declining load growth profile for Kitsap County winter peak demand over the 10 year period 2018-2027. The Kitsap County normal winter peak load has an average annual load growth (decline) of minus 0.4% per year over next 10 years (2018-2027), with 100% conservation. With 0% conservation, the County winter peak demand grows at an average annual load growth of 0.9% per year.

Figure 3-1 shows the PSE normal winter peak load forecast for Kitsap County over the 10 year period 2018-2027 with 100% and 0% level of conservation. As shown in the forecast, conservation offsets the growth in electric demand over the 10 year period. With no conservation, Kitsap County normal winter demand is expected to grow from 512 MW in 2018 to 560 MW in 2027. PSE's conservation measures of up to 79 MW over the 10 year period, offset (reduce) the electrical demand for the county to a declining trend – 560 MW to 481 MW in 2027.

The PSE F2017 Kitsap County area load forecast was utilized for modeling of PSE's Kitsap peninsula load outside of Bainbridge Island, for analysis of PSE's transmission system on Kitsap peninsula. The proposed Bainbridge Island ferry electrification load information was not available at the time of release of the F2017 corporate load forecast. Therefore, the Ferry load was included separately in the analysis.

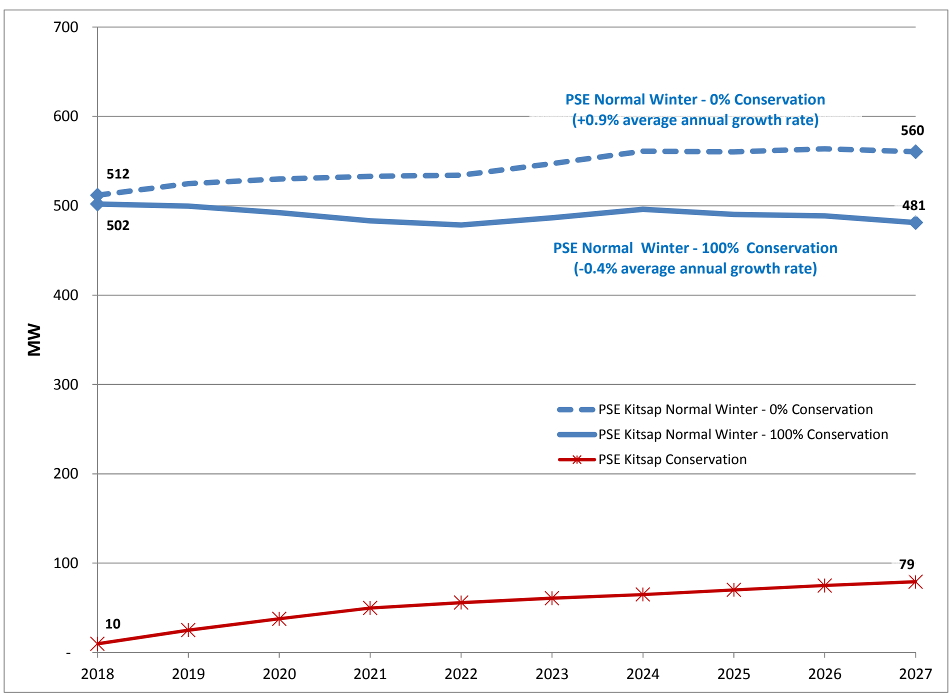


Figure 3-1: Kitsap County – PSE Normal Winter Peak F2017 Load Forecast (2018-2027) without/with Conservation

Appendix A and Appendix B provide the PSE F2017 Kitsap County peak load forecast for normal winter and normal summer conditions.

The PSE F2017 corporate load forecast is a 20 year[6] (2018-2037) load projection of peak winter and summer demand; however the study utilized the initial 10 years of the load forecast for the Bainbridge needs assessment for the 10 year planning horizon of 2018-2027. Peak winter load forecast is provided for “normal” winter conditions at 23°F. Peak summer load forecast is provided for “normal” summer conditions at 89.5 °F. Load forecast is also provided with respect to PSE’s implementation of conservation at 100% and 0% level.

PSE uses the “normal” weather load forecast at 100% conservation for planning PSE’s system; however 0% conservation was used for as a sensitivity study in transmission analysis to verify system performance at higher loading level.

The PSE F2018 load forecast became available in July of 2018 after substantial completion of this needs assessment. The PSE F2018 load forecast utilizes the same county level conservation values as the F2017 forecast as the conservation forecasts values are updated every 2 years. Appendix C details the F2018 normal winter forecast.

In comparison the F2018 normal winter load forecast has a slightly higher load projection than F2017, due to following reasons:

- More than 50% of difference in load forecast from 2017 to 2018 for the first 3 years comes from 2018 updated block load assumptions for new block load additions in Kitsap County. These load additions in the first 3 years (2018 to 2020) included 36 MW of new block loads such as the Bainbridge Island Ferry terminal (10 MW), Kingston Ferry terminal (10 MW), Harrison Hospital expansion (6 MW), Bitcoin (3 MW) and Clearwater Casino expansion (2 MW).
- The 2018 load forecast is higher in the long term due to updated economic and demographic forecast assumptions in 2018.

3.2 Bainbridge Island Load Forecast

PSE generated a 10 year *Bainbridge Island Load Forecast* (2018-2027) for normal winter and normal summer conditions using the following methodology:

Navigant Consulting developed a bottom-up winter load forecast for Bainbridge Island. The “bottom-up” forecast is detailed in Appendix D of the Bainbridge Island Electric System Solutions Report, Bainbridge Island Non-Wires Alternative Analysis, Navigant Consulting, page 3. Navigant relied on “the refined “bottom-up” calculation of load net of planned DSM[7] programs, which includes zip code-specific cost-effective EE savings, and recalculation of demand-side management (DSM) capacity savings based on local substation load shapes, line losses, and power factor.” This bottom-up winter load forecast was used as the Bainbridge Island Load Forecast for winter. This bottom-up winter load forecast used the historical winter peak demand for Bainbridge Island 3-substation group in the past 5 year period 2013-2017, as the starting load. The historic peak load was grown at annual load growth rates from PSE F2017 county level forecast, and included the 2021 anticipated ferry block load addition. The bottom-up

[6] Forecast Horizon is for 20 years, however the assessment period is for the first ten years. Years 11-20 is included in distribution assessment for use in developing solutions.

[7] DSM as used by Navigant Consulting is synonymous with Conservation

demand savings calculated for Bainbridge Island zip code were then applied to generate the net bottom-up normal winter load forecast with conservation.

The summer load forecast for the *Bainbridge Island Load Forecast* was generated with similar methodology, except that the bottom-up calculation of demand savings was not used. This is because the impact of efficiency measures on summer loading is minimal.

Figure 3-2 shows the Bainbridge Island Load Forecast for normal winter and summer conditions for the 3 substation group that includes Port Madison, Murden Cove and Winslow substations and the ferry load addition in 2021. Bainbridge Island winter peak load grows at an average annual load growth of 1.8 percent a year over the 10 year period 2018-2027, as compared to a declining minus 0.4 percent for the rest of Kitsap County.

Appendix D details the Bainbridge Island local area load forecast for normal winter and normal summer conditions.

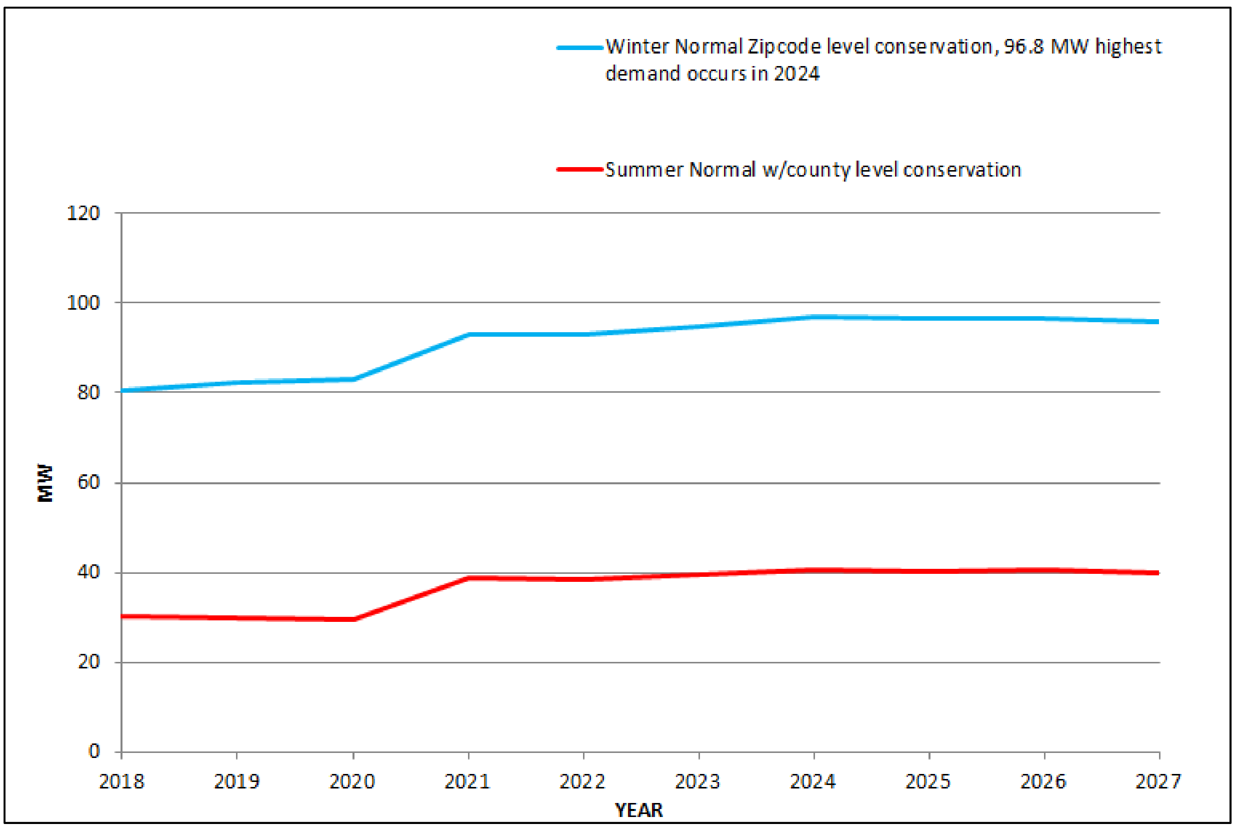


Figure 3-2: Bainbridge Island Load Forecast – Normal Winter and Normal Summer

4 Transmission Needs Assessment

This section assesses the transmission system needs for Bainbridge Island over the 10 year planning horizon (2018-2027). The transmission system needs assessment utilized the PSE F2017 corporate load forecast and PSE's Bainbridge Island local area load forecast for projecting Kitsap County and Bainbridge Island load for the 10 year period.

4.1 Transmission Study Assumptions

Following are the major assumptions utilized in the transmission needs assessment for Bainbridge Island:

- The load levels for Bainbridge Island for the 10 year planning horizon 2018-2027 normal winter load forecast at 23°F are from the Bainbridge Island Load Forecast detailed in section 3.2.
- The load levels for entire Kitsap County are from the PSE F2017 corporate load forecast for Kitsap County for the 10 year planning horizon 2018-2027.
- A base case was modeled for normal winter load with 100% conservation using the Bainbridge Island Load Forecast at the maximum winter loading of 96.8 MW for Bainbridge Island in 2024 during the 10 year planning horizon 2018-2027.
- A sensitivity case was developed to study impact of greater electrical loading under 0% conservation over the 10 year planning horizon 2018-2027, at a maximum winter loading of 99 MW for Bainbridge Island in 2026.

4.2 Transmission Capacity AssessmentMethodology

PSE follows the NERC and WECC planning standards[8] for transmission capacity assessment. The assessment involves review of the transmission system for any thermal overloads or voltage violations for forecasted load, under normal system state (N-0) and abnormal system state involving different types of contingencies (N-1, N-1-1, bus). The contingencies are categorized under TPL-001-4 as P0 through P7. PSE plans for load forecasted at winter peak at 23°F and summer peak at 89.5°F.

4.2.2 Performance Criteria for Thermal Overload and Voltage Limits

PSE has thermal operating limits for normal and emergency operation, which are temperature based limits the equipment can operate under without failing. Normal operating limit is a specific electric loading that a facility can support through the daily demand cycles. The emergency limit is a higher than normal loading that the facility can support for a finite period. PSE's transmission assessment utilizes the normal facility rating for normal state (no contingencies) and emergency facility rating for abnormal system state involving a contingency.

The TPL-001-WECC CRT-3criterion requires PSE to operate the transmission system within 95% to 105% of nominal voltage for normal conditions (P0), and 90% to 110% of nominal voltage during contingencies (P1 through P7). Voltage deviation is not allowed to exceed 8% for single contingency events (P1).

[8] TPL-001-4 (https://www.nerc.com/files/TPL-001-4.pdf) *and TPL-001-WECC CRT-3 (https://www.wecc.biz/reliability/tpl-001-wecc-crt-3.pdf)*

4.2.3 Transmission Assessment Results

Transmission assessment for Bainbridge Island was performed over the following range of contingencies (P0 through P7):

P0: No Contingencies (Normal System)

The existing transmission system on the island can carry the projected loads over the 10 year planning horizon (2018-2027) with no overloading or voltage violations under a normal system configuration, i.e. no contingencies.

P1: Single Contingency (Loss of one transmission line)

Bainbridge Island is supplied by 2-115 kV transmission lines from Foss Corner switching station in North Kitsap – the Foss Corner – Port Madison line and Port Madison Tap off the Bremerton – Foss Corner line. Either supply transmission line will carry the projected load for Bainbridge Island for the 10 year planning horizon (2018-2027).

There are two radial transmission lines that originate from Port Madison substation - Winslow Tap (Port Madison to Winslow substation) and Murden Cove Tap (Port Madison to Murden Cove substation). Under loss of either radial transmission line, the de-energized substation load may be switched to other substations on the island using distribution ties, in the summer; PSE is extremely limited on switching ability in the winter months. For example, for a loss of Murden Cove substation, the load may be switched over to Winslow, Port Madison or both substations.

The single transmission contingencies studied on Bainbridge Island were the loss of the either transmission tap line. The loss of the Murden Cove Tap transmission line results in an outage of the Murden Cove substation, and it is assumed that all of Murden Cove substation load is switched to Winslow substation over distribution ties. The Winslow Tap transmission line feeding Winslow substation will then carry the load of Winslow substation, Murden Cove substation and the 10 MW ferry load. This is a conservative assumption since the distribution system under peak loading does not support switching the de-energized Murden Cove substation customers entirely to Winslow substation, (see the distribution system capacity Section 5.3.2), However such assumption tests the transmission capacity of the Winslow Tap transmission line for an emergency measure such as installing a mobile substation off the Winslow Tap transmission line, to pick Murden Cove customers for the loss of Murden Cove Tap transmission line.

The Winslow Tap line conductor of 4/0 ACSR has sufficient transmission capacity to support the Murden Cove Tap contingency with no overloads or voltage violations in the studied base cases and the sensitivity case of 0% conservation.

The loss of the Winslow Tap transmission line results in an outage of the Winslow Substation, and it is assumed that all of Winslow substation load is switched to Murden Cove substation over distribution ties except during peak demand.

The Murden Cove Tap line conductor of Tern 795 ACSR has sufficient transmission capacity to support the Winslow Tap contingency with no overloads or voltage violations in the studied base cases and the sensitivity case of 0% conservation.

P2: Single Contingency (Opening of one transmission line without fault, bus section fault etc.)

Results for P2 single contingencies on transmission lines are same as P1, described above. Results for single contingencies involving bus outage are covered under P4 below.

P3: Multiple Contingency (Loss of generator unit followed by loss of another transmission element)

P3 contingencies do not apply to the study area as there are no generators connected to the transmission system on Bainbridge Island.

P4: Multiple Contingency (Bus Outage)

A bus contingency on the island does not result in any overloads or voltage violations in the studied base cases and the sensitivity case of 0% conservation. No violations of the NERC TPL-001-4 were found due to a P4 contingency.

However, bus configuration is a reliability concern that a single bus contingency event at a switching station could cause an island-wide outage until PSE could perform manual switching to restore power. Outage restoration might take 3 to 4 hours to perform. The loss of load for the P4 contingency is allowed under the NERC TPL-001-4 planning standard.

P5: Multiple Contingency (Fault plus relay failure to operate)

Results for P5 contingency are same as P4 contingencies.

P6: Multiple Contingency (Loss of two transmission elements in succession)

Bainbridge Island is supplied by two transmission lines. Loss of both transmission supply lines will de-energize all substations on the island, resulting in an island-wide outage. Loss of connected load for a multiple contingency (P6) is considered a consequential loss of load, and is allowed under the NERC TPL-001-4 planning standard.

The Bainbridge Island winter peak load is projected in the range of 80 MW to 97 MW over the 10 year period 2018-2027 (see Figure 3-2). Per PSE Transmission Planning Guidelines, the load served by two transmission sources is recommended in the range of 100 MW to 150 MW or a maximum of 4 distribution substations. Therefore, Bainbridge Island projected load over the next 10 years is adequately served by two transmission sources.

Bainbridge Island is served at the end of PSE's transmission system on Kitsap peninsula. As such, certain contingencies on Kitsap peninsula will impact service to Bainbridge Island.

P7: Multiple Contingency (Loss of two transmission elements simultaneously)

There are no two transmission elements on common structure on Bainbridge Island or the north Kitsap County transmission loop serving Bainbridge Island, therefore no contingencies needed to be studied in this category.

4.3 Transmission Reliability Assessment

This section discusses reliability performance of Bainbridge Island over the 5 year period 2013 to 2017 and provides an assessment of reliability of the transmission system serving Bainbridge Island.

Figure 4-1 and Figure 4-2 show reliability performance[9] of Bainbridge Island (all three substations – Port Madison, Winslow and Murden Cove) and Winslow substation, over a 5 year period – 2013 to 2017, in comparison to PSE Kitsap County and PSE company-wide service area in terms of observed SAIDI and SAIFI. Winslow substation was included in isolation for comparison, as it had the highest count and duration of outages of the 3 island substations. The outage data excludes storm related events for comparison to established PSE non-storm Service Quality Indices (SQIs). Reliability metrics were reported with transmission and distribution outage components.

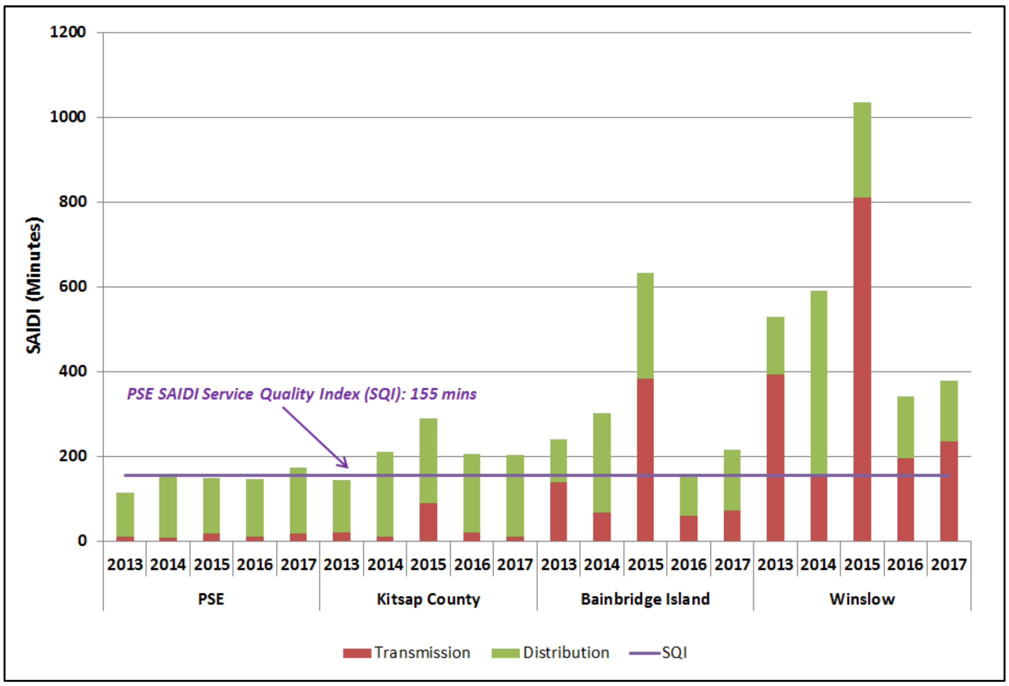


Figure 4-1: Comparison of Non-Storm SAIDI Performance for Bainbridge Island (average customer outage minutes from 2013 to 2017)

[9] Reliability metrics of SAIDI and SAIFI were evaluated for each subset of customer base considered – PSE company-wide, Kitsap County, Bainbridge Island and Winslow substation, from 5 years of non-storm outage data (2013-2017).

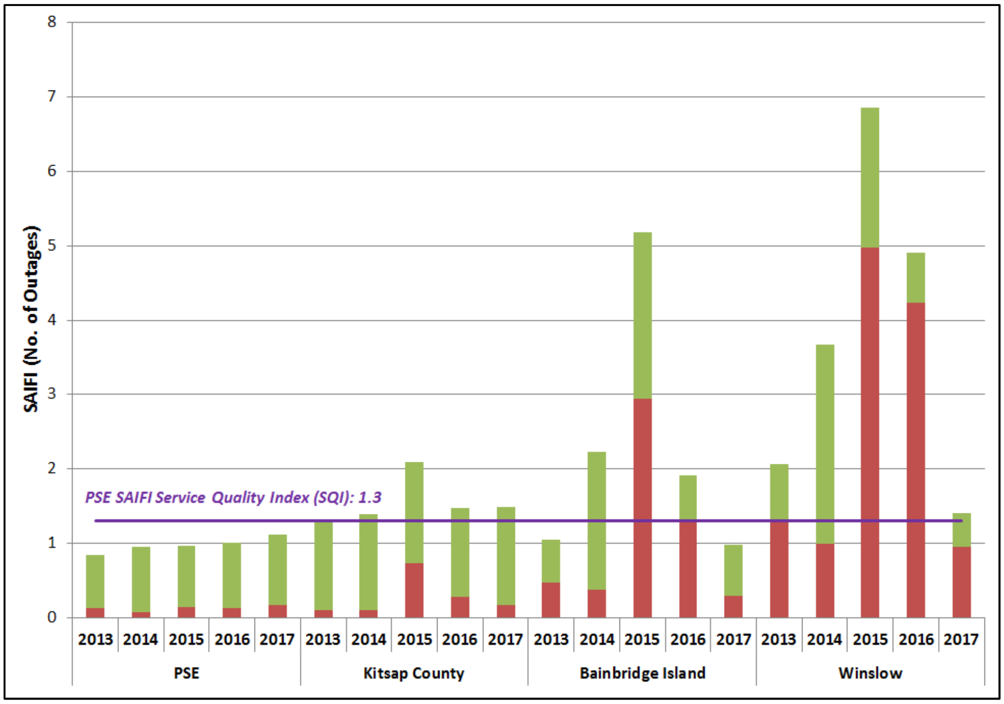


Figure 4-2: Comparison of Non-Storm SAIFI Performance for Bainbridge Island (average number of outages from 2013 to 2017)

Reliability metrics show that customers on Bainbridge Island, in particular Winslow substation, experienced longer and more frequent outages in comparison to Kitsap County and PSE company-wide over the 5 year period 2013-2017.

Excluding storms, Bainbridge Island 5-year average SAIDI for 2013-2017 was 310 customer minutes of service interruption a year or 2 times the PSE service quality index of 155 customer minutes of service interruption a year. Bainbridge Island 5-year average SAIFI for 2013-2017 was 2.27 customer service interruptions a year or approximately 75 percent more service interruptions than the PSE service quality index of 1.3 customer service interruptions a year.

Winslow substation customers had the lowest service reliability on Bainbridge Island. Winslow customer's 5-year average SAIDI for 2013-2017 was 576 customer minutes of service interruption a year or nearly 4 times PSE service quality index of 155 customer minutes of service interruption a year. The Winslow 5-year average SAIFI for 2013-2017 was 3.78 customer service interruptions a year or nearly 3 times the PSE service quality index of 1.3 customer service interruptions a year.

Transmission outages are a significant proportion of customer outages experienced on Bainbridge Island. For 2013-2017, transmission outages contributed an average 47% of customer minutes of service interruption a year for Bainbridge Island, and an average 63% of customer minutes of service interruption a year to Winslow substation - in comparison to an average 10% transmission outage contribution to PSE company-wide customer minutes of service interruption.

4.3.1 Transmission Reliability Analysis

The transmission system analyzed includes the two 115 kV transmission supply lines, the Foss Corner – Port Madison line and the Foss Corner – Keyport line, as well as two radial 115 kV transmission lines of Winslow Tap and Murden Cove Tap.

Figure 4-3 shows a timeline of sustained outages to Bainbridge Island distribution substations over the 5 year period 2013-2017, due to outages on the transmission system.

Figure 4-4 shows a corresponding timeline of transmission line outages that resulted in sustained and momentary outages to Bainbridge Island substations. Outages involving island-wide events are outlined in red.

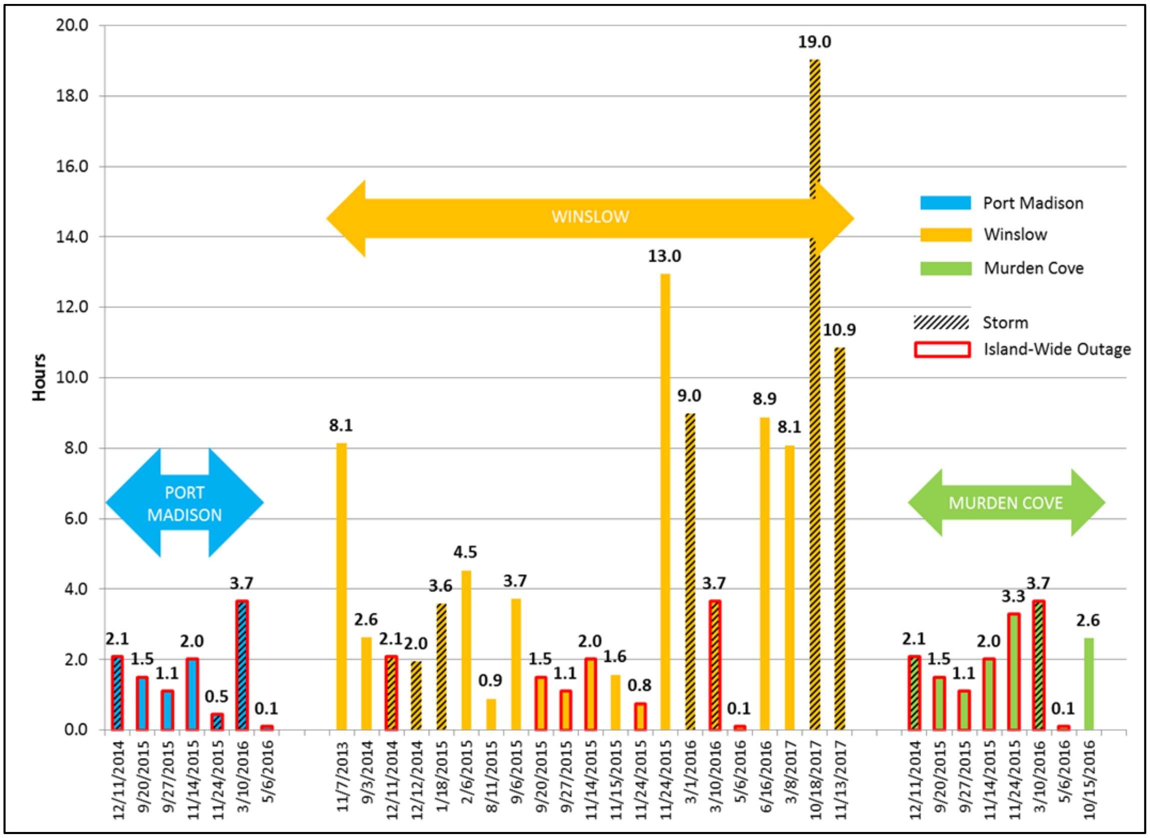


Figure 4-3: Bainbridge Island Substation Outages 2013-2017 on Loss of Transmission

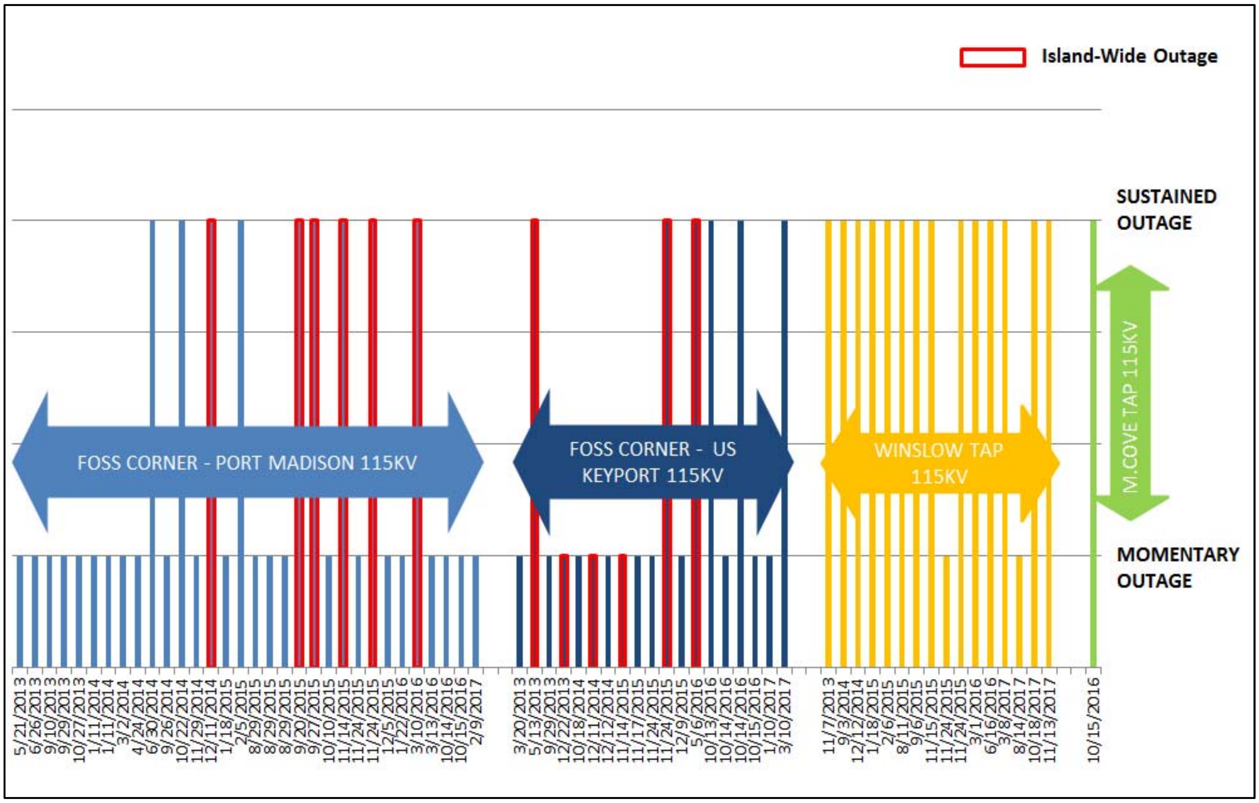


Figure 4-4: Bainbridge Transmission Line Outages (2013-2017) – Sustained and Momentary

Table 4-1 provides a summary of Bainbridge Island substation outages due to contingencies on the transmission system, as shown in Figure 4-3.

Table 4-2 provides a summary of transmission line outage data shown in Figure 4-4.

Table 4-1: Bainbridge Island Substation Outage Summary 2013-2017 – Due to Loss of Transmission

Substation	Island-Wide Outages	Individual Substation Outages	Total Substation Outages
Port Madison	7	0	7
Winslow	7	14	21
Murden Cove	7	1	8
TOTAL	21	15	36

Table 4-2: Bainbridge Island Transmission Line Outage Summary (2013-2017)

Transmission Line	Sustained Outages	Momentary Outages	Total Outages
Foss Corner – Port Madison	9	26	35
Foss Corner – Keyport	6	15	21
Port Madison – Winslow Tap	14	1	15
Port Madison – Murden Cove Tap	1	0	1

Table 4-3 provides a breakdown of Bainbridge Island transmission line outages (2013-2017) by cause.

Table 4-3: Bainbridge Island Transmission Line Outage Summary by Cause (2013-2017)

Transmission Line	Total Outages	Trees/ Vegetation	Equipment	Unknown
Foss Corner – Port Madison	35	19	0	16
Foss Corner – Keyport	21	12	1	8
Port Madison – Winslow Tap	15	14	1	0
Port Madison – Murden Cove Tap	1	1	0	0
TOTAL	73	47	2	24

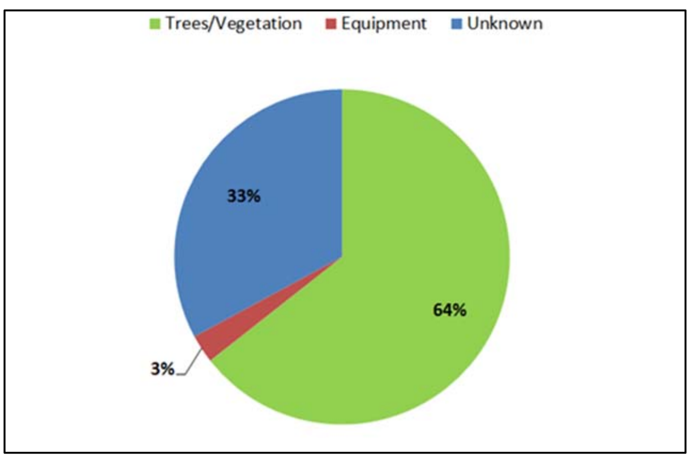


Figure 4-5: Bainbridge Island Transmission Outages by Cause (2013-2017)

Appendix E provides further details regarding Winslow Tap transmission outages and the factors responsible for the longer outage restoration time for Winslow Tap outages.

4.3.2 Reliability Analysis Summary

There were a total of 36 sustained outages to Bainbridge Island substations over the 5 year period 2013-2017, ranging from 6 minutes to 19 hours, due to outages on the transmission system. Twenty one of the 36 Bainbridge substation outages involved 7 island-wide outage events due to loss of both 115 kV transmission supply lines to the island. These events resulted in simultaneous outage to all three Bainbridge substations. The remaining 15 substation outages involved loss of radial transmission taps serving Winslow (14 transmission tap outages) and Murden Cove (1 transmission tap outage).

Winslow substation had the highest count of substation outages on Bainbridge Island, with 21 outages over the 5 year period or on average 4 outages a year. Fourteen of the 21 or nearly 70% of Winslow substation outages were caused by Winslow Tap transmission outages. The other 7 Winslow substation outages were part of island-wide outage events impacting entire Bainbridge Island. Restoration time of the Winslow Tap transmission line ranged from 0.9 hours to 19 hours. Outage restoration on the Winslow tap has been reported by PSE crews as difficult and time consuming, due to poor access on some cross-country sections of the transmission line.

Trees were a major cause of the transmission line outages impacting Bainbridge Island, comprising 64% of total transmission outages, as shown in Figure 4-5. A large proportion of outages (33%) were reported with unknown cause, most of which are suspected to be tree-related.

4.3.3 Island-Wide Outages Assessment

Island-wide outage events constituted a significant proportion (nearly 60%) of substation outages to Bainbridge Island.

- There were 7 island-wide outage events impacting Bainbridge Island over the 5 year period (2013-2017), ranging from 6 minutes to 3.7 hours.
- 3 out of the 7 island-wide outage events (9/20/2015, 9/27/2015 and 5/6/2016) happened when one of the transmission supply lines feeding Bainbridge was taken out of service for construction.
- 6 out of the 7 island-wide outages were caused by tree-related events.

The recurrence of island-wide outage events in 2013-2017 demonstrates vulnerability of transmission service to Bainbridge Island from two 115 kV transmission supply lines. However, 3 of the 7 island-wide outage events happened when PSE had taken one of the transmission supply lines, Foss Corner – Port Madison 115 KV, out of service to support construction for capacity upgrade. With the capacity upgrade of the supply line completed in 2016, PSE expects an improvement in reliability of the transmission supply lines to Bainbridge Island and reduced risk of island-wide outages.

4.4 Transmission Operations Assessment

The following issues were identified by PSE Operations departments:

Transmission Operating Flexibility:

There is no operating flexibility at the transmission level between the radial transmission taps to Winslow and Murden Cove substations. During winter months of peak electric demand on the island, if PSE has to perform emergency repair of equipment on the radial transmission tap to Winslow or Murden Cove substation, then some customers served by the affected substation might experience outage as there is no backup transmission line to feed either substation, and the distribution system on the island does not have enough capacity to backup all customers of the affected substation.

Access to the Winslow 115 kV Tap Transmission Line for Repair and Maintenance:

PSE line crews have poor access to cross country sections of the Winslow 115 kV tap. A transmission line outage on 10-18-2017 caused by broken transmission wishbone crossarm took PSE crews 19 hours to repair due to poor access to the failed crossarm location.

Transmission Capacity Deficiency on Kitsap Peninsula:

PSE performs week-ahead transmission operations planning analysis for the PSE transmission system and recommend operating plans to mitigate system violations that may occur under contingencies. During peak winter conditions, multiple contingencies involving certain 115 kV transmission lines or bulk transformers on the Kitsap peninsula can overload the transmission system and cause low voltage, impacting Bainbridge Island. PSE's operating plan to mitigate the transmission system overloads and low voltage under such contingencies is to reduce (shed) load in North Kitsap County and Bainbridge Island. Shedding load to mitigate line overloads is not a preferred practice at PSE, but may need to be adhered to as an interim measure until transmission capacity upgrades are implemented on the Kitsap Peninsula. PSE's Kitsap transmission needs assessment identified transmission capacity deficiencies on the Kitsap Peninsula and a separate transmission project will address Kitsap Peninsula needs.

4.5 Transmission Equipment Condition Assessment

4.5.1 Aging Infrastructure

Winslow Tap Transmission Line Aging Infrastructure:

The Winslow Tap transmission line was installed in 1960 at the time of energization of Winslow substation. The 4.5 mile transmission line consists of 4/0 ACSR conductor with wishbone crossarm construction. PSE has concerns about the condition of the wishbone crossarms that were installed in 1960s and 1970s. The transmission outage on Winslow 115 kV tap on 10-18-2017 was caused by failure of a transmission wishbone crossarm.

PSE conducted a line inspection of the Winslow tap in early 2019.

Key findings of the 2019 Winslow Tap inspection were:

- Nearly 50% of the line crossarms (39 out of 79) were in "reject" condition
- All poles (except 1 out of 79) met PSE pole strength criteria

PSE inspects transmission lines on a 10 year cycle. The PSE transmission line inspection criterion considers equipment status of "reject" as failing but non-critical condition and recommends replacement within 3 years. A “priority reject” is considered critical condition and requires replacement in 1 to 3 months.

Given the high proportion (50%) of cross arms on the line in reject condition, PSE considers replacing the reject crossarms in the next 1 to 3 years as a system need, as this need lies in the 10 year planning horizon of the needs assessment.

4.6 Transmission Needs and Concerns

The transmission assessment identified needs and concerns for the existing transmission system serving Bainbridge Island in Kitsap County.

4.6.1 Transmission Needs

The transmission needs for Bainbridge Island are summarized below.

Transmission Reliability Need:

- Customers on Bainbridge Island, in particular customers served from Winslow substation, experienced longer and more frequent outages in comparison to Kitsap County and PSE company-wide over the 5 year period (2013-2017). Excluding storms, Bainbridge Island 5-year average SAIDI for 2013 to 2017 was 2 times PSE service quality index of 155 customer minutes of service interruption a year. Bainbridge Island 5-year average SAIFI was 75% higher than PSE service quality index of 1.3 customer service interruptions a year.
- Transmission outages are a significant proportion of customer outages experienced on Bainbridge Island. In 2013-2017, transmission outages contributed on average 47% of customer minutes of service interruption a year for Bainbridge Island, in comparison to an average 10% transmission outage contribution to PSE company-wide customer minutes of service interruption.
- Nearly 70% of transmission-related customer minutes of service interruption on Bainbridge Island were caused by outages on the Winslow 115 kV tap. The remaining 30% of Bainbridge customer minutes of service interruption were attributed to island-wide outage events due to loss of both transmission supply lines to the island.
- Winslow substation, served radially by the Winslow 115 kV tap, had 21 outages over the 5 year period (2013-2017), an average of nearly 4 substation outages per year. Nearly 70% of the Winslow substation outages were caused by the loss of Winslow Tap transmission line due to tree related events. The remaining 30% Winslow substation outages were part of island-wide outage events.

Transmission Aging Infrastructure Need on Winslow Tap:

Majority of the Winslow Tap 115 kV line design is wishbone crossarm construction identified by PSE as a reliability risk. PSE’s field inspection of the Winslow tap in 2019 found 50% of the Winslow tap crossarms were in “reject” condition needing replacement within 3 years. Given the high proportion (50%) of the wishbone crossarms requiring replacement, PSE considers the aging infrastructure on the Winslow Tap as a system need.

4.6.2 Transmission Concerns

This section summarizes the concerns with the transmission system. These concerns are not required to be addressed, however solutions that eliminate concerns should be evaluated as an added benefit.

Transmission Operating Flexibility:

There is no operating flexibility at the transmission level between the radial transmission taps to Winslow and Murden Cove substations. During winter months of peak electric demand on the island, if PSE has to perform emergency equipment repair on the radial transmission tap to Winslow or Murden Cove substation, then some customers served by the affected substation might experience outage as there is no backup transmission line to feed either substation, and the distribution system on the island does not have enough capacity to backup all customers of the affected substation.

Potential Load Shedding and Low Voltage:

Under certain multiple contingencies on Kitsap peninsula, the transmission system faces overloading on transmission lines and bulk transformers and low voltage, which impacts Bainbridge Island. These concerns will be addressed under PSE's solution for Kitsap transmission system needs.

Potential Island-Wide Outage:

Overlapping outages on the two transmission supply lines feeding Bainbridge Island will result in de-energization of all 3 substations on Bainbridge Island simultaneously. There were 7 such island-wide outage events affecting Bainbridge Island in the 5 year period 2013-2017, ranging from 6 minutes to nearly 4 hours. The recurrence of island-wide outage events over the 5 years, primarily caused by tree related events, is indicative of the vulnerability of the 2 transmission lines supply system serving Bainbridge Island, to tree related incidents. However, PSE rebuilt the 2 transmission supply lines in North Kitsap in 2016 and expects the line upgrades to improve reliability of the two supply lines and mitigate possibilities of island-wide outages.

5 Distribution Needs Assessment

This section assesses the distribution system needs for Bainbridge Island over the 10 year planning horizon (2018-2027). The distribution system needs assessment utilized the Bainbridge Island local area load forecast described in Section 3.2 for projecting Bainbridge Island load for the 10 year period.

5.1 Distribution Study Assumptions

The following key assumptions were adopted in this assessment:

- PSE Distribution Planning Guidelines were used for the performance criteria in this study
- The needs study period is for the 10 year period of 2018 through 2027
- Reliability and outage data are considered in the assessment
- There are no PSE DER's (Distributed Energy Resources) on the feeders
- There is 606 kW of interconnected net metering generation capacity on Murden Cove feeders MUR-13 126 kW, MUR-15 82 kW, MUR-16 52 kW, MUR-17 346 kW
- There is 815kW of interconnected net metering generation capacity on Winslow feeders WIN-12 134 kW, WIN-13 196 kW, WIN-15 356 kW, WIN-16 129 kW
- There is 307 kW of interconnected net metering generation capacity on Port Madison feeders PMA-12 87 kW, PMA-12 22 kW, PMA-12 142 kW, PMA-12 56 kW
- MW Load Forecast converted to MVA for capacity analysis using historic .978 Power Factor at peak

5.2 Distribution Capacity Assessment

PSE's Planning Department monitors the electrical loads in all areas throughout our service territory in anticipation of meeting future system needs and to correct deficiencies in the electrical system.

5.2.1 Distribution Substation Group Capacity

When the loads in an area reach 85% of existing substation capacity for a study group of 3 substations or more, the need to add additional substation capacity is triggered to maintain operational flexibility. The Bainbridge Island study area consists of a three substation grouping of Port Madison, Murden Cove, and Winslow. Each of these substations has a nameplate rating of 25 MVA and can be utilized to 132% of that value in the winter and 108% in the summer, resulting in a winter group capacity of 99 MVA and a summer group capacity of 81 MVA. The 85% trigger for additional group capacity under N-0 is 84 MVA winter and 69 MVA summer.

Table 5-1summarizes the N-0 and the N-1 capacity limits for PSE's standard 25 MVA distribution substation transformers.

Single Distribution Subsbstation Capacity Limits (25 MVA Nameplate)			
(N-0)		(N-1)	
Winter 132%	Summer 108%	Winter 144%	Summer 116%
33 MVA	27 MVA	36 MVA	29 MVA

Table 5-1: Substation Capacity Limits

5.2.2 Distribution Feeder Capacity

When the loads in an area reach approximately **83%** of existing capacity for either overhead (OH) or underground (UG) feeder sections for an individual feeder or Distribution Feeder Group under N-0 system operating conditions the planning need to study adding additional feeder capacity is triggered. These capacity limits are shown in Table 2-1 and Table 5-3. This trigger allows for solutions to be studied and put in place before conductor capacity limits are reached and allows for operational flexibility.

Distribution Feeder Group Capacity is the collective capacity of all feeders serving a particular area. These consists of 2-5 feeders that serve load that can be realistically be used to support the study area and facilitate sharing of load. Feeder grouping should be considered in urban and suburban areas or when there are existing adjacent feeders in rural locations.

Table 5-2 summarizes the N-0 and N-1 capacity limits for PSE's standard overhead feeder conductor (either 336 AAC or 397 ACSR tree wire at the PSE standard 12.47 kV system voltage) per PSE Standards and Operating Limits. Added load above these capacity limits would require additional feeder capacity to serve new load. Table 5-2 applies to the entire overhead feeder portion of the twelve feeders in this study that includes, MUR-13, 15, 16, and 17, WIN-12, 13, 15, and 16, and PMA-12, 13, 15, and 16. All of these circuits contain underground feeder sections that are more limiting than its overhead feeder sections.

Overhead Feeder Conductor Limits (Amps)				
Conductor	Winter (23F)		Summer (86F)	
	(N-0)	(N-1)	(N-0)	(N-1)
4/0 ACSR	503	519	410	432
336 ACSR T/W	600	650	542	573
397 AAC	600	650	597	631

Table 5-2: Distribution Overhead Feeder Capacity Limits

Underground (UG) Feeder Capacity: Under N-0 and depending on the number of feeder runs in the trench, the capacity limit is 394-552 Amps per PSE Standard. Added load above the corresponding capacity limit would require additional feeder capacity. For UG feeders the N-0 capacity limit is the same as the N-1 planning limit. In this study all feeders have UG portions that parallel another feeder so the ratings for two feeder runs in a trench were used in the capacity analysis.

Table 5-3 summarizes the N-0 capacity and the N-1 emergency capacity for PSE's standard underground feeder conductor 750 MCM Al per PSE Standards at the standard system voltage of 12.47 kV. Table 5-3 applies to all underground feeder sections for the twelve distribution feeders in the Bainbridge Island study area.

Rating Type	Feeder Runs in Trench			
	One	Two	Three	Four
Operational Load (N-0) Planning Trigger, 83% Utilization	458 A	403 A	359 A	327 A
Emergency Load (N-1) Planning Trigger and (N-0) Capacity Limit, 100% Utilization	552 A	486 A	433 A	394 A

Table 5-3: Distribution Underground Feeder Capacity Triggers and Capacity Limit

5.3 Distribution Capacity Results

5.3.1 Distribution Substation Group Capacity (N-0)

Figure 5-1 illustrates forecasted demand for the Bainbridge Island load forecast for the distribution substation group of MUR-1, WIN-1, and PMA-1, with load included for ferry electrification. This figure also illustrates the N-0 capacity limit of the station group.

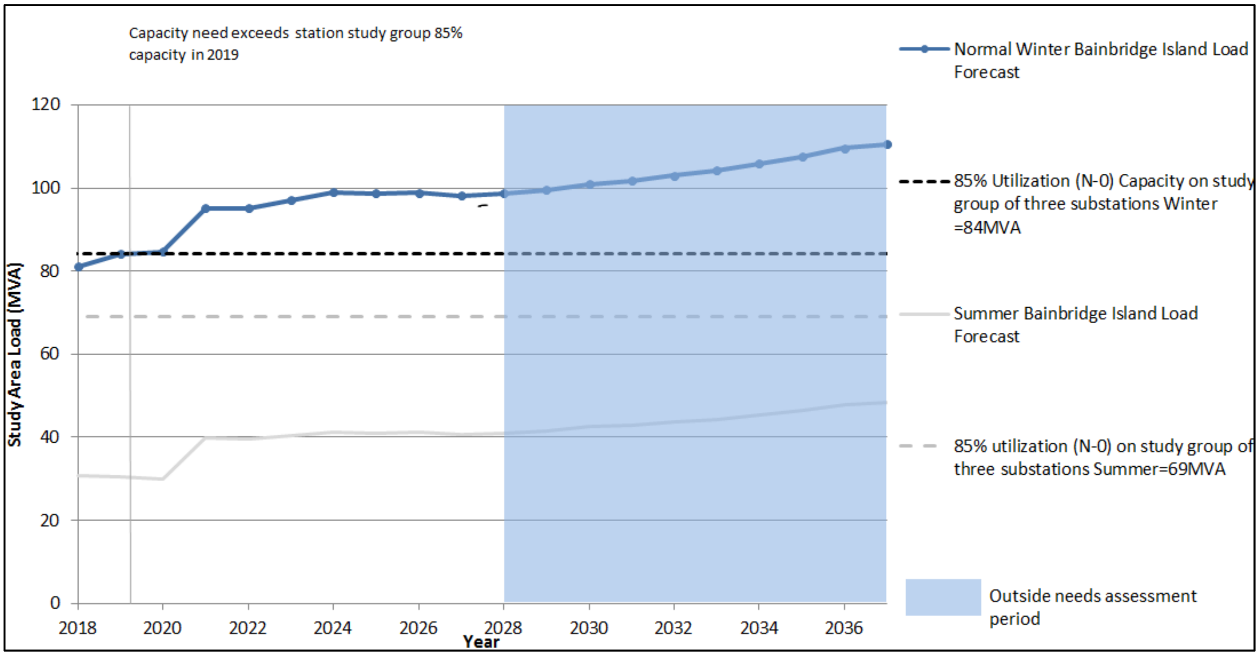


Figure 5-1: Distribution Substation Group N-0 Loading and Capacity

Table 5-4 shows the anticipated station group loading, N-0 group capacity need and the percentage over the need by year through the study period. Red indicates values over capacity.

The need to add N-0 station capacity to this study group is in 2019.

Table 5-4: Distribution Substation Group N-0 Capacity Need Overview by Year

Normal Winter	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Bainbridge Island Load Forecast w/DSM (MW)	80.7	82.4	83.0	93.2	93.1	94.9	96.8	96.5	96.7	96.0
Forecasted Load w/DSM (MVA) .978PF	82.4	84.3	84.8	95.2	95.2	97.0	99.0	98.7	98.9	98.1
N-0 Group Capacity (85%)	84	84	84	84	84	84	84	84	84	84
% Loading of Group Capacity Limit	98.1%	100.3%	101.0%	113.4%	113.3%	115.5%	117.9%	117.4%	117.7%	116.8%

5.3.2 Distribution Substation Group Capacity (N-1)

Substation group capacity under loss of one substation is a distribution planning concern. This study highlights a concern that N-1 capacity is deficient and some load could not be served during peak loading with a substation out until a mobile substation could be put in place temporarily.

Figure 5-2 illustrates the N-1 capacity limits of the station group with ferry load. Without improvements 24.8 MVA (Year 2024) is at risk of needing to be dropped under N-1 condition during periods of peak demand.

N-1 station capacity to the study group is currently deficient. On February 12th 2018 at 07:15 AM while MUR-1 was off line for an emergency replacement due to transformer failure, load levels on adjacent substations reached 37.6 MVA at Winslow and 39.6 MVA at Port Madison. The combined coincident load at the time was 77.2 MVA, 5.2 MVA above the N-1 planning guideline limit of 144% utilization of available capacity. The 144% utilization threshold prevents an unacceptable loss of life risk to the transformer due to accelerated aging from heat stress. Load shedding would have been required if loading would have persisted. Fortunately, MUR-1 was restored and picked up load at 10:00 AM. An N-1 load loss at peak historic demand of 79.7 MVA would require a 7.7 MVA load shed to reach the acceptable 144% N-1 utilization.

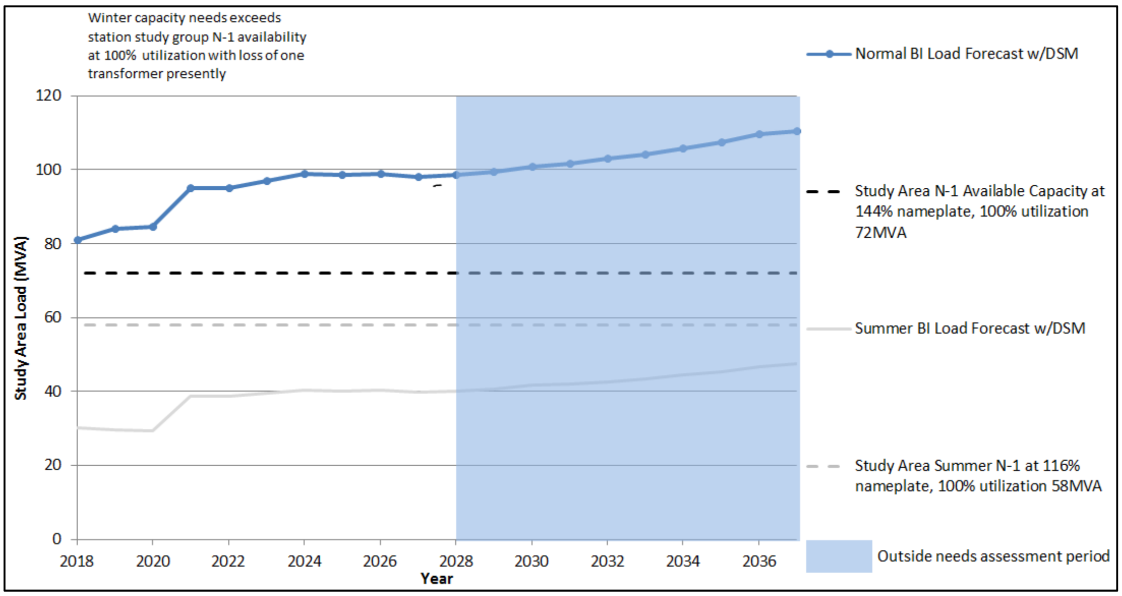


Figure 5-2: Distribution Substation Group N-1 Loading and Capacity Concern

5.3.3 Distribution Feeder Group Capacity - Winslow Downtown Area

Figure 5-3 illustrates the feeder group serving the Winslow downtown area which also includes service to the Winslow Ferry Terminal. This feeder group consists of WIN-15, WIN-16, MUR-13, MUR-16, and MUR-17. This group was studied with electrification of the Bainbridge to Seattle ferry in 2021.

Feeder capacity in this group is determined by the limiting feeder section which is the underground sections that share a common trench with one other feeder section.

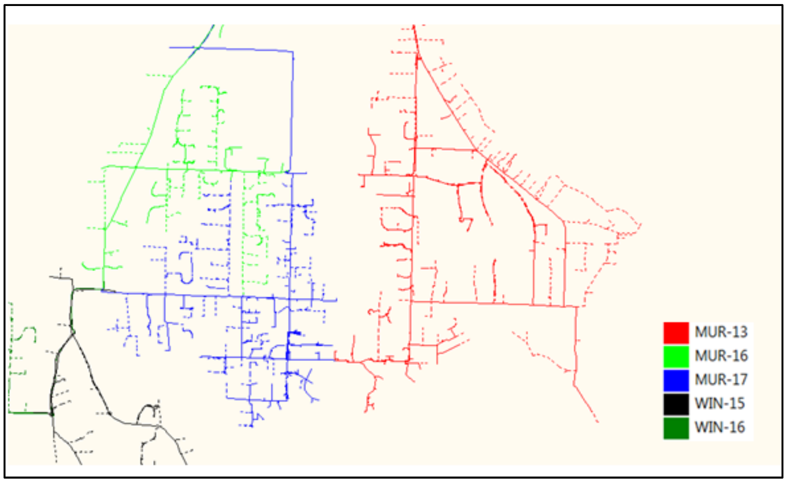


Figure 5-3: Graphical Representation of Feeder Group in Winslow Downtown Area

5.3.3.1 Distribution Feeder Group Analysis - Winslow Downtown Area

Table 5-5 summarizes forecasted demand and limits for the downtown Winslow feeder group and individual feeders with the ferry electrification load. The yellow highlighted cells indicate when the individual feeder or the group of feeders exceeds 83% utilization that is a trigger to add capacity to maintain operation flexibility and red indicates the year in which capacity is exceeded. Figure 5-4 illustrates graphically the feeder group loading.

Table 5-5: Distribution Feeder Group Forecast in Winslow Downtown Area and Capacity Limits with Ferry Load

Feeder 83% Utilization	403	Amps								
Feeder 100% Utilization	486	Amps								
Feeder Group 83% Utilization	2017	Amps								
Feeder Group 100% Utilization	2430	Amps								
W/Ferry WIDSM	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
WIN-15	433.0	436.0	437.2	436.7	446.2	456.3	454.4	455.8	451.8	454.5
WIN-16	28.6	28.8	28.9	493.8	494.5	495.1	495.0	495.1	494.8	495.0
MUR-16	240.0	241.7	242.3	242.0	247.3	252.9	251.9	252.6	250.4	251.9
MUR-17	395.3	398.0	399.1	398.6	407.3	416.5	414.8	416.0	412.4	414.8
MUR-13	419.8	422.6	423.8	423.3	432.5	442.3	440.5	441.8	438.0	440.6
Group	1516.7	1527.1	1531.3	1994.4	2027.8	2063.1	2056.6	2061.3	2047.4	2056.8
Group Utilization	62%	63%	63%	82%	83%	85%	85%	85%	84%	85%

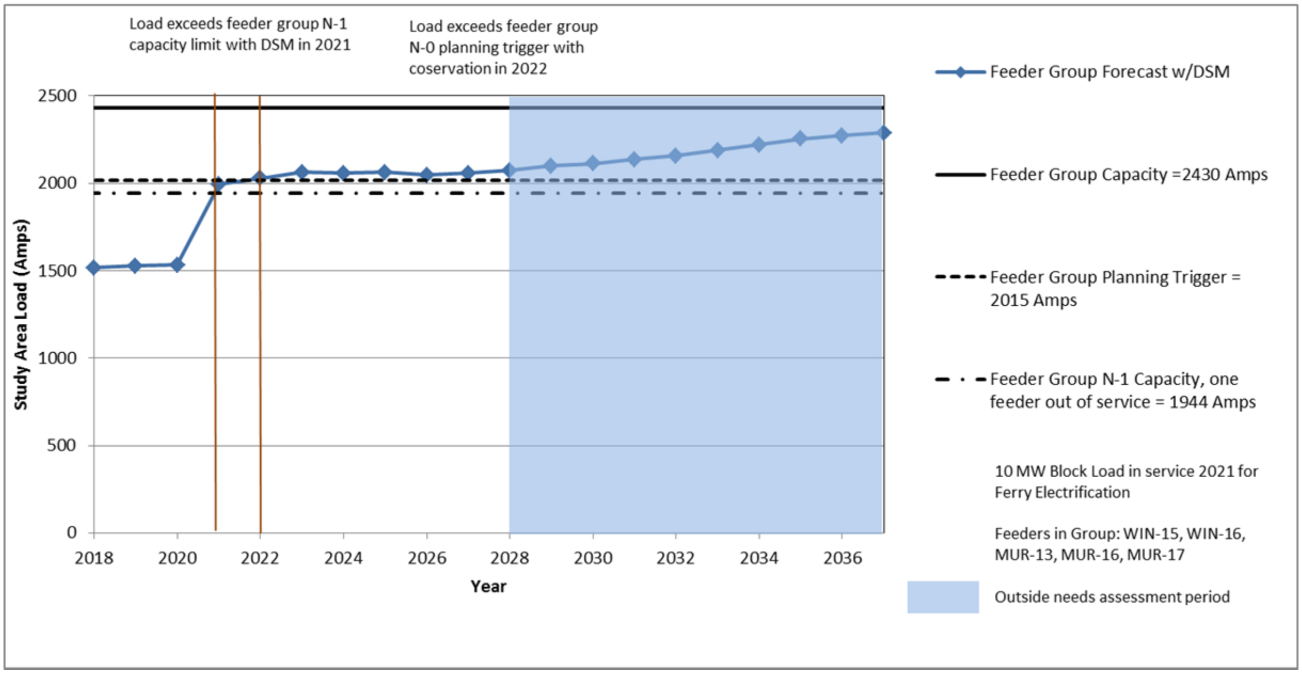


Figure 5-4: Distribution Feeder Group Winslow Downtown Area Loading and Capacity with Ferry Electrification

Additional feeder capacity is needed in the downtown Winslow area if the ferry electrification load is added to existing feeder group; however, Washington State Ferries is planning on utilizing a rate schedule that will require them to install a dedicated feeder to serve their load. With installation of the dedicated feeder the feeder load forecast is represented in Table 5-6. Yellow represents where loading exceeds the 83% Utilization of an individual feeder or group. No capacity limit is exceeded however loading on WIN-15, WIN-17, and MUR-13 is a concern.

Table 5-6: Group and Individual Feeders Loading in Downtown Winslow Area

Feeder 83% Utilization	403	Amps								
Feeder 100% Utilization	486	Amps								
Feeder Group 83% Utilization	2017	Amps								
Feeder Group 100% Utilization	2430	Amps								
W/o Ferry W/DSM	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
WIN-15	433.0	436.0	437.2	436.7	446.2	456.3	454.4	455.8	451.8	454.5
WIN-16	28.6	28.8	28.9	28.8	29.5	30.1	30.0	30.1	29.8	30.0
MUR-16	240.0	241.7	242.3	242.0	247.3	252.9	251.9	252.6	250.4	251.9
MUR-17	395.3	398.0	399.1	398.6	407.3	416.5	414.8	416.0	412.4	414.8
MUR-13	419.8	422.6	423.8	423.3	432.5	442.3	440.5	441.8	438.0	440.6
Group Amps	1516.7	1527.1	1531.3	1529.4	1562.8	1598.1	1591.6	1596.3	1582.4	1591.8
Group Utilization	62%	63%	63%	63%	64%	66%	65%	66%	65%	66%

5.3.4 Individual Distribution Feeder Capacity Outside Downtown Winslow Area

Load forecasts for each feeder that exceeds the planning study trigger on the rest of the Bainbridge Island study area are shown in Table 5-7. No capacity need exists within this study period; however, should be monitored to ensure 100% utilization will not be exceeded in future.

Table 5-7: Individual Feeders That Exceed 85%[10] Utilization in Study Period

Feeder 83% Utilization			403	Amps							
Feeder 100% Utilization			486	Amps							
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
WIN-13		389	392	393	392	401	410	408	410	406	408
PMA-15		423	426	427	426	436	446	444	445	441	444

5.4 Distribution Reliability Assessment

5.4.1 Distribution Reliability Background

Some areas in Kitsap County are challenged by frequent outages with many occurring for a long duration. This is primarily due to trees falling and exposure to storms from the peninsula geography and corridors that are difficult to access for maintenance and vegetation management.

At PSE, reliability performance of the electric system is evaluated through the SAIFI and SAIDI metrics. PSE's Planning Department monitors the outage frequency and durations, specific to each of the approximately 1100 circuits in its entire service territory. Of those circuits a worst performing list is maintained to help identify circuits in need of reliability improvements. The criteria for a circuit's placement onto the worst performing list are summarized in Section 5.4.2. Circuits identified on this list are targeted for reliability improvements to enhance performance to reduce the primary driver metric for placement on the list by 50%.

5.4.2 Distribution Reliability Circuit Criteria

PSE uses the following performance data for all circuits for the years 2013-2015[11] to identify circuits which need attention. Circuits are identified if any of the following criteria is met:

1) Customer Minutes Interrupted (CMI) – Any circuit with more than 3,000,000 CMI on non-Major Event Day (MED) over three years.
2) CMI - Any circuit with at least two out of three years with CMI > 750,000 non-MED customer minutes (750,000 is roughly ½ of 1 percent of companywide CMI).
3) SAIDI - At least two out of three years with circuit SAIDI > 300 minutes (non-MED). Circuits with fewer than 50 customers are excluded.
4) SAIFI - At least two out of three years with circuit SAIFI > 2 (non-MED).
5) Circuits in the top 50 worst of the averaged positions in any of the annual rankings for the years 2011-2015 for all-in CMI (includes MED).

The above list is ranked in order of primary driver for inclusion on the list from highest (line 1) to lowest (line 5). If a circuit meets multiple of the above criteria, the highest driver met is the primary driver. The primary driver is used for determining improvement targets discussed in Section 5.4.1.

[10] Ratings based on two feeders in common trench

[11] Circuits needing attention list was based on performance data for 2013-2015. List is not updated every year as it takes multiple years to plan and construct some reliability projects.

5.4.3 Historical Distribution Reliability Performance Data (2013-2015) and Analysis

There are two circuits on Bainbridge Island, PMA-12 and WIN-13 that have reliability concerns.

Table 5-8 through Table 5-10 summarize the outage data for circuits PMA-12 and WIN-13. Values in red are shown if above the criteria as described in section 5.4.2. WIN-13 is on the worst performing list due to Criteria 5 in which WIN-13 was among the top 50 worst of the averaged positions from 2011-2013.

Table 5-8: SAIDI Performance (2013-2015)

	Non-MED SAIDI (IEEE, T_{MED} adj for catastrophic storm) (Minutes)			
	YEAR			
Circuit	**2013**	**2014**	**2015**	**Avg SAIDI (2013-2015)**
PMA-12	71	351	301	241
WIN-13	272	618	127	339

Table 5-9: SAIFI Performance Criteria (2013-2015)

	Non-MED SAIFI (IEEE, T_{MED} adj for catastrophic storm) (Interruptions)			
	YEAR			
Circuit	**2013**	**2014**	**2015**	**Avg SAIFI (2013-2015)**
PMA-12	0.49	5.72	2.85	3.02
WIN-13	1.33	4.90	1.38	2.54

Table 5-10: CMI Performance (2013-2015)

	Non-MED CMI (IEEE, T_{MED} adj for catastrophic storm) (Minutes)			
	YEAR			
Circuit	**2013**	**2014**	**2015**	**Total (2013-2015)**
PMA-12	71,158	349,753	301,190	722,101
WIN-13	334,219	761,003	156,295	1,251,517

The annual SAIDI reliability performance data of PMA-12 and WIN-13 for 2013-2015 is summarized in

Table 5-8. PSE System SAIDI average from 2013-2015 is 143 minutes. All data is MED excluded. Both PMA-12 and WIN-13 have significantly higher than system average values:

- 2013-15 Average SAIDI for PMA-12 customers is 241 minutes (169% of system average)
- 2013-15 Average SAIDI for WIN-13 customers is 339 minutes (237% of system average)

Annual SAIFI reliability performance data for PMA-12 and WIN-13 for 2013-2015 is summarized in Table 5-9. System SAIFI average from 2013-2015 is 0.94 interruptions per customer. All data is MED excluded. Both PMA-12 and WIN-13 have significantly higher than system average values:

- 2013-15 Average SAIFI for PMA-12 customers is 3.02 interruptions per customer (321% of system average)
- 2013-15 Average SAIFI for WIN-13 customers is 2.54 interruptions per customer (270% of system average)

PSE's planning group target is to reduce the top driver for placement on the worst performing list by 50%.

The primary driver for PMA-12 is SAIDI > 300 minutes non-MED, 2 out of 3 years. PMA-12 had SAIDI values for 2013 of 71, 2014 of 351, and 2015 of 301. Reduction of just 2 annual minutes each would have prevented this from being a driver for inclusion by dropping the 2015 value below 300. Applying a 50% annual reduction to the average 2013-15 non-MED SAIDI value of 241 would result in a goal to reduce the annual average by 120 minutes. Recently completed and planned projects will accomplish this reduction.

Recently completed and planned reliability improvement projects in the study area are shown at https://psebainbridge.com/completed-projects and https://psebainbridge.com/current-projects.

The primary driver for WIN-13 is CMI (Includes MED) for the years 2011-2015. The 50% reduction of primary driver goal is not applicable for this driver. Improvements to average SAIDI and SAIFI could be considered to move performance of this circuit towards system averages.

5.5 Distribution Operations

5.5.1 Circuit Voltage

PSE's Distribution Planning Guideline targets a minimum of 119 volts and maximum of 126 volts at the primary side of all distribution service transformers under N-0 (no segment of the system is out of service) conditions. The 119 volt minimum is to allow for up to a 5 volt drop across the service transformer and service conductor to deliver 114 volts minimum at the customer meter or point of service per PSE Standard. A minimum of 113 volts is required at the primary side of all distribution service transformers under N-1 (one segment of the system is out of service) conditions to deliver 108 volts minimum at the customer meter or point of service.

System modeling using loading levels projected for winter has identified areas near 119 volts that is a concern that should be monitored to ensure service voltage above 114 volts.

5.5.2 Phase Balance

Distribution Planning Guidelines recommends that phase imbalance should be no greater that 100 amps between any two phases. Circuits with imbalance greater than 100 amps at system peak in 2012-2016 are summarized in Table 5-11.

Table 5-11: Historic Circuit Imbalance Greater Than 100 Amps

Circuit	Year	Phases	Magnitude	Phases	Magnitude
PMA-12	2016	B-A	165	C-A	196
PMA-12	2015	B-A	127	C-A	179
PMA-12	2014	B-A	16*	C-A	8*
PMA-12	2013	B-A	110	C-A	128
PMA-12	2012	-	-	C-A	110
PMA-13	2016	A-B	147	-	-
PMA-13	2015	A-B	109	-	-
PMA-13	2014	A-B	113	-	-
PMA-13	2013	A-B	113	-	-
PMA-15	2013	A-B	107	-	-
PMA-16	2016	-	-	C-A	176
PMA-16	2015	-	-	C-A	115
PMA-16	2014	-	-	C-A	182
PMA-16	2013	-	-	C-A	190
PMA-16	2012	-	-	C-A	134

*System was abnormal configuration at time of reading

5.5.3 Cold Load Pickup

Cold Load Pickup is the period when loads are coming back on line after extended outages. In areas without a high gas penetration, demands during cold load pickup can be 2-3 times higher than the peak demands. When loading is close to capacity, circuit breakers can operate and/or fuses can melt and open without operational intervention to bypass, which slows restoration time.

Circuits MUR-13, MUR-17, WIN-15, and PMA-15 are heavily loaded, especially during the winter due to primarily electric heating. Extended outages on these circuits require operations intervention to prevent circuit breakers from opening as cold load is picked up.

5.5.4 Operational Flexibility

Operational flexibility on Bainbridge Island is limited by loading that is not evenly distributed between substations and circuits. Distribution sources are essentially limited to the 3 existing substations on the island. Geography limits the available and potential electrical ties between the existing substations and leads to a greater possibility of longer outages when outages do occur. Recently completed improvements and improvements scheduled for 2019-20 creates a feeder tie network as shown in Figure 5-5. Although the tie possibilities are robust, feeder loading at peak demand will limit ability to pick up all customers under scenarios that tie two heavily loaded circuits.

A loss of a substation transformer under peak winter demand exceeds the capacity limit (144% of available nameplate) of the other transformers that remain in service. The overloading of Port Madison and Winslow occurred when Murden Cove was offline as detailed in Section 5.3.3. In the event of a loss of a transformer at peak loading it is estimated it would take a minimum of 24 hours to evaluate the outage, transport, set up and energize a mobile substation in order to restore customers. A mobile was not used in the recent loss of Murden Cove as the transformer replacement was within three hours of energizing.

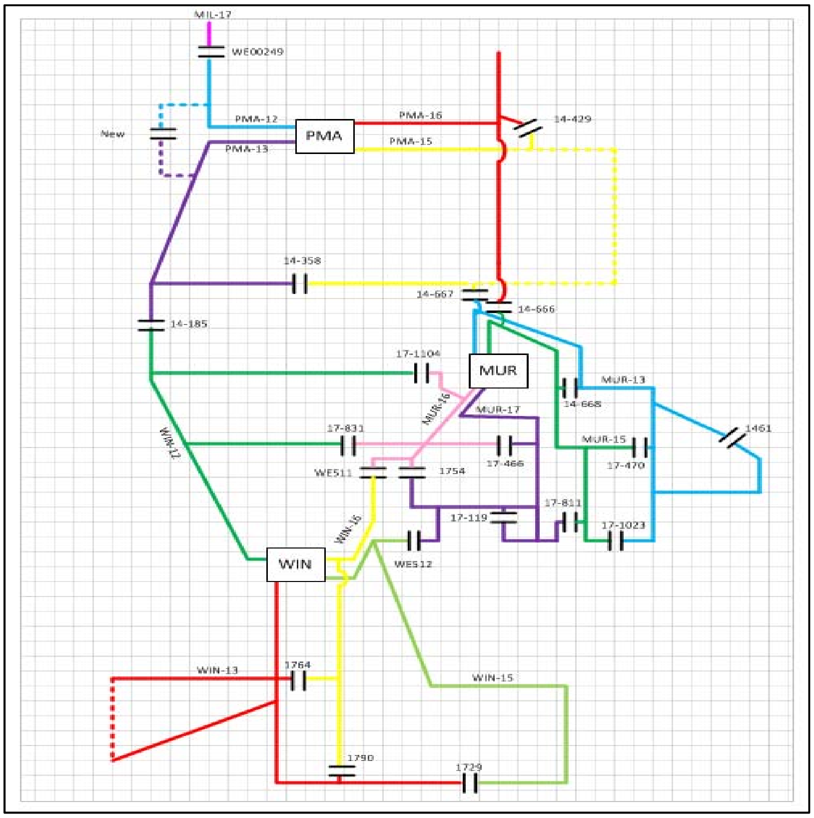


Figure 5-5: Distribution Feeder Tie Points (After Planned Projects through 2020)

5.6 Distribution Substation Equipment

5.6.1 Distribution Station Equipment Condition

<u>Murden Cove</u>: The 115-12kV bank was recently replaced due to transformer failure. The transformer is a PSE standard 25MVA bank and was placed in service in February 2018.

The distribution getaway cables on MUR-13 and MUR-15 are 1970's vintage Yellow Jacket cables. These cables have a distinct yellow outer layer that makes them easily identifiable. Yellow Jacket cables have been identified as more likely to fail than other vintage cable sand PSE replaces this type of getaway cable when the opportunity exists, such as when other work and/or outage can be leveraged to justify replacement. There is not currently a replacement program to eliminate yellow jacket cables.

<u>Winslow</u>: The 115-12kV 25MVA station transformer is a PSE standard and was placed in service in 1982. As of December 2017, the health of the transformer is good and has an estimated life expectancy of 2030.

Port Madison: The 115-12kV 25MVA station transformer is a PSE standard and was placed in service in 1981. As of December 2017, the health of the transformer is good and has an estimated life expectancy of 2027. Transformers can continue to operate well past expectant life estimates and regular maintenance and tests will be used to determine when replacement becomes necessary.

The distribution getaway cables are 1970's vintage Yellow Jacket cables.

All three transformers see numerous faults due to heavy trees and windy weather on Bainbridge Island which creates vegetation outages of the existing transmission lines. According to IEEE Standard C57.91, conditions which over work the transformers may cause early aging of the infrastructure.

5.7 Distribution Needs and Concerns

There are needs and concerns on the existing distribution system for Bainbridge Island in Kitsap County.

5.7.1 Distribution Needs

The following distribution needs for Bainbridge Island have been identified through this assessment.

Substation Group Capacity:

Additional substation group capacity is needed on Bainbridge Island over the next 10 years starting in 2019 due to native load growth and continuing through study period due to native load growth and load associated with electrification of the Seattle-Bainbridge ferry expected in 2021, to keep the island's projected load within PSE's distribution planning guidelines. The highest magnitude of capacity need is forecasted in 2026 with a magnitude of 14.5 MW.

Distribution Reliability:

Both PMA-12 and WIN-13 have much higher than average values for SAIDI and SAIFI as compared to the entire system. Reliability improvements are needed in this study area to improve these values closer to system averages. PSE's planning group targets to reduce the top driver for placement by 50%. To accomplish the 50% reduction of the primary driver on PMA-12 a reduction of 120 average annual non-MED SAIDI minutes would be required.

The primary driver for WIN-13 is CMI (Includes MED) for the years 2011-2015. The 50% reduction of primary driver goal is not applicable for this driver. Improvements to average SAIDI and SAIFI could be considered to move performance of this circuit towards system averages. Average annual SAIDI reduction of 198 minutes and average annual SAIFI reduction of 1.6 interruptions would bring WIN-13 to average annual system level.

There are completed and planned projects on PMA-12 and WIN-13 to improve the reliability; therefore no additional reliability projects on these circuits are necessary.

Distribution Operations:

The following are distribution operation's needs:

- PMA-12 feeder imbalance is 96 Amps over guideline recommended 100 Amp imbalance limit.
- PMA-13 feeder imbalance is 47 Amps over guideline recommended 100 Amp imbalance limit.
- PMA-16 feeder imbalance is 76 Amps over guideline recommended 100 Amp imbalance limit.
- Voltage needs to be maintained at 119 volts minimum and 126 volts maximum under normal system configurations per planning guidelines.
- Areas of voltage less than 119V under present peak demands exist in the study area.

Phase imbalance is a need but can be addressed independently of other need solutions through changing lateral taps in the field.

5.7.2 Distribution Concerns

This section summarizes the concerns with the distribution system. Finding solutions that eliminate concerns should be evaluated as an added benefit.

Substation Capacity:

Substation capacity is presently deficient for the loss of a substation transformer in the study area. At historical peak load level, 7.7MVA of load is at risk to be dropped under N-1 conditions.

Feeder Capacity:

The distribution feeder capacity needs are for the circuit group of five feeders supplying the Downtown Winslow area. With the electrification of Bainbridge to Seattle Ferry currently planned by Washington State Ferries load would exceed N-1 (one element out of service) feeder capacity in the area leaving some customers in this commercial area at risk for long duration outages. There is also a distribution feeder capacity need as no individual existing feeder could accommodate the ferry block load addition. A dedicated new feeder will be required supply the ferry load under their tentative rate schedule. This additional dedicated feeder will eliminate the feeder group capacity need in the Downtown Winslow area.

Cold Load Pickup:

Due to primarily electric heating and heavy loading presently on MUR-13, MUR-17, PMA-15 and WIN-15 cold load pickup is a concern for the system and requires operations intervention to mitigate bringing loads back on after extended outages.

Feeder Capacity:

For individual feeders outside the Downtown Winslow feeder group, the following capacity concerns exist or will at expected peak demands.

- WIN-12 N-0 planning trigger as early as 2024 depending on level of conservation achieved.
- WIN-13 N-0 planning trigger as early as 2019 depending on level of conservation achieved.
- PMA-15 N-0 planning trigger already exists

Operations:

Areas of less than 119 volts at peak demand. These areas are a concern as service voltage needs to be monitored to ensure service voltage at the meter does not fall below 114 volts.

6 Conclusion

The Bainbridge Island Electric System Needs Assessment examined the island's transmission and distribution system for the 10-year planning horizon (2018-2027). PSE's planners assessed the island's future capacity needs based on the PSE F2017 corporate load forecast and PSE's Bainbridge Island Load Forecast. In addition, planners reviewed the transmission and distribution system's historical reliability performance to identify areas needing improvement.

As a result of this study, PSE identified that:

- Bainbridge Island customers experience more frequent and longer outages than the average PSE customer, and nearly half of those outage minutes are due to issues with the transmission system.
- Customers served by the Winslow substation have the worst reliability on the island, and secondarily Murden Cove substation. Nearly 70 percent of transmission customer minutes of service interruptions were from the Winslow Tap transmission line that feeds the Winslow substation.
- Demand for electricity is growing on the island due to anticipated population growth and ferry electrification.
- Some transmission and distribution issues are being addressed through other projects.[12]

The system needs and concerns for Bainbridge Island are summarized as follows:

- **Transmission Reliability need:** A reliability improvement need was identified to improve the performance of transmission service to Winslow substation.
- **Transmission Aging Infrastructure need:** An infrastructure replacement need was identified for the Winslow tap transmission line support structures that are nearing end of useful life and could potentially fail leading to unplanned outages and emergency repairs.
- **Substation Capacity need:** A distribution substation group capacity need of 14.5 MW was identified on Bainbridge Island within the 10 year study period to support general load growth of 4.5 MW and planned 10 MW load addition of WSDOT electric ferry.
- **Transmission Operating Flexibility concern:** Concerns related to ability to transfer load to support routine maintenance and outage management on the radial transmission lines feeding Winslow and Murden Cove substations.

Potential solutions must address all of the system needs identified in this study, while also considering the identified concerns.

[12] Off-island transmission issues are being addressed in the 2018 Kitsap Transmission Needs Assessment Report. Distribution reliability projects for PMA-12 and WIN-13 have been or have existing projects to address them.

Appendix A F2017 Kitsap County "Normal" Winter Load Forecast 2018-2037

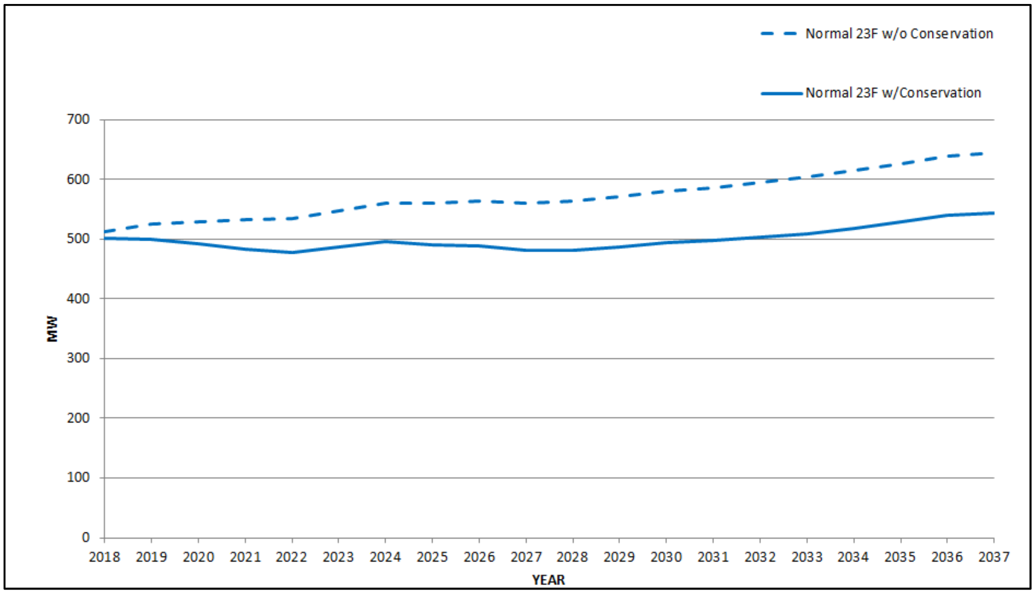


Figure A-1: Year End F2017 Kitsap County Winter Load Forecast

Table A-1: Annual Growth Rates F2017 for 2018-2037

F2017 Load Forecast w/Conservation			F2017 Load Forecast w/o Conservation		
December "Normal" Peak: 23 Degrees			December "Normal" Peak: 23 Degrees		
Year	Kitsap (MW)	Annual Rate	Year	MW	Annual Rate
2018	502		2018	512	
2019	500	-0.47%	2019	525	2.53%
2020	492	-1.47%	2020	530	1.02%
2021	483	-1.88%	2021	533	0.53%
2022	478	-0.97%	2022	534	0.25%
2023	486	1.70%	2023	547	2.45%
2024	496	1.97%	2024	561	2.52%
2025	490	-1.17%	2025	560	-0.11%
2026	489	-0.35%	2026	564	0.57%
2027	481	-1.51%	2027	560	-0.56%
2028	482	0.15%	2028	565	0.75%
2029	487	1.07%	2029	571	1.20%
2030	495	1.58%	2030	581	1.68%
2031	497	0.48%	2031	586	0.86%
2032	504	1.35%	2032	595	1.54%
2033	510	1.13%	2033	604	1.40%
2034	519	1.80%	2034	615	1.85%
2035	529	1.98%	2035	626	1.80%
2036	540	2.08%	2036	638	2.02%
2037	544	0.82%	2037	645	0.99%
Avg 10 year (2018-2027)		-0.4%	Avg 10 year (2018-2027)		0.9%
Avg 20 year (2018-2037)		0.4%	Avg 20 year (2018-2037)		1.2%

Appendix B F2017 Kitsap County "Normal" Summer Load Forecast 2018-2037

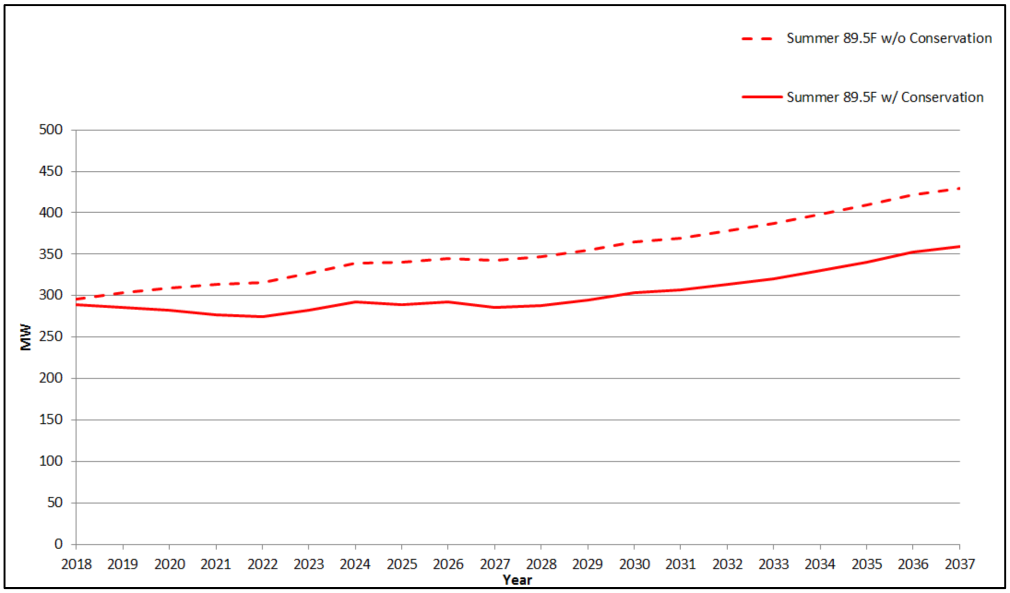


Figure B-1: Year End F2017 Kitsap County Summer Load Forecast

Table B-1: Annual Growth Rates F2017 for 2018-2037

F2017 Load Forecast w/Conservation			F2017 Load Forecast w/o Conservation		
Summer Peak: 89.5 Degrees			Summer Peak: 89.5 Degrees		
Year	MW	Annual Rate	Year	MW	Annual Rate
2018	289		2018	296	
2019	286	-1.06%	2019	304	2.71%
2020	282	-1.23%	2020	310	1.84%
2021	277	-1.80%	2021	313	1.19%
2022	275	-0.84%	2022	315	0.69%
2023	282	2.81%	2023	327	3.73%
2024	292	3.41%	2024	339	3.65%
2025	290	-0.81%	2025	340	0.21%
2026	292	0.81%	2026	345	1.58%
2027	286	-2.03%	2027	342	-0.91%
2028	288	0.62%	2028	347	1.41%
2029	294	2.33%	2029	355	2.31%
2030	303	3.06%	2030	365	2.78%
2031	306	0.97%	2031	369	1.17%
2032	313	2.21%	2032	378	2.37%
2033	321	2.33%	2033	388	2.55%
2034	330	3.00%	2034	399	2.84%
2035	340	3.00%	2035	409	2.59%
2036	352	3.61%	2036	421	3.02%
2037	359	2.02%	2037	429	1.84%
Avg 10 year (2018-2027)		-0.1%	Avg 10 year (2018-2027)		1.5%
Avg 20 year (2018-2037)		1.1%	Avg 20 year (2018-2037)		1.9%

Appendix C F2018 Kitsap County "Normal" Winter Load Forecast 2019-2038

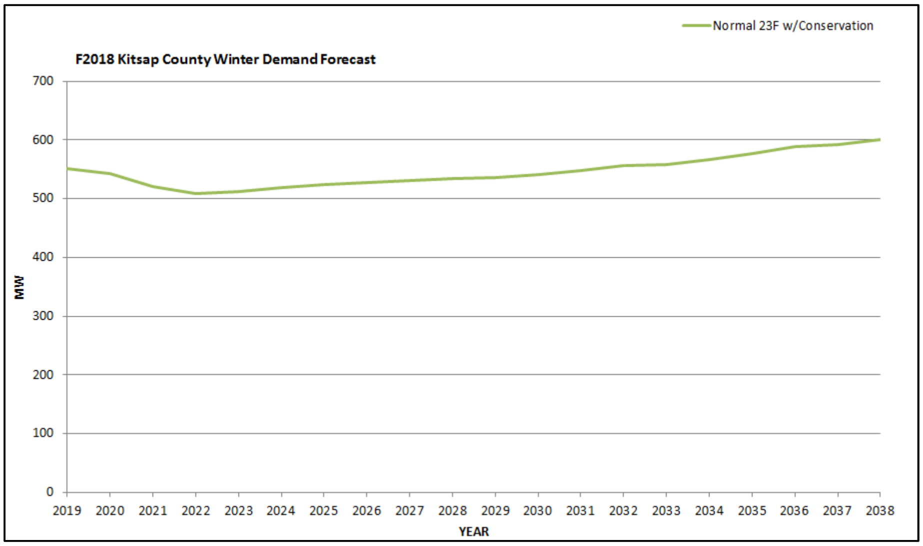


Figure C-1: F2018 Load Forecast Summary Winter Normal Kitsap w/Conservation

F2018 Load Forecast w/Conservation		
December "Normal" Peak: 23 Degrees		
Year	Kitsap (MW)	Annual Rate
2018	530	
2019	551	3.81%
2020	543	-1.36%
2021	520	-4.21%
2022	509	-2.12%
2023	512	0.46%
2024	519	1.48%
2025	523	0.75%
2026	528	0.86%
2027	530	0.45%
2028	535	0.93%
2029	535	0.10%
2030	541	1.01%
2031	547	1.13%
2032	556	1.60%
2033	559	0.55%
2034	566	1.34%
2035	577	1.92%
2036	588	1.97%
2037	592	0.60%
2038	600	1.29%
Avg 10 year (2019-2028)		0.1%
Avg 20 year (2019-2038)		0.6%

Table C-1: Annual Growth Rates F2018 for 2019-2038

Appendix D Bainbridge Island Load Forecast

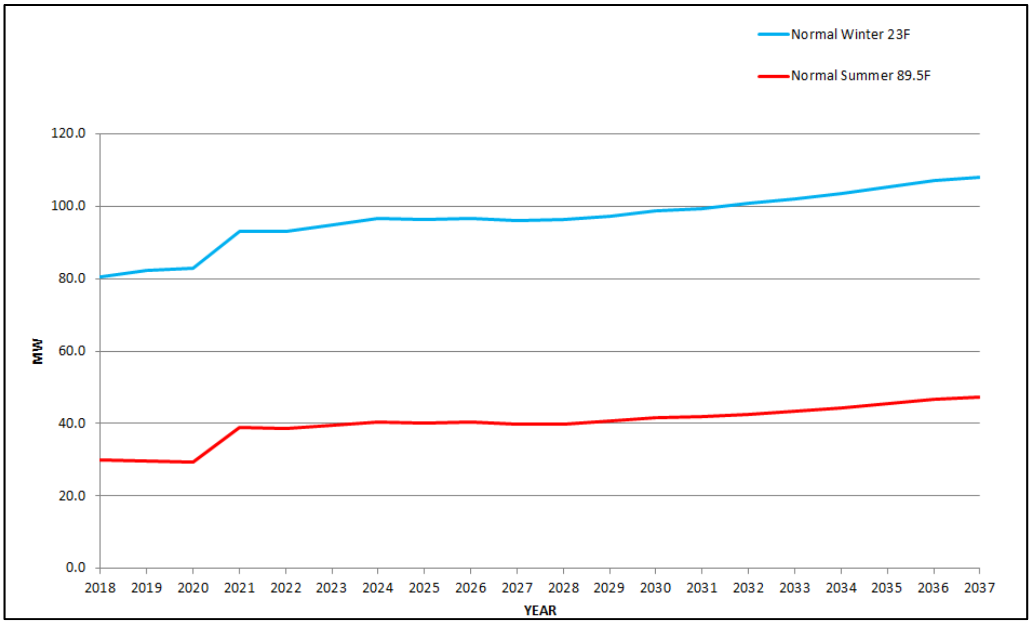


Figure D-1: Bainbridge Island Load Forecast

Table D-1: Annual Growth Rates Bainbridge Island Load Forecast

Bainbridge Island Load Forecast			Bainbridge Island Load Forecast		
December "Normal" Peak: 23 Degrees F			Summer Peak: 89.5 Degrees		
		Bainbridge			Bainbridge
Year	Bainbridge (MW)	Annual Rate	Year	Bainbridge (MW)	Annual Rate
2018	80.7		2018	30.1	
2019	82.4	2.1%	2019	29.7	-1.1%
2020	83.0	0.7%	2020	29.4	-1.2%
2021	93.2	12.3%	2021	38.8	32.2%
2022	93.1	-0.1%	2022	38.6	-0.6%
2023	94.9	1.9%	2023	39.4	2.1%
2024	96.8	2.0%	2024	40.4	2.5%
2025	96.5	-0.4%	2025	40.2	-0.6%
2026	96.7	0.3%	2026	40.4	0.6%
2027	96.0	-0.8%	2027	39.8	-1.5%
2028	96.5	0.5%	2028	40.0	0.5%
2029	97.4	1.0%	2029	40.7	1.7%
2030	98.8	1.4%	2030	41.6	2.3%
2031	99.5	0.7%	2031	41.9	0.7%
2032	100.8	1.3%	2032	42.6	1.7%
2033	102.0	1.2%	2033	43.4	1.8%
2034	103.6	1.6%	2034	44.4	2.3%
2035	105.3	1.6%	2035	45.4	2.3%
2036	107.2	1.8%	2036	46.7	2.8%
2037	108.2	0.9%	2037	47.4	1.6%
Avg 10 year (2018-2027)		1.8%	Avg 10 year (2018-2027)		2.8%
Avg 20 year (2018-2037)		1.5%	Avg 20 year (2018-2037)		2.3%

Appendix E Transmission Reliability Needs Addendum

This section describes in greater detail specific aspects of transmission reliability need on Bainbridge Island.

As described in the Bainbridge Needs Assessment report, 47% (or nearly 50%) of outage minutes on Bainbridge were caused by transmission outages. A significant proportion (70%) of the transmission outages were on the Winslow Tap transmission line. The Winslow Tap is a 4.5 mile radial[13] transmission line from Port Madison substation to Winslow substation.

Key observations regarding Winslow Tap transmission outages over past 5 years (2013 through 2017):

- Outages are long (from 1-2 hours to 13 hours per year)
- Outages are frequent (from 1 to 5 outages per year)
- During storms, reliability is worse

Reasons for poor reliability of the Winslow Tap:

- Heavy vegetation along Winslow Tap
- Difficult terrain and poor access along the line
- Limited distribution substation capacity for backup of Winslow substation

Heavy Vegetation along Winslow Tap

There is heavy vegetation along majority of Winslow Tap transmission corridor. The PSE transmission corridor is limited to 30 FT width or less, and has tall trees in the vicinity of the line. The vegetation is dense in a 1.6 mile cross country section of the line (from Lovgreen Rd to Paulanna Rd). Outside the cross country section, the vegetation exposure is less dense but remains in close proximity to the line.

Figure A-7 shows an aerial map of outages over past 5 years (2013 to 2017). The cross country section of line is outlined. As shown, <u>outages are spread along the line demonstrating that tree related vegetation contact is possible on the entire line route</u>.

Of the 15 Winslow Tap outages (2013 to 2017), 8 out of 15 or nearly 50% outages were in the cross country section of the line and the other 50% outages spread along the remainder of the line. PSE maintains a 3 year vegetation management cycle for the Winslow Tap. Due to heavy vegetation exposure and close proximity of the line to significant trees (tight corridor) for Winslow Tap, PSE standard vegetation management practice has not been successful in mitigating transmission outages on the Winslow Tap.

[13] A radial transmission line has a single source. The Winslow Tap transmission line is a radial line with source at Port Madison substation. A substation served by a radial transmission line loses power on outage of the radial line. A looped transmission line has two sources. A substation served from a looped transmission line does not lose power on loss of one source, and can be served by the second source.

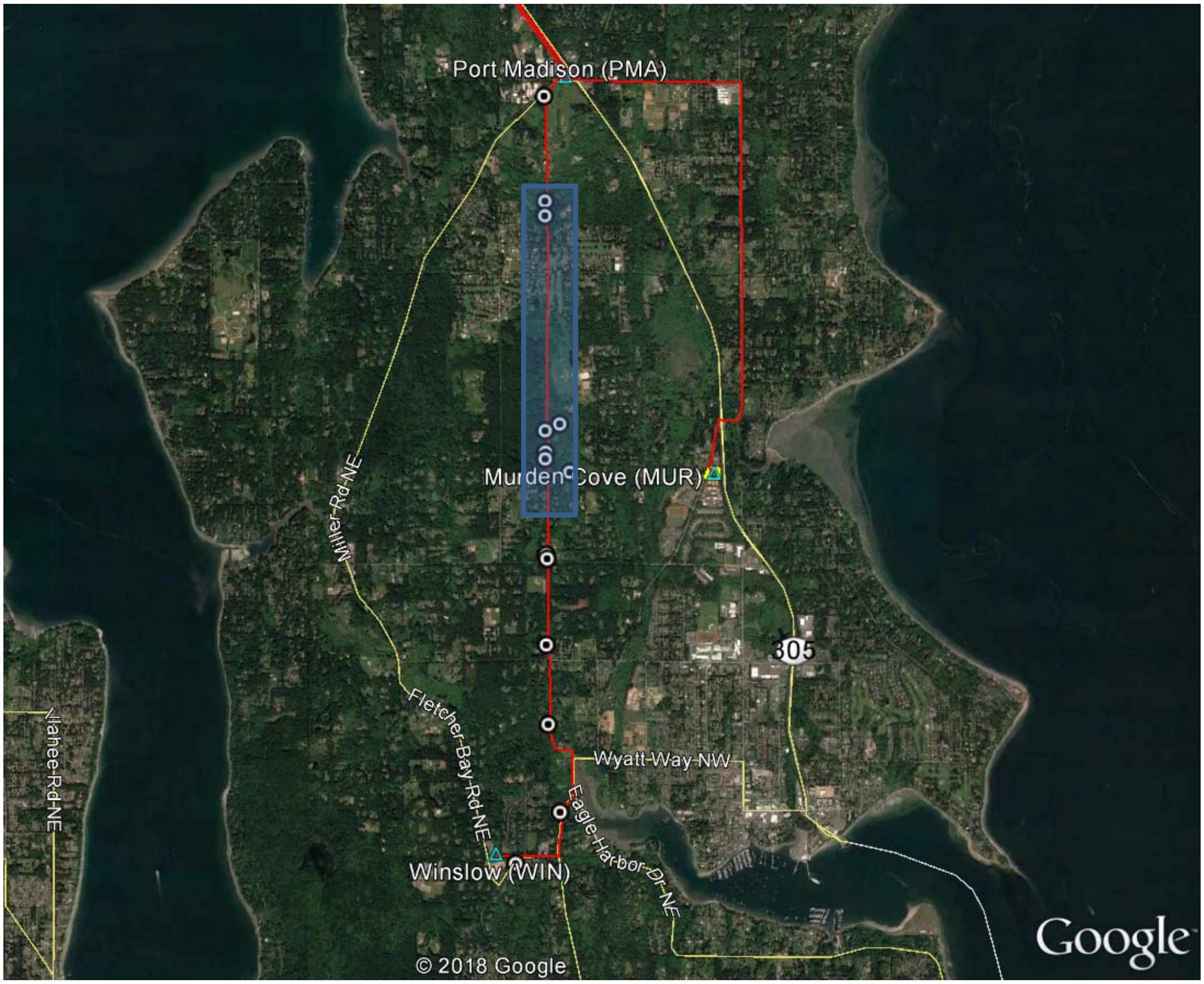


Figure E-1: Aerial map of Winslow Tap Transmission Outages (2013-2017)

Difficult terrain and limited access along Winslow Tap

A1.6 mile cross country section of Winslow Tap has dense vegetation, significant grade variation (of up to 40 feet), rocks, drainage channels and ground patches that remain wet throughout the year. PSE crews have 3 to 4 access identified points along the line to get to different poles. Some of the access points run through private property and require PSE to seek permission before mobilizing crews and equipment. The line along some non-cross country sections have a public or private road nearby but not in the immediate vicinity of the line, requiring crew to work through vegetation to get to the transmission line.

Key findings regarding access to the line:

- Winslow Tap cannot be patrolled for night-time outages due to difficult terrain and lack of a patrol path along the corridor. Helicopter patrols have been used during storms.
- Wet conditions and limited access along the corridor prolong outage repair times and restoration of transmission line. The conditions are worse during wet winter months such as the 36-hour storm outage on February 11, 2019 and 19-hour storm outage on October 18, 2018.

- PSE requires access through private property to mobilize crews and equipment to reach affected areas on the line, causing further delays.

Limited distribution substation capacity for backup of Winslow substation

During Winslow Tap transmission outages, PSE switches Winslow substation customers to the neighboring distribution substations (Murden Cove and Port Madison) over distribution ties. Due to high loading in winter months and limited distribution substation capacity on the island, switching customers over distribution ties for a transmission outage is involved and time-taking, as it requires more switching operations by the crews.

Key findings on distribution capacity backup:

- During high loading (winter months), for a Winslow Tap transmission outage, Winslow substation customers may remain without power until system load drops to a manageable level and Winslow substation load may be transferred to neighboring substations.
- Distribution backup of Winslow substation for scheduled transmission outages for planned maintenance activities is possible only during light load conditions (non-winter months).

Appendix F Ferry Electrification Plan

Sustainability and resilience

+ Design future vessels and terminals to be more environmentally friendly and flexible in design to accommodate new technology, changing transportation modes and increased passenger ridership.

WSF is the largest consumer of diesel fuel in Washington State, burning more than 18 million gallons each year. Because of this, WSF's operations generate the most carbon and other greenhouse gas emissions within the state transportation system. The Plan recommends that WSF leverage the need for new vessels to meet and exceed carbon dioxide emissions reduction requirements under state law. To cut fuel consumption, the Plan recommends building new vessels to use hybrid propulsion technology instead of full diesel engines. The use of this propulsion technology has benefits of reduced engine noise and vibration, potentially lessening effects on orcas and other marine life.

In April 2018, Governor Inslee approved $600,000 in funding to study conversion of WSF's three Jumbo Mark II Class vessels to plug-in electric-hybrid propulsion with charging connections at the terminals. These three vessels account for the highest fuel consumption and emissions in the fleet. Completing these conversions will reduce the carbon emissions from the current fleet by 25 percent.

Once WSF implements the capital investments in vessel and terminal infrastructure identified in the Plan, by 2040 the agency will have replaced 13 existing diesel vessels with electric-hybrid vessels and will have converted six vessels to plug-in hybrid. All hybrid vessels will be capable of charging at the terminal to realize the maximum benefit of hybrid propulsion. With the installation of terminal charging equipment, some vessels will be capable of full electric operation on shorter routes and others will use the plug-in hybrid system to supplement onboard engines. The following table shows the planned fleet composition over time. During the development of new vessel contracting requirements, the Plan recommends that a design charrette be held with technical design experts and departments within WSF to outline design elements of a future vessel to be most efficient and environmentally friendly.

Why electrify vessels?

The electrification of the WSF fleet provides measurable benefits in fuel/energy cost savings over the 20-year planning horizon and beyond. More importantly, measureable benefits in the CO_2 emissions into the atmosphere are projected at below 2050 reduction targets by 2034. That means moving more people in and around our region with less impact on our environment.

Figure F-1: Ferry Electrification Excerpt (Page 98) from WSF 2040 Long Range Plan (January 2019)

Sustainability and resilience

Planned fleet composition

	2019	2023	2030	2040
Plug-in Hybrid	0	4	12	22
Diesel	23	18	13	4
Total Fleet Size	23	22	25	26

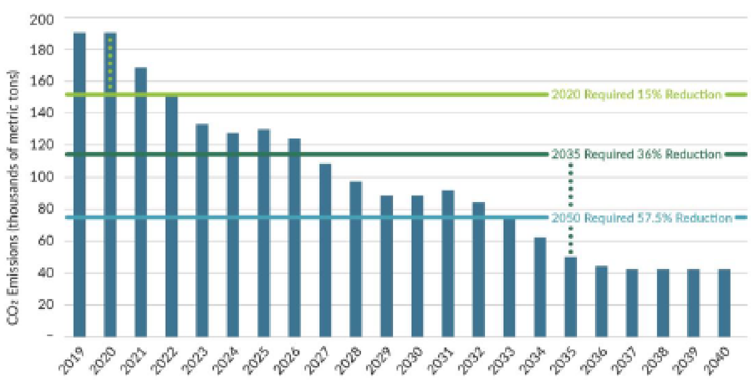
With this new, greener composition, the WSF fleet would achieve a 50 percent reduction in emissions and annual fuel consumption compared to today's fleet, from approximately 19 million gallons consumed in 2018 to approximately 9.5 million gallons consumed in 2040. Not only does this have significant positive effects on the environment, but also tremendous cost savings, as discussed in more detail in the Implementation, Investments and Financial Outlook section of the Plan.

2018 fuel consumption
19 million gallons

2040 fuel consumption
9.5 million gallons

The figure below shows the corresponding change in carbon emissions, which include meeting and exceeding state law requirements of a 36 percent reduction to 2005 emissions by 2035 and a 57.5 percent reduction by 2050. The Jumbo Mark II Class vessel conversions represent an initial 25 percent reduction in emissions upon the completion in 2023.

Annual CO_2 emissions and RCW 70.235.050 reduction requirements



While vessel fuel consumption, emissions and noise are central to the Plan's strategies and investments related to vessels, other smaller endeavors will make a difference. WSF should also consider waste management and waste diversion, the practice of trying to divert as much waste as possible out of the landfill by recycling and composting. This would be particularly relevant in the context of WSF's vendor contracts—for instance, galley service providers onboard vessels or other food service providers at terminals.

Figure F-2: Ferry Electrification Excerpt (Page 99) from WSF 2040 Long Range Plan (January 2019)

Appendix G Glossary

Term	Definition
Term	**Definition**
Block load	A large expected increase in electric energy demand from an existing or new customer.
Circuit	A circuit is the electric equipment associated with serving all customers under normal configuration from a specific distribution circuit breaker at a substation.
Concern	A “concern” is a non-critical issue that impacts system operations but is <u>not</u> required to be addressed by a solution; a solution that addresses an identified concern provides additional benefit.
Conservation	Measures to improve efficiency of customer’s electric loads reducing energy use and reducing peak demand.
Consumption	Consumption is the amount of electricity that customers use over the course of a year and it’s measured in kilowatt hours.
Contingency	Contingencies are a set of transmission system failure modes, when elements are taken out of service (e.g., loss of equipment).
Curtailable	A load that may be interrupted to reduce load on system during peak periods. Curtailable customers are on a different rate schedule than non-curtailable (firm) customers.
Demand	The amount of power being required by customers at any given moment, and it’s measured in kilowatts.
DR- Demand response	Flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility’s supply cost. Demand response is also the voluntary reduction of electricity demand during periods of peak electricity demand or high electricity prices. Demand response provides incentives to customers to temporarily lower their demand at a specific time in exchange for reduced energy costs.
Distributed generation	Small-scale electricity generators, like rooftop solar panels, located close to the source of the customer’s load.
Distribution line	A distribution line is a medium-voltage (12.5 kV-35 kV) line that carries electricity from a substation to customers. Roughly half of PSE's distribution lines are underground. Distribution voltage is stepped down to service voltage through smaller transformers located along distribution lines. Distribution lines differ from feeder as it includes the large feeder wire and smaller wire laterals.
Distribution System	A distribution system is the medium-voltage (12.5 kV-35 kV) infrastructure that carries electricity from a substation to customers and includes the substation transformer. System is the collective of all of this infrastructure in an entire study area.

Term	Definition
EPRI- The Electric Power Research Institute	The Electric Power Research Institute conducts research, development, and demonstration projects for the benefit of the public in the United States and internationally. As an independent, nonprofit organization for public interest energy and environmental research, they focus on electricity generation, delivery, and use.
Feeder	A feeder is the largest conductor section of a circuit and generally
Institute of Electrical and Electronics Engineers (IEEE)	A professional association, promoting the development and application of electro-technology and allied sciences for the benefit of humanity, the advancement of the profession, and the well-being of our members.
Integrated Resource Plan (IRP)	The Integrated Resource Plan (IRP) is a forecast of conservation resources and supply-side resource additions that appear to be cost effective to meet the growing needs of our customers over the next 20 years. Every two years, utilities are required to update integrated resource plans to reflect changing needs and available information.
Interim Operating Plan (IOP)	A temporary plan to address a transmission system deficiency and meet performance requirements, until a solution takes effect. An IOP may consist of a series of operational steps to radially operate the system, run generation or implement load shedding.
Kilovolt (kV)	A kilovolt (kV) is equal to 1,000 volts of electric energy. PSE uses kilovolts as a standard measurement when discussing things like distribution lines and the energy that reaches our customers.
Load	The total of customer demand plus planning margins and operating reserve obligations.
Load forecast	A load forecast is a projection of how much power PSE's customers will use in future years. The forecast allows PSE to plan upgrades to its electric system to ensure that current and future customers continue to have reliable power. Federal regulations require that utilities plan a reliable system based on forecasted loads. When developing a load forecast, PSE takes multiple factors into account like current loads, economic and population projections, building permits, conservation goals, and weather events.
Load shedding	Load shedding is when a utility intentionally causes outages to customers because demand for electricity is exceeding the capacity of the electric grid. Load shedding is the option of last resort and is conducted to protect the integrity of the electric grid components in order to avoid a larger blackout. This is not a practice that PSE endorses as a long-term solution to meet mandatory performance requirements.
Major Event Day (MED)	Any day in which the daily system SAIDI exceeds the annual threshold value. Outages on those days are excluded from the SAIDI performance calculation.

Term	Definition
Megawatt (MW)	A megawatt (MW) is equal to 1,000,000 watts of electric energy. PSE uses megawatts as a standard measurement when discussing things like system load and peak demand. MW differs from MVA in that it is generally always lower and translates as energy that performs work. The amount of MW vs MVA is determined by load characteristics. Motor loads generally have a lower power factor (PF) than heating loads for example and as a result. MW=MVA*PF
Mega Volt-Amp (MVA)	A MVA is equal to 1,000,000 (Volt*Amps). MVA is generally slightly higher than MW. Equipment ratings are in MVA as the equipment heat rise is determined by actual MVA.
N-0	This is a planning term describing that the electric grid is operating in a normal condition and no components have failed.
N-1	This is a planning term describing an outage condition when one system component has failed or has been taken out of service for construction or maintenance.
N-1-1	This is a planning term describing outage conditions where two failures occur one after another with a time delay between them.
N-2	This is a planning term describing outage conditions where two failures occur nearly simultaneously.
Native Load Growth	Load growth associated with existing customers or new customers less than 1 MW.
Need	A constraint or limitation on the delivery system in providing safe and reliable electric supply to customers. A need is a “must-have” that is required to be addressed for the system in a timely manner (by a certain Need Date, as determined in a needs assessment)
Non-wires alternatives	Alternatives that are not traditional poles, wires and substations. These alternatives can include demand reduction technologies, battery energy storage systems, and distributed generation.
NERC- North American Electric Reliability Corporation	NERC establishes the reliability standards for the North American grid. NERC is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the bulk power system in North America, as certified by FERC. NERC develops and enforces Reliability Standards and annually assesses seasonal and long-term reliability. PSE is required to meet the Reliability Standards and is subject to fines if noncompliant.
Peak demand	Customers’ highest demand for electricity at any given time, and it’s measured in megawatts.
Proven technology	Technology that has successfully operated with acceptable performance and reliability within a set of predefined criteria. It has a documented track record for a defined environment, meaning there are multiple examples of installations with a history of reliable operations. Such documentation shall provide confidence in the technology from practical operations, with respect to the ability of the technology to meet the specified requirements.

Term	Definition
Reasonable project cost	Reasonable project cost means holistically comparing costs and benefits to project alternatives. This includes dollar costs, as well as duration of the solution, risk to the electric system associated with the type of solution (e.g., is the solution an untested technology), and impacts to the community.
Right of way	A corridor of land on which electric lines may be located. PSE may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.
Sensitivities	Sensitivities are circumstances or stressors under which the contingencies are tested (e.g., forecasted demand levels, interchange, various generation configurations).
Substation	A substation is a vital component of electricity distribution systems, containing utility circuit protection, voltage regulation and equipment that steps down higher-voltage electricity to a lower voltage before reaching your home or business.
Substation group	A grouping of 2-5 substation transformers that are situated close enough to each other that loads in the study area can be switched from one station to an adjacent station for maintenance, construction, or permanent load shifting. For Bainbridge Island, the substation group includes 3 distribution substations – Port Madison, Murden Cove and Winslow.
Substation group capacity	The aggregate distribution transformer capacity of the substation group for winter and summer rating, calculated in MVA. Example: Winter/Summer ratings of distribution transformers at Port Madison (33 MVA/28 MVA), Murden Cove (33 MVA/28 MVA) and Winslow (33 MVA/28 MVA); Substation Group Capacity for Bainbridge Island (Winter/Summer): 99 MVA/84 MVA.
SAIDI- System Average Interruption Duration Index	SAIDI is the length of non-major-storm power outages per year, per customer. SAIDI is commonly used as a reliability indicator by electric power utilities. Outages longer than 5 minutes are included.
SAIFI- System Average Interruption Frequency Index	SAIFI is the frequency of non-major-storm power outages per year, per customer. SAIFI is commonly used as a reliability indicator by electric power utilities. Interruptions longer than 1 minute are included.
Transformer	A transformer is a device that steps electricity voltage down from a higher voltage, or steps it up to a higher voltage, depending on use. On the distribution system, transformers typically step the voltage down from a distribution voltage (12.5 kV) to 120 to 240 volts for customers' residential use. Transformers are the green boxes in some residences' front yard or the barrel-like canisters on utility poles.
Transmission line	Transmission lines are high-voltage lines that carry electricity from generation plants to substations or from substation to substation. Transformers at the substation "step down" the electricity's transmission voltage (55 to 230 kilovolts) to our primary distribution voltage (12.5 kV).

Bainbridge Island Electric System Solutions Report

Bainbridge Island, WA

Strategic System Planning
July 2019

PUGET SOUND ENERGY

Bainbridge Island Electric System Solutions Report

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July 2019

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Executive Summary

After completion of the Bainbridge Island Electric System Needs Assessment, Puget Sound Energy (PSE) and industry experts conducted analyses of traditional alternatives (wires) and non-wires alternatives (NWAs) to determine a cost-effective solution that addresses the identified system needs for Bainbridge Island over the 10 year planning horizon.

The City of Bainbridge Island (Bainbridge Island) is separated from the Kitsap Peninsula by the Agate Pass waterway and bridge. Puget Sound Regional Council has identified Bainbridge Island as an urban area for the Growth Management Act. The island is home to a population of 24,400 residents and Washington State Ferries Eagle Harbor Maintenance Facility and Ferry Terminal.

PSE's System Planning department regularly assesses electrical system needs to ensure PSE can reliably serve residents and businesses over a 10-year planning horizon. The Bainbridge Island Electric System Needs Assessment determined the island's grid has reliability, capacity, and aging infrastructure needs during the 10-year planning horizon on both the transmission and distribution systems.

PSE's proposed solution for Bainbridge Island is a combination of a new 115 kilovolt (kV) transmission line, battery storage, distributed energy resources, and replacement of aging infrastructure. Together these solutions will meet growing demand and improve reliability for Bainbridge Island customers.

Bainbridge Island Electric Needs

The Bainbridge Island Electric System Needs Assessment report identified needs and concerns[1] for PSE's transmission and distribution system on Bainbridge Island, which are briefly described below.

System needs and concerns for Bainbridge Island are:

- **Transmission Reliability need:** A reliability improvement need was identified to improve the performance of the Winslow Tap transmission line that feeds Winslow substation. Nearly 70 percent of the transmission related customer minutes of service interruption[2] on Bainbridge Island were from outages to the Winslow Tap transmission line.
- **Transmission Aging Infrastructure need:** An infrastructure replacement need was identified for the Winslow Tap transmission line support structures that are nearing end of useful life and could potentially fail leading to unplanned outages and emergency repairs.
- **Substation Capacity need:** A distribution substation group capacity need of 14.6 MW was identified on Bainbridge Island within the 10 year planning horizon (2018-2027) to support general load growth of 4.6 MW and planned 10 MW load addition for the new ferry electrification charging load. The anticipated capacity need is expected to grow to 16.6 MW by 2030 due to general load growth increase by 2 MW. Per the PSE Solution criteria a solution must last 10 years. The Needs Assessment shows that additional

[1] PSE defines "need" as a system deficiency that is required to be addressed by a solution, preferably by the identified date of need. A "concern" is a non-critical issue that impacts system operations but is not required to be addressed by a solution; a solution that addresses an identified concern provides additional benefit.

[2] Outages considered over the past 5 year period 2013-2017. Refer to Bainbridge Island Electric System Needs Assessment Report – Transmission Reliability Assessment, Section 4.3.

substation capacity is needed by 2020. Therefore, the need of 16.6 MW is the ultimate need for a viable solution to last until 2030.

- **Transmission Operating Flexibility concern:** Concerns related to ability to transfer load to support routine maintenance[3] and outage management. Winslow and Murden Cove substations are on radial transmission taps (single transmission source) with no transmission backup. Customers served from these two substations have potential for outage in the event of an unplanned transmission outage or emergency transmission equipment repair situation due to lack of transmission backup.

Alternatives Analyzed

PSE, along with Navigant Consulting (Navigant) and Quanta Technology (Quanta), studied various alternatives for meeting the needs identified for the Bainbridge Island transmission and distribution system. This solutions report details conventional wires and non-wires alternatives considered to solve the aforementioned needs. Various alternatives were screened for viability using the solutions criteria detailed in Section 1.2.

PSE studied conventional wires alternatives, while Navigant and Quanta were contracted to review these alternatives, analyze non-wires alternatives (NWA), and analyze hybrids of wires and non-wires alternatives. The goal of their analyses was to consider the technical and economic feasibility of potential alternatives which could meet Bainbridge Island needs.

PSE studied various wires alternatives, and determined the top-wires alternative to include:

- New transmission line (loop) between Winslow and Murden Cove substations
- New substation with new feeders
- Winslow Tap transmission line rebuild[4]

Navigant considered a NWA consisting of both battery energy storage and distributed energy resources (DERs). A DER is defined as “a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to reduce system demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load”.[5] Quanta considered the feasibility of a non-wires alternative consisting of entirely battery energy storage systems.

<u>Navigant’s Non-wires Alternatives Analysis</u>

Navigant’s Non-wires Alternatives Analysis reviewed and analyzed three approaches:

1. Traditional wires scenario
2. Exclusive non-wires scenario
3. Hybrid non-wires scenario

---

[3] PSE limits routine equipment maintenance to summer months when loading is light and backup is available from the distribution system.

[4] Rebuild of the Winslow Tap transmission line involves replacing transmission poles, support structures and line conductor.

[5] National Association of Regulatory Utility Commissioners. "NARUC Manual on Distributed Energy Resources Rate Design and Compensation." November 2016. http://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0

Key takeaways from Navigant's study:

- A hybrid alternative comprising of wires and non-wires components to meet the reliability and capacity needs is "technically feasible and economically-preferable to the wired solution."[6]
- An exclusive non-wires alternative would be "technically possible but not realistic"[7] due to the area needed and cost of battery storage needed at various locations, the need for aggressive tree-trimming and removal[8], and the ability to meet the timeframe to meet the island's needs.
- PSE could delay the need for investment in a new distribution substation by focusing on battery storage, DERs, and block load curtailment (if Washington State Ferries chooses to connect the new ferry electrification charging load as a curtailable resource).

Navigant's analysis is described in Section 4.3.1 and available in full in Appendix D.

Quanta's Battery Storage Analysis

Quanta evaluated an all-battery storage alternative to potentially address both the transmission system reliability and distribution system capacity needs. Quanta reviewed the conventional solutions, assessed the siting and sizing of battery storage to meet reliability and capacity needs, considered potential locations for utility-scale battery energy storage, and conducted a comparative analysis of costs.

Quanta's analysis concluded that:

- An alternative with only battery energy storage would require large grid-scale energy storage sites at five locations on the island. Each site would include between one and up to 35 shipping containers, and four of the locations would be new sites not associated with a substation.
- At minimum, an all-battery storage solution would cost at least $20 million more than the conventional wires alternative; this alternative's cost will increase due to interconnection costs and siting of the batteries.[9]

Quanta's analysis is described at length in Appendix E and is summarized in Section 3.3.2.

Hybrid Alternatives Analysis

PSE further assessed the hybrid solution suggested by Navigant by identifying a location for their recommended battery. Based on power flow analysis completed in the Quanta Technology report, PSE assessed that the most appropriate location for this approximately 3.3 MW battery is likely at Murden Cove Substation.

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[6] Appendix D, Bainbridge Island Non-Wires Alternative Analysis, Navigant Consulting, page 1

[7] Appendix D, Bainbridge Island Non-Wires Alternative Analysis, Navigant Consulting, page 2

[8] PSE defines "aggressive" vegetation management (e.g., tree trimming and removal) as a substantial distance beyond our standard practices. In some cases, the vegetation management area may be equal to the height of the surrounding trees from the edge of the wire zone.

[9] While one battery could be located at substation property, the four other large batteries would need to be located around the island. Locations of those potential sites were not considered, but if additional land needed to be purchased this would also increase the differential between the wired alternative and the all-battery storage alternative.

Top Alternatives Analysis

PSE then further evaluated the estimated costs of the top reliability, capacity and aging infrastructure alternatives, which is shown in the table below.

Table 0-1: Summary of Top Alternatives[10] [11] [12] [13]

	Top Wires Alternative	Top Non-Wires Alternative (All BESS)	Top Hybrid Alternative
Primary Need: Winslow Tap Transmission Reliability	Transmission Loop (Winslow to Murden Cove)	TOTAL BESS: 25.1 MW/79.2 MWH MUR: 13.7 MW/34.8 MWH MUR-15: 0.4 MW/0.4 MWH, PMA-13/WIN-12: 3.2 MW/9 MWH, MUR-17/WIN-15: 3.4 MW/15 MWH WIN-13: 4.4 MW/20 MWH	Transmission Loop (Winslow to Murden Cove)
Primary Need: Substation Group Capacity	New Distribution Substation		Ferry Curtailment: 10 MW up to 182 hours 50% BESS@MUR: 3.3 MW/5 MWH 50% DER: 3.3 MW
Primary Need: Winslow Tap Aging Infrastructure	Rebuild Transmission Line-Replace Poles & Wire, Improve Corridor Access, Acquire Necessary Rights & Veg Mgmt	Rebuild Transmission Line-Replace Poles & Wire, Improve Corridor Access, Acquire Necessary Rights & Veg Mgmt	Rebuild Transmission Line-Replace Poles & Wire, Improve Corridor Access, Acquire Necessary Rights & Veg Mgmt
Total Cost Estimate Range (Base to High)	$42.5 million to $85 million	$66 million to $132 million	$38 million to $76 million
Decision Factors	- Expertise - Long term solution - High reliability	- 10 year solution - Add with growth - New operational strategies needed - High cost	- 10 year solution - Add with growth - New operational strategies needed - Local EE and DR

Solution for Improving Bainbridge Island Reliability

PSE determined that a hybrid alternative presents the best solution for cost-effectively meeting Bainbridge Island electric transmission and distribution system needs. This alternative also provides an opportunity to assess the viability of energy storage and distributed energy resources to allow deferral of traditional distribution system infrastructure additions. A hybrid solution is consistent with both our

[10] Costs are estimate based on similar past projects in other areas of PSE service territory. Does not include site-specific engineering.

[11] The costs shown for the wires portions of all alternatives are capital investment costs.

[12] Costs shown for battery storage systems in Top Non-Wires Alternative (all-BESS) are from the Quanta Technology Report, Appendix E, Table 7.1, Storage-Only Solution (Option), Total Capital Investment cost ($37.7M). A 25% cost estimating contingency is added to the cost in that report to be consistent with how other costs in this table are shown. The capital investment cost is shown to be consistent with the presentation of the wires alternative.

[13] Costs shown for Top Hybrid Alternative, Primary Need: Substation Group Capacity are from the Navigant Consulting Report, Appendix D, page 24 which notes a portfolio cost between $4.5M (including DR) and $5.5M (excluding DR). The higher portfolio cost of $5.5M is used here to remain conservative. A 25% cost estimating contingency is added to the cost in that report to be consistent with how other costs in this table are shown. The costs and benefits for the measures of this portfolio are from the PSE 2017 IRP. These costs and benefits are in present value terms and are levelized to be consistent with the PSE 2017 IRP. Further discussion of this is in Appendix D, Section 3.1.

customers' expectations to lead us into the future and policy direction from the Washington Utilities and Transportation Commission (WUTC).

The hybrid solution:

- Invests in traditional transmission infrastructure to replace aging equipment and improve reliability.
- Deploys battery storage and DERs to support the island's electric load growth and ferry electrification without the need for additional substation infrastructure.
- Adds a transmission loop that improves reliability and supports future technologies.
- Provides cost savings as compared to the conventional wires alternative.

<u>Specifically, the proposed hybrid solution:</u>

- Improves transmission and distribution reliability by building approximately 3.5 miles of new overhead transmission line between Murden Cove and Winslow substations that will create a transmission "loop". The loop will also improve operating flexibility on the transmission system to both Winslow and Murden Cove substations.
- Addresses the aging infrastructure need for the Winslow Tap transmission line by rebuilding the line and improving the corridor for maintainability and operability of the line.
- Addresses Bainbridge Island's distribution capacity need with:
    - Connecting the new ferry electrification charging load (10 MW) as a curtailable resource.
    - Installing an approximately 3.3 MW/5 MWh battery storage system (planned for Murden Cove substation).
    - Implementing an approximately 3.3 MW DER portfolio on Bainbridge Island, with customer-side resources such as energy efficiency, renewable distributed generation, and potential of demand response.

See Figure 0-1 for an illustration of the proposed solution.

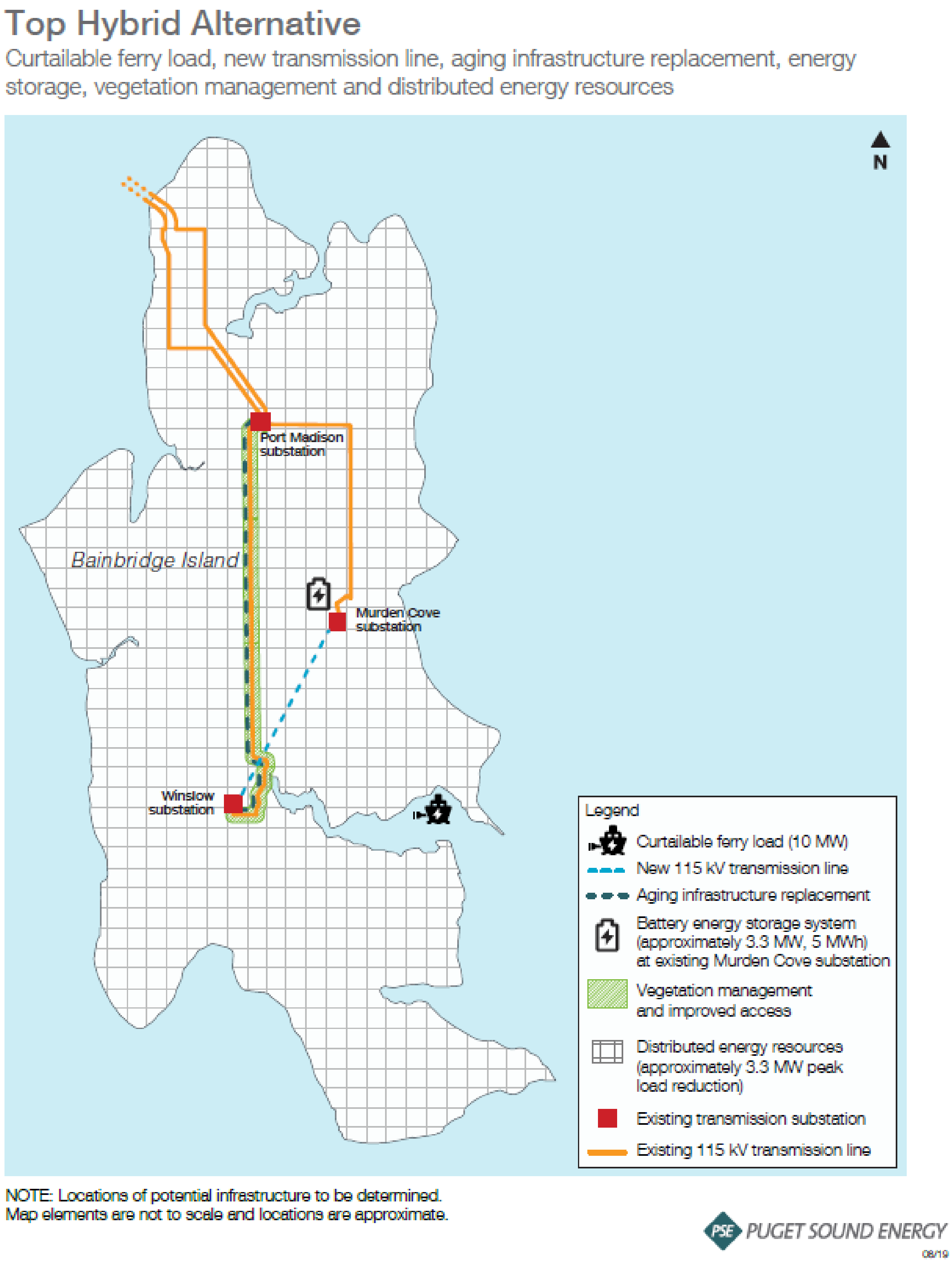

Figure 0-1: Proposed Solution - Hybrid Alternative 1

1 Introduction, Methodology and Key Assumptions

After completion of the Bainbridge Island Electric System Needs Assessment, PSE and industry experts conducted analyses of traditional alternatives (wires) and non-wires alternatives (NWAs) to determine a cost-effective solution that addresses the identified system needs for Bainbridge Island over the 10 year planning horizon.

1.1 Methodology

This solutions study used the following process:

1. Step one: Brainstorm potential solution types to solve the identified system needs, including conventional wires type, non-wires type like batteries, energy efficiency and distributed energy resources (DERs), and hybrid type that involved combination of wires and non-wires components.
2. Step two: Identify possible alternatives for each solution type. PSE studied conventional wires alternatives, Navigant studied various non-wires alternatives, and Quanta studied an all-battery storage alternative.
3. Step three: Assess the most promising alternatives using the solutions criteria for system performance in terms of capacity, reliability, asset life and constructability; and determine "viable" alternatives. An alternative was considered "viable" if it met all identified system needs and the solutions criteria.
4. Step four: Identify and compare the most viable alternatives.
5. Step five: Compare the top alternatives in terms of cost, benefits, drawbacks and risks to identify the proposed solution.

Figure 1-1 shows the process flow for the solutions study methodology.

PSE started the analysis with many conventional wires alternatives (as shown in Appendix A) and then shortlisted the alternatives to viable alternatives that met Bainbridge Island needs and the solutions criteria. The viable wires alternatives were compared in terms of cost, benefits, drawbacks and risks to generate the top-wires alternative. The top-wires alternative was used as a reference for development of non-wires and hybrid alternatives. As a final step, the top alternatives for the wires, non-wires and hybrid categories were compared to determine the proposed solution that best met Bainbridge Island needs.

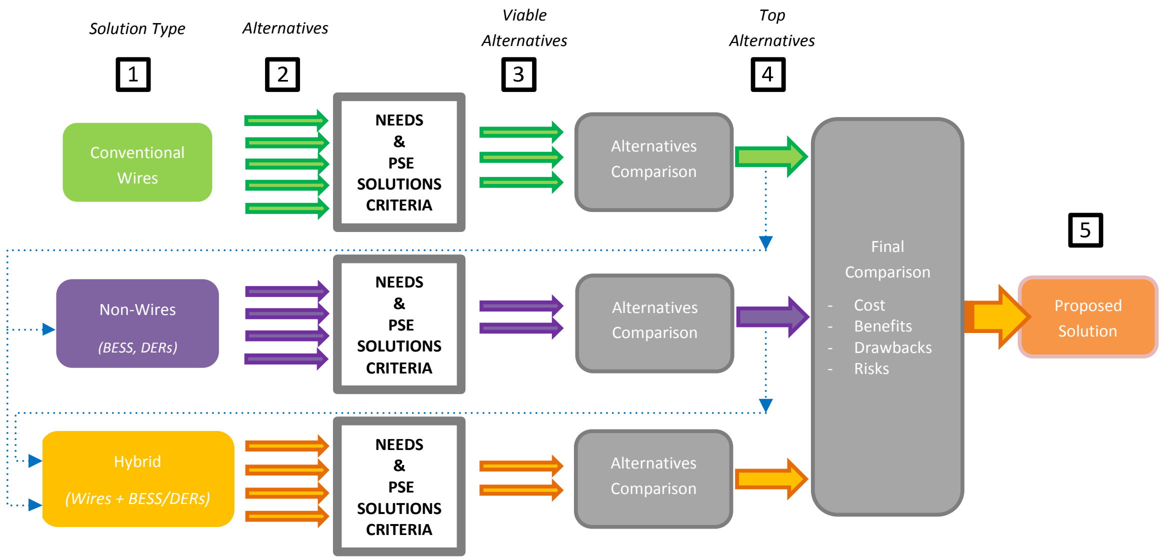

Figure 1-1: PSE Solutions Study Methodology

1.2 Solution Criteria

PSE evaluates alternatives with electrical and non-electrical criteria. These criteria are based on federal requirements, PSE planning guidelines, and industry standards, as well as project implementation considerations.

A proposed alternative is considered viable if it addresses all identified system *needs* and meets the solutions criteria. A viable alternative is not required to but may also address identified *concerns*, if deemed prudent or advantageous to include in the project scope.

Technical Criteria:

1. Must meet all performance criteria:

   - Address needs identified within the ten year study period (2018-2027)
   - Does not re-trigger any of the needs identified in the Needs Assessment for 10 years or more after the solution is in service
   - Normal winter peak load forecast with 100% conservation
   - Normal summer peak load forecast with 100% conservation

   Transmission:

   - Applicable transmission planning standards including mandatory North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) standards (e.g., NERC TPL-001-4 and WECC TPL-001-WECC-CRT-3.1)
   - Applicable PSE Transmission Planning Guidelines as follows:
     - o Transmission planning guideline for upgrading existing infrastructure in radial transmission line configuration when load served exceeds 15 to 20 MW
   - ≤ 100% of Planning's normal limit for lines and transformers for NERC TPL-001-4 P0-P7 contingencies for the 10-year planning horizon

- Take into account planned transmission system improvement projects that are expected to be in-service within study period
- No load shedding
- No interim operating plans

Distribution:

- Applicable PSE Distribution Planning Guidelines as follows:
  - o Individual substation utilization in study area ≤ 100% of capacity
  - o Total utilization of all substations in study group ≤ 85% of capacity
  - o ≤ 100% of overhead individual feeder limits for N-0 and applicable N-1 scenarios
  - o ≤ 100% of underground individual feeder limits for N-0 and applicable N-1 scenarios

Reliability:

- For areas with high non-MED[14] SAIDI[15] or non-MED SAIFI[16], solution must reduce non-MED SAIDI and non-MED SAIFI.

Aging Infrastructure:

- Addresses all major equipment with less than 10 years of useful life
- Addresses key infrastructure impacted by aging infrastructure replacements

Design Requirements:

- Must meet applicable Institute of Electrical and Electronics Engineers (IEEE) and NERC standards
- Must meet Washington Administrative Code (WAC) and National Electrical Safety Code (NESC) safety codes
- Must use PSE standard equipment as applicable and be consistent with the PSE Major Equipment Committee's spare equipment strategy
- Must meet PSE best practices for operations and maintenance

2. Must address all relevant PSE equipment overloads and voltage violations identified in the Needs Assessment.
3. Must address all relevant needs identified in the Needs Assessment Report.
4. Must not cause any adverse impacts to the reliability or operating characteristics of PSE's or neighboring utility system.

<u>Non-technical Criteria</u>:

1. Feasible permitting
2. Reasonable project cost

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[14] MED (Major Event Day): See definition in Glossary

[15] SAIDI (System Average Interruption Duration Index): See definition in Glossary

[16] SAIFI (System Average Interruption Frequency Index): See definition in Glossary

3. Uses proven technology that may be adopted at a system level
4. Constructible within reasonable timeframe

1.3 Study Assumptions

For this solutions study, the following key assumptions were used:

- The 10-year planning horizon for the solutions study is from 2018 to 2027.
- Solution study horizon will be extended, if necessary, to accommodate solution criteria that states the solution must meet the need for at least 10 years.
- The study used the PSE corporate county level load forecast to project Kitsap County load; and PSE's Bainbridge Island load forecast[17] for specifically projecting Bainbridge Island load for the solution window.
- For alternatives involving battery energy storage system (BESS):
    - An 8 hour backup for transmission outages was considered sufficient duration for PSE to repair and restore most transmission line outages[18].
    - For outages that can exceed the assumed repair duration time, PSE System Operations and crews will have enough time margin, with the BESS backup, to manage area loads and switch the outaged load (or portion of the outaged load) to available capacity. This approach was considered reasonable and practical for sizing BESS alternatives.
- With regards to the ferry electrification charging load addition:
    - Anticipated as early as 2021.
    - PSE considered the load as curtailable. As of 2019, WSF has elected to pursue a curtailable rate schedule that allows PSE to interrupt service to the ferry charging load for up to 182 hours in a year.
- The estimated cost of acquiring land rights was included in each alternative.

[17] See Bainbridge Island Electric System Needs Assessment report for details on load forecast for Bainbridge Island

[18] Excludes storm related outages which can take longer duration for restoration. 8-hour battery backup covered 90% of transmission outages affecting Bainbridge Island in the past 5 year period 2013-2017

2 Needs Summary

PSE performed a needs assessment for Bainbridge Island's transmission and distribution system. The needs assessment determined that over the 10-year planning horizon, the needs and concerns were primarily in these areas – service reliability, system capacity, aging infrastructure, and operating flexibility. This is summary of the needs. For the complete needs assessment, refer to the Bainbridge Island Electric System Needs Assessment report.

2.1 Needs and Concerns

The Bainbridge Island Electric System Needs Assessment examined the island's transmission and distribution system for the 10-year planning horizon (2018-2027). PSE's planners assessed the island's future capacity needs. In addition, planners reviewed the transmission and distribution system's historical reliability performance to identify areas needing improvement.

As a result of this study, PSE identified that:

- Bainbridge Island customers experience more frequent and longer interruptions than the average PSE customer, and nearly half of those interruptions minutes are due to issues with the transmission system.
- Nearly 70 percent of transmission customer minutes of service interruptions were from the Winslow Tap transmission line that feeds the Winslow substation.
- Demand for electricity is growing on the island due to anticipated population growth and ferry electrification.
- Some transmission and distribution issues are being addressed through other projects.[19]

The system needs and concerns[20] for Bainbridge Island are summarized as follows:

- **Transmission Reliability need:** The Winslow Tap transmission line feeding Winslow substation has experienced longer and more frequent outages in comparison to Kitsap County and PSE company-wide.
- **Transmission Aging Infrastructure need:** The Winslow Tap transmission line support structures are nearing end of useful life and could potentially fail leading to unplanned outages and emergency repairs.
- **Substation Capacity need:** A distribution substation group capacity need of 14.6 MW was identified on Bainbridge Island within the 10 year study period to support general load growth of 4.6 MW and planned 10 MW load addition for the new ferry electrification charging load.
- **Transmission Operating Flexibility concern**[21] – Concerns related to ability to transfer load to support routine maintenance and outage management. Winslow and Murden Cove substations are on radial transmission taps with no operating flexibility at the transmission level.

[19] Off-island transmission issues are being addressed in the Kitsap Transmission Needs Assessment. Distribution reliability projects for PMA-12 and WIN-13 have existing projects to address them.

[20] A *need* is defined as a constraint or limitation on the delivery system in providing safe and reliable electric supply to customers. A need is a "must-have" that is required to be addressed for the system in a timely manner (by a certain Need Date) as determined in the Needs Assessment study for a planning horizon and defined in the Solutions Criteria. A *concern* is a non-critical issue that impacts system operations but may be overcome with alternate work plans. Concerns if unattended for long period manifest into needs, and may then require attention. A solution is required to address all identified system needs and may or may not address concerns.

Potential alternatives must address all of the system needs identified in this study, while also considering the operating flexibility concerns.

[21] Operational flexibility relates to the ability to transfer load to support routine maintenance and outage management. PSE limits equipment maintenance to non-winter months when loading is light and backup is available from the distribution system. Since there is no transmission backup for Winslow or Murden Cove substations, an unplanned or emergency transmission repair event in winter can lead to outages for some customers.

3 Top Alternatives Analysis

PSE, Navigant and Quanta studied a variety of wires and non-wires options, which are listed below for reference. Alternatives were developed to meet all identified needs of Bainbridge Island through a combination of the various potential wires and non-wires options. The alternatives were classified in 3 categories – wires, non-wires, and hybrid that included both wires and non-wires options. This section of the report discusses and compares the top alternatives for the wires, non-wires and hybrid categories.

Alternatives consisted of a combination of the following options that were considered:

- Wires options
  - Replace aging infrastructure on Winslow Tap
  - Rebuild Winslow Tap
  - Add a new substation
  - Add additional transformer in an existing substation
  - Replace existing substation transformers with larger transformers to add capacity
  - Add a new 115 kV transmission line between Winslow and Murden Cove substations
  - Add a submarine transmission line to connect to Winslow substation from Bremerton
- Non-wires options
  - Standard vegetation management[22]
  - Aggressive vegetation management
  - Battery storage
  - Distributed energy resources (DERs)

Appendix A describes the full range of specific wires, non-wires and hybrid alternatives that were considered in the evaluation. Some alternatives were eliminated and deemed *non-viable* as they did not meet the PSE solution criteria as defined in Section 1.2. Alternatives that met all Bainbridge Island needs and the PSE solution criteria were deemed *viable* and considered for further evaluation. Viable alternatives for each category were compared to determine the top alternative for the category.

3.1 No Action Alternative

PSE considered a scenario where no action is taken to improve the transmission reliability and distribution capacity needs; however, the aging infrastructure need of the Winslow Tap will be addressed for safety and overall reliability considerations.

Under this alternative, PSE would continue to operate and maintain the system as is done now with little expectation for service reliability improvement. Expected island electric load growth demand could exacerbate this situation.

Specifically, the substation group capacity planning guideline may be exceeded as early as 2019/2020, which limits operational system flexibility resulting in longer duration outages. Addition of expected WSF ferry electrification charging load as early as 2021 would further limit system operation. Flexibility

[22] PSE defines standard vegetation management as trimming and removal that is based on an analysis of our internal standards and local conditions by our vegetation management team. For Bainbridge Island, our existing corridor standard is 60 feet.

is also needed to properly maintain systems and perform required system maintenance. Without needed flexibility customers will be subject to scheduled outages for system maintenance and repairs.

This option also does not address the transmission reliability need of the Winslow Tap. Customers fed from that station will continue to see a high frequency of interruptions from the transmission source. With the limited group capacity operating flexibility this load cannot be shifted to other substations resulting in lengthy outages.

It is important to note that due to the potential safety risk, the replacement of Winslow Tap aging infrastructure is included in the no action alternative. Failure of aging infrastructure dictates that PSE replace equipment and rebuild the existing transmission line.[23]

3.2 Top Wires Alternative

PSE's top wires alternative is detailed below, other wires alternatives considered but not selected are summarized in Appendix A.

Top Wires Alternative (see Figure 3-1):

- Construct a 115 kV transmission line from Murden Cove substation to Winslow substation to create a looped transmission system to improve transmission reliability for Bainbridge Island (notably for Winslow substation and also beneficial for Murden Cove substation).
- Construct a new 25 MVA substation in south Bainbridge Island to address the substation group capacity need.

The top wires alternative was selected over the other viable wires alternatives because of the reliability benefit. Reliability would be improved both by the looped transmission line (decreased transmission outages and outage durations) and by the decrease in number of customers served by any one substation (decreased customer outages) for Winslow and Murden Cove substations with the addition of a new 25 MVA substation.

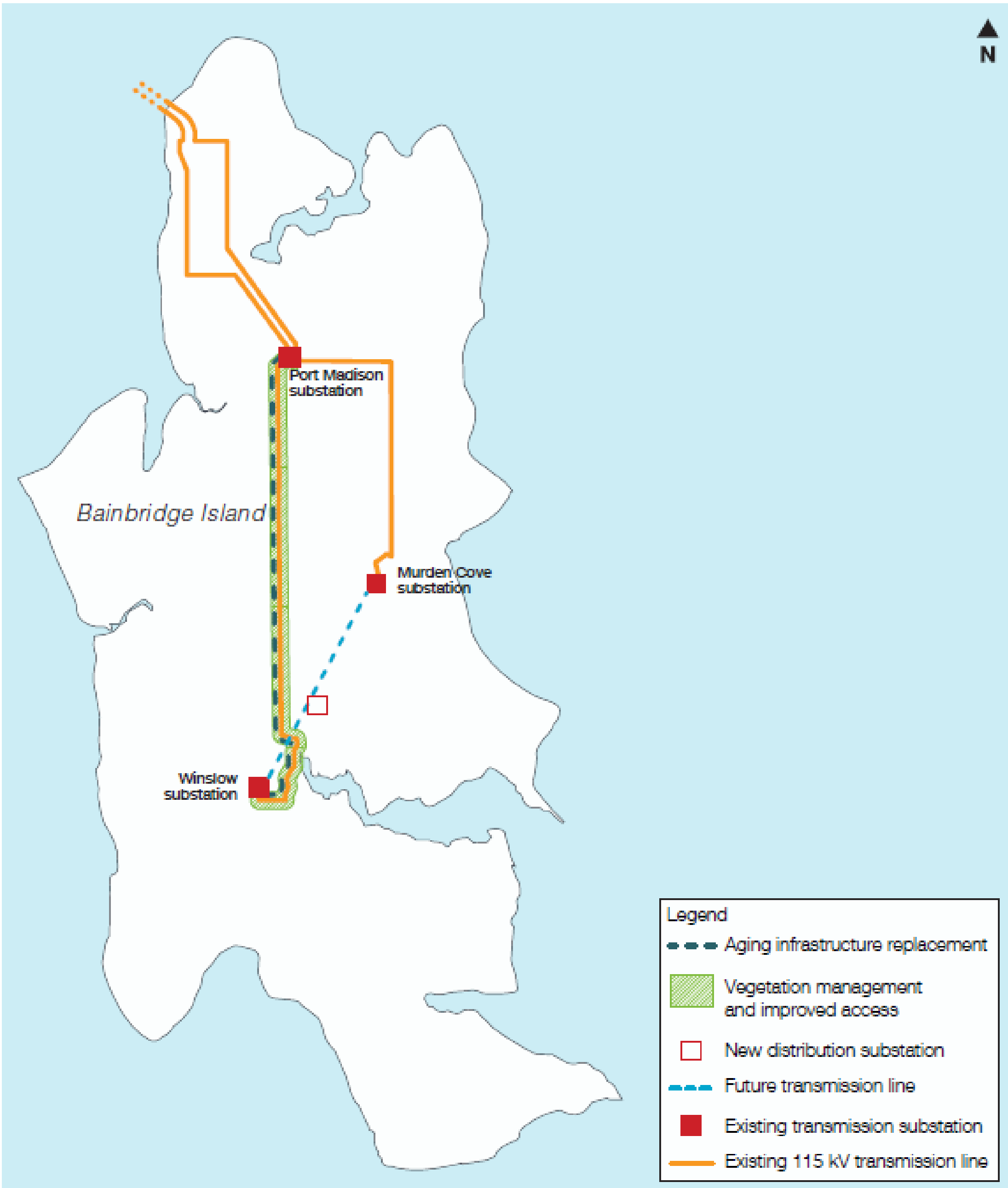
This option provides the best feeder configurations and facilitates future distribution automation implementation. Distribution automation isolates failed distribution equipment and restores service to as many customers as possible with automatic switching.

The new substation would ideally be in a location with relatively easy access to transmission lines and would minimize the construction of new distribution feeders to integrate the new substation into the existing distribution system.

[23] Refer to Appendix C "Addressing Transmission Aging Infrastructure Need" to see further explanation of PSE's assessment of options for corridor improvement.

Top Wires Alternative

New distribution substation, new transmission line, aging infrastructure replacement and vegetation management



NOTE: Locations of potential infrastructure to be determined.
Map elements are not to scale and locations are approximate.

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Figure 3-1: Top Wires Alternative

3.3 Top Non-Wires Alternatives

PSE contracted two consultants to perform non-wires analysis. Both considered the technical and economic feasibility of an alternative that consists entirely of non-wires alternatives (NWAs). Navigant considered alternatives consisting of both energy storage and other distributed energy resources (DERs), while Quanta considered the feasibility of an alternative consisting entirely of energy storage.

3.3.1 Energy Storage and Distributed Energy Resource Analysis by Navigant Consulting

Navigant reviewed whether energy storage and DERs could meet the needs of Bainbridge Island. The DERs that were included in the analysis for Bainbridge are energy efficiency (EE), demand response (DR), solar photovoltaic (PV), and renewable combined heat and power (CHP). These items as well as the resources that were considered but not included in the Bainbridge analysis are detailed in Table 1 of Appendix D.

Navigant's Non-wires Alternatives Analysis reviewed and analyzed three approaches:

1. **Traditional wires scenario**: Navigant reviewed the traditional wires alternative developed by PSE to meet Bainbridge Island needs and concerns. This alternative included a new 115 kV transmission line, expansion of the Winslow and Murden Cove substations, a new substation and new distribution feeders, and a rebuild of the Winslow Tap transmission line.
2. **Exclusively non-wires scenario:** Navigant analyzed a range of NWAs, which included energy efficiency, energy storage, renewable distributed generation like solar and renewable combined heat and power, and demand response[24]. In addition, Navigant considered vegetation management in their overall assessment but not in their detailed analysis.
3. **Hybrid non-wires scenario:** Navigant combined a new 115kV transmission line loop, battery storage, distributed energy resources, connection of the new ferry electrification charging load (10MW) as a curtailable resource, and rebuilding of the Winslow Tap transmission line.

In order to evaluate whether the needs on Bainbridge Island could be met exclusively with NWAs, Navigant considered both the narrow set of NWAs defined above as well as items not typically considered as NWAs, such as vegetation management, as discussed in Section 1.3.1 of Appendix D. They deconstructed the challenges on Bainbridge Island by two dimensions – the specific identified project need and the grid elements. The two purposes of this were to define the specific challenge being considered as well as identify where that challenge fits in the overall picture of Bainbridge Island needs. The deconstruction is done this way in order to cover the entire potential range of alternatives—wires and non-wires. The deconstruction into grid elements was divided into transmission and distribution components to be consistent with the existing grid architectural structure. This deconstruction, as well as the assessment of whether the project need can be met by NWAs, is referred to as a "Decision Tree" and is shown in Figure 2 of Appendix D.

Navigant concluded that NWAs would not aid transmission aging infrastructure or transmission operational flexibility on Bainbridge Island. However, NWAs could provide distribution capacity, some additional distribution reliability, and potentially distribution operational flexibility.

[24] As defined by the Northwest Power and Conservation Council, demand response is "the voluntary and temporary reduction in consumers' use of electricity when the power system is stressed". https://www.nwcouncil.org/energy/energy-topics/demand-response

Navigant also considered whether a broader definition of NWAs to include vegetation management could meet the Bainbridge Island needs. Navigant noted that some of the needs "would be extremely hard to meet with NWAs. For example, addressing transmission reliability without the Winslow 115 kV Tap rebuild and without addressing some of the aging infrastructure needs is a significant challenge."[25]

Key findings from Navigant's study:

- A hybrid alternative of wire and non-wires alternatives to meet the reliability and capacity needs is "technically feasible and economically-preferable to the wired solution."[26]
- PSE could delay the investment in a new distribution substation by focusing on battery storage, DERs, and working with WSF to have the ferry electrification charging connected as a curtailable load.
- Navigant concluded that while an all-NWA is technically possible, it is not a practical alternative.

With regards to the all-NWA options, Navigant specifically noted that, "considering the likely need for significant additional electric storage at various locations on the island, the need for aggressive tree-trimming and removal (counter to community values on Bainbridge Island), and the roll-out timeframe necessary to meet the full set of defined needs with an exclusively NWA solution, Navigant does not think such a solution could be realistically achieved."[25]

Navigant further noted that, "to provide similar levels of operational flexibility and reliability as the traditional solution, additional batteries would be needed to provide grid support for four to eight hours. These batteries would be needed in addition to the batteries and other measures needed to meet the growing capacity needs. Navigant estimated that the costs for these additional batteries would be considerably more than the costs of the traditional solution related to grid flexibility and reliability."[25] The detailed analysis that was undertaken by Quanta Technology did evaluate the cost of an alternative consisting entirely of batteries and is documented in the next section.

3.3.2 Energy Storage Analysis by Quanta Technology

Quanta analyzed whether multiple battery energy storage systems could meet the defined needs on Bainbridge Island. They ran power flow studies and analyzed optimal locations for battery siting and sizing to meet the defined needs on Bainbridge Island. The conditions and assumptions under which they conducted their analysis included the use of load shifting and feeder switching and are detailed further in Section 2 of Appendix E.

The results of Quanta's analysis yielded an alternative consisting of five batteries with a total combined rating of 28.2 MW/91.2 MWh. The batteries would be distributed throughout the island at locations shown in Table 3-1 and in Figure 3-2 along circuits or at a substation.

One of the five batteries could be located at substation property, while the four other large batteries would be at locations determined around the island on specific circuits and not at a substation. At minimum, an all battery storage alternative would cost at least $20 million more than the conventional wire alternative as documented further in Section 5; this alternative's cost will increase due to interconnection costs and siting of the batteries.

[25] Appendix D, Bainbridge Island Non-Wires Alternative Analysis, Navigant Consulting, page 11

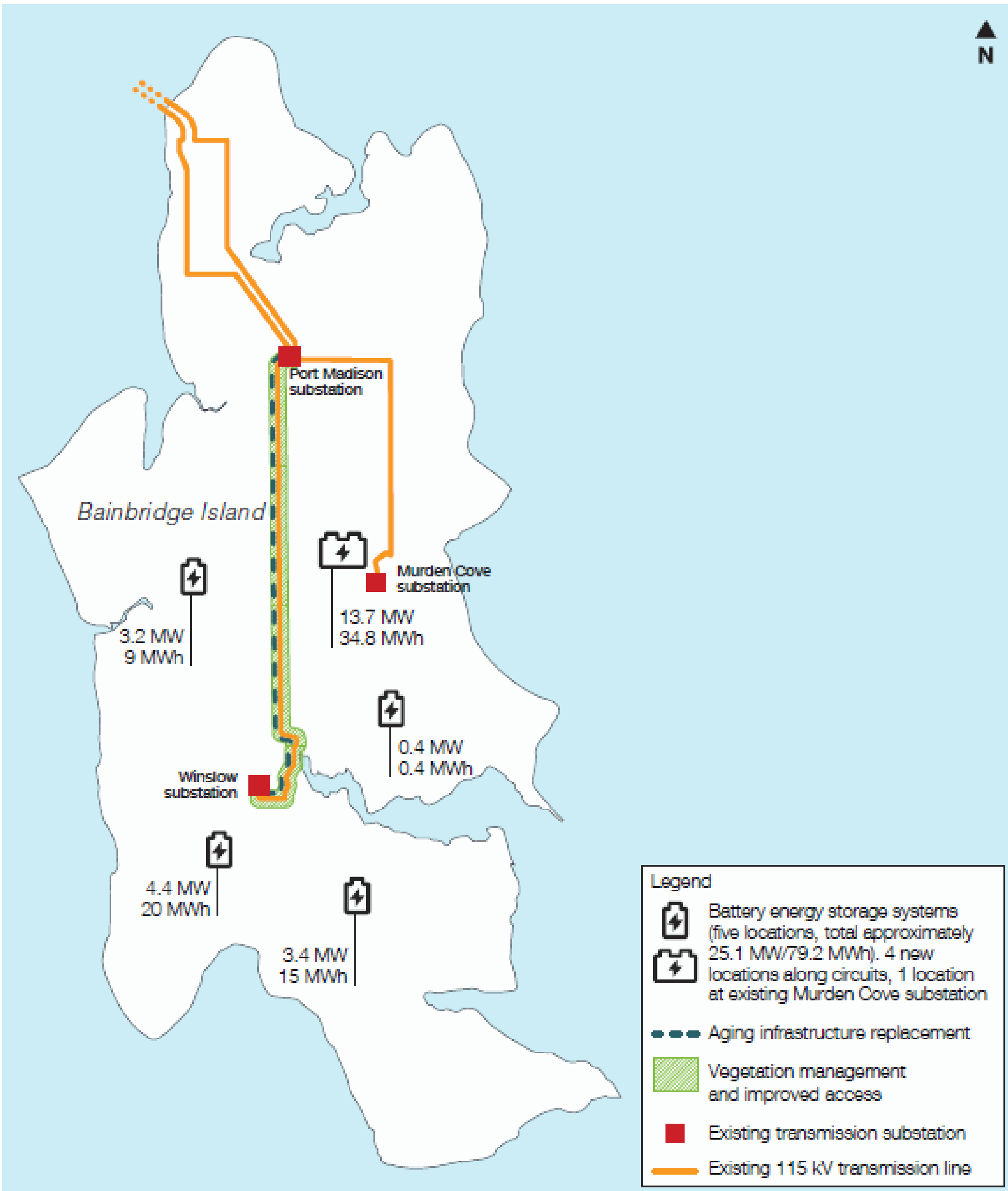
[26] Appendix D, Bainbridge Island Non-Wires Alternative Analysis, Navigant Consulting, page 1

Table 3-1: Battery Sizes and Locations

Location	Battery Storage System Size
Circuit WIN-13	4.4 MW/20 MWH
Circuit MUR-17/WIN-15	3.4 MW/15 MWH
Circuit PMA-13/WIN-12	3.2 MW/9 MWH
Circuit MUR-15	0.4 MW/0.4 MWH
Murden Cove Distribution Substation	13.7 MW/34.8 MWH
Total	**25.1 MW/79.2 MWH**

Top Non-wires Alternative (all-battery)

Battery energy storage system, aging infrastructure replacement
and vegetation management



NOTE: Locations of potential infrastructure to be determined.
Map elements are not to scale and locations are approximate.

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Figure 3-2: All BESS Alternative

3.4 Top Hybrid Alternative

Upon noting the high cost and challenges of a full non-wires alternative, PSE asked Navigant to consider the potential hybrid alternatives that would include both traditional wires components and other needs met through NWAs. The review of key system elements was made in the "Decision Tree" discussed in the previous section and shown in Figure 2 of Appendix D with a detailed explanation of their analysis procedure noted in Section 3.3.1 of this report.

Navigant's analysis concluded that an exclusively non-wire alternative was impractical for solving the island's needs; however, a combination of non-wires and traditional components could. Their analysis indicated potential to meet capacity needs for the distribution component of the alternative. Navigant recommended connecting the ferry as an interruptible load, as previously discussed in Section 3.3.1. More detailed analysis focused on identifying the potential of DERs to address the remaining distribution capacity needs.

The method that Navigant used for determining the achievable technical potential to meet these distribution capacity needs was to consider the incremental potential available beyond the "business as-usual" procurement that PSE already does for demand-side resources (with discussion of this incremental potential analysis in Section 2.1 of Appendix D). **"**To include storage and other DERs into a single optimal portfolio, Navigant developed a levelized cost of capacity (LCOC) calculation. This allows comparison of resources based on the present value of the net costs for providing local capacity deferral."[27] This method is detailed in Section 3 of Appendix D.

The results of this technical potential and economic analysis concluded that:

- A "NWA portfolio including energy efficiency (EE), [battery] storage, renewable distributed generation (DG), and the option of demand response (DR), has the potential to cost-effectively defer the wired alternative until 2030 given current load forecasts."[28] The portion of the wires alternative that could be deferred is the distribution substation.
- Navigant recommended sizing the storage to meet 50% of the capacity needs in 2030 with their analysis indicating that "a 3.3 MW, 5 MWh battery would provide sufficient flexibility for PSE to study and pilot targeted DR and EE programs to meet the other 3.3 MW of need before DSM resources become absolutely necessary to meet the need"[29].

Based on power flow analysis completed in the Quanta report (Section 6.1.2 of Appendix E), PSE has assessed that the likely most appropriate location for this 3.3 MW battery is Murden Cove substation.

In order to confirm the size and resource mix noted above, Navigant recommended launching a pre-implementation NWA analysis to validate the DSM portion of the results. For the storage portion of the alternative, these results help to provide an indicative value of storage for consideration in planning. PSE is undertaking the suggested validation of the DSM portion of the results, and based on the results of that investigation the size of the approximately 3.3MW/5MWh could adjust so that between the battery and the DSM portion of the alternative the entire 6.6 MW capacity need is met.

[27] Appendix D, Bainbridge Island Non-Wires Alternative Analysis, Navigant Consulting, page 21

[28] Appendix D, Bainbridge Island Non-Wires Alternative Analysis, Navigant Consulting, page 3

[29] Appendix D, Bainbridge Island Non-Wires Alternative Analysis, Navigant Consulting, page 4

In conclusion, Navigant's recommended hybrid alternative includes the following features:

- Addresses reliability with a conventional transmission "loop" to connect substations. A new overhead transmission line between Murden Cove and Winslow substations would ensure each substation will be connected to two transmission lines. If one line goes out, the other line will still feed the substation and provide power to customers.
    - Targeted vegetation management supplements the transmission reliability benefits that the transmission loop provides.
- Addresses distribution capacity through a three-pronged non-wires alternative approach, which defers the wires alternative of a distribution substation until at least 2030.
    - Connecting the new ferry electrification charging load (10 MW) as a curtailable resource.
    - A NWA portfolio including energy efficiency, energy storage, renewable distributed generation, and the option of demand response.
    - A battery sized to meet 50 percent of the capacity needs in 2030. "Navigant's analysis indicates that an approximately 3.3 MW / 5 MWh battery would provide sufficient flexibility for PSE to study and pilot targeted DR and EE programs to meet the other 3.3 MW of need before these demand side management (DSM) resources become absolutely necessary to meet the need."[30]
- Addresses aging infrastructure need for the Winslow Tap transmission line by rebuilding the line. PSE's plan for this is discussed in Appendix C.

All of the potential hybrid alternatives that arose from the analysis in Navigant's report are presented in Appendix A with descriptions of why the other considered alternatives are not the top hybrid alternative.

[30] Appendix D, Bainbridge Island Non-Wires Alternative Analysis, Navigant Consulting, page 4

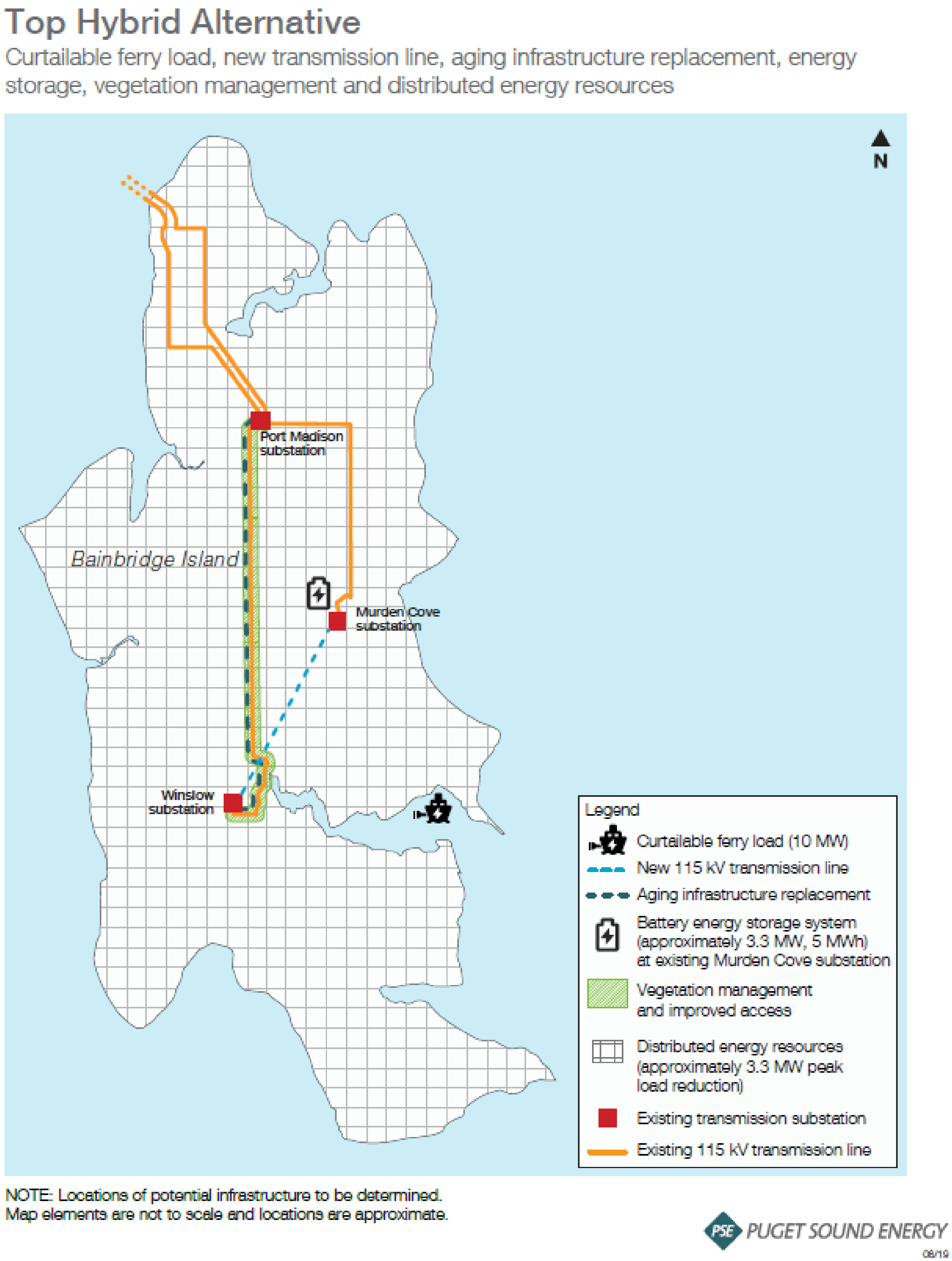

Figure 3-3: Top Hybrid Alternative

3.5 Top Alternatives Comparison

The top wires, non-wires, and hybrid alternatives were described in Section 3. The key aspects of each of these alternatives are shown below in Table 3. In addition, the project costs for each potential alternative are noted and include a 25% cost estimating contingency. The hybrid and full wires alternative are closer in cost, but the all battery energy storage system (BESS) alternative is significantly more expensive. The potential benefits, drawbacks and risks of each alternative are discussed following the summary table.

Table 3-2 Summary of Top Alternatives and Costs[31] [32] [33] [34]

	Top Wires Alternative	Top Non-Wires Alternative (All BESS)	Top Hybrid Alternative
Primary Need: Winslow Tap Transmission Reliability	Transmission Loop (Winslow to Murden Cove)	TOTAL BESS: 25.1 MW/79.2 MWH MUR: 13.7 MW/34.8 MWH MUR-15: 0.4 MW/0.4 MWH, PMA-13/WIN-12: 3.2 MW/9 MWH, MUR-17/WIN-15: 3.4 MW/15 MWH WIN-13: 4.4 MW/20 MWH	Transmission Loop (Winslow to Murden Cove)
Primary Need: Substation Group Capacity	New Distribution Substation		Ferry Curtailment: 10 MW up to 182 hours 50% BESS@MUR: 3.3 MW/5 MWH 50% DER: 3.3 MW
Primary Need: Winslow Tap Aging Infrastructure	Rebuild Transmission Line-Replace Poles & Wire, Improve Corridor Access, Acquire Necessary Rights & Veg Mgmt	Rebuild Transmission Line-Replace Poles & Wire, Improve Corridor Access, Acquire Necessary Rights & Veg Mgmt	Rebuild Transmission Line-Replace Poles & Wire, Improve Corridor Access, Acquire Necessary Rights & Veg Mgmt
Total Cost Estimate Range (Base to High)	$42.5 million to $85 million	$66 million to $132 million	$38 million to $76 million
Decision Factors	- Expertise - Long term solution - High reliability	- 10 year solution - Add with growth - New operational strategies needed - High cost	- 10 year solution - Add with growth - New operational strategies needed - Local EE and DR

[31] Costs are estimate based on similar past projects in other areas of PSE service territory. Does not include site-specific engineering.

[32] The costs shown for the wires portions of all alternatives are capital investment costs.

[33] Costs shown for battery storage systems in Top Non-Wires Alternative (all-BESS) are from the Quanta Technology Report, Appendix E, Table 7.1, Storage-Only Solution (Option), Total Capital Investment cost ($37.7M). A 25% cost estimating contingency is added to the cost in that report to be consistent with how other costs in this table are shown. The capital investment cost is shown to be consistent with the presentation of the wires alternative.

[34] Costs shown for Top Hybrid Alternative, Primary Need: Substation Group Capacity are from the Navigant Consulting Report, Appendix D, page 24 which notes a portfolio cost between $4.5M (including DR) and $5.5M (excluding DR). The higher portfolio cost of $5.5M is used here to remain conservative. A 25% cost estimating contingency is added to the cost in that report to be consistent with how other costs in this table are shown. The costs and benefits for the measures of this portfolio are from the 2017 IRP. These costs and benefits are in present value terms and are levelized to be consistent with the 2017 IRP. Further discussion of this is in Appendix D, Section 3.1.

3.5.1 Decision Factors - Wires Alternative

When considering the top wires alternative, there are clear benefits and potential drawbacks and risk.

A clear benefit is that the option presents a longer term alternative as typical wires infrastructure is in service for 30 plus years. The wires alternative has an advantage that PSE has strong expertise and experience in building wires solutions to address its electrical system needs.

A drawback is that the alternative is more capital intensive upfront and requires the building of a new substation that the hybrid alternative does not require. A risk of building this longer-term alternative is possibly over-building capacity. Bainbridge Island needs 6.6 MW[35] of capacity, while a substation would add 33 MVA (winter) of distribution capacity which exceeds what is needed.

3.5.2 Decision Factors - Non-wires and Hybrid Alternatives

The full non-wires or hybrid alternatives have some benefits, drawbacks, and risks that are similar between them.

As a benefit, both alternatives allow for deferral of the distribution substation. However, both alternatives involve some non-wires elements that are scoped to be a 10 year solution. The lifespan for non-wires elements that is shorter than typical wired alternative can be seen as both a drawback (perhaps PSE needs to do additional work after 10 years) but potentially a risk-laden benefit (maybe PSE does not need the substation at 10 years and so constructing it may be over-building). Rather than the potential for over-building, PSE can instead add with growth as it occurs.

As discussed in Section 3.3, the full non-wires alternative was deemed not reasonable by both consultants (Navigant and Quanta) that performed analysis in the area as well as by PSE. Navigant's review noted that this alternative would be "technically possible but not realistic".[36] More specifically they note that, "considering the likely need for significant additional electric storage at various locations on the island (at considerable cost), the need for aggressive tree-trimming and vegetation management (counter to community values on Bainbridge Island), and the roll-out timeframe necessary to meet the full set of defined needs with an exclusively NWA solution, Navigant does not think such a solution could be realistically achieved."[37] Navigant further elaborates on this considerable cost as "to provide similar levels of operational flexibility and reliability as the traditional solution, additional batteries would be needed to provide grid support for four to eight hours. These batteries would be needed in addition to the batteries and other measures needed to meet the growing capacity needs. Navigant estimated that the costs for these additional batteries would be considerably more than the costs of the traditional solution related to grid flexibility and reliability."[37]

Quanta's analysis indicates that five batteries would be required and would be distributed throughout Bainbridge Island along circuits and at a substation. While one battery could be located at substation property, locations for the four other batteries would need to be determined around the island. The cost of this is estimated to be at least $20 million more than the traditional wires alternative. Quanta did not include interconnection costs in their estimates, however PSE has included a very conservative interconnection cost estimate (included in Table 3-2). Given that these are conservative estimates it is

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[35] Per Navigant Bainbridge Island assessment, Bainbridge Island has distribution capacity need of 6.6 MW with the addition of electric ferry service as a curtailable load.

[36] Appendix B, Bainbridge Island Non-Wires Alternative Analysis, Navigant Consulting, page 2

[37] Appendix B, Bainbridge Island Non-Wires Alternative Analysis, Navigant Consulting, page 11

reasonable that the differential between the wires alternative and the all-battery storage alternative that Quanta developed would only increase. Additionally, locations of the potential battery storage sites were not considered, but if additional land is needed to be purchased this would only increase the differential between the wires alternative and the all-battery storage alternative that Quanta developed. This eliminates the consideration of the full non-wires alternative and narrows the alternative possibilities down to the proposed wires alternative and hybrid alternative.

As displayed in Table 3-2, the hybrid alternative presents the opportunity to adapt and operate new technologies – energy storage and DERs – to meet electric system needs. It is consistent with both our customers' expectations to lead us into the future and the Washington Utilities and Transportation Commission policy statement of October 2017 (Docket UE-151069 and U-161024). In addition, adopting this new technology allows us to gain further operational experience in energy storage and DERs. Incorporating the transmission loop as part of the alternative enables future technologies by providing a reliable transmission backbone which is important for customers to be able to enjoy the benefits of enabling more flexible grid technologies (such as distribution automation). It also provides some cost savings as compared to the wires alternative.

Given these reasons, the top hybrid alternative incorporating traditional wired investment for the transmission needs and a combination of energy storage and DERs for distribution capacity needs is PSE's proposed solution.

4 Proposed Solution

The top alternatives were presented in Section 3. Other alternatives that were considered are presented in Appendix A.

Based on the alternatives analysis, the proposed solution is the top hybrid alternative that is shown in Figure 3-3. The hybrid alternative:

- Invests in traditional transmission infrastructure to replace aging equipment and improve reliability.
- Deploys battery storage and DERs to support the island's electric load growth and ferry electrification without the need for additional substation infrastructure.
- Adds a transmission loop that improves reliability and supports future technologies.
- Provides cost savings as compared to the conventional wires alternative.

<u>The primary needs being addressed and the components of the proposed hybrid solution are:</u>

- Improves transmission and distribution reliability by building approximately 3.5 miles of new overhead transmission line between Murden Cove and Winslow substations that will create a transmission "loop". The loop will also improve operating flexibility on the transmission system to both Winslow and Murden Cove substations.
- Addresses the aging infrastructure need for the Winslow Tap transmission line by rebuilding the line and improving the corridor for maintainability and operability of the line.
- Address Bainbridge Island's distribution capacity need by:
    - Connecting the new ferry electrification charging load (10 MW) as a curtailable resource.
    - Installing an approximately 3.3 MW/5 MWh battery storage system (planned for Murden Cove substation)
    - Implementing an approximately 3.3 MW DER portfolio on Bainbridge Island, with customer-side resources such as energy efficiency, renewable distributed generation, and the potential for demand response.

Appendix A Alternatives Considered

Appendix A summarizes the alternatives considered while developing the preferred solution. An alternative is considered viable if it meets all system needs and the solutions criteria; otherwise it is deemed non-viable and eliminated from further consideration.

The following table format is utilized in this section to describe the alternatives considered, and the determination of viability of these alternatives.

NAME STATUS	SCOPE SUMMARY	DECISION FACTORS (N) Indicates criteria not met but could be met with cost sharing (X) Indicates criteria not met (Y) Indicates criteria met	

NAME – Name of Alternative

STATUS – Viable or Eliminated

SCOPE SUMMARY – High level description of scope of alternative considered

DECISION FACTORS – N, X or Y (as described above)

Wires Alternatives w/o Transmission Loop (No Loop (NL))

This section describes the wires alternatives that do not include a transmission loop between Murden Cove and Winslow Substations as part of the alternative, referred to as the No Loop (NL) alternatives.

Table A-1: Alternative Comparison: No Loop Wires Alternatives

NAME STATUS	SCOPE SUMMARY	DECISION FACTORS	
NL-1 ELIMINATED	Winslow Tap rebuild with widened transmission corridor	Meets all technical criteria • Does not meet PSE Transmission Planning guideline with load levels exceeding recommended limit of 15-20 MW for radial lines – Winslow Tap and Murden Cove Tap • Does not add needed substation capacity Feasible permitting Reasonable project cost Uses proven technology Constructible within reasonable timeframe	X Y Y Y Y
NL-2 ELIMINATED	Install new substation and Winslow Tap rebuild with widened transmission corridor	Meets all technical criteria • Does not meet PSE Transmission Planning guideline with load levels exceeding recommended limit of 15-20 MW for radial lines – Winslow Tap and Murden Cove Tap • Does not meet PSE Transmission Planning guideline with more than 1 distribution transformer on a radial line Feasible permitting Reasonable project cost Uses proven technology Constructible within reasonable timeframe	X Y Y Y Y

NAME STATUS	SCOPE SUMMARY	DECISION FACTORS	
NL-3 ELIMINATED	Double bank Winslow sub and Winslow Tap rebuild with widened transmission corridor	Meets all technical criteria • Does not meet PSE Transmission Planning guideline with more than 1 distribution transformer on a radial line Feasible permitting Reasonable project cost Uses proven technology Constructible within reasonable timeframe	X Y Y Y Y
NL-4 ELIMINATED	Double bank Murden Cove sub and Winslow Tap rebuild with widened transmission corridor	Meets all technical criteria • Does not meet PSE Transmission Planning guideline with more than 1 distribution transformer on a radial line Feasible permitting Reasonable project cost Uses proven technology Constructible within reasonable timeframe	X Y Y Y Y
NL-5 ELIMINATED	Add a 115 kV line underground from Port Madison to loop Winslow, double bank Winslow and Winslow Tap rebuild	Meets all technical criteria Feasible permitting Reasonable project cost • Underground transmission cost is much greater than overhead option • Would require community cost sharing[38] Uses proven technology Constructible within reasonable timeframe	Y Y N Y Y
NL-6 ELIMINATED	Underground portions of existing Winslow 115 kV tap (in areas of heavy vegetation)	Meets all technical criteria • Does not meet PSE Transmission Planning guideline with load levels exceeding recommended limit of 15-20 MW for radial lines – Winslow Tap and Murden Cove Tap • Does not add needed substation capacity Feasibility of permitting Reasonable project cost • Would require community cost sharing Uses proven technology Constructible within reasonable timeframe	X N N Y Y

[38] Because there is a technically viable overhead transmission line route, PSE will not consider an underground option as viable overall. However, that does not eliminate underground transmission lines as an option **if** the community is interested and willing to invest in undergrounding the transmission lines pursuant to Schedule 80. State regulations require PSE to first consider building overhead transmission lines because of their combination of reliability and affordability, both of which are important to our customers.

NAME STATUS	SCOPE SUMMARY	DECISION FACTORS	
NL-7 ELIMINATED	Replace existing 25 MVA transformers at Murden Cove and Winslow subs with 40 MVA transformers and vegetation management with Winslow Tap rebuild	Meets all technical criteria • Does not meet PSE Transmission Planning guideline with load levels exceeding recommended limit of 15-20 MW for radial lines – Winslow Tap and Murden Cove Tap • Does not meet PSE standard equipment requirement Feasibility of permitting Reasonable project cost Uses proven technology Constructible within reasonable timeframe	X Y Y Y Y
NL-8 ELIMINATED	Submarine 115 kV, and new overhead 115 kV line on either side of water, double bank Winslow sub and vegetation management with Winslow Tap rebuild	Meets all technical criteria Feasibility of permitting Reasonable project cost Uses proven technology Constructible within reasonable timeframe	Y X X Y X

Wires Alternatives w/ Transmission Loop (With Loop (WL))

This section describes the wires alternatives that include a transmission loop as part of the alternative referred to as With Loop (WL) alternatives.

Table A-2: Alternative Comparison: With Loop Wires Alternatives

NAME STATUS	SCOPE SUMMARY	DECISION FACTORS	
WL-1 VIABLE	New substation and looped overhead transmission line (Winslow to Murden Cove) and Winslow Tap rebuild	Meets all technical criteria Feasibility of permitting Reasonable project cost Uses proven technology Constructible within reasonable timeframe	Y Y Y Y Y
WL-2 VIABLE	Looped overhead transmission line (Winslow to Murden Cove), double bank Winslow sub and Winslow Tap rebuild	Meets all technical criteria Feasibility of permitting Reasonable of project cost Uses proven technology Constructible within reasonable timeframe	Y Y Y Y Y
WL-3 VIABLE	Looped overhead transmission line (Winslow to Murden Cove), double bank Murden Cove sub and Winslow Tap rebuild	Meets all technical criteria Feasibility of permitting Reasonable project cost Uses proven technology Constructible within reasonable timeframe	Y Y Y Y Y
WL-4 ELIMINATED	Looped overhead transmission line (Winslow to Murden Cove), replace existing 25 MVA transformers with 40 MVA transformers and Winslow Tap rebuild	Meets all technical criteria • Does not use PSE standard equipment Feasibility of permitting Reasonable project cost Uses proven technology Constructible within reasonable timeframe	X Y Y Y Y

NAME STATUS	SCOPE SUMMARY	DECISION FACTORS	
WLU-1, WLU-2, WLU-3 ELIMINATED	Same alternatives as WL-1 through WL-3 except transmission loop is underground	Meets all technical criteria Feasibility of permitting Reasonable project cost • Would require community cost sharing Uses proven technology Constructible within reasonable timeframe	Y Y N Y Y
WLU-4 ELIMINATED	Same alternatives as WL-4 except transmission loop is underground	Meets all technical criteria • Does not use PSE standard equipment Feasibility of permitting Reasonable project cost • Would require community cost sharing Uses proven technology Constructible within reasonable timeframe	X Y N Y Y
WL-5 ELIMINATED	Loop overhead transmission line (Winslow to Murden Cove) and Winslow Tap rebuild	Meets all technical criteria • Does not add needed substation capacity Feasibility of permitting Reasonable project cost Uses proven technology Constructible within reasonable timeframe	X Y Y Y Y
WLU-5 ELIMINATED	Same alternative as WL-5 except transmission loop is underground	Meets all technical criteria • Does not add needed substation capacity Feasibility of permitting Reasonable project cost • Would require community cost sharing Uses proven technology Constructible within reasonable timeframe	X Y N Y Y
WL-6 ELIMINATED	Submarine 115kV cable and new overhead 115 kV transmission lines on either side of water, with looped transmission line, double bank Winslow sub and Winslow Tap rebuild	Meets all technical criteria Feasibility of permitting Reasonable project cost Uses proven technology Constructible within reasonable timeframe	Y X X Y X

Table A-3: Viable Alternatives Comparison: With Loop (WL) Wires Alternatives[39 40]

	Alternative WL-1	Alternative WL-2	Alternative WL-3
	Scope	**Scope**	**Scope**
Primary Need: Winslow Tap Transmission Reliability	Transmission Loop (Winslow to Murden Cove)	Transmission Loop (Winslow to Murden Cove)	Transmission Loop (Winslow to Murden Cove)
Primary Need: Substation Group Capacity	New Distribution Substation	Double Bank- Winslow	Double Bank - Murden Cove
Primary Need: Winslow Tap Aging Infrastructure	Rebuild Transmission Line- Replace Poles & Wire, Improve Corridor Access, Acquire Necessary Rights & Veg Mgmt	Rebuild Transmission Line- Replace Poles & Wire, Improve Corridor Access, Acquire Necessary Rights & Veg Mgmt	Rebuild Transmission Line- Replace Poles & Wire, Improve Corridor Access, Acquire Necessary Rights & Veg Mgmt
Additional Costs - Land (ROW, Property)	Sub. property available, 25 FT wide ROW for loop	25 FT wide ROW for loop	25 FT wide ROW for loop
Total Cost Estimate Range (Base to High)	$42.5 million to $85 million	$42.5 million to $85 million	$40.2 million to $80.4 million
Decision factors	-Long term solution (20-30 years) -Ferry load may not need to be curtailed -High Cost	-Long term solution (20-30 years) -Ferry load may not need to be curtailed -High Cost	-Long term solution (20-30 years) -Ferry load may not need to be curtailed -High Cost

[39] Costs are estimate based on similar past projects in other areas of PSE service territory. Does not include site-specific engineering.

[40] The costs shown for the wires portions of all alternatives are capital investment costs.

All-Battery Alternatives (AB)

This section describes an all-battery alternative.

Table A-4: Alternative Comparison: All-Battery Alternative

NAME STATUS	SCOPE SUMMARY	DECISION FACTORS	
AB-1 ELIMINATED	Total BESS size: 25.1 MW/79.2 MWH Murden Cove Sub: 13.7 MW/34.8 MWH Circuit MUR-15: 0.4 MW/0.4 MWH Circuit PMA-13/WIN-12: 3.2 MW/9 MWH Circuit MUR-17/WIN-15: 3.4 MW/15 MWH WIN-13: 4.4 MW/20 MWH	Meets all technical criteria Feasibility of permitting Reasonable project cost Uses proven technology Constructible within required timeframe	Y Y X X Y

Hybrid Alternatives (HA)

This section describes hybrid alternatives which are a combination of wires and non-wires alternatives.

Table A-5: Alternative Comparison: Hybrid Alternatives

NAME STATUS	SCOPE SUMMARY	DECISION FACTORS	
HA-1 VIABLE	Looped overhead transmission line (Winslow to Murden Cove), 3.3 MW battery at Murden Cove sub, 3.3 MWs distributed energy resources (DERs), connect new ferry electrification load (10 MW) as a curtailable resource, and Winslow Tap rebuild	Meets all technical criteria Feasibility of permitting Reasonable project cost Uses proven technology Constructible within required timeframe	Y Y Y Y Y
HA-2 VIABLE	Looped overhead transmission line (Winslow to Murden Cove), 6.6 MW battery at Murden Cove sub, connect new ferry electrification load (10 MW) as a curtailable resource, and Winslow Tap rebuild	Meets all technical criteria Feasibility of permitting Reasonable of project cost Uses proven technology Constructible within required timeframe	Y Y Y Y Y
HA-3 ELIMINATED	Winslow Tap rebuild with widened transmission corridor, 6.6 MW battery at Murden Cove sub, and connect new ferry electrification load (10 MW) as a curtailable resource	Meets all technical criteria • Does not meet PSE Transmission Planning guideline with load levels exceeding recommended limit of 15-20 MW for radial lines – Winslow Tap and Murden Cove Tap Feasibility of permitting Reasonable project cost Uses proven technology Constructible within required timeframe	X X Y Y X

NAME STATUS	SCOPE SUMMARY	DECISION FACTORS	
HA-4 ELIMINATED	Winslow Tap rebuild with widened transmission corridor, 3.3 MWs distributed energy resources (DERs), and 3.3 MW battery at Murden Cove sub, and connect new ferry electrification load (10 MW) as a curtailable resource	Meets all technical criteria • Does not meet PSE Transmission Planning guideline with load levels exceeding recommended limit of 15-20 MW for radial lines – Winslow Tap and Murden Cove Tap Feasibility of permitting Reasonable project cost Uses proven technology Constructible within required timeframe	X X Y Y X

Table A-6: Viable Alternative Comparison: Hybrid Alternatives[41] [42]

	Alternative HA-1	Alternative HA-2
	Scope	**Scope**
Primary Need: Winslow Tap Transmission Reliability	Transmission Loop (Winslow to Murden Cove)	Transmission Loop (Winslow to Murden Cove)
Primary Need: Substation Group Capacity	Ferry Curtailment: 10MW up to 182 hours 50% BESS@MUR: 3.3 MW/5 MWH 50% DER: 3.3MW	Ferry Curtailment: 10MW up to 182 hours 100% BESS@MUR: 6.6 MW/12.9 MWH
Primary Need: Winslow Tap Aging Infrastructure	Rebuild Transmission Line-Replace Poles & Wire, Improve Corridor Access, Acquire Necessary Rights & Veg Mgmt	Rebuild Transmission Line-Replace Poles & Wire, Improve Corridor Access, Acquire Necessary Rights & Veg Mgmt
Total Cost Estimate Range (Base to High)	$38.1 million to $76.2 million	$41.8 million to $83.6 million
Decision factors	- 10 year solution - Add with growth - New operational strategies needed - Local EE and DR	- 10 year solution - Add with growth - New operational strategies needed

[41] Costs are estimate based on similar past projects in other areas of PSE service territory. Does not include site-specific engineering.

[42] The costs shown for the wires portions of all alternatives are capital investment costs.

Appendix B Addressing Transmission Reliability Need

This section describes PSE's recommended approach to address the Bainbridge Island transmission reliability need, specifically the Winslow Tap transmission outages, by building a new transmission line (loop) that connects Winslow and Murden Cove substations. This section describes the looped transmission configuration for Bainbridge Island and its benefits in greater detail.

As described in the Bainbridge Island Electric System Needs Assessment report, 47% (or nearly 50%) of outage minutes on Bainbridge were caused by transmission outages. A significant proportion (70%) of the transmission outages were on the Winslow Tap transmission line. The Winslow Tap is a 4.5 mile radial[43] transmission line from Port Madison substation to Winslow substation.

Key observations regarding Winslow Tap transmission outages over the 5 year period between 2013 and 2017:

- Outages are long (from 1-2 hours to 13 hours per year)
- Outages are frequent (from 1 to 5 outages per year)
- During storms, reliability is worse

Reasons for poor reliability of the Winslow Tap:

- Heavy vegetation along Winslow Tap
- Difficult terrain and poor access along the line[44]
- Limited distribution substation capacity for backup of Winslow substation

Figure B-1 shows an aerial map of the Winslow Tap transmission line outages over the 5 year period 2013-2017, and outlines the cross country section of line with difficult terrain and poor access. As shown in the figure, outages are spread across the entire line due to vegetation exposure on the entire line route.

[43] A radial transmission line has a single source. The Winslow Tap is a radial transmission line with source at Port Madison substation. A substation served by a radial transmission line loses power when there is an outage of the radial line. A looped transmission line has two sources. A substation served from a looped transmission line does not lose power on loss of one source, and can be served by the second source.

Figure B-1: Aerial Map of Winslow Tap Transmission Outages (2013-2017)

Applicable Transmission Planning Guidelines – Looped Transmission

PSE Transmission Planning Guidelines state *"a radial transmission line should only be used to serve a single bank substation when conditions are such that load can be picked up by surrounding substations through distribution switching to accommodate forced or planned outages. The load should be no more than 15 to 20 MW. The load should be mostly residential in rural areas where lines built along public rights-of-way…."*

PSE recommends a transmission system upgrade for Bainbridge Island in accordance with its Transmission Planning Guidelines, from the existing radial transmission lines to a looped transmission system by building a new transmission line (loop) connecting Winslow and Murden Cove substations.

The existing radial transmission lines to Winslow and Murden Cove substations do not meet PSE's Transmission Planning Guidelines for the following reasons:

- Peak load served from Winslow and Murden Cove substations has reached 24 MW and 28 MW respectively, which exceeds the planning guideline load threshold of 15 to 20 MW for radial transmission service.

- Both substations cannot be offloaded to surrounding substations for a forced or planned transmission outage (on radial line) during high loading in winter months.
- Per the guideline, radial transmission lines should serve mostly rural residential loads. Winslow and Murden Cove substations serve an urban customer base with significant commercial and industrial loads such as the Bainbridge Ferry terminal in downtown Winslow area.
- A significant portion (35 percent) of the Winslow Tap radial transmission line is not along public rights-of-way but on cross country corridor with poor access and difficult terrain that results in longer outage restoration time.

The transmission system upgrade will significantly improve transmission reliability on Bainbridge Island (notably for Winslow Substation) and provide operating flexibility for the transmission system on the island. A looped transmission system is recommended for the following reasons:

- The looped transmission system is routinely utilized by PSE to serve urban areas in other parts of its service territory and is a significant improvement in reliability over a radial transmission system.
- A looped transmission system provides transmission service for a substation in the event of loss of one of the two transmission sources for a substation, and provides operating flexibility on the transmission system to take out one transmission source for planned maintenance. The probability of both transmission sources going out concurrently is low, but possible.

Recommendation – Build Looped Transmission Configuration

The looped transmission alternative builds 3 to 3.5 miles of new transmission line connecting Winslow substation to Murden Cove substation and creates a transmission loop. Figure B-2 shows an electrical one line diagram comparing the existing radial transmission system on Bainbridge Island to a looped transmission system.

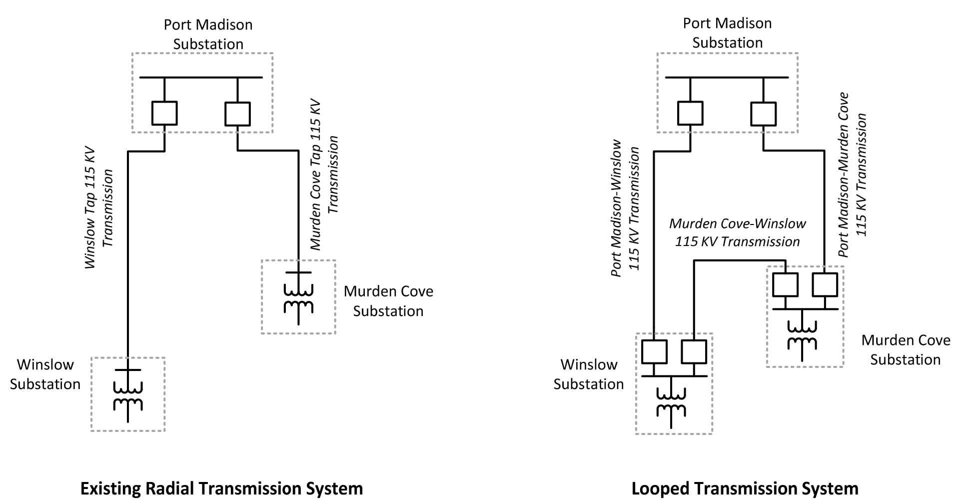


Figure B-2: Looped Transmission System Upgrade for Bainbridge Island

Benefits of a looped transmission system for Bainbridge Island:

- The looped transmission system will bring a second transmission source to Winslow substation besides the existing Winslow Tap. In this case, loss of the existing Winslow Tap will not cause outage to Winslow Substation, as it will remain energized from the second transmission source (new line from Murden Cove substation) and maintain service to Winslow customers.

- The looped transmission system provides reliable transmission service for both Winslow and Murden Cove Substations.
- The looped transmission system provides operating flexibility on the transmission system for planned transmission outages without impacting customers.
- PSE will plan good access for the new transmission line (loop) from Murden Cove Substation to Winslow Substation and therefore, this new line will be superior to the Winslow Tap in terms of access; and may be quickly put back in service if taken out by an unplanned outage.

Appendix C Addressing Transmission Aging Infrastructure Need

This section describes PSE's recommended approach to address Bainbridge Island's transmission aging infrastructure need, specifically for the Winslow Tap transmission line, by rebuilding the Winslow Tap transmission line in its existing corridor. This section describes the options analyzed and considerations in reaching the recommendation for the line rebuild.

The Winslow Tap transmission line was built in 1960 and constructed with wishbone type crossarm design. PSE considers the wishbone crossarms of 1960s-70s vintage a reliability risk because they have started to fail in other parts of PSE service territory. Because of these concerns, PSE contracted Osmose Utilities Services to conduct a field inspection on the Winslow Tap transmission line in January 2019.

Key findings of the Winslow Tap inspection were:

- Nearly 50% of the line crossarms (39 out of 79) were in "reject" condition
- All poles (except 1 out of 79) met PSE pole strength criteria

PSE inspects transmission lines on a 10 year cycle. The PSE transmission line inspection criterion considers equipment status of "reject" as failing but non-critical condition and requires replacement in 1 to 3 years. A "priority reject" is considered critical condition and requires emergency replacement in 1 to 3 months.

Options Analyzed

PSE considered different options to address the Winslow Tap aging infrastructure need, such as:

- Reframe poles (50% of line crossarms)
- Replace and reframe poles (50% of line poles and crossarms)
- Replace and reframe all poles and crossarms (100% of line poles and crossarms)
- Fully rebuild Winslow Tap by replacing poles, crossarms and line conductor

The analysis of these options required consideration to different factors such as cost effectiveness, asset life, engineering design and construction, and customer and environmental impact. These considerations are discussed below.

Cost effectiveness:

PSE determined that, although the wishbone crossarm is the failing element on the Winslow Tap, reframing an aged pole to replace a reject wishbone crossarm was not cost effective. This is because reframing a transmission pole requires much of the same rigor of permitting, engineering design, construction access, line shutdown, vegetation management, site restoration and customer outreach as would be needed for replacement of the pole and its attachments (crossarms, guys, insulators). The incremental cost of pole replacement was marginal and PSE considered full pole replacement a cost-effective measure to address a reject wishbone crossarm, and results in longer asset life.

Asset Life:

The 2019 Winslow Tap line inspection indicated that 50% of the line crossarms that were of wishbone construction design were in reject condition and nearing end of useful life. PSE pole replacement guidelines require replacement of pole equipment in reject condition within 3 years. PSE strongly believes that a greater number of poles and crossarms could be added to reject status and become new candidates for replacement by the next 10 year inspection cycle (2028). This is for the following reasons:

- Uniform age of equipment on the line (mostly 1960 vintage) and similar field conditions in the transmission corridor will likely lead to other equipment previously deemed to be in acceptable condition to start failing in a similar manner in the near term.
- PSE has seen a noticeable increase in the number of *reject* and *priority reject* poles on lines that are older than 60 years. Based on the age of Winslow Tap line (mostly 1960 vintage) and observed equipment failure data, it is likely that Winslow Tap non-reject poles and arms will deteriorate to reject or priority reject status by the next inspection cycle.
- The 2019 Winslow Tap inspection was a visual inspection of crossarms from ground level. There is possibility of additional wishbone crossarms with internal decay or decay unidentified due to limitations of a visual inspection, especially one from ground level.
- The wishbone crossarm is not a standard construction for PSE since the 1980s. A reject wishbone crossarm replacement to current PSE standard transmission framing can require a taller pole and potentially impact neighboring structures, leading to greater number of pole replacements.

PSE also believes that some poles may be in worse condition near the crossarm level than that reported from strength testing at ground level. Due to limited access and no corridor pathway to bring a bucket truck, most of Winslow Tap transmission poles need to be climbed by crew to work on the line. Given the age of these poles, the crew may find some of these aging poles unsafe to climb and require pole replacement.

PSE does not have an age criteria for line conductors, however some utility research publications recommend a mean useful life of 70 years for existing older ACSR[45] conductors for planning purposes. The Winslow Tap 4/0 ACSR conductor is 1960 vintage and will reach its expected useful life of 70 years after the 10 year planning horizon (in 2030).

Engineering design and construction

PSE determined that the engineering design and construction will be most efficient with a single stage full line rebuild. Replacing only the existing identified reject condition crossarms will be a short term measure and will not address replacement of remaining wishbone crossarms or other line equipment that are expected to fail in the near future. PSE believes that rebuilding the Winslow Tap in multiple phases will not be cost effective due to reworking multiple tasks in preparation of the upgrades – project management, customer outreach, project permitting, vegetation management, site restoration, coordinating line shutdowns and mobilizing crews to the corridor for construction.

[45] Aluminum conductor steel reinforced (ACSR) is a type of high strength stranded conductor with a central steel core surrounded with one or more layers of aluminum strands

Customer and Environmental Impact

PSE believes that multiple phases of construction to replace Winslow Tap aging infrastructure will not be favorable to customers and will have a greater impact to the environment. A single stage full rebuild of the Winslow Tap provides a comprehensive solution that will replace all aged infrastructure – poles, crossarms and conductors and extends life of Winslow Tap transmission line for the long term.

Recommendation

Based on the considerations discussed above, PSE recommends a complete rebuild of the Winslow Tap transmission line to replace all poles, structures and line conductor. This will address aging infrastructure need and provide enhanced reliability for customers. A high level scope for the improvements includes:

- Replace 100% of poles and structures on the line. Replace line conductor with bigger conductor.
- Review and acquire rights along the corridor as necessary to expand the Winslow Tap transmission corridor in the cross-country section to current PSE rights-of-way standard and clear vegetation on the corridor.
- Create a graveled access road along the transmission corridor in the cross country section to facilitate a patrol pathway.

Appendix D Navigant Consulting Report

See *Bainbridge Island Non-Wires Alternative Analysis,* Navigant Consulting, July 9, 2019.

Appendix E Quanta Technology Report

See *Energy Storage Planning to Support Bainbridge Island, Final Report,* Quanta Technology, April 23, 2019, Version 4.

Appendix F Glossary

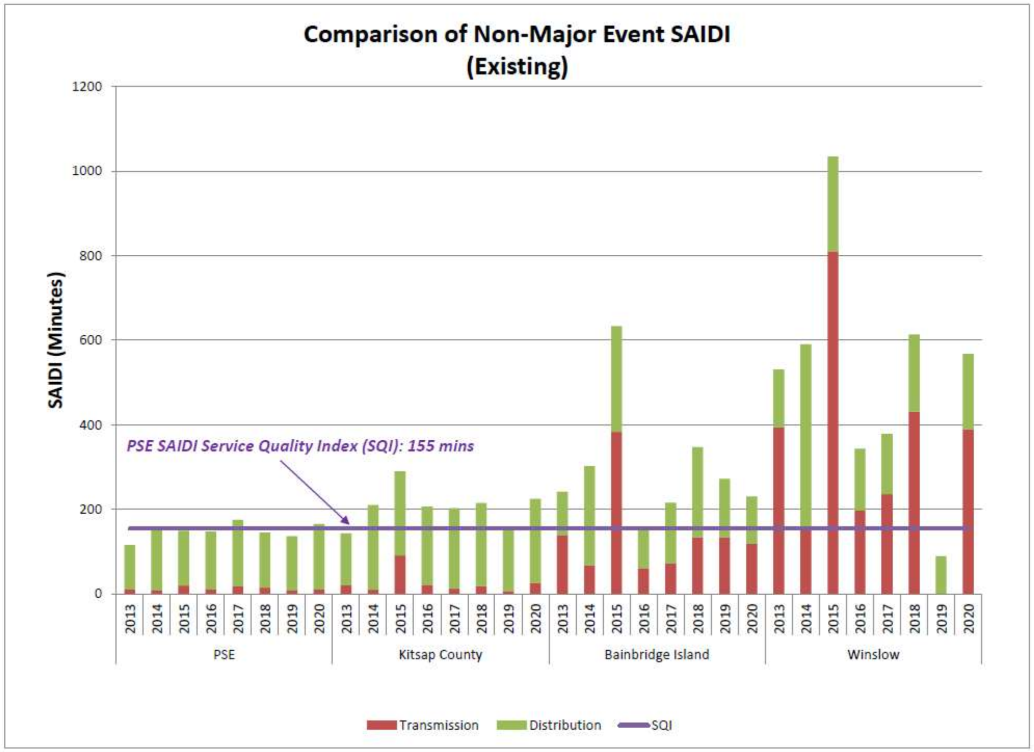
Term	Definition
Term	**Definition**
Block load	A large expected increase in electric energy demand from an existing or new customer.
Circuit	A circuit is the electric equipment associated with serving all customers under normal configuration from a specific distribution circuit breaker at a substation.
Concern	A “concern” is a non-critical issue that impacts system operations but is not required to be addressed by a solution; a solution that addresses an identified concern provides additional benefit.
Conservation	Measures to improve efficiency of customer’s electric loads reducing energy use and reducing peak demand.
Consumption	Consumption is the amount of electricity that customers use over the course of a year and it’s measured in kilowatt hours.
Contingency	Contingencies are a set of transmission system failure modes, when elements are taken out of service (e.g., loss of equipment).
Curtailable	A load that may be interrupted to reduce load on system during peak periods. Curtailable customers are on a different rate schedule than non-curtailable (firm) customers.
Demand	The amount of power being required by customers at any given moment, and it’s measured in kilowatts.
DR- Demand response	Flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility’s supply cost. Demand response is also the voluntary reduction of electricity demand during periods of peak electricity demand or high electricity prices. Demand response provides incentives to customers to temporarily lower their demand at a specific time in exchange for reduced energy costs.
Distributed generation	Small-scale electricity generators, like rooftop solar panels, located close to the source of the customer’s load.
Distribution line	A distribution line is a medium-voltage (12.5 kV-35 kV) line that carries electricity from a substation to customers. Roughly half of PSE's distribution lines are underground. Distribution voltage is stepped down to service voltage through smaller transformers located along distribution lines. Distribution lines differ from feeder as it includes the large feeder wire and smaller wire laterals.
Distribution System	A distribution system is the medium-voltage (12.5 kV-35 kV) infrastructure that carries electricity from a substation to customers and includes the substation transformer. System is the collective of all of this infrastructure in an entire study area.

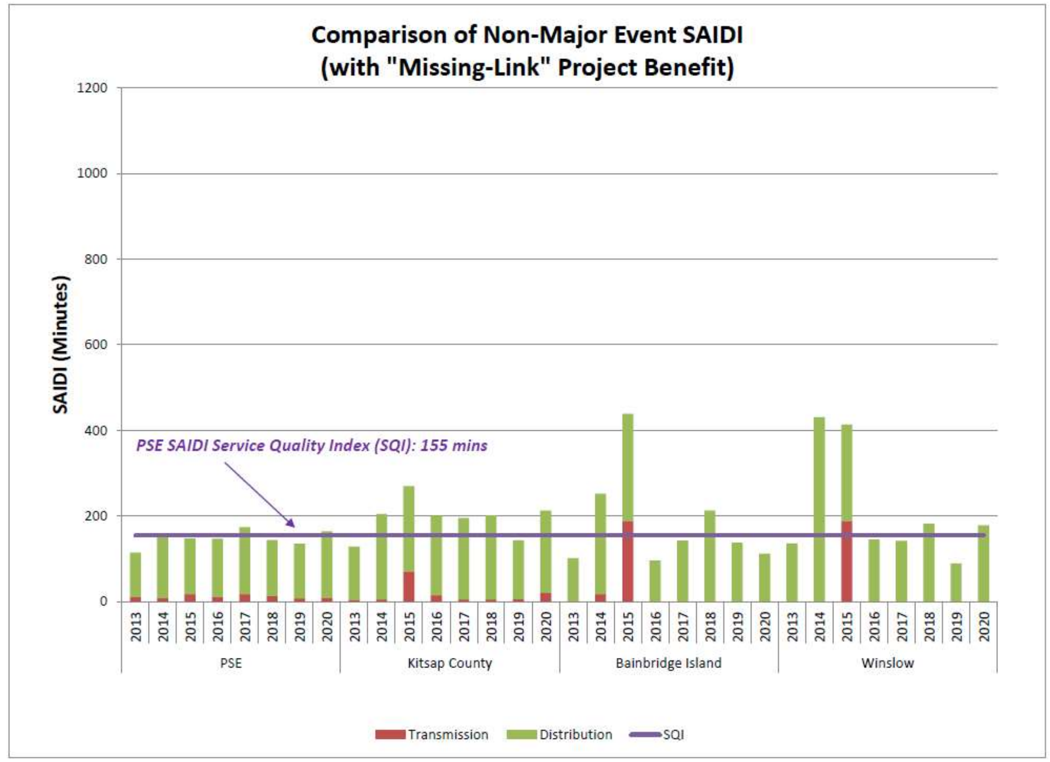
Term	Definition
EPRI- The Electric Power Research Institute	The Electric Power Research Institute conducts research, development, and demonstration projects for the benefit of the public in the United States and internationally. As an independent, nonprofit organization for public interest energy and environmental research, they focus on electricity generation, delivery, and use.
Feeder	A feeder is the largest conductor section of a circuit and generally
Institute of Electrical and Electronics Engineers (IEEE)	A professional association, promoting the development and application of electro-technology and allied sciences for the benefit of humanity, the advancement of the profession, and the well-being of our members.
Integrated Resource Plan (IRP)	The Integrated Resource Plan (IRP) is a forecast of conservation resources and supply-side resource additions that appear to be cost effective to meet the growing needs of our customers over the next 20 years. Every two years, utilities are required to update integrated resource plans to reflect changing needs and available information.
Interim Operating Plan (IOP)	A temporary plan to address a transmission system deficiency and meet performance requirements, until a solution takes effect. An IOP may consist of a series of operational steps to radially operate the system, run generation or implement load shedding.
Kilovolt (kV)	A kilovolt (kV) is equal to 1,000 volts of electric energy. PSE uses kilovolts as a standard measurement when discussing things like distribution lines and the energy that reaches our customers.
Load	The total of customer demand plus planning margins and operating reserve obligations.
Load forecast	A load forecast is a projection of how much power PSE's customers will use in future years. The forecast allows PSE to plan upgrades to its electric system to ensure that current and future customers continue to have reliable power. Federal regulations require that utilities plan a reliable system based on forecasted loads. When developing a load forecast, PSE takes multiple factors into account like current loads, economic and population projections, building permits, conservation goals, and weather events.
Load shedding	Load shedding is when a utility intentionally causes outages to customers because demand for electricity is exceeding the capacity of the electric grid. Load shedding is the option of last resort and is conducted to protect the integrity of the electric grid components in order to avoid a larger blackout. This is not a practice that PSE endorses as a long-term solution to meet mandatory performance requirements.
Major Event Day (MED)	Any day in which the daily system SAIDI exceeds the annual threshold value. Outages on those days are excluded from the SAIDI performance calculation.

Term	Definition
Megawatt (MW)	A megawatt (MW) is equal to 1,000,000 watts of electric energy. PSE uses megawatts as a standard measurement when discussing things like system load and peak demand. MW differs from MVA in that it is generally always lower and translates as energy that performs work. The amount of MW vs MVA is determined by load characteristics. Motor loads generally have a lower power factor (PF) than heating loads for example and as a result. MW=MVA*PF
Mega Volt-Amp (MVA)	A MVA is equal to 1,000,000 (Volt*Amps). MVA is generally slightly higher than MW. Equipment ratings are in MVA as the equipment heat rise is determined by actual MVA.
N-0	This is a planning term describing that the electric grid is operating in a normal condition and no components have failed.
N-1	This is a planning term describing an outage condition when one system component has failed or has been taken out of service for construction or maintenance.
N-1-1	This is a planning term describing outage conditions where two failures occur one after another with a time delay between them.
N-2	This is a planning term describing outage conditions where two failures occur nearly simultaneously.
Native Load Growth	Load growth associated with existing customers or new customers less than 1 MW.
Need	A constraint or limitation on the delivery system in providing safe and reliable electric supply to customers. A need is a "must-have" that is required to be addressed for the system in a timely manner (by a certain Need Date, as determined in a needs assessment)
Non-wires alternatives	Alternatives that are not traditional poles, wires and substations. These alternatives can include demand reduction technologies, battery energy storage systems, and distributed generation.
NERC- North American Electric Reliability Corporation	NERC establishes the reliability standards for the North American grid. NERC is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the bulk power system in North America, as certified by FERC. NERC develops and enforces Reliability Standards and annually assesses seasonal and long-term reliability. PSE is required to meet the Reliability Standards and is subject to fines if noncompliant.
Peak demand	Customers' highest demand for electricity at any given time, and it's measured in megawatts.
Proven technology	Technology that has successfully operated with acceptable performance and reliability within a set of predefined criteria. It has a documented track record for a defined environment, meaning there are multiple examples of installations with a history of reliable operations. Such documentation shall provide confidence in the technology from practical operations, with respect to the ability of the technology to meet the specified requirements.

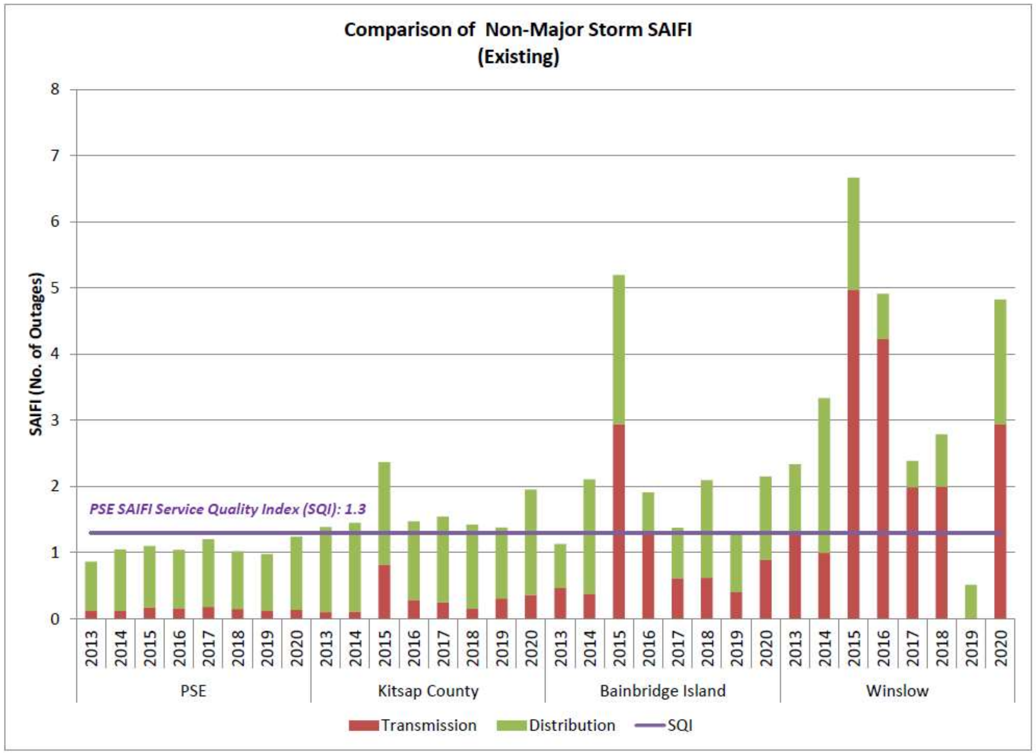
Term	Definition
Reasonable project cost	Reasonable project cost means holistically comparing costs and benefits to project alternatives. This includes dollar costs, as well as duration of the solution, risk to the electric system associated with the type of solution (e.g., is the solution an untested technology), and impacts to the community.
Right of way	A corridor of land on which electric lines may be located. PSE may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.
Sensitivities	Sensitivities are circumstances or stressors under which the contingencies are tested (e.g., forecasted demand levels, interchange, various generation configurations).
Substation	A substation is a vital component of electricity distribution systems, containing utility circuit protection, voltage regulation and equipment that steps down higher-voltage electricity to a lower voltage before reaching your home or business.
Substation group	A grouping of 2-5 substation transformers that are situated close enough to each other that loads in the study area can be switched from one station to an adjacent station for maintenance, construction, or permanent load shifting. For Bainbridge Island, the substation group includes 3 distribution substations – Port Madison, Murden Cove and Winslow.
Substation group capacity	The aggregate distribution transformer capacity of the substation group for winter and summer rating, calculated in MVA. Example: Winter/Summer ratings of distribution transformers at Port Madison (33 MVA/28 MVA), Murden Cove (33 MVA/28 MVA) and Winslow (33 MVA/28 MVA); Substation Group Capacity for Bainbridge Island (Winter/Summer): 99 MVA/84 MVA.
SAIDI- System Average Interruption Duration Index	SAIDI is the length of non-major-storm power outages per year, per customer. SAIDI is commonly used as a reliability indicator by electric power utilities. Outages longer than 5 minutes are included.
SAIFI- System Average Interruption Frequency Index	SAIFI is the frequency of non-major-storm power outages per year, per customer. SAIFI is commonly used as a reliability indicator by electric power utilities. Interruptions longer than 1 minute are included.
Transformer	A transformer is a device that steps electricity voltage down from a higher voltage, or steps it up to a higher voltage, depending on use. On the distribution system, transformers typically step the voltage down from a distribution voltage (12.5 kV) to 120 to 240 volts for customers' residential use. Transformers are the green boxes in some residences' front yard or the barrel-like canisters on utility poles.
Transmission line	Transmission lines are high-voltage lines that carry electricity from generation plants to substations or from substation to substation. Transformers at the substation "step down" the electricity's transmission voltage (55 to 230 kilovolts) to our primary distribution voltage (12.5 kV).

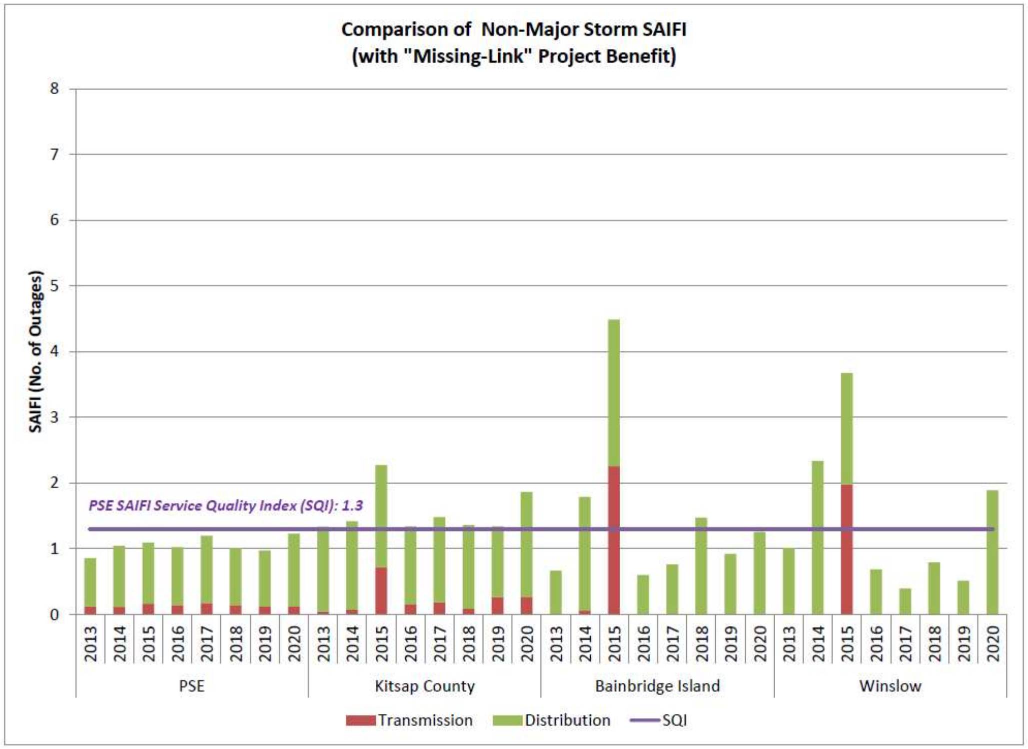
Appendix 4: SAIDI graphs with and without the "missing link"
See graphs below comparing Bainbridge to PSE's system and Kitsap County.



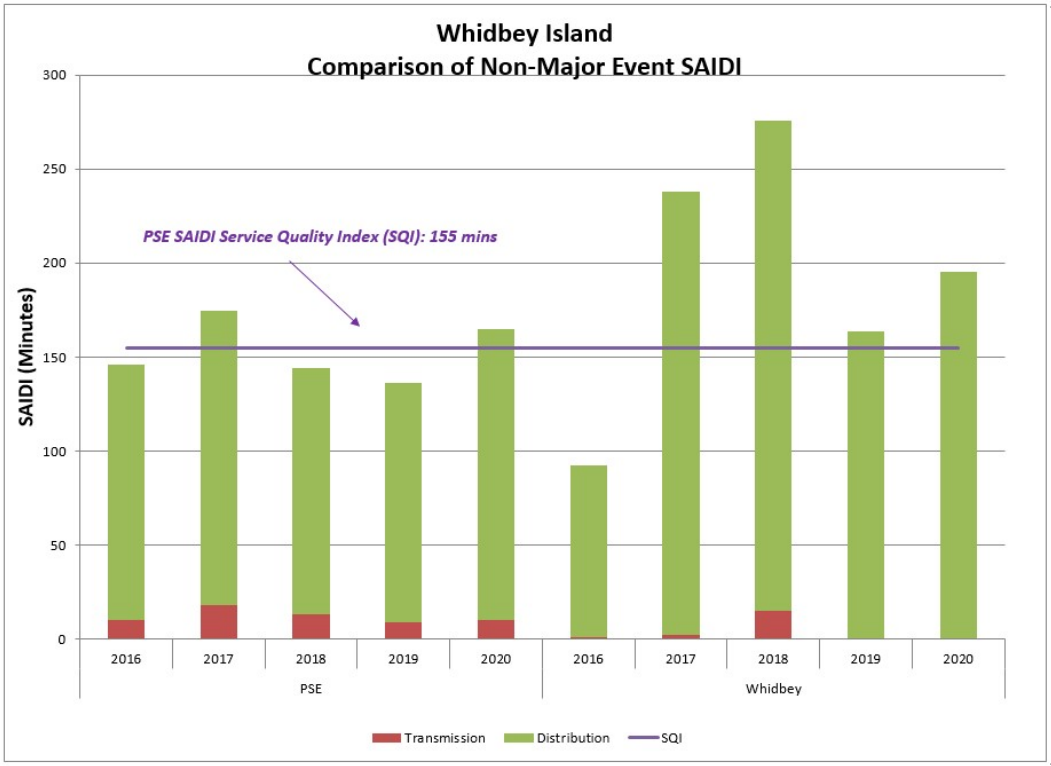


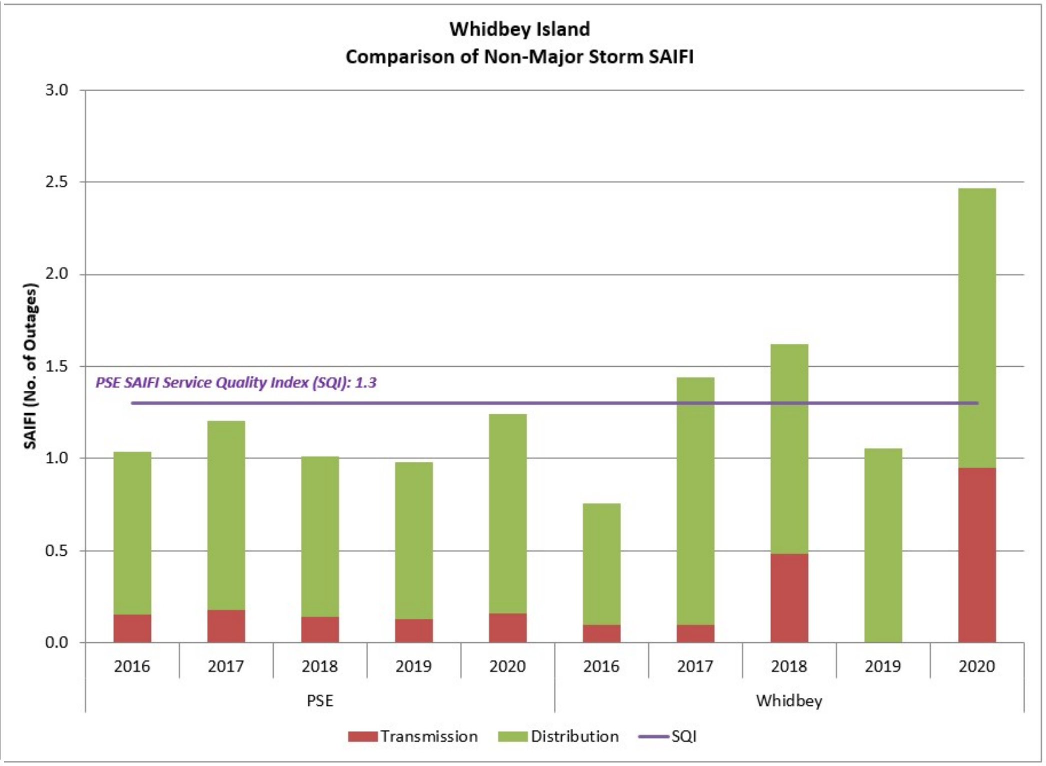
Appendix 5: SAIFI graphs with and without the “missing link”
See graphs below comparing Bainbridge to PSE’s system and Kitsap County.





Appendix 6: Whidbey Island SAIDI and SAIFI charts





Bainbridge Island
Non-Wires Alternative Analysis

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DISCLAIMER

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EXECUTIVE SUMMARY

Navigant performed an assessment of the potential for Non-Wires Alternatives (NWA) to meet the range of electricity delivery needs on Bainbridge Island (BI), and provided input to Puget Sound Energy (PSE) in preparation for an upcoming Stakeholder meeting on BI, at which NWA will be a topic of discussion.

Key findings include:

- A hybrid non-wires solution[1] used to meet some portion of distribution capacity needs is technically feasible and is economically-preferable to the wired solution[2] based on the analysis of net costs used in this report.
- PSE may cost-effectively delay reaching the investment planning trigger for the 3-substation group on BI from 2020 to approximately 2030 by leveraging the ferry electric load as a curtailable resource, by installing in front of the meter storage, and expanding the non-storage DER portfolio on BI.
- PSE should launch an NWA pre-implementation analysis to validate the results presented here, specifically exploring the cost uncertainty and implementation risk associated with customer-facing programs, such as ramp-up time, necessary incentives, and stakeholder concerns.

Background and Data Review: Navigant reviewed background documentation and data from PSE to understand the situation on BI, the existing electric infrastructure and constraints and potential traditional wired solutions that have been developed by PSE. Important sources of information included the DRAFT *Bainbridge Island Electric System Needs Assessment* (May 14th, 2018) developed by PSE as well as the *DRAFT Bainbridge Island Electric System Solutions Report* (August 1st, 2018) in addition to customer and load forecast data available from PSE. Navigant also leveraged the 2017 PSE Integrated Resource Plan (IRP) and the distributed energy resources (DER) potential study that was incorporated into the IRP[3] as well as other regional sources of information (e.g., Northwest Power and Conservation Council (NPCC) 7th Plan documentation) and Navigant's own engineering experience with NWA analysis and traditional transmission and distribution (T&D) planning and engineering.

Analysis Approach: Navigant worked with PSE to define the analysis parameters and deconstruct the overall problem into components appropriate for analysis. This approach helped the team identify actions that may meet specific portions of the needs, and to understand the timing and costs of those potential actions.

- Potential Solution Elements: the NWA solution elements and measures fall into two categories:
  - DERs considered in the analysis: The specific set of DERs considered in the analysis were developed in conjunction with the PSE Team. These include: **energy efficiency (EE), demand response (DR), customer-sited solar photovoltaics (PV), energy storage, and combined heat and power (CHP)** (renewable anaerobic digesters only).

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[1] A hybrid non-wired solution is defined as a solution that included both wired and non-wired components with the non-wired components dependent upon the wired components being constructed and in-service.

[2] A wired solution is defined as only traditional wired components such as poles, wires, transformers, etc.

[3] This DER potential study was titled "Conservation Potential Assessment" and was included as Appendix J of the *2017 PSE Integrated Resource Plan*. This study was performed by Navigant for PSE during 2016. The 2017 PSE IRP can be found at: https://www.pse.com/pages/energy-supply/resource-planning

- Broader definition of NWA considered but not analyzed: in our experience, the electric utility industry defines non-wires alternatives as a non-traditional investment (e.g. DERs) to replace or defer a traditional grid-side capital investment (e.g. poles, wires, transformers). However, stakeholders may interpret the term "non-wires alternatives" more broadly. For this reason, Navigant also considered traditional utility O&M activities such as vegetation management and targeted asset replacement in our overall assessment but did not include these in the detailed analysis.

- Problem Deconstruction and Definition: Navigant deconstructed the overall problem on Bainbridge Island along two dimensions: specific *identified needs*, and *grid elements* to 1) define the specific problem being considered, and 2) identify where that problem fits in the overall picture of BI needs. This deconstruction is intended to cover the entire potential range of solutions—wired and non-wired—so that stakeholders may see and understand that PSE is pursuing a comprehensive approach to meeting specific needs.
  - Needs deconstruction: specific areas of need, based on the PSE needs analysis structure, were considered separately. These areas were: *Capacity*, *Reliability*, *Operational Flexibility*, and *Aging Infrastructure*.
  - Grid deconstruction: Deconstruction into transmission and distribution components is consistent with the existing grid architectural structure, and it was useful in this case for defining the analysis components of the overall solution.[4]

- The team used the two types of deconstruction to analyze the following solutions:
  - Traditional Wired Approach: PSE has developed and documented a traditional wired solution that has a high probability of meeting the needs but is expensive relative to many grid investment projects.
  - Exclusively Non-Wired Alternative Approach: Navigant performed a preliminary assessment of meeting the entire set of identified needs using exclusively NWAs (as broadly defined above). This approach is technically possible but not realistic given the likely overall cost (large amount of electric storage capacity required) as well as significant disruption on Bainbridge Island (requires aggressive tree trimming and removal).
  - Hybrid Non-Wired Solution Approach: Navigant used the deconstruction above to individually examine specific elements of the need that are not addressed by the wired solution components associated with the transmission loop. While meeting the entire set of needs simultaneously will require further analysis, key portions of the needs—distribution substation capacity related needs—showed promise for non-wires solution approach, and so were analyzed in more depth.

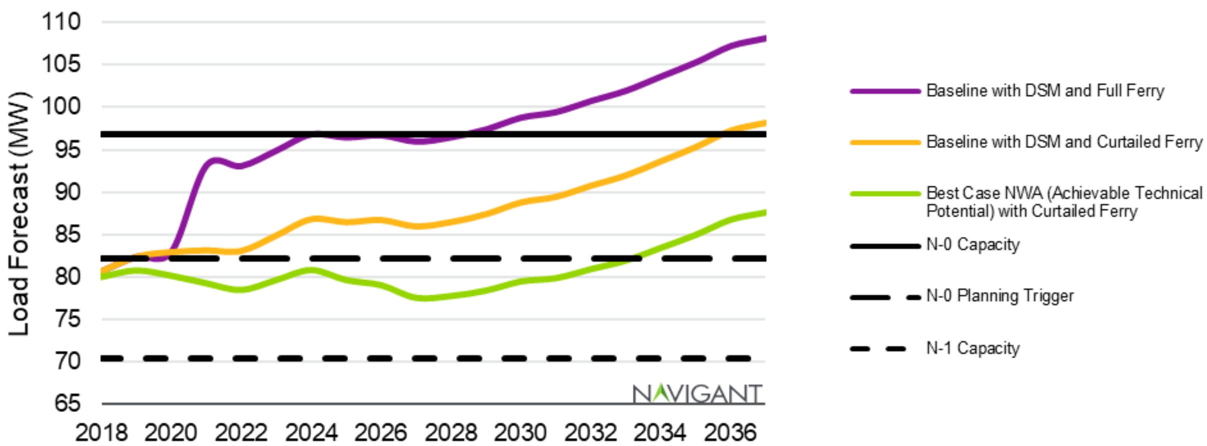
Distribution Capacity Analysis and Findings: the overall capacity needs for the grouping of three substations on Bainbridge Island drives key requirements in PSE's planning criteria. The team examined three different capacity thresholds for this three-substation grouping: *N-0 Capacity*, *N-0 Planning Trigger*,

[4] Note that additional levels of deconstruction are possible (e.g., a more granular deconstruction of the distribution grid might consider substations individually and further deconstruction could consider individual circuits). These further deconstruction levels were not explored as part of this study and are not critical to the findings presented here.

and *N-1 Capacity*. The *N-0 Planning Trigger* was selected as the key threshold for analysis focus. The other threshold values are shown in several of the graphics below for reference.

Navigant refined the analysis of baseline load forecast,[5] developed an estimate of achievable load reduction forecast using the DERs selected for the study, and examined the ferry electrification load as another key resource. The resulting load and DER forecast (excluding storage)[6] is shown in Figure 1.

Figure 1. Bainbridge Island Potential NWA Load Forecast Scenarios



Source: Navigant Analysis

Navigant's analysis concludes that PSE will likely be able to delay hitting the *N-0 Planning Trigger* for the 3-substation group on BI from 2020 to approximately 2030. The analysis made significant progress toward developing the non-wires distribution capacity solution and suggests that PSE can address local capacity needs based on a plan that:

a. Connects the ferry electrification load (10MW) as a curtailable resource

b. Incorporates storage to meet the capacity need in 2030 and provides operational flexibility between 2021 and 2029 to help provide insurance in the event that other demand-side resources don't perform as anticipated.

c. Aggressively pursues expanding the demand side management (DSM) portfolio on BI, to complement storage, as the more economical alternative to a traditional wired capacity expansion.

This analysis relies on the refined "bottom-up" calculation of load net of planned DSM programs, which includes zip-code-specific cost-effective EE savings, and recalculation of DSM capacity savings based on local substation load shapes, line losses, and power factor.

An NWA portfolio including EE, storage, renewable distributed generation (DG), and the option of DR has the potential to cost-effectively defer the wired alternative until 2030 given current load forecasts. Navigant recommends:

[5] The IRP baseline with full DSM was re-calculated using available local information from BI and assuming the same mix of cost-effective DSM measures used in the IRP.

[6] These figures do not include storage in consideration of the "Best Case NWA" because, technically, enough storage could defer the entire need in perpetuity—although installing a battery at every customer site would not be the most cost-effective solution. Storage therefore enters the analysis in Section 3 as an economic consideration.

- Sizing the storage to meet 50% of the capacity needs in 2030.
- Designing a portfolio that allows for some operational flexibility to test assumptions about DR costs and operational parameters. Navigant's analysis indicates that a 3.3 MW, 5MWh battery would provide sufficient flexibility for PSE to study and pilot targeted DR and EE programs before DSM resources become absolutely necessary to meet the need.
- As a next step, PSE should study and develop approaches to obtaining the EE, DG, and DR portions of the NWA portfolio on BI starting as soon as feasible.

The sections below detail the analysis approach, the technical DER potential analysis and the preliminary economic analysis.

1. ANALYSIS APPROACH

Navigant worked with PSE to define the analysis parameters and deconstruct the overall problem into logical components appropriate for analysis. This approach helped the team identify actions that may meet specific portions of the needs, and to understand the timing and costs of those potential actions.

1.1 Potential Solution Elements

The NWA solution elements and measures belong in two categories:

- DERs that were quantified in the analysis: The specific set of DERs considered in the analysis were developed in conjunction with the PSE Team.
- A Broader definition of NWA considered but not quantified or analyzed in detail: given that external stakeholders may interpret the term “non-wires alternatives” more broadly, it was felt that this consideration would be valuable.

Table 1 details the DERs that were included or excluded from the analysis and the rationale behind the decision.

Table 1. Distributed Energy Resources Considered in the Analysis

Resource Name	Description	Included for BI?	Rationale
Energy Efficiency	Utility run efficiency measures	Yes	Largest and most diverse DER
Codes and Standards	A cost-free resource that make new construction more energy efficient	No	Limited additional incremental savings on top of savings estimated in IRP
Fuel Conversion	Replacing electric equipment with natural gas-consuming equipment	No	No gas access in Bainbridge
Demand Response	Flexible, price-responsive loads which can be curtailed	Yes	Potential for targeted peak curtailment
Distributed Generation – Solar PV	Customer-side solar installations	Yes	Growing resource adoption
Distributed Generation – Combustion (CHP)	Includes renewable and non-renewable combustion	Yes- Only renewable CHP	Robust option for peak reduction
Distribution Efficiency	Combination of CVR and load phase balancing	No	Waiting for full deployment of Advanced Metering Infrastructure (AMI) in region (in agreement with 2017 IRP recommendation)

Generation Efficiency	Applies to parasitic loads served by a generator	No	Not applicable to region of interest
Energy Storage	Mainly battery storage	Yes	Provides a highly flexible resource

Source: Navigant Analysis

In addition to the DER definition provided above, Navigant also considered a broader definition of NWA. The logic behind this definition is that customers and other external stakeholders may interpret the term "non-wires alternatives" more broadly than the typical electric utility industry definition. For this reason, Navigant also considered activities such as vegetation management and targeted asset replacement in this broader definition. These activities were considered in our assessment, but we did not attempt to quantify impacts of these activities or value them monetarily in our detailed analysis. Nevertheless, including them in portions of the assessment proved to be instructive.

1.2 Problem Deconstruction

To understand the specific problem being considered and analyzed, and where that problem fits in the overall picture of BI needs, Navigant deconstructed the problem along two dimensions: specific *identified needs*, and *grid elements*. This deconstruction is intended to cover the entire potential range of solutions—wired and non-wired—so that PSE and stakeholders may see that a comprehensive approach to meeting specific needs has been taken.

Needs deconstruction: specific areas of *need*, based on the PSE needs analysis structure, were considered separately. These need areas were:

1. **Capacity -** Needs consisting of distribution capacity shortfall over the next ten years including *N-0 Capacity* and *N-0 Planning Trigger* threshold considerations based on PSE planning criteria.
2. **Reliability** - Needs consisting of all transmission and distribution reliability items including applicable N-1 feeder capacity, SAIDI and SAIFI metric reduction, and transmission outages.
3. **Operational Flexibility** - Needs related to the ability to transfer load to support routine maintenance, outage management, and planned seasonal switching.
4. **Aging Infrastructure -** Needs related to equipment nearing end of useful life and reduction of loading on equipment to effectively prolong lifespan.

Grid deconstruction: Navigant performed initial grid deconstruction at Bainbridge Island and deconstructed the grid need into the transmission and distribution elements of the required solution needed to meet the needs.[7] As a first order approximation, the proposed wired solution can be separated into transmission and distribution components that operate together.

1. **Transmission Components -** The transmission components include the new loop connecting Murden Cove and Winslow Substation. At a high-level this is to provide for increased reliability and to provide more operational flexibility. In addition, rebuild of aging infrastructure to improve reliability.

[7] Additional grid levels such as distribution circuit analysis could be investigated given additional time and effort.

2. **Distribution Components -** Additional distribution capacity needed for ferry electrification and to support anticipated load growth on Bainbridge Island.

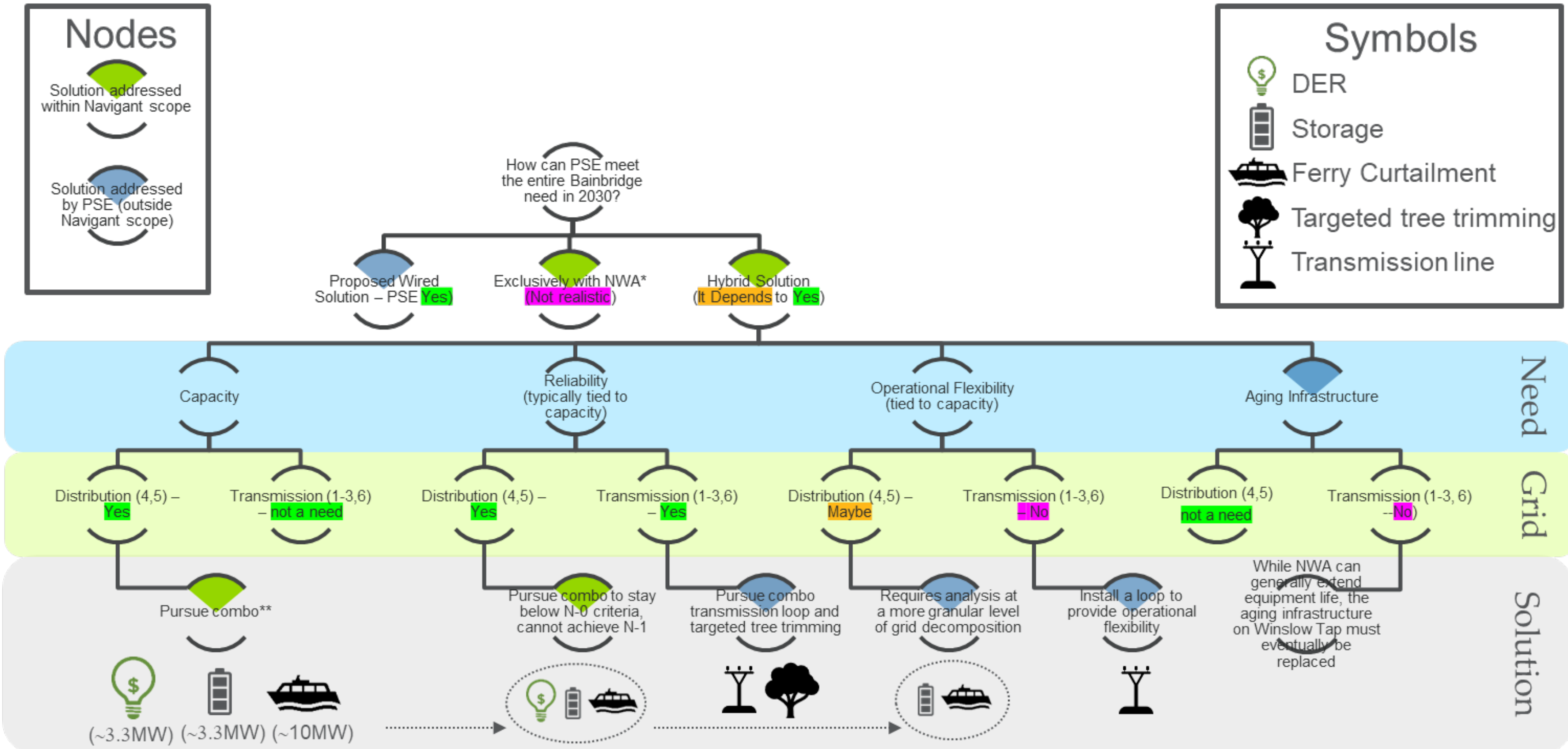
The distribution components depend upon the transmission components being constructed and in-service.[8] This deconstruction is consistent with the existing grid architectural structure, and we believe that the most significant conclusions can be drawn from this initial deconstruction.[9]

Visual Representation: a decision tree that depicts this deconstruction is shown below in Figure 2. The nodes of the decision tree represent deconstruction scenarios and are color coded to indicate which portions of the solution are addressed in the current analysis, and which are addressed outside of the current analysis. For example, PSE's analysis of traditional solutions is represented in several of the nodes by blue shading, as shown in the legend on the top-left.

[8] Typically, deconstruction of this type is more complicated, but PSE had created their proposed wired solution with input from transmission and distribution planners and tied the two together at the distribution substation level resulting in a meaningful and viable grid deconstruction.

[9] Note that additional levels of deconstruction are possible (e.g., a more granular deconstruction of the distribution grid might consider substations individually and further deconstruction could consider individual circuits). These further deconstruction levels were not explored as part of this study and are not critical to the findings presented here.

Figure 2. Bainbridge Island NWA Decision Tree



*Including all non-wire options: DER, ferry curtailment, tree trimming (not typically classified as NWA by industry)
**This combination primarily addresses capacity needs in 2030, and helps address N-1 capacity threshold for reliability needs; batteries and curtailable ferry can also provide operational flexibility
"YES" refers to a scenario in which NWA meets an element of the need (e.g., N-0), but perhaps not all elements of the need (e.g., N-1)

Source: Navigant Analysis

1.3 Solution Approaches

This overall deconstruction was used to answer the question "How can PSE meet the entire Bainbridge Island need" and to break that question down into sub-questions of "what portion of the needs can be met" by various deconstructions, leveraging different combinations of solution elements.

At the topmost level, three broad scenarios for meeting the set of identified needs are evident. These three scenarios are indicated by numbers in green boxes in Figure 2 and are:

1. **Proposed wired solution**: PSE has developed and documented a traditional wired solution based on current planning criteria and known wired components.
2. **Using exclusively NWAs** (broadly defined): Navigant considered solutions leveraging both the narrower definition of DERs and the broader definition NWAs (i.e., including vegetation management).
3. **Hybrid Non-Wired Solution**: where elements of the problem are met through traditional wired solution (or some other creative solution) and elements met through NWAs.

Navigant indicates successfully meeting the set of needs at a particular scenario node with a "YES" in Figure 2[10] and a "NO" where the meet at that node is not met, and a "MAYBE" where the situation is more nuanced and requires further explanation.

1.3.1 Traditional Scenario (Proposed Wired Solution)

Navigant reviewed the planning analysis and the traditional wired solution developed by PSE to meet Bainbridge Island transmission and distribution needs. This solution corresponds to the upper left node of the decision tree in Figure 2 and includes building a 115 kV transmission loop between Winslow and Murden Cove substations and installing a new distribution substation in the middle of the transmission loop. Sub-components with initial estimated costs of this solution are found in the *DRAFT Bainbridge Island Electric System Solutions Report* and are shown in Table 2.

Table 2. Preferred Traditional Wired Solution

	Scope of Work	2018 Unit Cost Estimate	2018 Cost Estimate	2018 Cost Estimate w/ 25% contingency
1.	Build 3 miles of new overhead 115 kV line b/w Murden Cove and Winslow on public ROW.	$2.5 M/mi.	$7.5 M	$9.4 M

[10] In some cases, this includes when NWA meets one threshold of the need (e.g. N-0 Capacity), but perhaps not all levels of the need (e.g. N-0 Planning Trigger).

2.	Expand Winslow substation bus to bring second 115 kV line. Install 2-115 kV breakers.		$1.5 M	$1.9 M
3.	Expand Murden Cove substation bus to bring second 115 kV line.		$0.8 M	$1.0 M
4.	Build new 115-13 kV distribution substation on transmission loop.		$8.0 M	$10.0 M
5.	Install 4-13 kV feeder getaways at new distribution substation.	$1.0 M/mi.	$1.0 M	$1.25 M
	TOTAL Cost.		$18.8 M	$23.6 M

Source: PSE DRAFT Bainbridge Island Electric System Solutions Report, August 1st, 2018
Note: Costs are July 2018 PSE cost estimate based on similar past projects in other areas of PSE service territory. Does not include site-specific engineering.

An additional component that PSE has categorized as a *potential upgrade* is shown in Table 3. Navigant included this in the traditional solution component consideration as an element that would clearly address some of the key transmission reliability needs that have been identified.

Table 3. Additional Components of Traditional Wired Solution

	Scope of Work	2018 Unit Cost Estimate	2018 Cost Estimate	2018 Cost Estimate w/ 25% contingency
	Potential Upgrades			
6.	Rebuild 4.5 miles of Winslow 115 kV tap. Rebuild will most likely replace all poles, relocate line and improve corridor for better access.	$2.5 M/mi. *New line construction cost estimate assumed.*	$11.25 M	$14.1 M

Source: PSE DRAFT Bainbridge Island Electric System Solutions Report, August 1st, 2018
Note: Costs are July 2018 PSE cost estimate based on similar past projects in other areas of PSE service territory. Does not include site-specific engineering.

After reviewing the needs document and solution approach, Navigant agrees that the traditional solution will meet the identified needs, as it is based on well understood, broadly used technologies and planning principles.

1.3.2 Exclusively Non-Wires Scenario

Navigant considered whether the entire set of identified needs could be met using exclusively NWAs (the scenario corresponding to item 2 in the decision tree in Figure 2) based on the two NWA definitions presented above:

- the narrower set of DERs selected for detailed analysis (Table 1 above) or
- the full range of NWAs were used (i.e., the broader definition described above including vegetation management, etc.)

Using selected DERs: In the narrower definition of NWA, we concluded that DER cannot fill the entire need or address the concerns expressed by PSE planning for the following reasons:

- Majority of the Winslow 115 kV tap design is wishbone wood cross arm construction built in the 1960s which is starting to fail (these DERs cannot prevent this aging and failure)
- PSE crews have reported poor access to certain cross-country sections of the Winslow 115 kV tap, resulting in prolonged restoration times for some transmission outages (this would require, among other things, more aggressive tree trimming and removal)
- The incidence of simultaneous outages in the two transmission lines feeding BI cannot be addressed with these DERs

Using Broader Definition of NWA: using the full range of NWAs (i.e., the broader definition described above including vegetation management, etc.) provides more flexibility and more possibilities. Again, some of the needs would be extremely hard to meet with NWAs. For example, addressing transmission reliability without the Winslow 115 kV tap rebuild and without addressing some of the aging infrastructure needs is a significant challenge.

Upon examination, Navigant concluded that while it is likely technically possible to meet the BI needs using this broader definition of NWAs, it is not a realistic solution. A detailed technical analysis using this broader definition of NWAs was not the focus of this study and was not performed. As part of the analysis of the Bainbridge Island NWA, Navigant reviewed the full projected costs for the traditional solution. Navigant also considered the varieties of needs that would be addressed by the traditional solution. Navigant found that to provide similar levels of operational flexibility and reliability as the traditional solution, additional batteries would be needed to provide grid support for four to eight hours. These batteries would be needed in addition to the batteries and other measures needed to meet the growing capacity needs. Navigant estimated that the costs for these additional batteries would be considerably more than the costs of the traditional solution related to grid flexibility and reliability. Considering the likely need for significant additional electric storage at various locations on the island, the need for aggressive tree-trimming and removal (counter to community values on Bainbridge Island), and the roll-out timeframe necessary to the meet full set of defined needs with an exclusively NWA solution, Navigant does not think such a solution could be realistically achieved.

1.3.3 Hybrid Non-Wires Solution Scenario

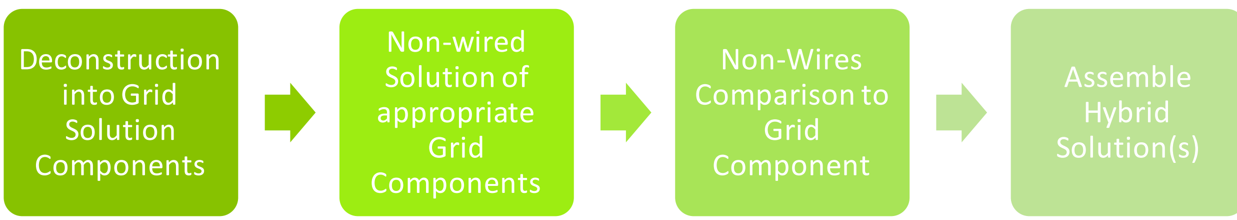
Hybrid non-wires solutions are represented on the decision tree by the 3rd node in Figure 2, node labelled "Hybrid Solution". In a hybrid non-wires scenario, elements of the need are met through traditional wired solution (or some other unspecified means) and other elements met through NWAs.

Navigant used the more limited definition of NWA solution elements (shown in Table 1above) to adhere to the original analysis objectives, which focused on leveraging the specific set of selected DERs to meet identified needs.[11] Initial rule-of-thumb assessment of the possible capacity reductions available on BI indicated the further, detailed analysis of the potential for NWAs to meet a portion of the needs was merited. Then Navigant proceeded with a more detailed analysis of possible hybrid non-wired solutions.

The value of *completely* deferring the distribution components of the proposed wired solution is $11.25M based upon the sum of line items 4 and 5 including the 25% contingency in Table 2. For determining if the hybrid non-wires solution is economically preferred to the traditional wired solution, Navigant compared the net cost of the non-wires solution needed to meet the distribution need out to the 2030 planning horizon to the value of a complete deferral of approximately $11.25M. Given the uncertainty in load growth projections beyond ten years and uncertainty in future costs of necessary distribution upgrades, Navigant did not estimate the costs that would be incurred past 2030.[12]

The process for assembling a hybrid non-wired solution is outlined in Figure 2, and each step is described below.

Figure 3. Hybrid Non-Wired Solution Process



Source: Navigant Analysis

1. The first step of deconstruction of the preferred solution into grid components takes the components of the preferred solution, numbered 1-6 in Table 2, and maps them to the nodes on the decision tree, either transmission or distribution, under each of the need items. Based on Navigant's engineering judgment, items 1-3, and 6 are transmission components that can be cleanly separated from the distribution components 4 and 5.
2. The next step is to assess which of the DER's could replace the traditional solution component group, both across all the needs categories and within the individual needs categories.
3. As the third step, Navigant compared these DERs to the traditional solution in terms of items such as risk and reliability of the resource, to determine if there is a reason to eliminate the DER from further consideration.
4. The final step is to assemble the hybrid non-wired solution. The hybrid non-wired solution assembled by Navigant and analyzed in future sections includes the traditional solution items 1-3, and 6 to meet the transmission needs and DERs to meet the distribution capacity needs and defer or replace the cost of items 4 and 5.

[11] A more comprehensive analysis incorporating storage, or even incorporating vegetation management and other O&M approaches is possible, but was not the focus of the analysis presented here.

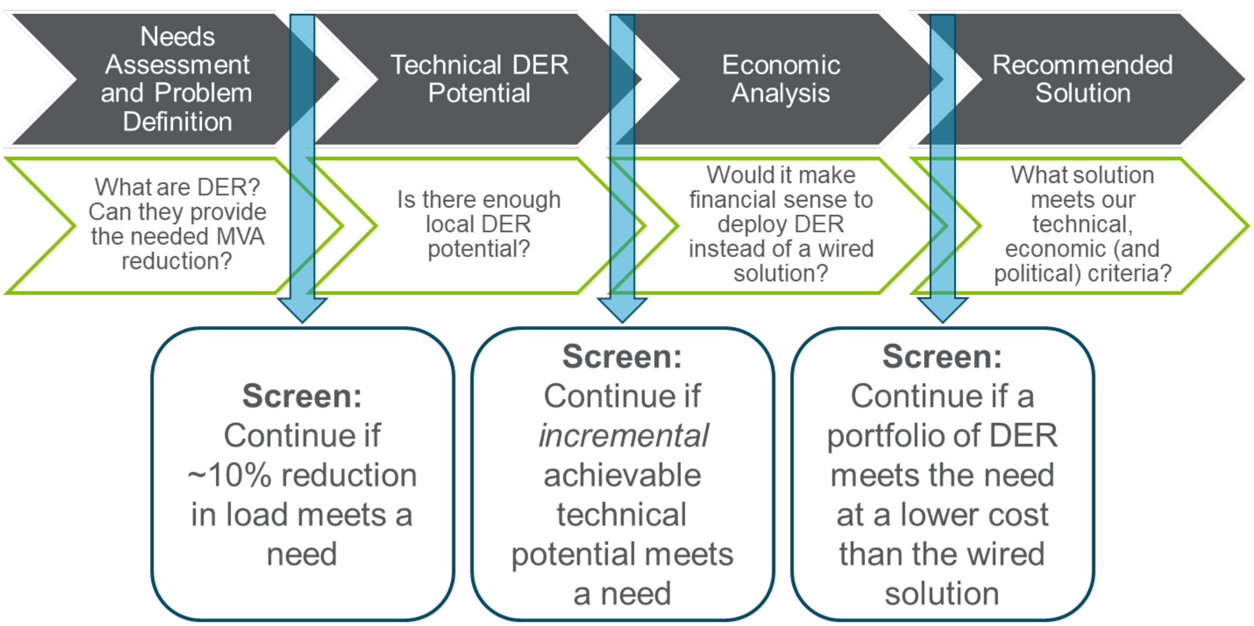
[12] For example, Navigant did not posit that this same wired solution would be built in some year after 2030, nor attempt to calculate the economic deferral value of the wired solution, which would require such an assumption.

For the transmission component in BI, the selected DERs were deemed incapable of realistically meeting the full set of needs.[13] Clearly a large amount of storage is technically capable of addressing large-scale transmission needs, but based upon Navigant's experience and engineering judgment it doesn't fit the pattern of typical non-wires solutions. However, individual transmission needs showed some promise of being addressed by NWAs and merited exploring through the screening process described in detail in the next section.

1.3.3.1 Screening Process for NWA Analysis

The next step after the hybrid non-wired solution has been assembled, is for those elements that have not yet been eliminated from further consideration to flow through the screening process as shown in Figure 4.

Figure 4. Screening Process for NWA Analysis



Source: Navigant Analysis

The first screening step is to do a simple needs assessment looking at the load growth in the area over the next 20 years. Before determining any DER potential, it is useful to consider whether a 10% reduction in demand-side load (excluding storage) can meet a need[14].

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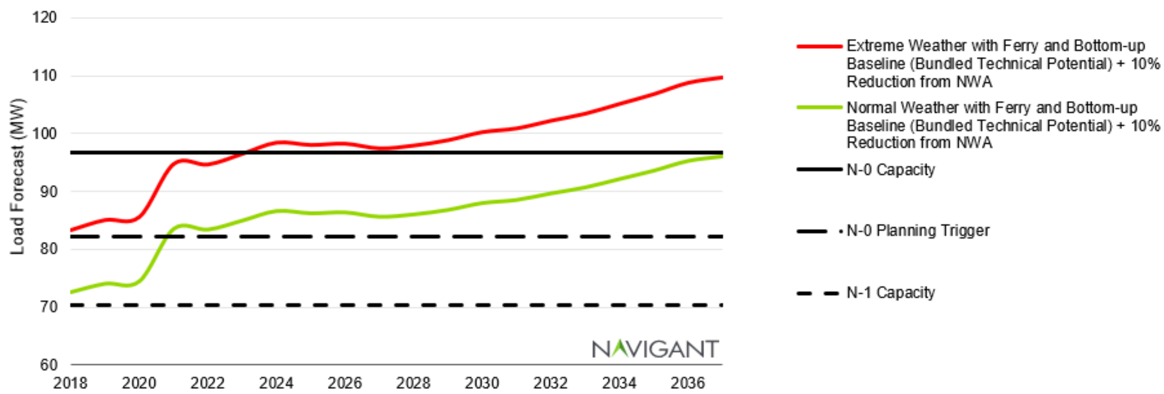
[13] Note that adding significant amounts of storage could help meet these needs, but is highly unlikely to be economically feasible in Navigant's judgement.

[14] Navigant found that a 10% reduction in peak load is a reasonable upper-bound expectation for achievable load reduction through a targeted non-storage DER-deployment. This is a general rule that may vary based on local circumstances or the presence of large curtailable loads. In this case, the electric ferry load is another, more-detailed consideration addressed in Appendix A.

Figure 5: A Comparison of Load Growth Scenarios with a Simple 10% Capacity Reduction



All scenarios assume a power factor of 97.8%; Normal weather assumes a winter peak of 23 degrees and extreme weather assumes a peak of 13 degrees; full technical potential includes DG - Renewable Combustion, DG - Solar, DR, and EE. Bundled technical potential includes DG - Renewable Combustion and EE measures in the top 3 LCOE bundles (LCOE < $70/MWh).

Source: Navigant Analysis

This step indicated potential to meet capacity needs for the distribution component of the solution—particularly with respect to the *N-0 Planning Trigger* threshold, under a load growth scenario of normal weather conditions with PSE business-as-usual DSM procurement, at least until 2021 when the ferry may become a capacity planning consideration. Navigant recommends connecting the ferry as an interruptible load, as detailed in Appendix A.

Given the inability of DER to materially impact transmission capacity and reliability on BI, and the exclusion of other non-wired solution such as tree-trimming and targeted operation and maintenance (O&M), the analysis subsequently focuses on identifying the problems on Bainbridge Island that DER can actually address, which are distribution capacity needs. The remaining steps in this process required significant analysis, which is detailed in the following three sections:

- Technical DER Potential
- Economic Analysis
- Conclusions and Recommendations

As part of this next step, Technical DER Potential, the team defined the capacity need as the *N-0 Planning Trigger* threshold (load must be below 85% of total capacity for the three-substation group on the Bainbridge Island). There are other capacity needs on BI such as N-1 capacity or circuit level N-1 capacity, but the *N-0 Planning Trigger* threshold was used for defining the amount of load reduction that the NWA must provide to successfully defer or replace the wired solution.

2. TECHNICAL DER POTENTIAL

The technical potential analysis leverages a methodology and definitions that are consistent with PSE's 2017 integrated resource plan and accepted in the Pacific Northwest. The analysis focuses on the overall capacity needs for the grouping of three substations on Bainbridge Island, which drives key requirements in PSE's planning criteria. Navigant refined the analysis of baseline load forecast, developed an estimate of achievable load reduction forecast using the DERs selected for the study, and examined the ferry electrification load as another key resource. The analysis details are described below.

2.1 Methodology and Definitions

The potential study seeks to identify all *incremental* achievable technical potential exclusive of what is already incorporated in the net load forecast. Incremental achievable technical potential (ATP) is defined as:

Incremental ATP = achievable technical potential – baseline load forecast with planned DSM

Achievable technical potential is a term used in the Pacific Northwest to represent DER potential that is achievable—considering customer economics, technology awareness, and market diffusion. Achievable technical potential is commonly referred to as "market potential" in other jurisdictions. For energy efficiency, achievable technical potential was specified as a percentage of the technical potential. The percentage of technical potential that was deemed achievable was by default 85% based on the Council's planning assumptions.[15] Navigant modeled the effects of time-dependent barriers to market adoption by applying the ramp rates provided by the Council in the Seventh Plan[16] to the maximum achievable technical potential. Navigant used a payback-based market approach in conjunction with a Bass diffusion model to forecast the adoption of PV and DR on Bainbridge Island. More details on methodology and data sources are available in the 2017 IRP Demand-Side Resource Conservation Potential Assessment Report.[17]

To define which portion of the achievable technical potential is "incremental," Navigant assumed baseline, "business-as-usual" procurement of demand-side resources by PSE, assumptions and methodology by resource type are stated below.

- EE and combustion DG- in the PSE IRP, PSE commits to pursuing levelized cost of energy (LCOE) bundles 1 through 3[18]. Navigant re-calculated the PSE net load forecast (net of demand-side resources) at the Bainbridge ZIP code level, assuming measure bundles 1-3 reach their full achievable potential. Appendix A contains more details on the baseline load forecast. The analysis of *incremental* EE and combustion DG only considers measures that were not in bundles 1 through 3 in the 2017 IRP.

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[15] *Achievable Savings – A Retrospective Look at the Northwest Power and Conservation Council's Conservation Planning Assumptions*: http://www.nwcouncil.org/media/29388/2007_13.pdf.

[16] See https://www.nwcouncil.org/energy/powerplan/7/technical for the supplemental data files that accompany the Council's Seventh Power Plan.

[17] https://pse.com/aboutpse/EnergySupply/Pages/Resource-Planning.aspx

[18] The IRP "bundles" demand side resources by levelized cost of energy, from lowest (bundle 1) to highest (bundle 10). During the IRP process, resource planners decided that bundles 1-3 would be cost-effective to pursue, therefore measures in these bundles are not eligible to be pursued as an incremental non-wires alternative on Bainbridge Island.

- PV – The team assumed PSE has no business-as-usual customer incentives for distributed PV adoption—therefore all achievable technical PV potential is eligible as incremental potential for the non-wires solution.
- DR– The team assumed PSE has no immediate plans for DR on Bainbridge Island, —therefore all achievable technical DR potential is available as incremental potential for the non-wires solution. For incremental DR, 4-hour DR events were assumed.
- Storage – Technically, storage might be sized to meet essentially the entire need on Bainbridge Island. So, the *technical potential* for storage is almost limitless. Therefore, storage is primarily considered in Section 3, the Economic Analysis. See also Figure 9 for an illustration of the phased approach Navigant took to including storage in the analysis as a progressive reduction in the capacity to be provided by non-storage DER.
- Ferry – Navigant determined that the ferry should not be considered for capacity planning purposes, assuming the ferry can be connected on an interruptible rate with a sufficient number of hours of curtailment to eliminate the ferry load from capacity planning needs. For more details on the ferry load calculations, see Appendix A.

The impact of each of these resources is defined for the actual peak period on Bainbridge Island, determined through analysis of the hourly load shapes for the three substations on the island. This analysis is discussed in further detail in Appendix B.

2.2 Incremental Technical Potential Analysis

This analysis relies on the refined "bottom-up" calculation of load, net of planned DSM programs, which includes zip-code-specific cost-effective EE savings, and recalculation of DSM capacity savings based on local substation load shapes, line losses, and power factor. See Appendix A for details on how the team refined the load forecast for this analysis.

Navigant used the PSE distribution planning criteria to establish limits against which the load forecast could be compared under various assumptions. The planning criteria for the three-substation grouping of Port Madison (PMA), Murden Cove (MUR), and Winslow (WIN) on BI leads to the following winter capacity limits:

- *N-0 Capacity Limit*: When loads in an area reach 100% of capacity for a substation group of three or more, no new load can be served until additional capacity is added to support the load.
- *N-0 Planning Trigger*: When the loads in an area reach approximately 85% of existing substation capacity for a study group of two to six substations, the need for additional capacity is triggered to maintain operational flexibility.
- *N-1 Capacity Limit*: Contingency situation wherein one of the three substations is out of service and the other two substations need to serve the load.

The three substations on BI are all 25 MVA banks and are operated following the capacity limits outlined in Table 4.

Table 4. Substation Bank Capacity Limits

Single Distribution Substation Loading (25 MVA Bank)	
Operational Load (N-0)	Emergency Load (N-1)

Winter 132% of nameplate	Summer 108% of nameplate	Winter 144% of nameplate	Summer 116% of nameplate
33 MVA	**27 MVA**	**36 MVA**	**29 MVA**

Source: PSE DRAFT Bainbridge Island Electric System Needs Assessment May 14th, 2018

Given these substation bank capacity limits and the assumed power factor, the substation group planning limits used for assessing need and success are as outlined in Table 5.

Table 5. Substation Group Planning Capacity Limits

Substation Group Planning Limit	Loading	Capacity Limit (MVA)	Capacity Limit (MW)
N-0 Capacity Limit	Operational load for winter at 132% of nameplate	99 MVA	96.8 MW
N-0 Planning Trigger	85% of operational load for winter at 132% of nameplate	84 MVA	82.2 MW
N-1 Capacity Limit	Emergency load for winter at 144% of nameplate	72 MVA	70.4 MW

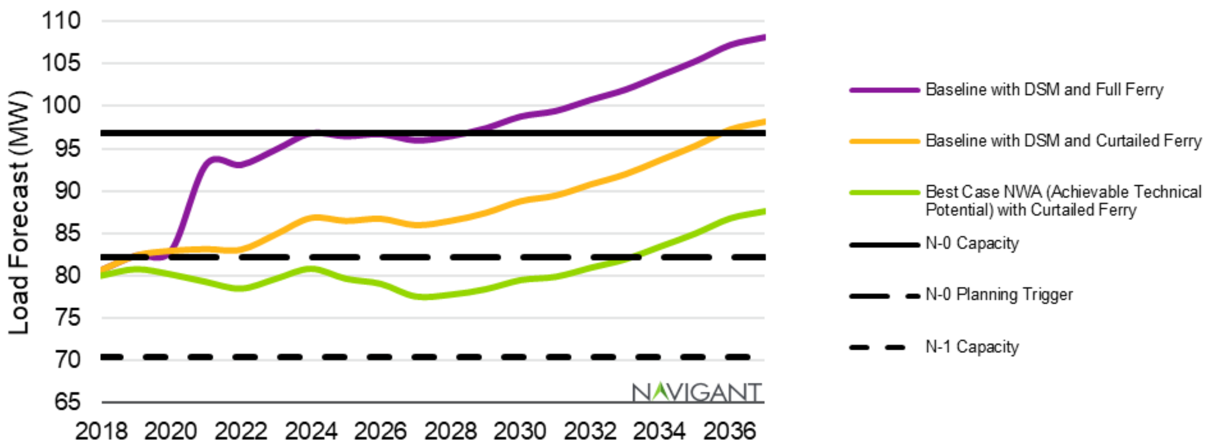
Source: PSE DRAFT Bainbridge Island Electric System Needs Assessment May 14th, 2018

These limits are included on the load forecast graphs to indicate where the projected load falls relative to each limit under the different assumptions examined. The *N-0 Planning Trigger* was selected as the key solution criteria that defines the primary capacity need for the analysis performed in this report.

As seen in Figure 6, the incremental technical potential (excluding storage) [19] brings the defined baseline load forecast below the *N-0 Planning Trigger* through at least 2033.

[19] These figures in the technical DER potential section do not include storage in consideration of the "Best Case NWA" because, technically, enough storage could defer the entire need in perpetuity—although installing a battery at every customer site would not be the most cost-effective solution. Storage therefore enters the analysis in Section 3 as an economic consideration.

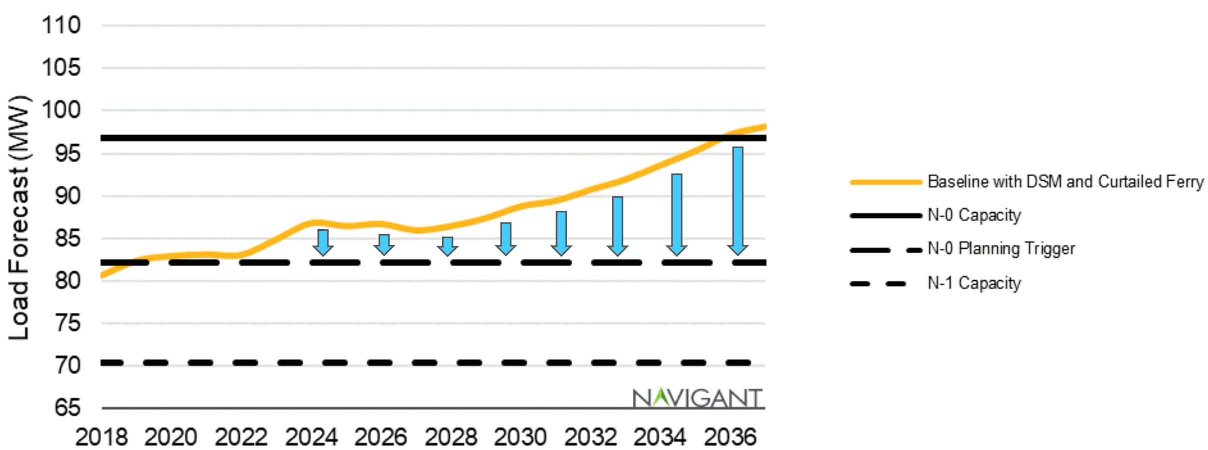
Figure 6. Effect of Incremental Technical Potential on Baseline Load Forecast



Source: Navigant Analysis

Another way to view the incremental technical potential on Bainbridge Island is to compare it to the need in the area, as illustrated in Figure 7 by the blue arrows between the defined baseline and the *N-0 Planning Trigger*.

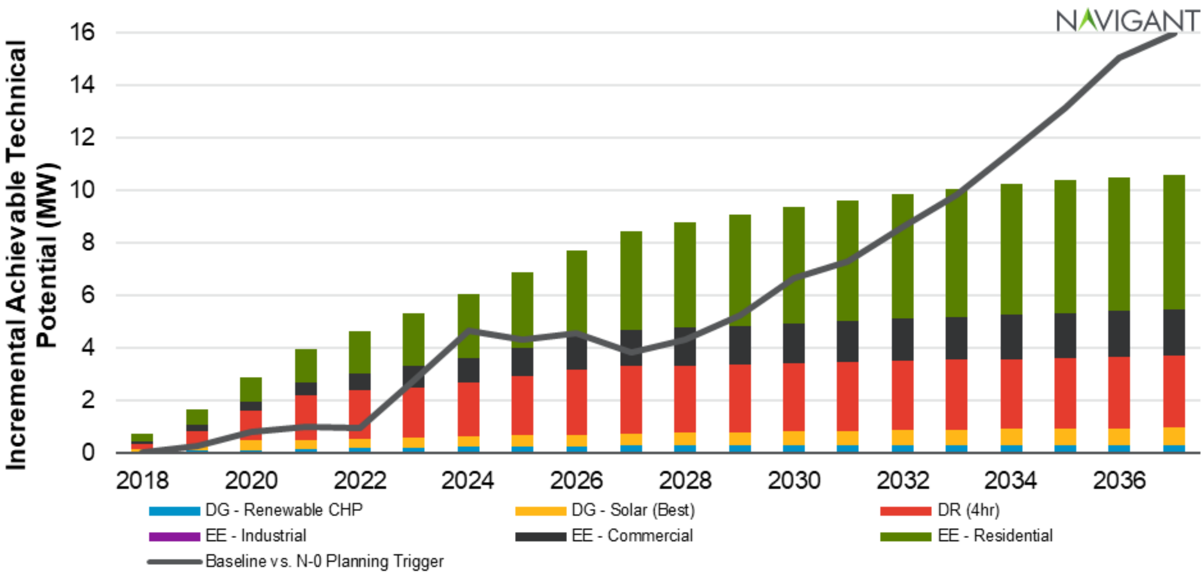
Figure 7. Illustration of Defined Need (Differed between Baseline and N-0 Planning Trigger)



Source: Navigant Analysis

This capacity need is shown as the grey line in Figure 8, where it is compared to the annual technical potential by resource type. The largest incremental achievable technical potential contribution is made by residential energy efficiency measures, followed by demand response resources.

Figure 8. Incremental Achievable Technical Potential by Resource Compared to Defined Need



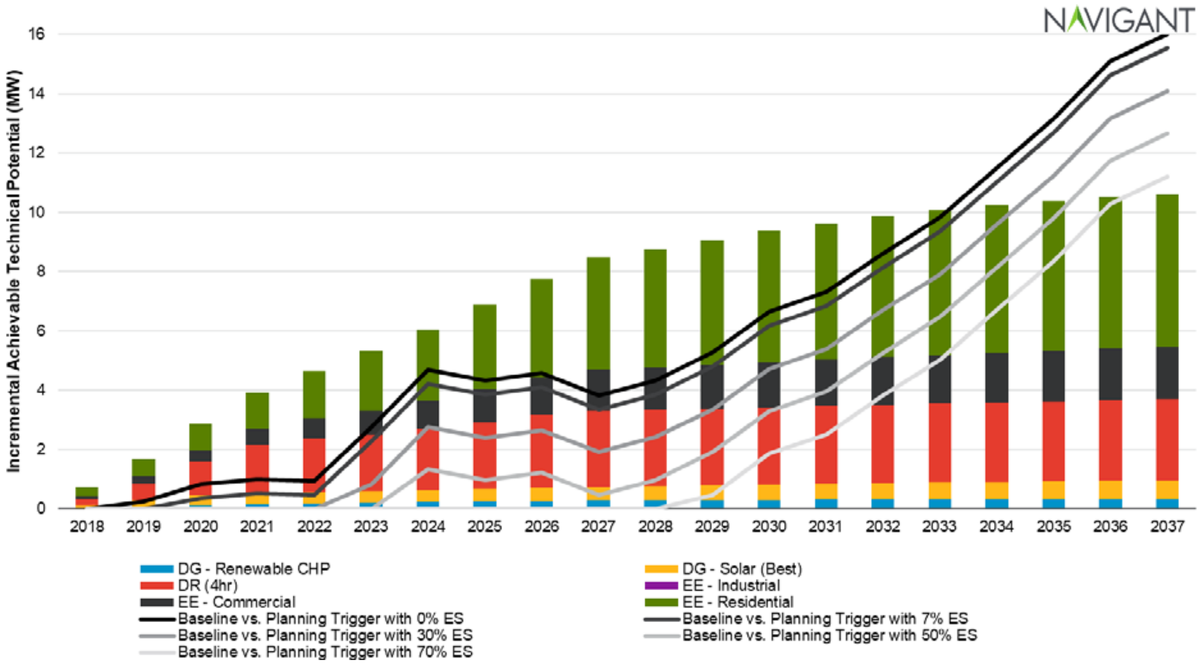
Source: Navigant Analysis

The Navigant team took a phased approach to adding storage to this analysis. At the extreme, storage can technically meet 100% of the need, as this resource is unconstrained by demand-side loads (as EE and DR are) and similarly unconstrained by fuel availability (as PV and renewable DG are). In other words, it is technically feasible to add a battery to every feeder or customer site on the island—though likely cost-prohibitive. Therefore, the team incorporated storage into the analysis using a three-step process:

1) Storage dispatch optimization. The team determined the optimal operating schedule for the storage, prioritizing dispatch of the energy in the storage by the following items in order:
    a. Three-substation group capacity deferral
    b. Bulk PSE system generation capacity deferral
    c. Energy trading based on 8,760 forecasts for PSE’s avoided energy costs
2) Storage sizing. The team took a parametric approach to determining the optimal storage size, using different sizing scenarios to meet a different percentage of the capacity needs in 2030 with storage. Results of this analysis are detailed in Appendix C.
3) Layering in other DER. For each storage sizing scenario, the remaining need is then met with the least-cost DER in the economic analysis. This leads to Figure 9, a revision of Figure 8, with different levels of the need to be met by DER based on different storage sizes.

Appendix C contains the detailed assumptions and methodology behind the storage analysis.

Figure 9: Incremental Achievable Technical Potential by Resource Compared to Defined Need by Storage Scenario



Source: Navigant Analysis

Figure 8 (without storage, shown on previous page) reiterates that the analyzed incremental DER could only theoretically meet the need until 2033 without storage. However, not all resources would need to be pursued to defer the need for a shorter amount of time—until 2030 for instance—and even fewer DER would be needed depending on the amount of storage included in the portfolio (as shown in Figure 9). An economic analysis can help PSE to decide 1) what is the appropriate portfolio of DER measures and storage capacity to defer the need, and 2) what deferral timeframe makes economic sense? The following section provides a foundation for answering those questions, with a focus on a targeted deferral timeframe of 2030. As discussed in Section 4, there are uncertainties associated with this economic analysis and Navigant recommends further study of cost and benefit components of the non-wires solution before implementation.

3. ECONOMIC ANALYSIS

This section includes an economic analysis of all DER and energy storage to determine whether the DER portfolio is lower cost than the conventional wired solution. The economics of the analysis depend on the target year for deferral. Unless stated otherwise, this section assumes that a DER portfolio that meets the capacity needs in 2030 qualifies as a complete deferral of the conventional wired investment of $11.25M. Therefore, the DER portfolio is economically-preferred if the net cost is less than $11.25M.

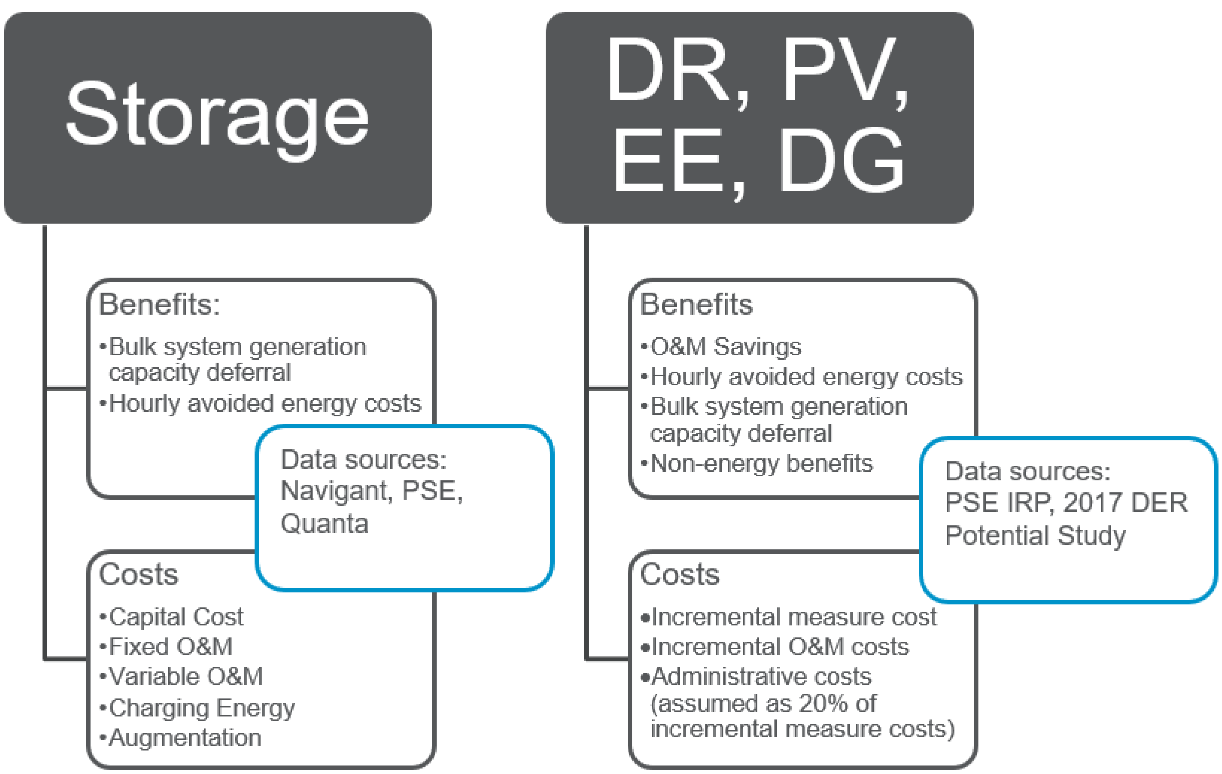
3.1 NWA Portfolio Cost Comparison

3.1.1 Levelized Cost of Capacity

To include storage and other DERs into a single optimal portfolio, Navigant developed a levelized cost of capacity (LCOC) calculation. This allows comparison of resources based on the present value of the net costs for providing local capacity deferral.

The LCOC accounts for the same costs and benefits for each measure as used in the 2017 IRP, but divided by the substation peak capacity savings of each measure rather than the annual energy savings of each measure. The team performed a congruent calculation for storage. Costs and benefits for the various resources are outlined in Figure 10.

Figure 10: Value Streams Included in LCOC Calculation



Source: Navigant Analysis

The LCOC is a net cost - considering the capital and implementation costs of the measures, net of any benefits. Costs and benefits are in present value terms (in 2020 dollars[20]) levelized over a 20-year horizon using PSE's Weighted Average Cost of Capital (WACC) (7.77%) to stay consistent with the 2017 IRP. Any monetary value for avoided T&D capacity is excluded from the calculation, so that the results can be compared directly with the costs of the distribution components of the conventional wired investment on Bainbridge Island[21].

$$LCOC\ (\$/MW) = \frac{PV\ of\ Costs\ (\$) - PV\ of\ Benefits\ (\$)}{PV\ of\ Capacity\ Savings\ (MW)}$$

The LCOC value is calculated on a measure-by-measure basis, with the value streams listed in Figure 10. Because the calculation accounts for a number of different value streams in one metric, the LCOC is best used to represent the relative value of each measure, not the absolute value of the portfolio of DER measures, and therefore caution should be used when comparing this portfolio to the cost of the wired solution.[22] For example, the actual expenditure on a portfolio of DER would be higher than the LCOC indicates, since it is a cost net of anticipated benefits. These values should be considered *preliminary*, as there may be additional costs associated with a targeted DER implementation (see Section 4 and Appendix C for a discussion of areas of further study). In addition, as discussed below, political and strategic considerations may influence which DERs (e.g. PV, DR) are included in the portfolio of DER.

3.1.2 Storage Analysis Summary

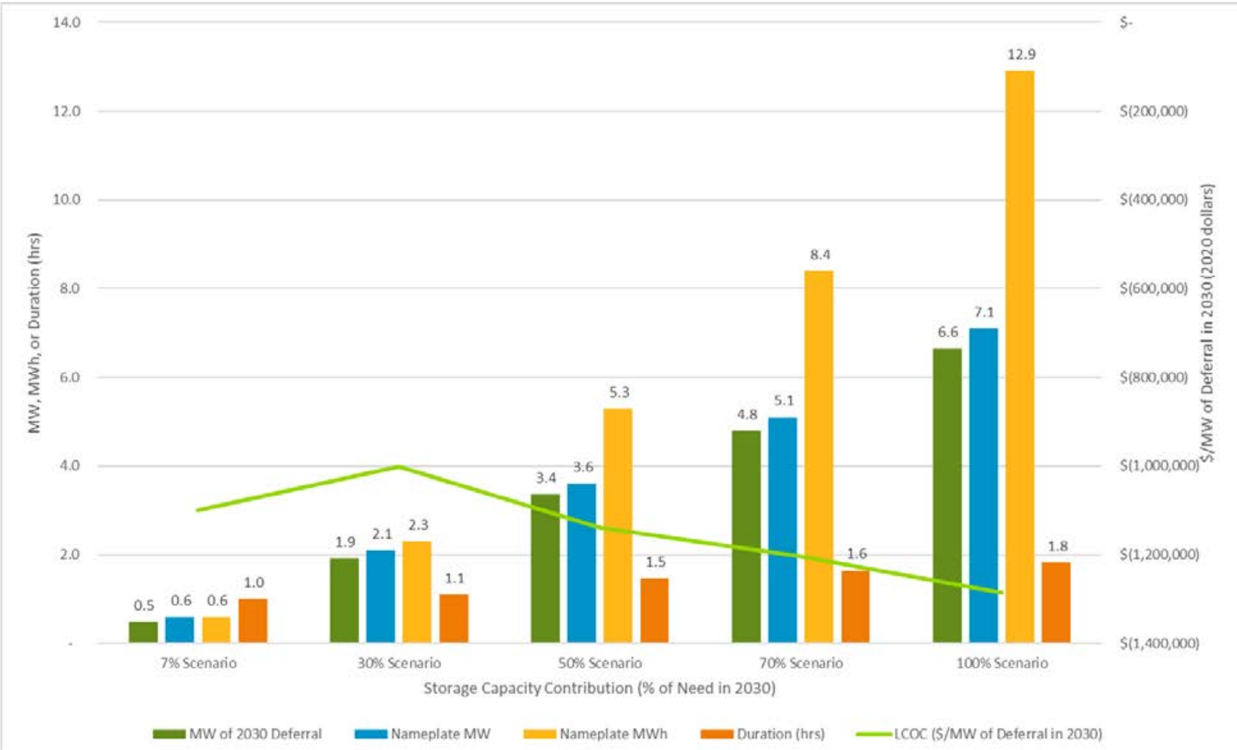
Navigant began the economic analysis by considering various storage sizes and system characteristics according to the historical substation load shape and forecast 2030 capacity needs. Figure 11 summarizes the results of this analysis, Appendix C contains the complete details of the methodology. The team concluded that, when considered alone, sizing the storage system to meet 30% of the 2030 need is the most cost-efficient system design as indicated in Figure 11 below. However, design of the optimal non-wires alternative portfolio must also consider the ability to add other non-storage DER (PV, renewable combustion generation, EE, and DR) to serve the capacity needs—which influences the optimal sizing of the storage system as discussed in the next section.

[20] Navigant assumed that the investment in a non-wires alternative portfolio—construction of storage or deployment of energy efficiency--would likely occur in 2020 due to realistic timing considerations and the fact that 2020 is the first year in which the load forecast exceeds the *N-0 Planning Trigger* threshold.

[21] The 2017 IRP did include a system-wide value of local capacity for DER on a $/MW-year basis. This non-specific value was determined by the Northwest Power and Conservation Council. Navigant did not include this value in the analysis, as these results are intended to be compared as an alternative to a specific local T&D investment.

[22] The up-front cost of the DER portfolio will be higher than the net cost which incorporates the various benefit streams generated by the portfolio.

Figure 11: Summary of Storage System Technical Characteristics and Costs



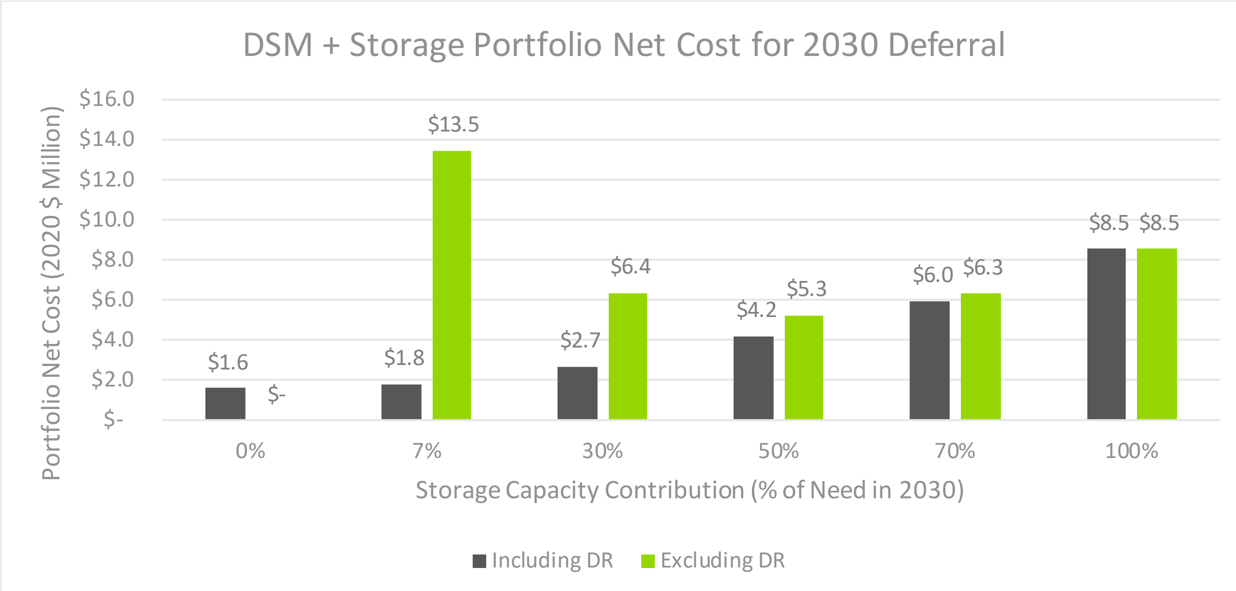
Source: Navigant Analysis

3.1.3 Developing a Portfolio of DER and Storage

When considering the LCOC calculations for all non-storage DER, the team noted that the net costs for DR potential are low and would benefit from further research. It is likely that there are some low-cost opportunities for DR on Bainbridge Island.[23] However, there is a wide range of cost and benefit uncertainty around how the DR measures were characterized for the 2017 IRP. In this report, we used data consistent with the IRP as the best available data to support this analysis. Therefore, Navigant developed two versions of the recommended solution—portfolios with and without DR. Figure 12 shows a summary of the net cost of each portfolio to defer the need until 2030. Note that it is not possible to develop a portfolio that meets the 2030 need without using DR or storage—hence there is no value for the “0% storage-excluding DR” case.

[23] A prior pilot of DR in BI concluded that a participation level of 20% could result in a possible 1 to 2 MW peak reduction. It also noted that the cost of implementing demand side conservation could be minimal, but based on the results from pilot project, demand response costs could also be sizable and may not compare favorably to other alternatives delivering similar benefits.

Figure 12: DER Portfolio Cost to meet the 2030 Capacity Need, With and Without DR



Source: Navigant Analysis

Note that with DR, the least-cost portfolio is just below $2M and includes no storage. The Navigant team recommends caution with this portfolio due to both DR measure characteristic uncertainty mentioned above, and the existence of a real yet unmonetized operational flexibility benefit provided by storage. Storage is a dispatchable resource,[24] so a certain amount of storage is beneficial to PSE to ensure the rest of the DER in the portfolio perform as planned from 2021-2029 before all resources are needed in 2030. Therefore, Navigant recommends sizing the storage to meet 50% of the capacity needs in 2030. This results in a ~$5.5M portfolio excluding DR, and a ~$4.5M portfolio including DR. So, depending on the economics of DR, PSE can expect that the *net cost* of the optimal portfolio is within this range, which is significantly less costly than the distribution components of the conventional wired upgrade (approximately $11.25M [25]). Note that the net cost does not represent the required expenditure for the non-wires solution, but the overall cost net of benefits mentioned in Section 3.1.1.

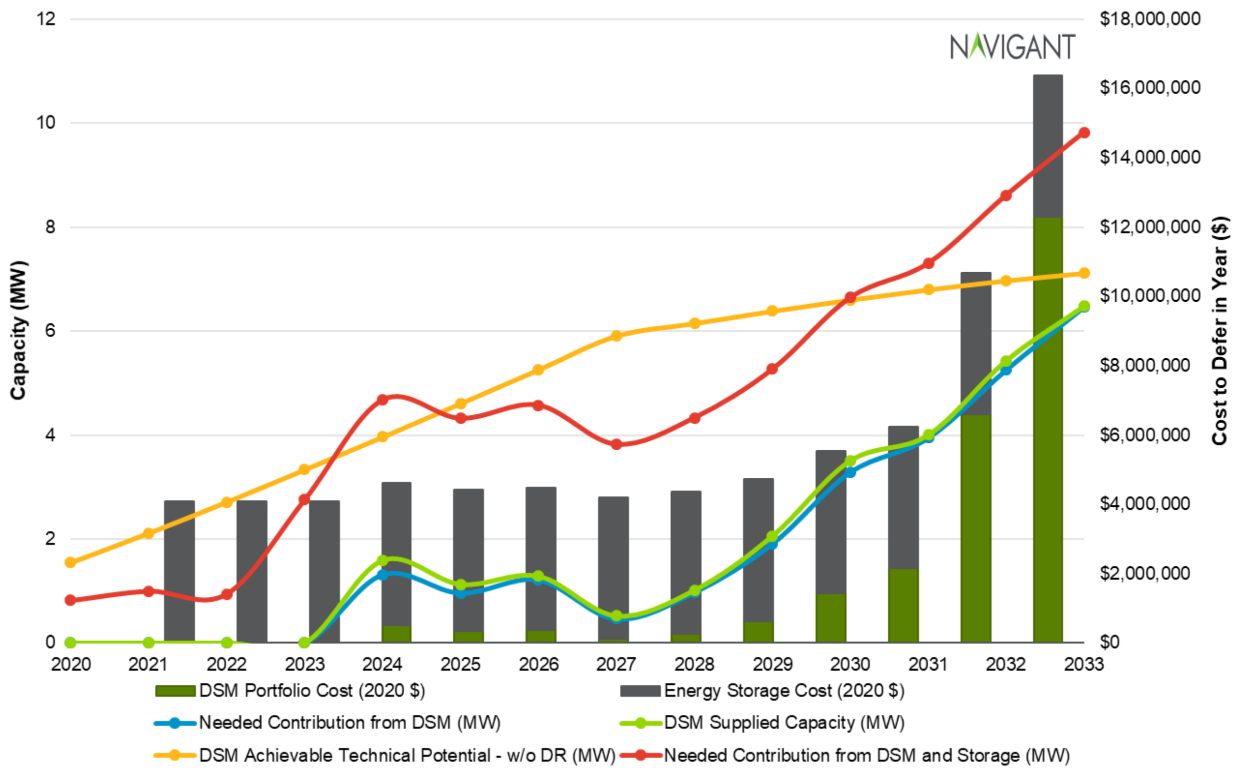
PSE may also seek to defer the need for a shorter or longer time period than 2018-2030. For example, a shorter deferral period may be less costly. Also, a shorter deferral period provides time for more information to be included in the load forecast and for updating the load forecast if necessary. PSE may also target a longer timeframe for additional planning buffer, which will increase the chances of completely avoiding the need for wired investments farther into the future. Figure 13 presents a picture of these options, excluding DR, with storage sized to meet 50% of the 2030 need. Because this scenario excludes any DR resources, Navigant believes this to be a conservative representation of the non-wires portfolio cost (in other words, if DR is pursued, it is likely to reduce the costs of the overall DER portfolio). In Figure 13 below, Navigant uses the term "DSM" as shorthand for energy efficiency (both residential and commercial) and renewable distributed generation (anaerobic digester) measures. As discussed in

[24] Note that DR is also a dispatchable resource; however its flexibility in use in extremely constrained in the number of times it can be used per year as well as how often it can be called. Thus, it provides little operational flexibility relative to battery energy storage.

[25] Note that costs are July 2018 PSE cost estimate based on similar past projects in other areas of PSE service territory. Does not include site-specific engineering.

Section 3.1.4, solar PV is not a cost-effective resource for capacity contributions to the January Bainbridge Island peak.

Figure 13. Supplied Capacity vs. Portfolio Costs over Time, with 50% Storage, Excluding DR



Source: Navigant Analysis

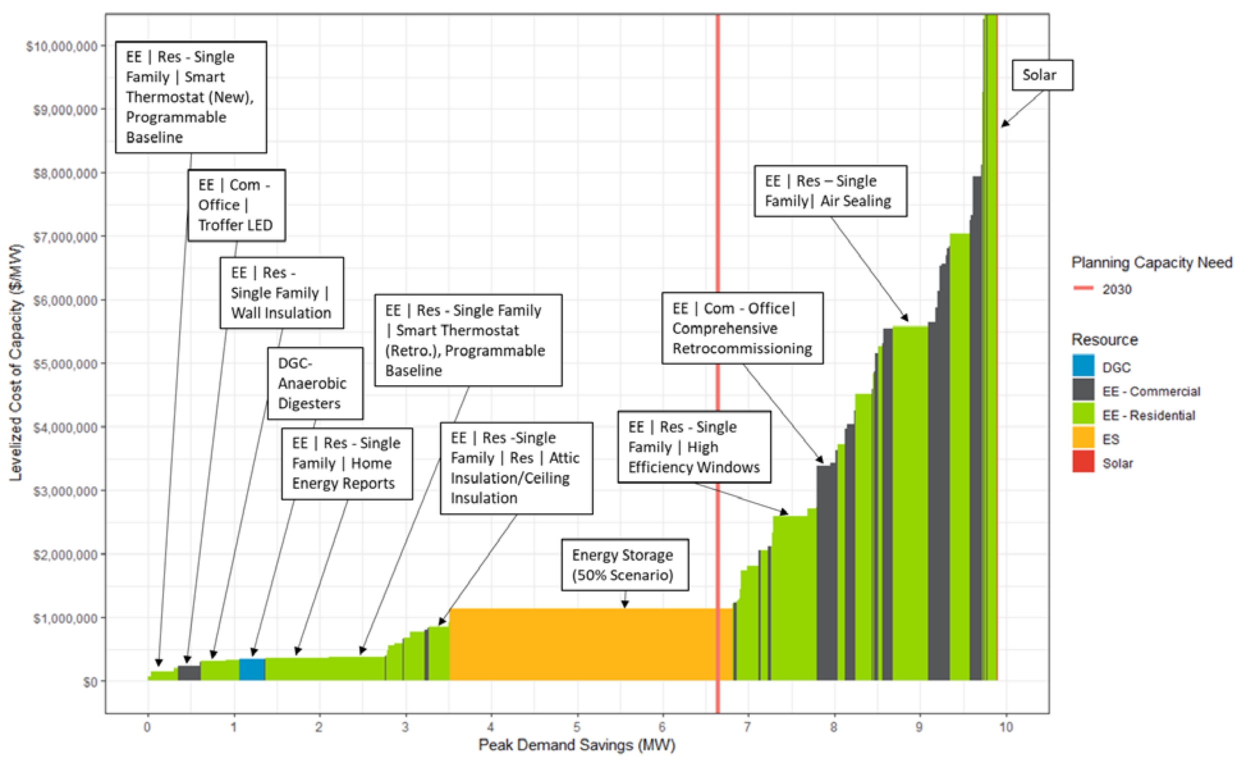
Because the incremental achievable technical potential grows over time (shown in Figure 8 and in Figure 9), and the capacity need varies in each year based on the load forecast, the net cost of the NWA portfolio depends on the number of years that PSE seeks to defer a wired investment. The bars in Figure 13 show the full cost in 2020 dollars of designing a portfolio that meets the need in each year shown on the y-axis. Figure 13 shows storage-only, if online by 2021, will meet the need at a cost of below ~$4M until 2024, when some DSM is required. Because the load forecast flattens and decreases from 2024-2028, the portfolio designed for 2024 will meet the need until 2029-2030, when the need for additional DSM increases the portfolio cost to ~$5.5M in 2030. Beyond 2030 PSE would need to acquire some of the more expensive elements of the DSM portfolio to continue to meet the capacity need, and therefore the portfolio costs increase dramatically. The needed contribution from DSM (blue line) accounts for the fact that the storage provides 3.3MW, 5MWh of deferral in each year—so that in 2030 half of the capacity is provided by storage and the other half by DSM (e.g., the green line is half of the red line).

This preliminary analysis demonstrates that a hybrid non-wired solution is technically feasible, and in most cases is economically-preferable to the wired solution—depending on the length of deferral that may be acceptable to PSE. After revisiting the NWA strategy on Bainbridge Island in light of the results of this preliminary economic analysis, PSE may decide that a more complete economic assessment and feasibility study are warranted. Further economic analysis should account for considerations associated with customer-facing programs, such as ramp-up time, program administrative costs, and stakeholder concerns—all of which may factor into the analysis as additional costs or benefits of pursing the hybrid non-wired solution.

3.1.4 DER Supply Curve

As a next step, PSE may seek to design the least-cost portfolio of DER to meet the need. To determine the specific measures that may compose this portfolio, Navigant developed a supply curve ordering DER options for capacity deferral from least cost to highest cost, shown from left to right in Figure 14 below, using a levelized cost of capacity calculation outlined in Section 3.1.1. The levelized cost of capacity (LCOC) is shown on the y-axis, while the cumulative capacity is shown on the x-axis. Figure 14 ranks all measures in the 2030 achievable technical potential estimate from lowest to highest cost—each bar represents a measure, and the width of each bar represents the three-substation group capacity savings (MW) that the measure can provide. The red vertical line is at 6.6 MW of capacity—the needed capacity in 2030.

Figure 14. DER Supply Curve (Excluding DR) Based on Levelized Cost of Winter Peak Capacity for Bainbridge Island

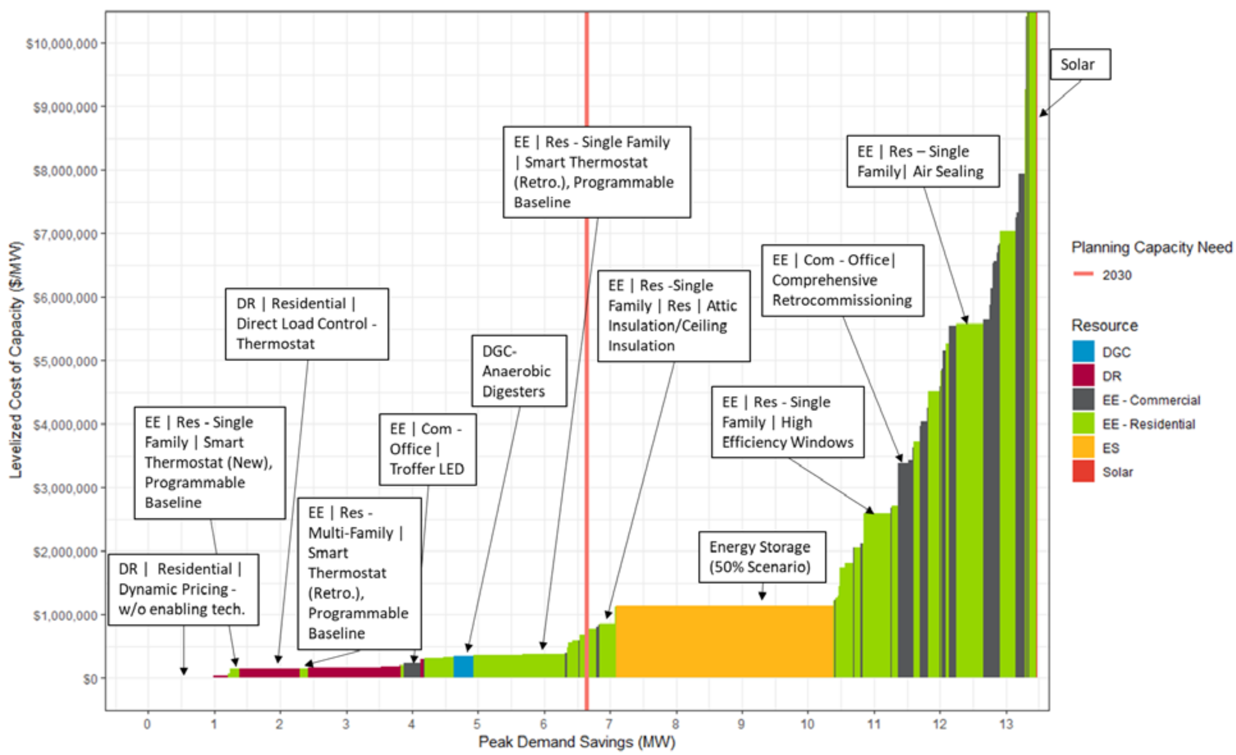


Source: Navigant Analysis

Recall that this analysis is constrained to examining *incremental* achievable technical potential only. PSE has already committed to pursuing cost-effective energy efficiency in the baseline "with DSM" net load forecast—so any negative cost demand-side resources are already being pursued and therefore not shown in this graph. Furthermore, as expected, solar makes a very small, high cost contribution to January capacity needs, which is barely visible on the far-right side of the graph.

Figure 15 shows the same graph with DR included. Note that the baseline "with DSM" forecast does not include any DR, which is why most of the low-cost DR resources appear to be lower cost than the EE in this figure—the even lower cost EE resources are already being pursued in the baseline load forecast. However, Navigant cautions against presuming that all DR on Bainbridge Island will be low-cost[26], because the resource is not well-developed in PSE territory, and therefore a conservative approach to a non-wires solution may include no DR. Note also in this scenario that the need can technically be met cost-effectively without any energy storage, yet Navigant recommends including some energy storage in the solution portfolio to maintain operational flexibility. Approximately 1 MW of DR measures on the left side of the graph have very close to $0 net cost and are therefore difficult to see on the graph.

Figure 15: DER Supply Curve (Including DR) Based on Levelized Cost of Capacity for Bainbridge Island



Source: Navigant Analysis

[26] In this preliminary analysis, Navigant leveraged data directly from the 2017 IRP to the greatest extent possible—but it is possible that the cost data for DR were not intended to be directly compared to other DER for local capacity deferral purposes. In future economic analysis, it may be prudent to continue to consider DR resources separately, or to re-characterize these resources to ensure that LCOC comparisons across all resource types are developed using a consistent set of assumptions.

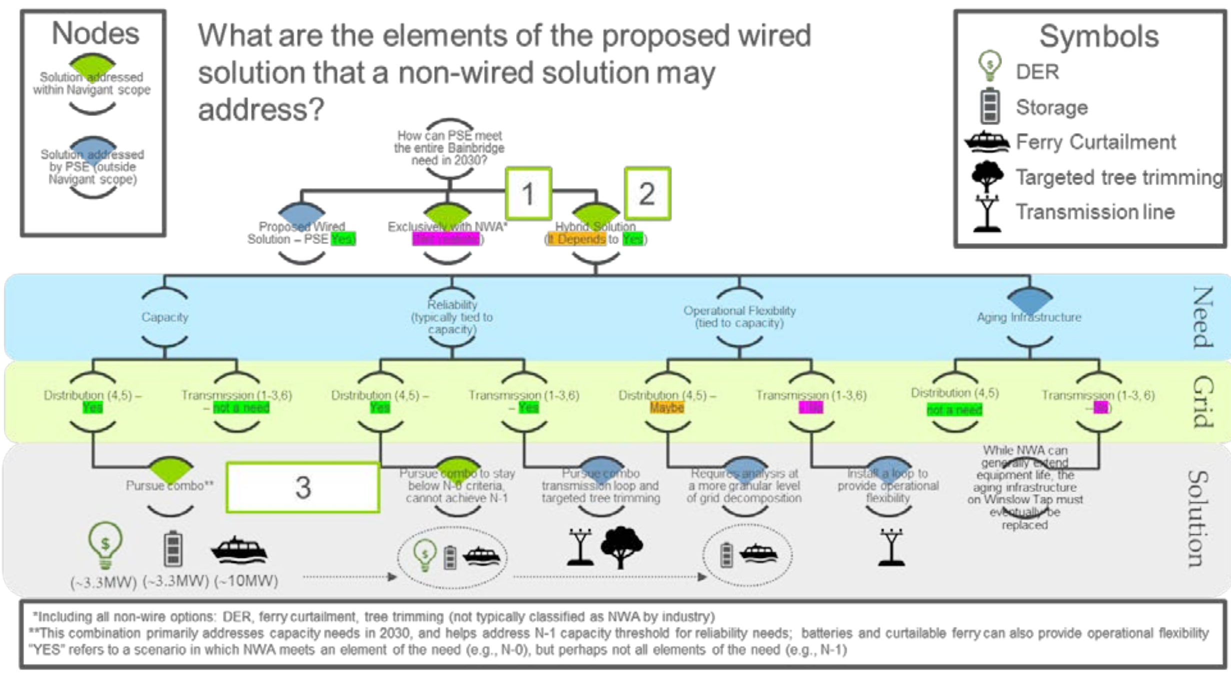
4. CONCLUSIONS AND RECOMMENDATIONS

Navigant has summarized below the conclusions and recommendations from the NWA assessment, including the DER potential assessment and economic analysis.

4.1 Conclusions

The decision tree framework introduced at the beginning of the report is useful for contextualizing the conclusions. The three numbers in Figure 16 below correspond to conclusions presented below in this section.

Figure 16. Bainbridge Island Decision Tree Including Numbered Recommendations



Source: Navigant Analysis

Navigant concluded the following:

1. It is not realistic or economically feasible for PSE to meet all the transmission and distribution needs on Bainbridge Island with solely a non-wires solution. Based on Navigant's high-level assessment and engineering judgment, however, it is likely that meeting the BI needs using the broad definition of non-wires alternatives discussed above is *technically* possible.[27] The costs and disruption on BI caused by this approach would be significant. Aging infrastructure and transmission reliability are key needs which are typically not economically feasible to address with NWAs.

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[27] The broad definition includes the DERs (EE, DR, renewable CHP, PV) as well as storage and vegetation management, along with targeted O&M measures. This solution would, in our estimation, need to include an aggressive use of storage that would be very expensive, as well as aggressive tree trimming and removal that would be highly visible to residents and counter to community values on BI. Or, for example, while it is theoretically and technically possible to develop island-able microgrids for each individual neighborhood on Bainbridge Island, Navigant believes this would be cost prohibitive and highly unlikely as an acceptable solution.

2. A hybrid non-wired solution using traditional wired investment for the transmission needs, and DER (non-wires) investment for distribution capacity and reliability needs is a viable option for consideration (see #3). The specific wired solution that serves as the baseline for this hybrid solution is the transmission loop on BI that satisfies the transmission capacity and reliability aspects identified in the *BI Needs* document. Further analysis of this hybrid solution may incorporate the broader definition of NWAs, e.g., including vegetation management, which may solve additional transmission reliability elements of the identified needs.

3. PSE can delay reaching the planning trigger for the 3-substation group on BI from 2020 to approximately 2030 (possibly beyond) by leveraging the ferry electric load as a curtailable resource and by aggressively pursuing and expanding the DER portfolio on BI. Thus, distribution capacity related needs can likely be met on BI. The analysis made significant progress toward developing the non-wires distribution capacity solution and suggests that PSE can address local capacity needs based on a plan that:
   d. Connects the ferry electrification load (10MW) as a curtailable resource
   e. Incorporates storage to meet the capacity need and provide operational flexibility to help ensure that other demand-side resources perform as anticipated.
   f. Aggressively pursues expanding the DSM portfolio on BI, to complement storage, as the more economical alternative to a traditional wired capacity expansion.

The portfolio identified can help meet a portion of reliability needs as well as provide operational flexibility—primarily through ferry curtailment capability and appropriate operation of storage. However, specific details and quantification of the reliability and operational flexibility value the DER portfolio provides requires further, more granular analysis.

4.2 Recommendations and Next Steps

The conclusions presented above lead Navigant to recommend the following Bainbridge Island specific actions:

- **Connect the Ferry as a Curtailable Load:** PSE should work with relevant stakeholders to plan and operationalize the ferry as a curtailable load. Curtailing the ferry provides an opportunity to reduce the capacity needs on Bainbridge Island. These types of "big wins" involving large customers are essential to non-wires projects in our experience. Navigant's analysis of the historical loads on Bainbridge Island from 2013-2017 indicate that the ferry would need to be curtailed an average of 30 hours a year[28] to avoid planning capacity needs around the ferry. If the ferry load cannot be curtailed, then an additional 10MW of capacity will be needed to reach the same deferral targets. This would require some combination of additional DERs, likely weighted heavily towards additional DR and storage given there is no more renewable combustion potential, and the supply of additional EE would be expensive.
- **Launch a Pre-Implementation NWA Analysis to Validate the DSM portion of the Results**: An NWA portfolio including EE, storage, renewable DG, and the option of DR has the potential to cost-effectively defer the wired alternative until 2030 given current load forecasts. PSE should study and

[28] Fewer curtailment hours may be necessary, depending on the intended charging schedule of the ferry and whether that schedule is coincident with peak hours on the three-substation group. For more details on the ferry analysis, see Appendix A.

develop approaches to obtaining the EE, DG, and DR portions of the NWA portfolio on BI starting as soon as feasible.

- **Pursue Answers to Key Questions**: Future feasibility studies of the ability for PSE to pursue a cost-effective non-wires solution on Bainbridge should address the following questions:
    a. Unforeseen costs. Are there unforeseen costs associated with developing a targeted implementation of DER for Bainbridge? The measure characteristic assumptions (incremental cost, lifetimes, unit energy savings) used in this report are consistent with PSE's 2017 IRP, so represent the best available data at the PSE system level, also considering the applicable measures for Bainbridge Island based on the specific customer loads in that ZIP code. However, there may be additional cost considerations associated with implementing a targeted DR/EE program. PSE staff in Strategic System Planning could seek internal expertise on this topic by presenting Customer Energy Management staff with the measures in the recommended DER portfolio and discuss implementation considerations. Finally, there may be other grid-side costs (e.g. feeder upgrades) associated with avoiding the substation upgrade as a result of implementing the DER-based hybrid-non-wires solution.
    b. DER Derating Factor. What is the appropriate "derating" factor to apply to behind-the-meter capacity resources on Bainbridge Island? Not all customers can be guaranteed to respond to a demand response event. Similarly, load shapes for energy saving measures vary by customer. This variance may present operational considerations at the local level—a context where averaging the savings across a population of fewer customers may not result in a smooth hourly savings profile. The potential impact of customer-by-customer variance is a reason that Navigant recommends including energy storage in the portfolio to "firm up" and smooth the savings from behind-the-meter resources. Storage can be used to test DER resources in the early years (2021-2023) when the capacity needs are not as high as later years (2024, then again in 2029). This analysis assumes that all behind-the-meter resources save energy during hours typical of each measure, using load shapes vetted during development of the 2017 IRP. As the local capacity needs are not significant in early years (2018-2022), as PSE begins to implement this targeted program, PSE should perform detailed evaluation, measurement, and verification of the DER savings to understand whether the DER capacity contributions are lower or higher than modeled in the current analysis—and revise program plans accordingly.
    c. Load Forecast Refinement. PSE is consistently refining load forecasting methodology, in particular as advanced metering infrastructure becomes more prevalent in the service area. The definition of the capacity needs depends on this load forecast, so this analysis should be revisited if PSE has reason to believe the load forecast has changed significantly from that used in the *Bainbridge Needs* document.
    d. Customer Adoption. Will customers on Bainbridge Island adopt DER at a rate faster or slower than the typical power customer in the Pacific Northwest? The achievable technical potential estimate for DER is based on technology diffusion "ramp rates" developed by the Northwest Power and Conservation Council. These are region-wide adoption assumptions, which may or may not apply to BI customers. Additional customer outreach and research on BI would help to determine how receptive customers may be to targeted NWA efforts—which would allow the program implementation team to set realistic goals and lead times that ensure enough DER is installed on the necessary timeframe.
- **Leverage These Findings to Align with BI Stakeholders:** PSE staff can use the findings presented here as input for development of NWA approach alternatives on Bainbridge Island. The findings and illustrations should allow PSE to present the complexities of the decision-making process and

relevant portions of the analysis to stakeholders in a way that is congruent with PSE's broader NWA strategy on Bainbridge Island. Specifically, PSE can consider:

a. How does PSE present the information to help stakeholders understand the grid needs on Bainbridge Island?

b. How will stakeholders define "non-wires solution," is that consistent with PSE's strategy, and how can PSE manage their expectations of this definition?

c. Which aspects of the hybrid solution may be challenged by the public or local community?

In addition, Navigant recommends the following actions that are not specific to Bainbridge Island:

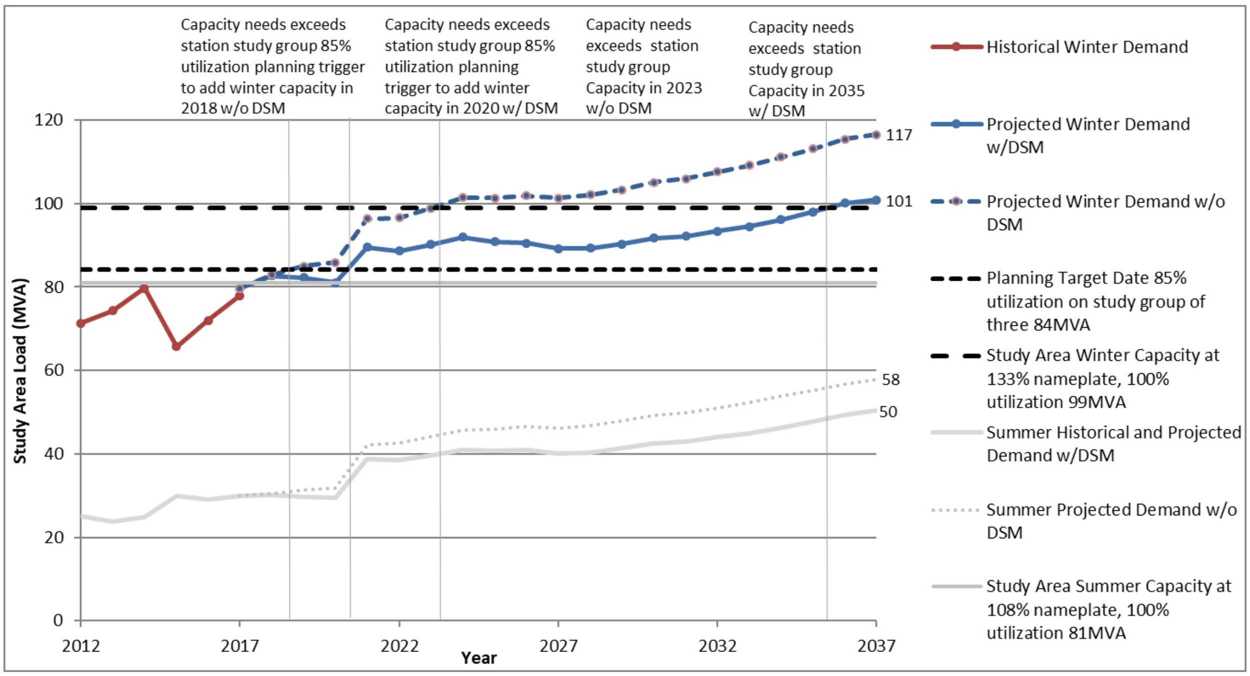
- PSE should *componentize* future wired planning solutions in a structured manner to provide flexibility in enabling wired, non-wires, and hybrid non-wires solutions. By this we mean tie the solution (transmission or distribution) to the specific need or needs addressed in the needs document. Whenever possible ensure that it is possible to decouple solutions into pieces that can be addressed using a hybrid non-wires strategy.
- PSE should select and develop a realistic non-wires pilot solution for implementation to begin to mature the non-wires process. The organizational learnings in planning and operations take time to incorporate fully and addressing low consequence non-wires or hybrid non-wires projects with enough time and pre-planned "off-ramps" will enable PSE to execute high-pressure non-wires solutions when they arrive.
- Non-wires alternative analysis requires significant quantitative complexity, considering multiple scenarios, using datasets from different divisions within PSE (Integrated Resource Planning, Strategic System Planning, Customer Energy Management, for example). PSE can use learnings from this Bainbridge Island analysis to develop a process for future NWA assessment. Such a process would require development of standardized quantitative analysis tools, and likely new processes within the organization.

APPENDIX A. BASELINE LOAD FORECAST

The baseline was developed beginning with PSE's load forecast for the substations on Bainbridge Island from the needs assessment. Forecast scenarios varied by three different variables: weather (normal or extreme), ferry (in place or not), and DSM (included or not). After several iterations, the baseline that was decided upon assumed normal weather conditions, without the Ferry, and with DSM called for in the IRP included. These iterations and decisions are discussed in more detail below.

A.1.1 Technical Adjustments

Figure A-1 PSE Initial Load Forecast



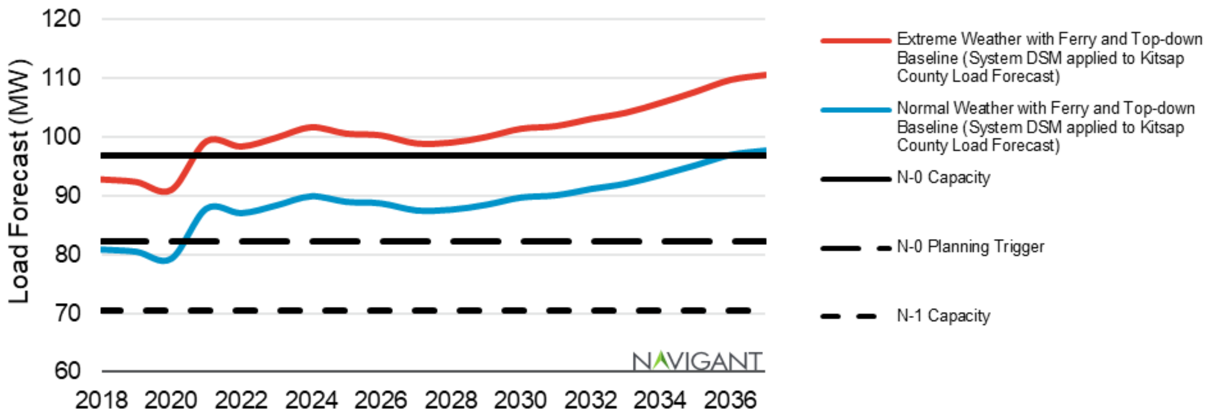
Source: Navigant Analysis

The PSE initial load forecast is shown in Figure A-1. A power factor conversion was applied on the MVA units to convert the forecast into MW load. The conversion factor was determined by comparing actual reads from the three substations on Bainbridge Island that were provided in MVA and MW. The load forecast was also disaggregated from the ferry impact, which was then included separately as a 10 MW load for the life of the ferry.

A.1.2 Winter Peak Weather

PSE-provided load forecasts based on "normal" and "extreme" winter peaks, corresponding to winter peak temperatures of 23°F and 13°F, respectively. The load forecast assuming the ferry load is included and using the top-down technical potential (assumptions discussed in sections A.1.3 below and 0 below) is shown in Figure A-2.

Figure A-2. Extreme Weather vs. Normal Weather Load Forecast



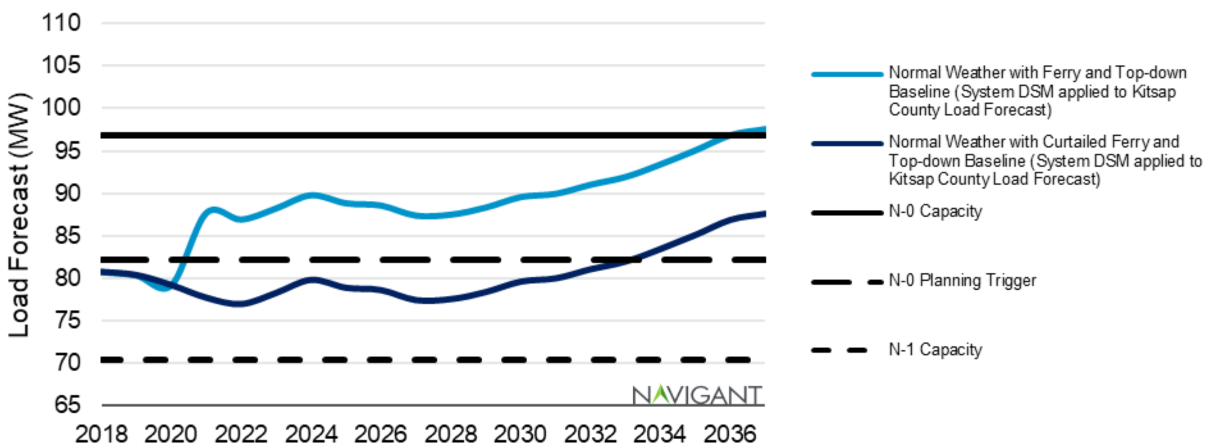
Source: Navigant Analysis

The normal weather scenario was selected as the baseline to represent a more average load forecast and remain consistent with PSE's selected load forecast.

A.1.3 Ferry Electrification

Ferry electrification in 2021 represents a large additional load (10 MW) which if not present would bring the load forecast below the N-0 Capacity threshold (assuming normal weather conditions and the top-down baseline DSM measures) and would defer the *N-0 Planning Trigger* from 2020 to 2033 or later, as seen in Figure A-3.

Figure A-3. Top-Down Baseline Forecast with and without Ferry Load

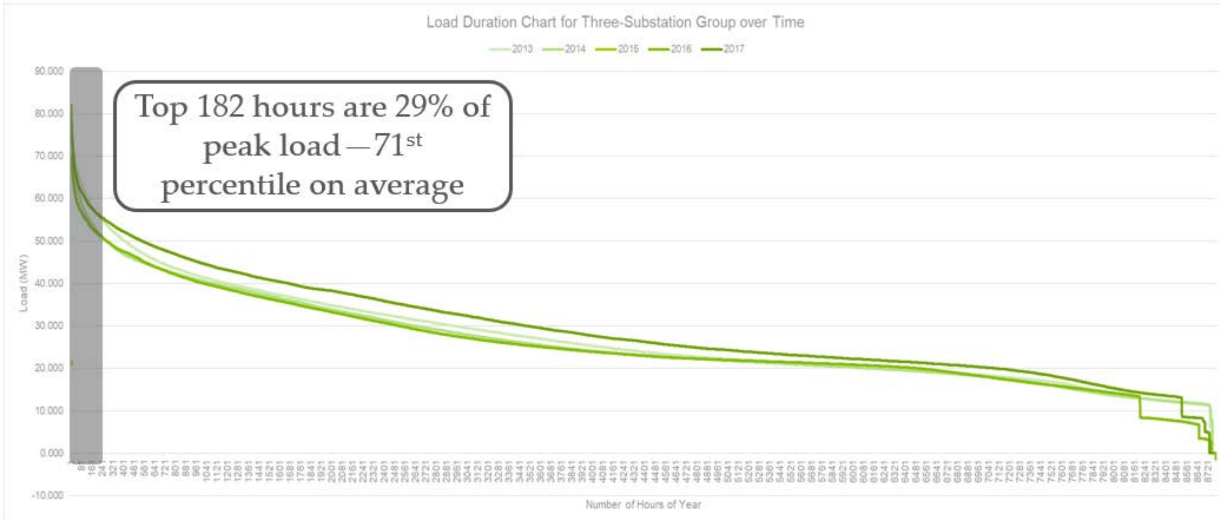


Source: Navigant Analysis

Importantly, the potential tariff structure for the ferry (Electric Tariff G, Schedule 46)[29] defines this load as interruptible for no more than 182 hours during a 12-month period. As illustrated in the load duration curve for the three-substation group below, the top 182 hours on Bainbridge Island over the past represent about 29% of the peak load.

[29] https://pse.com/aboutpse/Rates/Documents/elec_sch_046.pdf

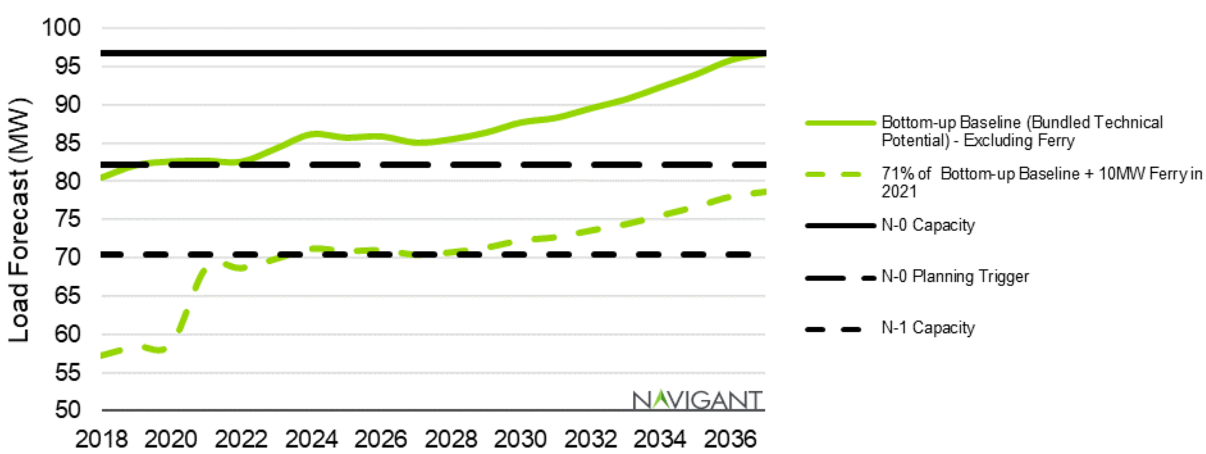
Figure A-4. Load Duration Chart and Illustrated Top 182 Hours for Three Substation Group



Source: Navigant Analysis

This means that if the ferry could be curtailed for the peak 182 hours in a year, then on the theoretical 183rd peak hour PSE would expect to supply the 10 MW ferry load plus 71% of the annual peak load. The question then becomes whether that load in the theoretical 183rd hour (71% of the peak plus the 10 MW ferry) is greater than the peak load in the top hour of the year without the ferry. As seen in Figure A-5, the peak load in the top hour of the year without the ferry is higher than the peak load in the 183rd hour, implying that with curtailment of the ferry PSE doesn't need to consider the ferry in the peak load forecast for capacity planning.

Figure A-5. Baseline Load Forecast Excluding Ferry vs. 183rd Peak Hour Plus Ferry Load

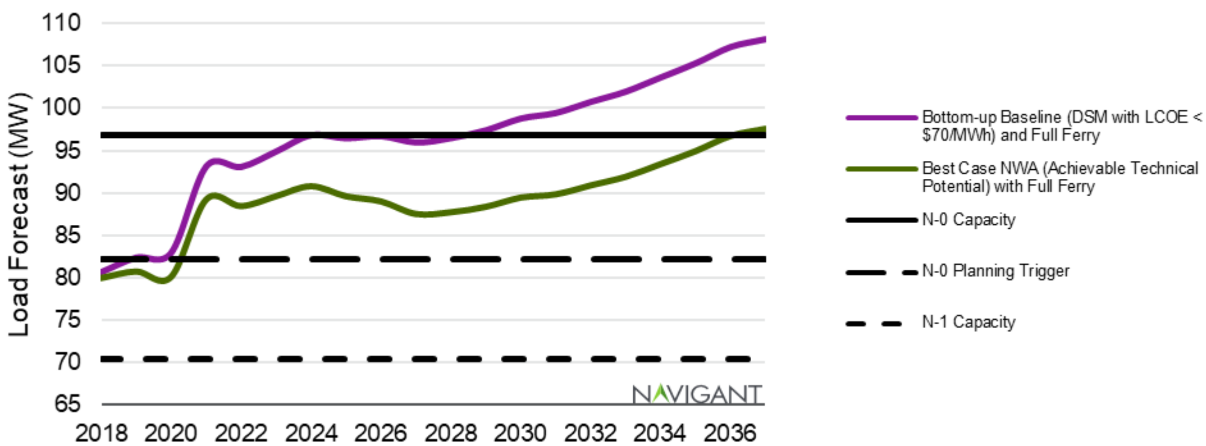


Source: Navigant Analysis

This analysis lead to the assumption that the ferry is curtailed as part of the baseline load forecast used to determine the capacity needs on Bainbridge Island.

This assumption depends on PSE's ability to utilize the ferry as a curtailable resource. One aspect that is then also important is when the decision to curtail the ferry load would need to be made. As seen in Figure A-6 (which utilizes the bottom-up baseline discussed in 0 below and the technical potential from the analyzed DER discussed in Section 2.2), the timing of the decision depends on the threshold for analysis. If the primary threshold is the *N-0 Planning Trigger* – as has been assumed throughout this work – then the DER alone would not be able to lower the load forecast when the ferry comes online in 2021, meaning that curtailing the ferry would need to be addressed from the beginning. However, if the *N-0 Capacity* threshold is considered instead, then the incremental DER could delay the need for ferry curtailment from 2023 to around 2035. Again, for this analysis the ferry was assumed to be a curtailable load starting in the near term (2020 and beyond).

Figure A-6. Baseline and Best-Case NWA Assuming the Ferry is Not Curtailed



Source: Navigant Analysis

Navigant analyzed the three-substation historical load to estimate how many hours the ferry may need to be curtailed each year. The need for the three-substation group is based on the peak load, and the ferry would add 10MW to load any time it is charging. Given that the ferry load is 10MW, the team ordered the hours from 1 to 8760 based on highest to lowest load, and identified which hour number is 10MW below the absolute peak as a proxy for how many hours the ferry may need to be curtailed. For example, on the 31st highest hour in 2013, even if the ferry was charging during that hour, the additional ferry load would not increase capacity needs on the three-substation group, because the 31st hour load + 10MW would still be less than the absolute peak load in 2013. The results in Table 6 ranged from 10-54 hours over the 5 years of historical load data, with an average curtailment of approximately 30 hours.

Table 6: Historic Analysis of a 10MW Load Reduction

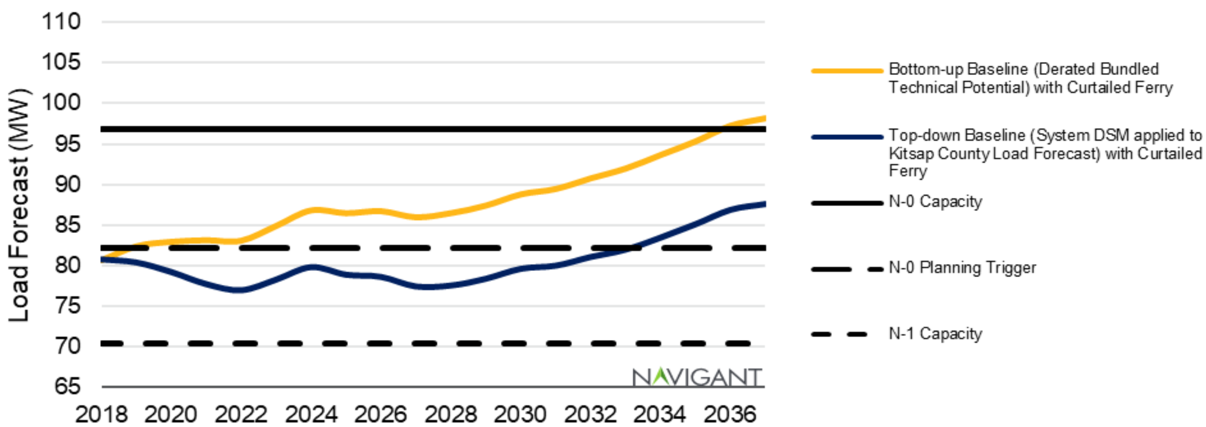
Hour ranking 10MW below annual peak load					
Average	**2013**	**2014**	**2015**	**2016**	**2017**
29.6	31	10	54	25	28

Source: Navigant Analysis

A.1.4 Business-as-Usual Measures (Top-Down vs Bottom-Up Potential Analysis)

The third variable for the baseline is inclusion of demand-side management that is already being pursued on Bainbridge Island as described in the 2017 IRP. The load forecast provided by PSE used a "top-down" method wherein system level DSM was applied to the Kitsap County Load Forecast. With access to the zip-code level data used to originally generate PSE's 2017 IRP, Navigant was able to develop a "bottom-up" forecast that analyzed resources for the 98110-ZIP code (Bainbridge Island) then sum the impact in that ZIP code for measures in the top 3 LCOE bundles (with an LCOE less than or equal to $70/MWh). As seen in Figure A-7, the "bottom-up" method or the "Bundled Technical Potential" yielded a higher load forecast for Bainbridge Island than the "top-down" method, likely because Bainbridge Island has more residential load as a fraction of overall load than average across the rest of Kitsap County, which may have led to an overestimate of commercial and industrial energy efficiency savings.

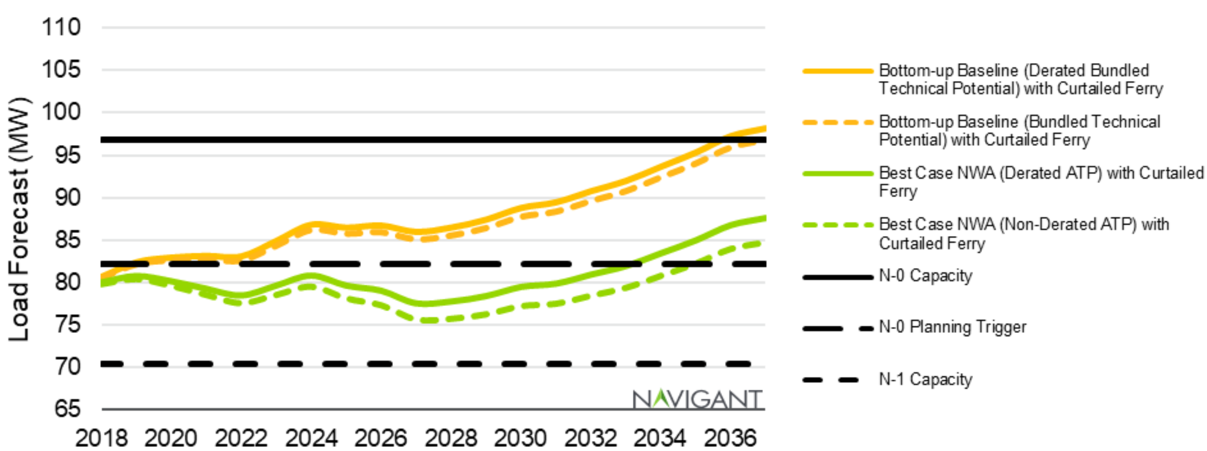
Figure A-7. "Bottom-Up" Bundled Technical Potential vs. Top-Down" DSM



Source: Navigant Analysis

When developing the bottom-up baseline, there was also a question on whether to apply an NPCC mandated achievability factor in addition to adoption factors that were already applied in the model. The NPCC dictates this achievability derating factor (typically 85%) for the service territory, which may not be suitable when developing a technical potential analysis specifically for Bainbridge Island given the demographic makeup and the urgency of the NWA program versus a typical, system-wide energy efficiency program. The decision to include the derating factor thus affects both the bottom-up baseline and the best-case NWA forecast, as can be seen in Figure A-8.

Figure A-8. Bottom-up Baseline and Best-Case NWA with and without Achievability Factor



Source: Navigant Analysis

The non-derated (dotted) lines represent a sort of best-case scenario with an achievability factor on Bainbridge Island of 100% rather than the prescribed value from the NPCC. While the difference is minor, this analysis uses the derated values to remain consistent with the NPCC, with the understanding that as incremental DER measures are pursued on Bainbridge Island the actual achievability factor can be determined.

APPENDIX B. PEAK PERIOD ANALYSIS

Using actual hourly load shape data from the three substations on Bainbridge Island over the past 5 years, the peak period was determined to be weekdays in December and January from 7:00 am to 11:00 am.

First, we analyzed the number of days each substation would surpass a given threshold for a certain hour of the day for each year, indicating the most typical peak hours, as illustrated in Figure B-1.

Figure B-1. Heat Map for 2017 Load for a Selected Bainbridge Substation and Year

Number of Days in 2017 above the Stated Threshold for each Month and Hour of Day for Selected Substation

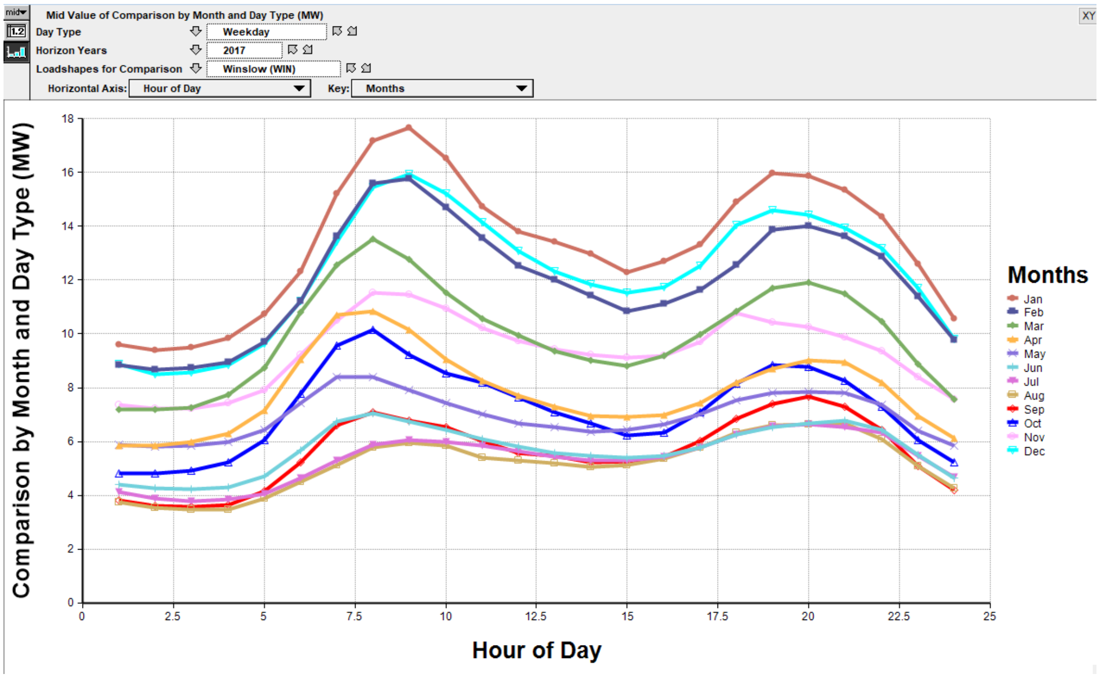
Threshold MW: 21 | Top: 51 Hours; >= 77.6% of 2017 Peak Load on the Sub

Hour of Day	January	February	March	April	May	June	July	August	September	October	November	December
1:00 AM	-	-	-	-	-	-	-	-	-	-	-	-
2:00 AM	-	-	-	-	-	-	-	-	-	-	-	-
3:00 AM	-	-	-	-	-	-	-	-	-	-	-	-
4:00 AM	-	-	-	-	-	-	-	-	-	-	-	-
5:00 AM	-	-	-	-	-	-	-	-	-	-	-	-
6:00 AM	-	-	-	-	-	-	-	-	-	-	-	-
7:00 AM	2	-	-	-	-	-	-	-	-	-	-	-
8:00 AM	7	1	-	-	-	-	-	-	-	-	-	3
9:00 AM	9	1	1	-	-	-	-	-	-	-	-	4
10:00 AM	9	-	1	-	-	-	-	-	-	-	-	4
11:00 AM	3	-	-	-	-	-	-	-	-	-	-	3
12:00 PM	-	-	-	-	-	-	-	-	-	-	-	1
1:00 PM	-	-	-	-	-	-	-	-	-	-	-	-
2:00 PM	-	-	-	-	-	-	-	-	-	-	-	-
3:00 PM	-	-	-	-	-	-	-	-	-	-	-	-
4:00 PM	-	-	-	-	-	-	-	-	-	-	-	-
5:00 PM	-	-	-	-	-	-	-	-	-	-	-	-
6:00 PM	-	-	-	-	-	-	-	-	-	-	-	-
7:00 PM	1	-	-	-	-	-	-	-	-	-	-	-
8:00 PM	1	-	-	-	-	-	-	-	-	-	-	-
9:00 PM	-	-	-	-	-	-	-	-	-	-	-	-
10:00 PM	-	-	-	-	-	-	-	-	-	-	-	-
11:00 PM	-	-	-	-	-	-	-	-	-	-	-	-
12:00 AM	-	-	-	-	-	-	-	-	-	-	-	-

Source: Navigant Analysis

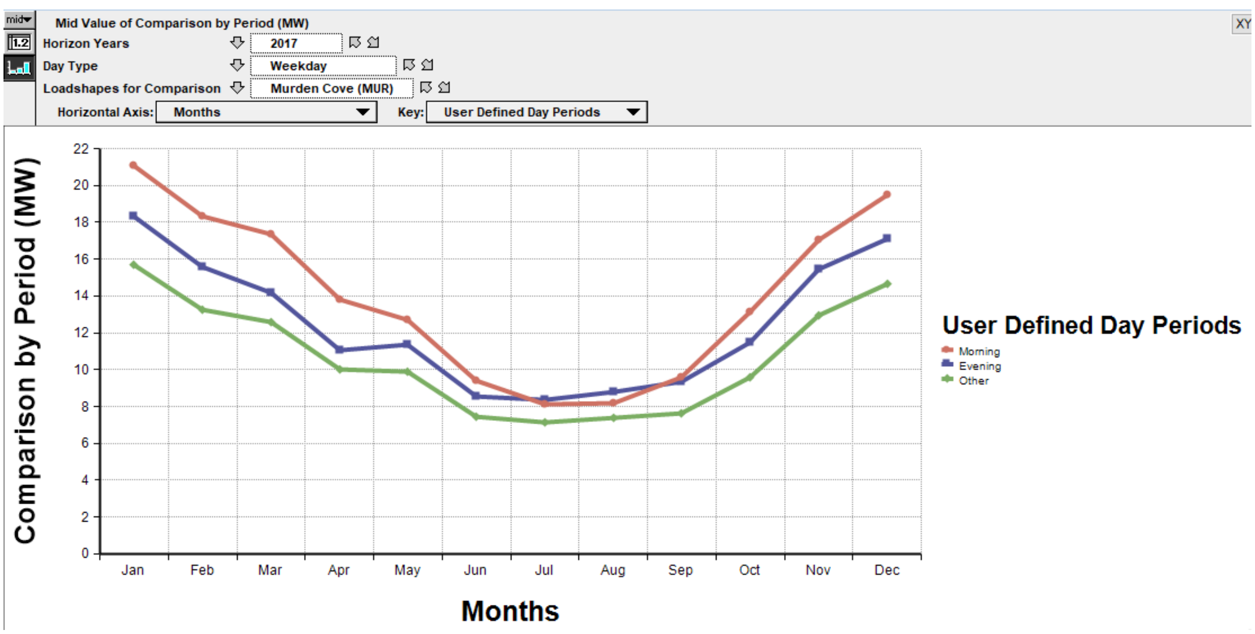
This analysis quickly indicated that mornings in January and December had the most typical peak periods, which differed slightly from PSE's system peak period which also includes the night time. Additional analysis was performed to better understand the load profile on Bainbridge Island. As illustrated in Figure B-2, Figure B-3, and Figure B-4, while there is an evening peak present on Bainbridge Island (especially in the winter), it is not as large as the morning peak. In Figure B-5, we can see that the load has remained steady on average over the past 5 years, though 2017 presented a large increase.

Figure B-2. Average Daily Load by Month for a Selected Bainbridge Substation and Year



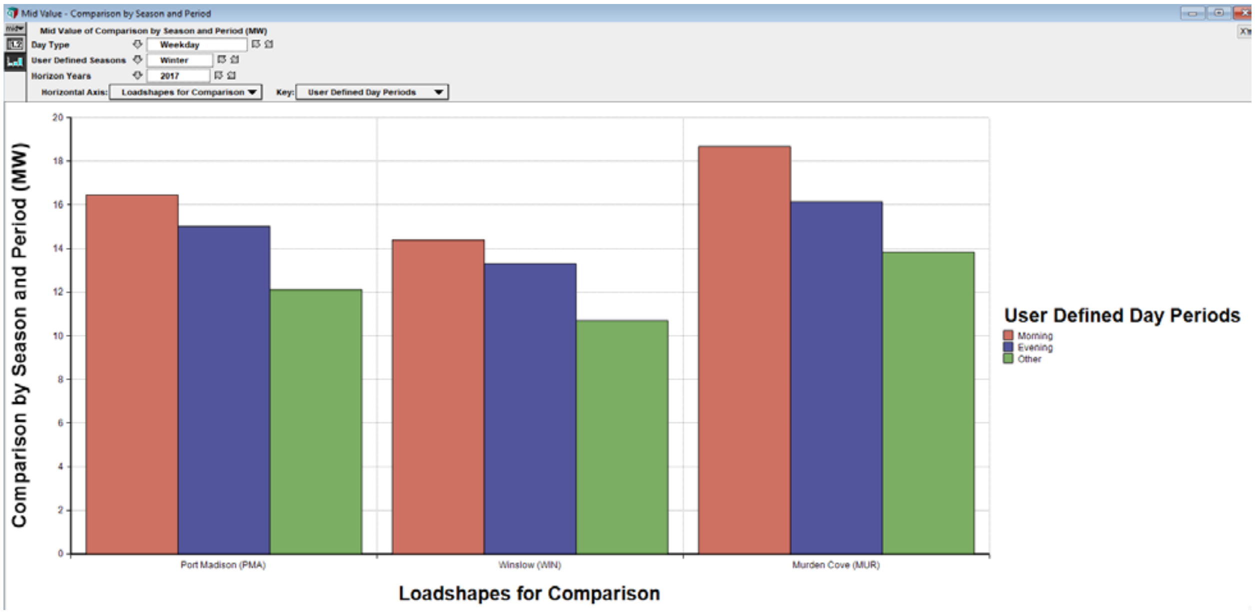
Source: Navigant Analysis

Figure B-3. Average Monthly Load by Day Period for a Selected Bainbridge Substation and Year



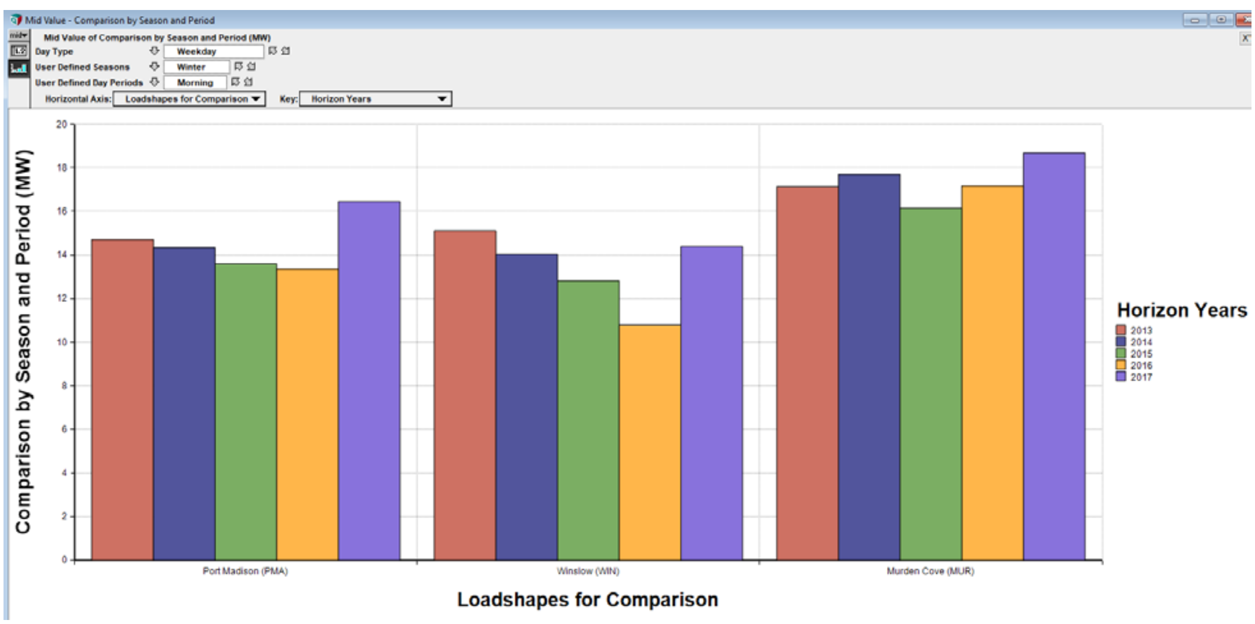
Source: Navigant Analysis

Figure B-4. Average Load by Day Period in Winter across Bainbridge Island Substations



Source: Navigant Analysis

Figure B-5. Average Winter Morning Load Over Time for Bainbridge Island Substations



Source: Navigant Analysis

This analysis indicated that mornings in December and January represent the peak period for Bainbridge Island.

APPENDIX C. ENERGY STORAGE ANALYSIS

To incorporate energy storage into the portfolio analysis, energy storage systems were assessed in incremental sizes. The approach generally followed these steps:

1. Establish inputs and assumptions
2. Size the energy storage system based upon deferral need
3. Optimize energy storage dispatch for maximum economic gain
4. Evaluate LCOC of storage based upon need met
5. Incorporate storage into portfolio

The following sub-sections describe the methodology and assumptions for each of these steps.

C.1.1 General Assumptions

Table C-1. provides an overview of the assumptions used in the energy storage analysis. The assumptions are consistent with the typical range of values for lithium-ion batteries.

Table C-1. Assumptions for Energy Storage Analysis

GENERAL	
Cycle Life	4,500 cycles (to 80% of rated energy)
Degradation	Annual degradation calculated based upon number of cycles each year. Assumed constant energy due to annual augmentation to counteract degradation.
Efficiency	90%
Equipment replacement	Annual battery augmentation (forecasted battery unit cost) to counter degradation
Financing	7.6% weighted average cost of capital
Inflation	2.5% escalation applied to operating costs and revenues
COSTS	
Capital cost[30]	\$550/kW of rated power + \$350/kWh of rated energy (2018 basis), decreasing annually at 8%/yr through 2022, then 4%/yr afterward
Fixed O&M	3% of capex per year, inflated annually
Variable O&M	\$2/MWh
Augmentation	Cost of annual battery augmentation based upon degradation (MWh) at forecasted unit battery cost (\$/MWh) in each year
Charging	Cost of charging based upon weighted average hourly energy value (\$/MWh) when charging and annual energy consumed for charging (MWh)
REVENUES	
Capacity (generation)	Annual value from IRP based upon 6-11am and 5-10pm peak periods in December

[30] These costs reflect front-of-meter installed cost including a rough estimate of land lease costs for a large bulk system as well as interconnection.

Energy	Revenue from charging based upon weighted average hourly energy value ($/MWh) when discharging and annual energy export for discharging (MWh)

Source: Navigant Analysis

C.1.2 Sizing

The team sized the storage to meet the capacity needs in 2030, defined as the bottom-up with DSM load forecast, with the ferry curtailed, against the *N-0 Planning Trigger* threshold (see Appendix A for more details on the need definition).

To evaluate incremental amounts of storage within the portfolio, discrete system sizes were evaluated based upon the percentage of the 2030 need meet (7%, 30%, 50%, and 70%). The minimum power required to meet the need, adjusting for losses,[31] was rounded up to the nearest 0.1 MW. The energy rating was determined based upon the minimum energy (rounded up to the nearest 0.1 MWh) necessary to remain below the maximum load (determined by the percentage of need met) with the rated power based upon the shape of the 2017 load curve for Bainbridge Island.[32] For 2030, the load curve was scaled proportionally in each hour based upon the ratio between peak load in 2030 versus 2017.

C.1.3 Dispatch Optimization

Optimal hourly dispatch in 2030 was evaluated for each system size based upon three applications: local capacity need, system capacity need, and energy price arbitrage. Based upon the maximum load (determined by the percentage of need met), a minimum discharge power was set for each applicable interval. A maximum charge power was also set for each applicable hour to avoid exceeding the maximum load.

Hourly dispatch was optimized to maximize economic value from generation capacity (as defined above) and energy arbitrage based on PSE-provided avoided energy costs. The forecasted value of generation capacity in 2030 ($/kW-yr) was converted into an hourly value in applicable hours based upon the number of relevant hours in the year. The combined hourly energy and capacity prices were used to determine the optimal charge and discharge strategy (while meeting minimum requirements for deferral).

C.1.4 Levelized Cost of Capacity Calculation

The levelized cost of capacity was calculated based upon expected annual costs and revenues (includes avoided costs) assuming a similar dispatch profile each year over the life of the system. Capital, fixed O&M, variable O&M, charging, and augmentation costs were calculated as described in Table C-1. The energy (MWh) basis for charging, variable O&M, and augmentation costs were calculated based upon the annual storage dispatch profile.

The annual amount of deferral (MW) was calculated as the minimum of the annual deferral need (based upon the *N-0 Planning Trigger*) and the amount of need met in 2030. The amount of capacity was assumed to be constant each year and based upon the average power output during capacity hours (as

[31] Actual need reduction, after losses, was assumed to be the square-root of the assumed round-trip efficiency (e.g., $90\%^{1/2} = 95\%$) multiplied by the rated power. This assumes equal losses during charging and discharging.

[32] The load curve was normalized as a % of annual MWh consumption occurring in each hour, such that a sum of the % values across all 8760 hours of 2017 equals 100%.

defined in Table C-1.). Energy revenue was calculated based upon the annual discharged energy (assumed to be constant) and the energy price (escalated 2.5% annually).

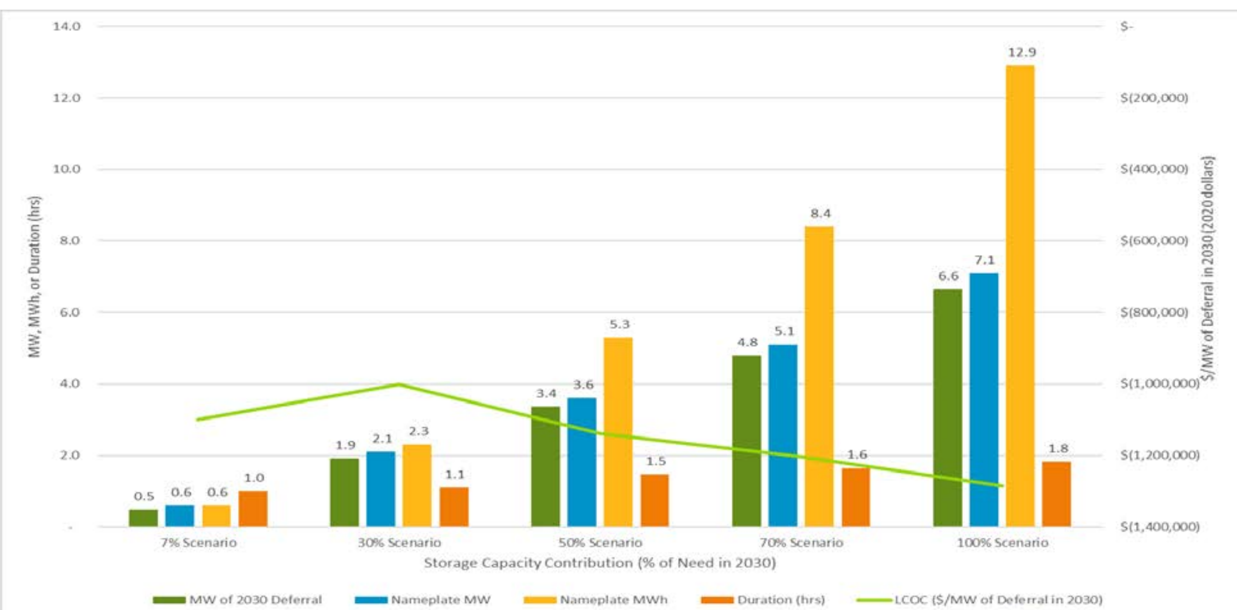
The levelized cost of capacity ($/MW) was calculated by calculating the net present value of costs and revenue ($) to 2020 dollars using a 7.6% discount rate, then dividing by the amount of need met in 2030 (MW).

The LCOC was evaluated with and without including various revenue streams. Additionally, the LCOC was evaluated using PSE's hourly avoided cost of energy in place of hourly Energy Imbalance Market (EIM) values. The dispatch optimization was calculated over one year using EIM values, and the weighted average EIM prices ($/MWh) during discharging (charging) were observed to be approximately equal to the annual average of the second highest (lowest) hourly price in a day. Thus, to approximate value based upon PSE's avoided cost of energy, weighted average discharging (charging) values were assumed to be equal to the annual average of the second highest (lowest) hourly avoided cost in a day. The amount of energy for charging and discharging was assumed to be the same.

C.1.5 Portfolio Analysis

Navigant began the economic analysis by considering various storage sizes and system characteristics according to the historical substation load shape and forecast 2030 capacity needs. Figure C-1 summarizes the results of this analysis, this section contains the complete details of the methodology. The team concluded that, when considered alone, sizing the storage system to meet 30% of the 2030 need is the most cost-efficient system design. However, design of the optimal non-wires alternative portfolio must also consider the ability to add other non-storage DER (PV, renewable combustion generation, EE, and DR) to serve the capacity needs—which influences the optimal sizing of the storage system as discussed in Section 3 of the main report.

Figure C-1: Summary of Storage System Technical Characteristics and Costs



Source: Navigant Analysis

Section 3 indicates how these results were combined with a portfolio of least-cost non-storage DER to develop the recommended non-wires solution.

C.1.6 Interpretation of Results

These results help to provide an indicative value of storage for consideration in planning. However, it should be noted that further analysis would be required before moving forward with the implementation of a specific storage system, as the actual LCOC may vary depending upon a variety of factors. The following variables and uncertainties provide examples of parameters that can significantly impact storage system sizing and LCOC:

- **Load shape** – The systems were sized to meet the need based upon the Bainbridge load shape in 2017. As other DSM strategies are employed over time, the load shape will become flatter around peak hours, requiring a longer duration (hr) of storage to meet the same need (MW), which increases the LCOC.
- **Peak load** – The systems were sized to the minimum amount necessary to meet the forecasted need (MW) in 2030. To ensure that sufficient capacity is available, in case the need is greater than forecasted, a system with greater power (MW) and a longer duration (thus higher cost in $/MW) may be prudent. It is possible that the future need may be larger or smaller than forecasted.
- **Oversizing** – To ensure that sufficient power and energy are available, the system may be oversized to mitigate uncertainty in load shape and peak load. Thus, a system with greater power (MW) and a longer duration (thus higher cost in $/MW) may be desired, which could increase the LCOC.
- **Staggered deployment** – Storage could be deployed incrementally over time to defer costs further into the future and reduce the LCOC. This would be an alternative method to help mitigate uncertainty in the load shape and load forecast.
- **Use case** – The assumed use case of storage is a utility-scale system used for deferral, generation capacity, and energy arbitrage. Alternative use cases may offer a more promising LCOC. For example, PSE may be able to utilize the storage to optimize the dispatch of its generation portfolio to lower costs, which may offer greater value than energy arbitrage. PSE could also consider additional upfront costs for islanding capabilities to increase customer benefits by improving circuit reliability.

Energy Storage Planning To Support BAINBRIDGE ISLAND

Final Report

PREPARED FOR: Puget Sound Energy (PSE)

REPORT DATE: April 23, 2019
(Version 4a)

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VERSION HISTORY:

Version	Date	Description
0.1	9/07/2018	Draft Report
0.2	10/5/2018	Updated Draft Report – Revised the planning criteria; Updated the analysis, and Report format per feedback received from PSE on 9/27/2018.
1	10/31/2018	Updated Draft Report – Corrected typo-graphical errors and enhanced the report readability in response to comments from received PSE on 10/25/2018.
2	2/19/2019	Updated Version 1 of the report to address new comments from PSE and included a stacked review analysis.
3	4/12/2019	Updated Version 2 of the report to address few editorial comments from PSE and to also include revenue stacking analysis of the Storage Only (Option) solution.
4	4/23/2019	Updated to address few editorial comments from PSE.
4a		Scrutinized CEII data

EXECUTIVE SUMMARY

Quanta Technology, LLC, was retained by Puget Sound Energy (PSE) to investigate the feasibility of designing an optimized energy storage solution to resolve three areas of known grid constraints in the Kitsap Peninsula, at the lowest cost. The three areas include Seabeck area, Bainbridge Island, and rest of Kitsap Peninsula.

The study findings are organized into three reports, one for each study area. This report focuses on Bainbridge Island and supports PSE's transmission planning and engineering teams with identifying and designing competitive non-wire alternative (NWA) solutions using energy storage.

Quanta Technology has followed its proven three-phase process with evaluation and decision points in between: 1) screening of candidate projects, 2) detailed siting and sizing, and 3) detailed techno-economic evaluations of candidate projects. The study started by analyzing and quantifying the T&D grid challenges as the peak winter load forecast evolves over time. Candidate storage solutions were then postulated during the screening phase and evaluated for technical efficacy and cost effectiveness. The promising solutions were further analyzed and optimized using Quanta Technology's customized siting and sizing tools, and simulated using industry standard tools such as Synergi.

This Bainbridge Island study focused on a 10 year planning horizon (2018 through 2027) using a baseline load forecast scenario that includes Demand Side Management (DSM) and a Ferry charging station starting its operation in 2021; and addressed three system needs[1], namely:

- transmission reliability (Winslow Tap outages[2])
- substation capacity (group)
- feeder reliability (Winslow-13)

The study concludes that these three system needs can be resolved using either a conventional T&D solution or an energy storage solution consisting of a group of 5 storage systems appropriately located and sized.

The conventional T&D solution was proposed by PSE planners and was analyzed in this study to ensure its technical efficacy in meeting the three system needs. The storage solution was also carefully designed to address each of the three system needs. The storage solution's overall size was methodically optimized by exploiting the following levers: (1) existing PSE feeder switching schemes, (2) proposing modifications to the switching schemes to enable shifting more loads between feeders, and (3) finding sites where one storage solution can address two or three of the system needs

[1] Based on Bainbridge Island Electric System Needs Assessment Report, PSE Strategic System Planning, May 14, 2018 draft

[2] PSE Strategic System Planning identified a new system need in January, 2019 for replacing aging infrastructure on the Winslow 115kV Tap related to wishbone wood cross-arm construction of the line. This study does not recommend a battery storage solution to address the need of replacing Winslow tap aging infrastructure, as battery storage can provide only a limited period of backup for a system outage and cannot support prolonged outages from system failure.

simultaneously. The detailed siting and sizing analysis in Task 3 (Section 6) details all the steps taken in this study to optimize the storage solution.

The optimized storage solution requires 5 storage systems to mitigate the capacity and reliability needs in the Bainbridge Island as tabulated below.

ID	Location	Storage-Only Solution	System Need
1	PMA-13/WIN-12	3.2 MW/ 9 MWH	Winslow Tap Reliability
2	WIN-13	4.4 MW/20 MWH 4.2 MW/12 MWH	Winslow Tap Reliability & Winslow-13 Feeder Reliability Winslow-13 Feeder Reliability (exclusive)
3	MUR-17/WIN-15	3.4 MW/ 15 MWH	Winslow Tap Reliability
4	MUR-15	0.4 MW/ 0.4 MWH	Winslow Tap Reliability
5	Murden Cove Distribution Station	13.7 MW/ 34.8 MWH	Winslow Tap Reliability & Substation Capacity Needs
	Total	**29.3 MW / 91.2 MWH**	**All 3 Needs**

The lifetime economic analysis of the optimized storage-only solutions was compared against the conventional T&D solution over the 10 year planning horizon, and the results are tabulated below.

All Costs are Present Value ($M)	Conventional T&D Solution[3]	Storage-Only Solution[4]	Storage-Only Solution (Option)[4]
Application	Distribution Capacity & Reliability	Distribution Capacity & Reliability	Distribution Capacity & Reliability (Excluding WIN-13 feeder reliability)
Project Need Date	2018	2018	2018
Storage Size MW/MWh Min Size to Meet System Needs Upsized to Mitigate Degradation	 - -	 29.3MW / 91.2 MWh 29.3MW / 111 MWh	 25.1MW / 79.2 MWh 25.1MW / 97 MWh
Capital Investment – Conventional Storage	 $24.2[5] -	 - $43.2[6]	 - $37.7[6]

[3] Conventional T&D solution asset life of 45 years
[4] Storage-Only solution asset life of 15 years
[5] Costs are July 2018 PSE cost estimate based on similar past projects in other areas of PSE service territory. Does not include site-specific engineering.
[6] Costs do not include interconnection costs, land and permitting costs, and other costs associated with distribution automation
[7] See Appendix A which describes the Levelized Real Cost Analysis Method

Total	$24.2[5]	$43.5[6]	$37.7[6]
Capital Levelized Real Cost[7] (over 10 years)	$10.0	$32.6	$28.2
O&M Cost (over 10 years)	$0.4	$1.6	$1.4
Total Cost (over 10 years)	**$10.4**	**$34.1**	**$29.6**
Cost Ratio	**100%**	**328%**	**284%**

Quanta Technology utilized its detailed storage models and its expertise in benefit/cost modeling. The analysis included all the relevant cost components such as capital and O&M, taking into account storage lifecycles, efficiency, and capacity fading issues. However, it does not include interconnection costs, land and permitting costs and other costs associated with distribution automation. This study finds the storage-only solution to be over 3 times more expensive in meeting the system needs than the conventional T&D solution.

PSE requested an optional storage-only solution for meeting 2 needs – Winslow Tap Reliability & Substation Capacity Need. WIN-13 reliability need was determined to be met with a planned construction of conventional feeder undergrounding project in 2019-2020. Removing the WIN-13 feeder reliability need, reduces the size of the storage-only solution to 25.1 MW/79.2 MWH (97 MWH – upsized for battery degradation). The cost of the optional storage-only solution for meeting 2 needs is $37.7M (2018 dollars) and approximately 2.8 times of the conventional wire solution cost.

The study examined in detail the economic potential of the storage assets to provide additional service and thus offset their costs. Two potential services were analyzed, the system capacity service and the energy arbitrage. The additional revenues generated by the excess capacity of the storage assets after meeting the system needs were relatively small, with a 10 year present value of $2.4M for the Storage-Only solution, and $2.1M for the Storage-Only (Option) solution. Thus after accounting for the revenue stacking opportunities, the storage solutions were still around 3 times the cost of the conventional solution.

It is important to note that care should be exercised when comparing storage solutions to conventional T&D solutions. Each solution has additional attributes (e.g., benefits and risks) that have not been evaluated in this analysis. For example, the energy storage solution can address reliability needs for a finite amount of time (assumed 8 hours for transmission outages and 4 hours for distribution outages) whereas the conventional T&D solution provides a solution with an indefinite time. This analysis focused on the primary function of each solution in terms of grid capacity and/or reliability to accommodate projected load development for a period of 10 years beyond the installation date (2019-2029). It is challenging to procure and install the battery systems within 12 months, although it is not impossible. Beyond that period, the economics and ease of expanding each solution to accommodate further load development might be significantly different. Additionally, each type of solution might provide additional system, customer, or economic benefits that are not captured in this analysis. A comprehensive long-term comparative evaluation is beyond the scope of this study.

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1 INTRODUCTION

Quanta Technology has collaborated with Puget Sound Energy (PSE) to investigate the feasibility of applying energy storage solutions to address three known areas of constraints in the Kitsap peninsula. The locations of the constraints are:

1. Town of Seabeck Area (West Kitsap)
2. Bainbridge Island (Supplied from Kitsap Peninsula)
3. Kitsap Peninsula (Whole Peninsula)

This report focuses on Bainbridge Island. Quanta Technology uses a three phase methodology: 1) Screening, 2) Detailed Siting and Sizing, and 3) Techno-economic analysis, which includes modeling and understanding the constraints, reviewing of conventional solutions, optimizing the siting and sizing of storage, benefit cost analysis, and life cycle cost analysis. Bainbridge Island was examined for standalone energy storage solutions.

The following sections describe in greater detail the energy storage planning methodology, describe the existing constraints and conventional solutions, assess the viability of energy storage as a technical and economical solution for the constraints, determine the storage site and size requirements, and perform a comparative economic study including the lifetime costs and benefits of the energy storage solutions as compared to the conventional solutions.

2 STUDY METHODOLOGY

The Study methodology is performed in three major phases; Phase 1 - Review Conventional Solutions, System constraints and Need Years; Phase 2 - siting, sizing, and preliminary designs of energy storage solutions; and Phase 3 - detailed techno-economic evaluations of candidate projects (Figure 2-1 below).

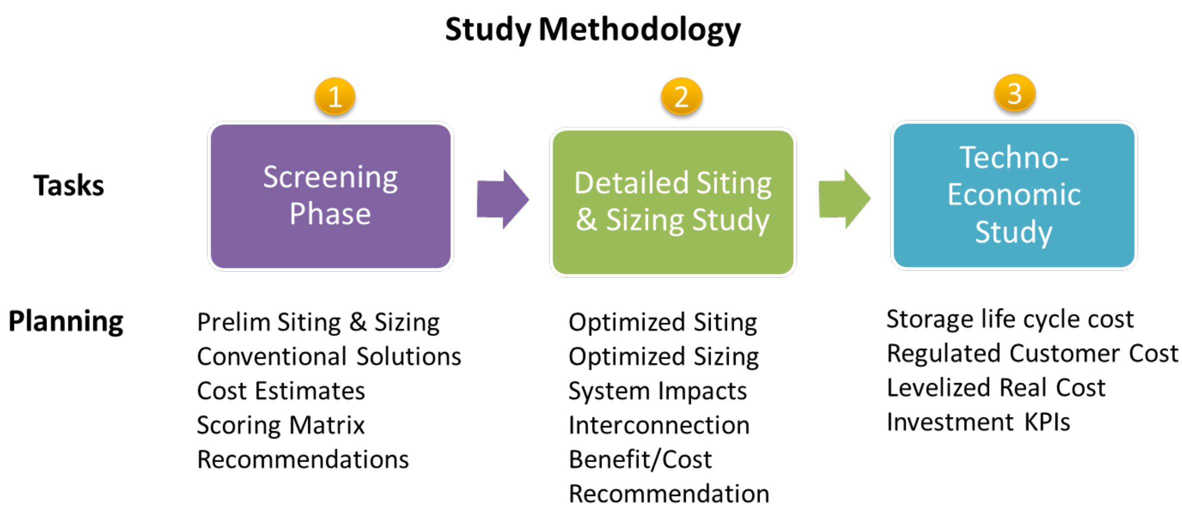


Figure 2-1. Study methodology.

This study addresses the reliability and capacity needs of the Bainbridge Island transmission and distribution system for the 10 year period of 2018-2027 with storage-only solution. The projected system load assumes the implementation of DSM initiatives and addition of 10 MW ferry charging station in 2021. The study is organized into 4 tasks as follows:

- **Task 1**: Review System Constraints

The reliability and capacity needs of the Bainbridge Island's grid that have been addressed in this study follow, along with a commentary on the implications for the storage siting and sizing:

  - Winslow Tap reliability: Winslow substation experienced 22 outages over a 6 year period (2012-2017), an average of nearly 4 substation outages per year. Nearly 70% (15 out of 22) of the Winslow substation outages were caused by the loss of Winslow transmission tap due to tree related events. Therefore, the storage solution should be sized to securely serve the load that would have been interrupted after the outage of the Winslow substation, while accounting for any potential support from Murden Cove and Port Madison substations.

  - Substation Capacity requirements: Considering PSE planning guidelines, the substation group capacity planning trigger of 85% (or 84 MVA) for Winslow, Murden Cove and Port Madison substations will be exceeded after the addition of ferry load at Murden Cove Distribution Station. Therefore, the storage solution should be sized to mitigate the overage of the substation group utilization capacity limit.

- Winslow–13 feeder reliability: The storage solution should be sized to carry the entire load served by the feeder until the restoration work is completed, in order to improve the reliability indices of SAIDI and CMI.

- **Task 2**: Review Conventional Solutions:

The study assessed the technical efficacy of a conventional solution (that was developed by PSE planning team) in addressing the three system needs that were identified in Task 1.

- **Task 3**: Detailed Siting and Sizing of Storage Solutions

  The storage systems were initially sited and sized to address each of the three system constraints, and then optimized to leverage their locational synergies to address multiple (i.e., two or three) system needs simultaneously. The following elaborates on the methodology used to address each system need.

  Storage Siting and Sizing for Winslow Tap Reliability:

  - Storage size (MW and MWh) is optimized to provide backup to Winslow substation load for up to 8 hours[5] after outage of the Winslow transmission tap.
  - Using PSE's existing switching schemes, the feeders at Winslow Substation are first switched onto feeders at Murden Cove and Port Madison distribution stations and then the storage size requirements for each overloaded feeder is determined.
  - The possibility of load shifting from the heavily loaded to lightly loaded feeders is investigated in order to optimize the storage size requirements.
  - Due to the nature of the load profile of the ferry charging station served by the Murden Cove substation, which differs from the other system load profiles, the analysis of the storage sizes is taken in two steps. The initial step of the analysis quantifies the storage sizes without the ferry load, and then the second step increments the storage sizes to account for the ferry load.
  - After the feeder switching scheme and the recommended load shifting operations, the storage size is further analyzed to mitigate any distribution transformer overloads above the winter emergency limit of 36 MVA.
  - If a storage system is located on a feeder, its siting along a feeder is selected to mitigate overloads on all the sections of the feeder and to avoid reverse power flow as protection systems in the distribution grid generally have visibility only in one direction.
  - The MW size of a storage system is determined using a snapshot of the system model at the highest peak load, while the storage capacity in MWh is determined using a "state of charge" simulation using time-series power flow analysis with an hourly-resolution (i.e., 8760 snapshots) over a whole year.

  Storage Siting and Sizing for Substation Capacity needs:

[5] PSE required 8-hour backup of substation load for a transmission outage to provide sufficient time for crews to restore transmission service. A 4-hour backup of feeder load was required for feeder outage restoration.

- The storage size required to mitigate any violations of the substation group capacity utilization limit are investigated, considering the ferry load to be in service starting in the year 2021.
- Individual substation capacity utilization limits are expected to be resolved by load shifting from substations exceeding their capacity limit to relatively lightly loaded substations. Therefore, such needs are not considered in this analysis.

Storage Siting and Sizing for Winslow 13 Reliability Needs[6]:

- In order to have a comparable performance to the conventional solution, the storage size is optimized to back up the entire feeder's load for 4 hours.

- **Task 4: Techno-Economic Modeling**.
  - The storage and conventional solutions are modeled side-by-side for the planning horizon of 10 years.
  - A Financial model of the storage solution and the conventional solution is developed to capture all the pertinent costs (capital and O&M), leading to a comparative analysis between the two solutions.

[6] Bainbridge Island Electric System Needs Assessment, PSE Strategic System Planning, May 14, 2018

3 BAINBRIDGE ISLAND – BACKGROUND INFORMATION

The aggregate winter peaking load on Bainbridge Island is predominantly all-electric heating, and reached 77 MW in peak winter (2016/17) and 26 MW in peak summer (2017). The Bainbridge Ferry terminal has proposed a new 10 MW electric ferry charging station in 2021 at its terminal on Bainbridge Island.

The three 25 MVA substation transformers on the island approach and are projected to exceed the 85% group capacity threshold despite on-going demand side management (DSM) programs.

This study explores the application of energy storage to address the capacity and reliability needs of energy delivery in the Island for the 10 year period of 2018 through 2027.

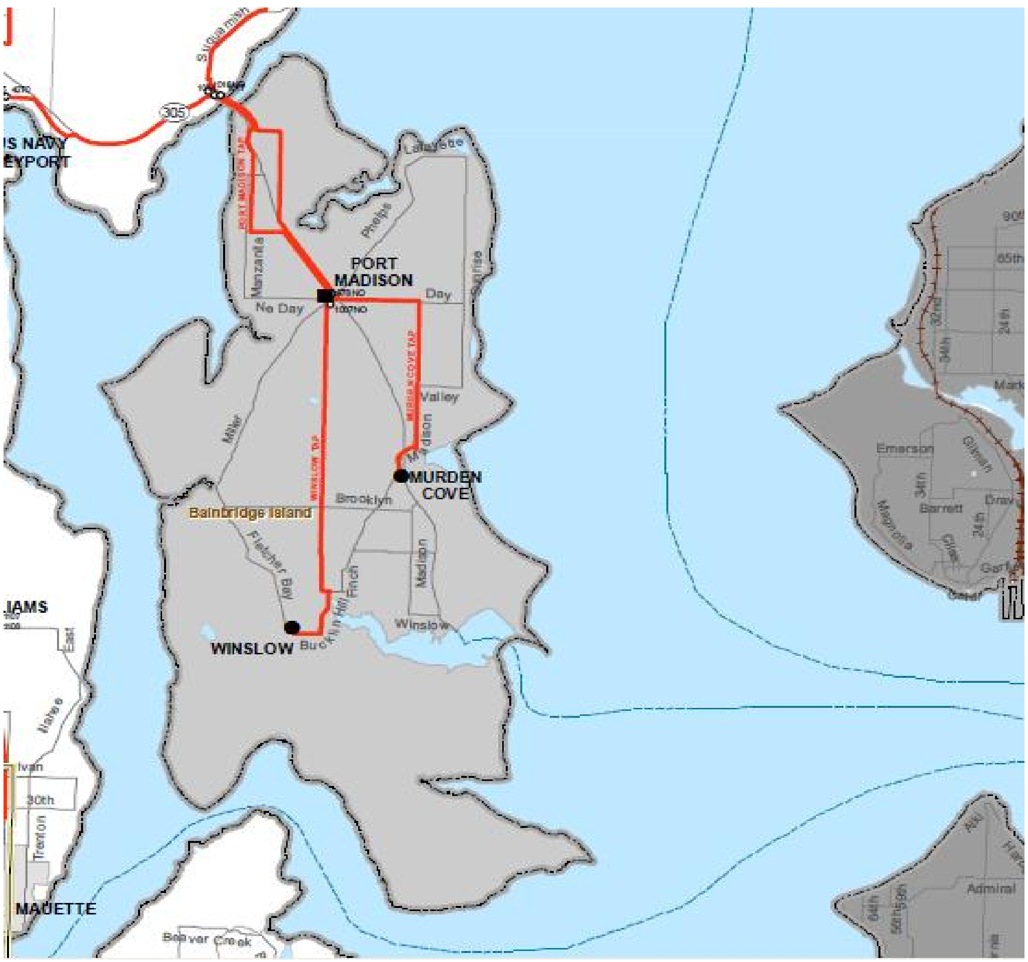


Figure 3-1. Bainbridge Island study area.

3.1 Peak Load Forecast

PSE forecasts (Table 3-1) the normal winter peak load to increase by 11 MVA (14%) for 2018 through 2027, and by an additional 13 MVA (14%) for 2027 through 2037, without DSM measures. However, with full implementation of all planned DSM measures, the winter peak is expected to decline by 1 MVA (-1%) 2018 through 2027, and to increase by 11 MVA (14%) 2028 through 2037.

The proposed Ferry charging station in 2021 will increase the projected peak load by 10-13 MVA over a 20 year forecast horizon. It is worth noting that the planning criteria sets the combined normal (N-0) loading limit of the 3 distribution substations at 84 MVA (i.e., 85% of the winter normal rating of 99 MVA), which will trigger a need for capacity upgrades by 2021 as shown in Table 3-2.

Table 3-1. Projected Normal Winter Peak Load (MVA) of Bainbridge Island

Load in Bainbridge Island		2017	2027	2037
Without Ferry	Without DSM	80	91	104
	With DSM		79	90
With Ferry Load (10 MW)	Without DSM	80	101	117
	With DSM		89	101

The planning criteria for this study considers a base scenario that includes the Ferry charging station and 100% DSM. Under this planning scenario, the normal peak load forecast (MVA) is shown in Table 3-2.

Table 3-2. Projected Normal Winter Peak Load (MVA) of Bainbridge Island with 100% DSM and Ferry

Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
MVA	80	83	82	81	**90**	89	90	92	91	91	89
Year	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	
MVA	89	90	92	92	93	94	96	98	100	101	

3.2 Distribution System

Bainbridge Island load is served from 12 feeders:

- 4 feeders from Port Madison substation (PMA-12, PMA-13, PMA-15, PMA-16),
- 4 feeders from Murden Cove substation (MUR-13, MUR-15, MUR-16, MUR-17), and
- 4 feeders from Winslow substation (WIN-12, WIN-13, WIN-15, WIN-16).

All three substations utilize the PSE standard 115-12kV 25 MVA transformers. Table 3-3 shows the winter normal and emergency ratings for PSE distribution transformers.

For Bainbridge Island, all feeders have UG portions that parallel another feeder, so the ratings for two feeder running in a common trench of 486A or 10.5 MVA were used in the capacity analysis.

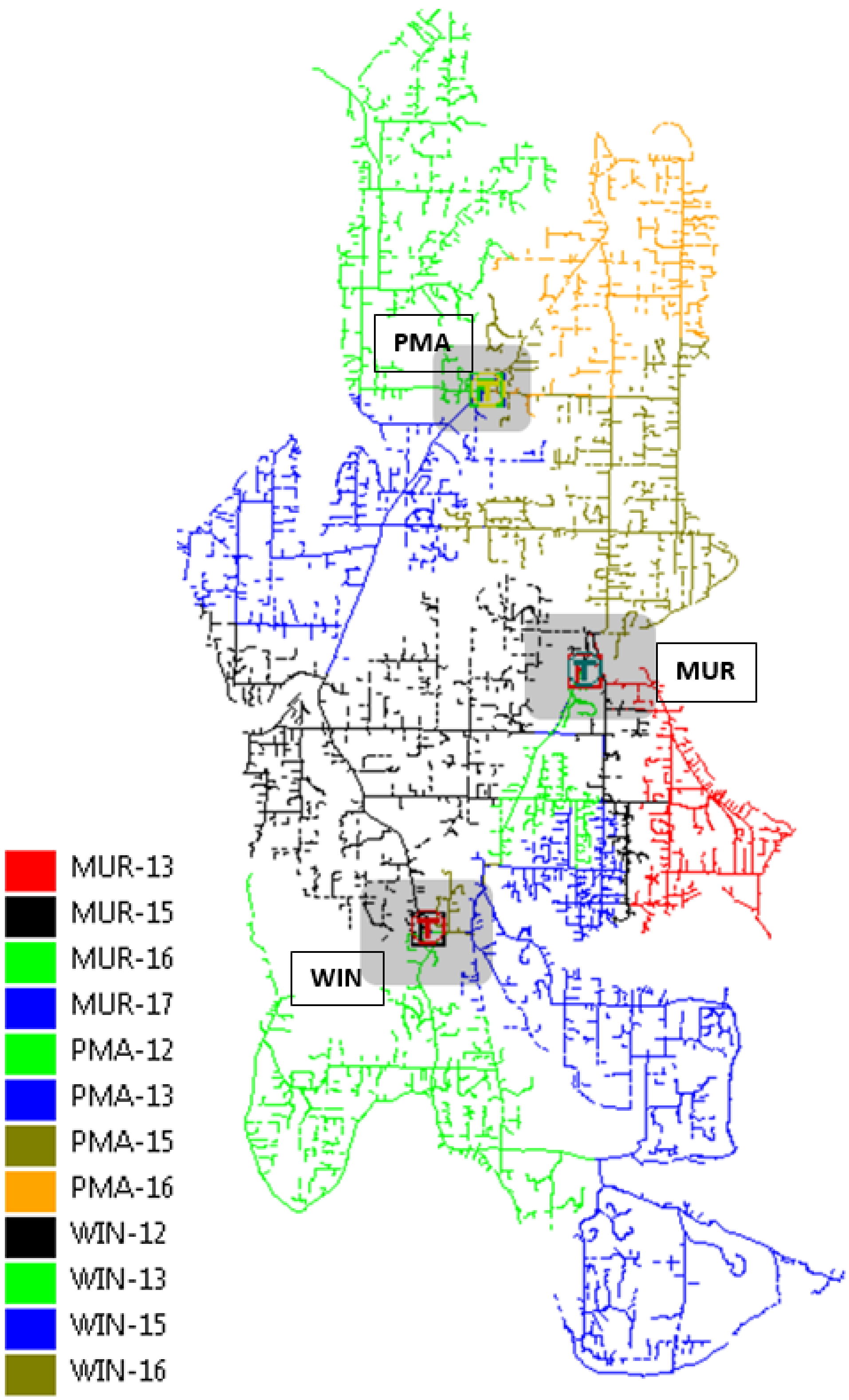


Figure 3-2. Distribution feeders on Bainbridge Island.

Table 3-3 Normal and Emergency Limits of Distribution Transformers

Distribution Transformers in Bainbridge Island		
Substations	**Winter Normal Limit**	**Winter Emergency Limit**
PORT MADISON	33 MVA	36 MVA
MURDEN COVE	33 MVA	36 MVA
WINSLOW	33 MVA	36 MVA

3.3 Ferry Terminal Charging Station

Washington State Ferries has proposed a new 10 MW electric ferry charging station at its terminal on Bainbridge Island. The charging station is assumed to be served by a new feeder out of the Murden Cove substation.

3.4 PSE Relevant Solution Criteria and System Needs

The following are the key relevant criteria that were used in this study in assessing and designing solutions:

1. **Planning Horizon:** Within the ten year study period (2018 through 2027). However, the solution should address system needs for 10 years after the project is put in service.
2. **Load Forecast**: Normal winter and summer peak forecast with 100% conservation and with the Ferry charging station.
3. **Distribution substation group utilization** ≤ 85% of winter normal limit (i.e., 84 MVA).
4. **Distribution substation individual utilization** ≤ 100% of winter normal limit (i.e., 33 MVA).
5. **Distribution overhead feeder loading** ≤100% of normal limits (i.e., 600 A or 12.95 MVA at 12.47 kV nominal voltage) for N-0 and applicable N-1 scenarios.
6. **Distribution underground feeder loading** ≤100% of normal limits (i.e., 486 A or 10.5 MVA) for N-0 and applicable N-1 scenarios.
7. **Reliability**: Must not increase non-MED SAIDI and non-MED SAIFI. For PSE worst performing circuit, solution must reduce the top driver annually by 50%.

The three system needs that should be addressed by all solutions are:

1. Transmission reliability (loss of Winslow Tap) – required transmission backup for 8 hours.
2. Substation grouping capacity (N-0)
3. WIN-13 distribution reliability – required backup for 4 hours[7]

[7] Bainbridge Island Electric System Needs Assessment, PSE Strategic System Planning, May 14, 2018 draft

4 TASK 1: REVIEW SYSTEM CONSTRAINTS

The study reviewed the historical performance of the Bainbridge grid against the three identified system needs and summarized the following observations.

Transmission Reliability:

- Winslow substation had 22 outages over a 6 year period (2012-2017), an average of nearly 4 substation outages per year. Nearly 70% (15 out of 22) of the Winslow substation outages were caused by the loss of Winslow transmission tap due to tree related events. The remaining 7 Winslow substation outages were part of blackout events (6 out of 7 were tree related) impacting the entire Bainbridge Island.
- A 115 kV bus outage at a substation will simultaneously drop all substations on the island resulting in a blackout.
- Under N-1-1 contingencies resulting in loss of two of the three backbone transmission lines in Central Kitsap County, the third backbone transmission line gets overloaded. To prevent transmission line overload under N-1-1 contingency, PSE utilizes an Interim Operating Plan to shed load in North Kitsap County and/or Bainbridge Island.
- The loss of two of the three bulk transformers supplying Kitsap peninsula (N-1-1 contingency) results in overloading the third bulk transformer and voltage collapse on the peninsula, which impacts Bainbridge Island.

Distribution

- Station Capacity
  - The N-1 distribution station capacity is a concern, and not a system need. The system need is - substation group capacity utilization exceeding 85% (or 84 MVA) in 2021 with the Ferry load addition. Additional substation capacity might be needed under normal conditions (N-0) as early as 2021 with the Ferry charging station load and with DSM.
- Feeder Capacity
  - Group of feeders supplying Downtown Winslow exceed 83% feeder group capacity utilization in 2021.
  - PMA-15 is currently over planning trigger, and WIN-12 & 13 will be the same. However, considering 100% of feeder capacity as per PSE guidelines, there are no feeder capacity needs during the 2018-2027 study year.

Distribution Substation Group

The distribution substations each have a normal winter rating of 33 MVA and emergency winter rating of 36 MVA (Table 3-3). Therefore, under N-0, the substation group capacity is 99 MVA and under N-1, the substation group capacity is 72 MVA. Based on the projected load growth described in Table 3-1 and PSE planning guidelines of 85% of Substation Group capacity utilization, the need for additional capacity in the with DSM Scenario is in year 2021 upon commissioning of the ferry load fed from Murden Cove distribution substation. Without ferry load, there is no need for additional substation capacity in the 2018-2027 study period.

Distribution Feeder Group Capacity Winslow Downtown Area

The Winslow area feeder group consists of WIN-15, WIN-16, MUR-13, MUR-16, and MUR-17. The feeders are comprised of both overhead and underground conductors. The ferry load addition is planned on a new dedicated feeder from the Murden Cove Distribution Station and this is not a part of Winslow downtown area feeder group. The feeder group planning trigger and capacity limits are shown in Table 4-1 below.

Table 4-1 Downtown Winslow Feeder group capacity limits

Limit	Limit (Amps)
N-0 Planning Trigger UG	2015
N-1 Planning Trigger UG	1944
N-0 Capacity UG	2430

During the study period of 2018 through 2027, the maximum feeder group loading reaches 1540 Amps in the With DSM Scenario and 1692 Amps in the Without DSM Scenario. Therefore, there is no need for additional distribution feeder capacity in the Winslow downtown area during the study period.

5 TASK 2: REVIEW CONVENTIONAL SOLUTIONS

The conventional solution provided by PSE is to build a new 115 KV transmission line connecting Winslow and Murden Cove substations, and a new distribution substation with a 115 kV/12.5 kV transformer. Table 5-1 below provides a detailed description and cost estimate of the proposed solution. This allows all substations to backup each other and to supply needed capacity for the future.

Table 5-1. Proposed Conventional Solution and its Estimated Cost

	Scope of Work	2018 Unit Cost Estimate[1]	2018 Cost Estimate[1]	2018 Cost Estimate w/ 25% contingency[1]
1.	Build 3 miles of new overhead 115 kV line b/w Murden Cove and Winslow on public ROW	$2.5 M/mi.	$7.5 M	$9.4 M
2.	Expand Winslow substation bus to bring second 115 kV line. Install 2-115 kV breakers.		$1.5 M	$1.9 M
3.	Expand Murden Cove substation bus to bring second 115 kV line.		$0.8 M	$1.0 M
4.	Build new 115-13 kV distribution substation on transmission loop.		$8.0 M	$10.0 M
5.	Install 4-13 kV feeder getaways at new distribution substation.	$1.0 M/mi.	$1.0 M	$1.25 M
6.	Convert a section on Winslow 13 feeder to Under Ground		$ 0.64 M	$ 0.8 M
	TOTAL Cost		**$19.44 M[1]**	**$24.35 M[1]**

[1]Costs are July 2018 Puget Sound Energy cost estimate based on similar past projects in other areas of PSE service territory. Does not include the site-specific engineering costs.

6 TASK 3: DETAILED SITING AND SIZING OF STORAGE SOLUTIONS

The siting and sizing analysis considers the three system needs: transmission reliability, distribution group capacity, and WIN-13 distribution reliability. Each of the 3 system needs is analyzed to determine the corresponding storage capacity requirement, and then combined into an overall sizing recommendation.

6.1 Storage Siting and Sizing Analysis for Winslow Transmission Tap Reliability Need

Winslow substation had 22 outages over a 6 year period (2012-2017), an average of nearly 4 substation outages per year. Nearly 70% (15 out of 22) of the Winslow substation outages were caused by the loss of Winslow transmission tap due to tree related events.

A storage-only solution is investigated to address the low reliability of Winslow Tap, and to determine the storage capacity requirements under the outage of Winslow Substation. Upon switching of feeders from Winslow distribution station to Murden Cove and Port Madison distribution stations, storage capacity requirements to mitigate overloads on individual distribution feeders and transformers are determined. Storage size requirements for each of these elements are described below.

6.1.1 Storage Siting and Sizing to Mitigate Overloads in Distribution Feeders

The initial stage of the investigation assessed potential violations of the distribution feeder limits after the switching of Winslow feeders onto the other feeders under the outage of Winslow tap according to the switching schemes provided by PSE. The second stage of the analysis examined any potential overloads of the substation transformer.

The analysis revealed that switching of Winslow substation load to adjacent substations on loss of transmission, causes capacity violations on the system and that the need year is current. The installation year is assumed to be 2019 and the storage was designed to address system needs through year 2029. In the period of 2019-2029 With DSM Scenario, the load forecast in the year 2019 is the highest and is used to determine the storage size requirements.

Two strategies to optimize the storage capacity were investigated:

- Load shifting (from loaded feeders to under-loaded feeders).
- Enhanced feeder switching scheme.

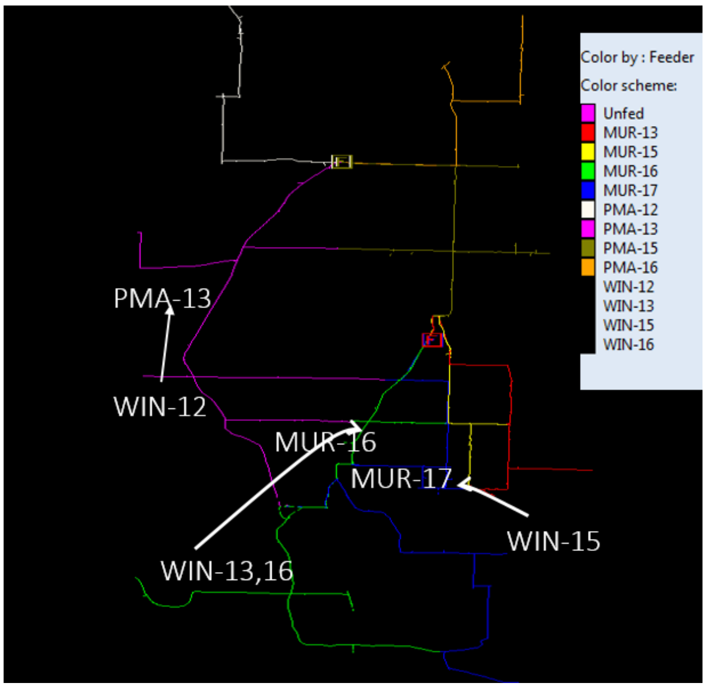
Under the outage of Winslow transmission tap, Winslow – 12, 13, 15 and 16 feeders are switched onto Murden Cove and Port Madison distribution station using PSE switching schemes as follows:

- Winslow 12 feeder is switched onto Port Madison 13 feeder by closing 17-282 switch. This switching operation ties Port Madison -13 and Winslow 12. WIN12-L switch at the Winslow Station is open to avoid loops in the system.

- Winslow 13 and 16 feeders are switched onto Murden Cove 16 feeder. Initially, Winslow 13 and 16 feeders are tied together by closing 17-1145-P4 switch. The Winslow 13 and 16 feeders are switched onto Murden Cove 16 by closing WE00511switch. WIN13-L and WIN16-L switches at the Winslow Distribution station are opened to avoid loops in the system.

- Winslow 15 feeder is switched onto Murden Cove – 17 by closing WE00512 switch. This switching operation ties Murden Cove -17 and Winslow 15. WIN15-L switch at the Winslow Station is open to avoid loops in the system.

Upon switching the feeders from Winslow to Murden Cove and Port Madison Distribution station with the above switching schemes, Murden Cove-16, 17 and Port Madison – 13 feeders are found to be overloaded. Figure 6-1 below shows the feeders' loading and system configuration after applying the switching scheme.



Feeders for MURDEN COVE	Demand - MVA
MUR-13	9.218
MUR-15	5.959
MUR-16	14.082
MUR-17	17.788
MURDEN COVE Totals	47.029
Feeders for PORT MADISON	Demand - MVA
PMA-12	5.718
PMA-13	13.444
PMA-15	9.285
PMA-16	5.446
PORT MADISON Totals	33.876

Figure 6-1 System Configuration and Feeder Loadings after Winslow outage

Assuming an 8 hour restoration time for Winslow Tap, the following are the storage requirements for the 3 overloaded feeders.

- MUR 16 – 4.4 MW/20 MWH
- MUR 17 – 8 MW/45 MWH
- PMA 13 – 3.2 MW/9 MWH

Therefore the total storage requirements are 15.6 MW/74 MWH.

Possible reduction in storage size requirements is investigated next using different load shifting schemes by switching portions of load from the overloaded feeders to the feeders which are lightly loaded using the switches at existing tie points.

Load Shifting:

Considering the lightly loaded feeders such as MUR – 15, PMA – 12, 16 from Figure 6-1, load shifting from these overloaded feeders is investigated to optimize the storage sizes required.

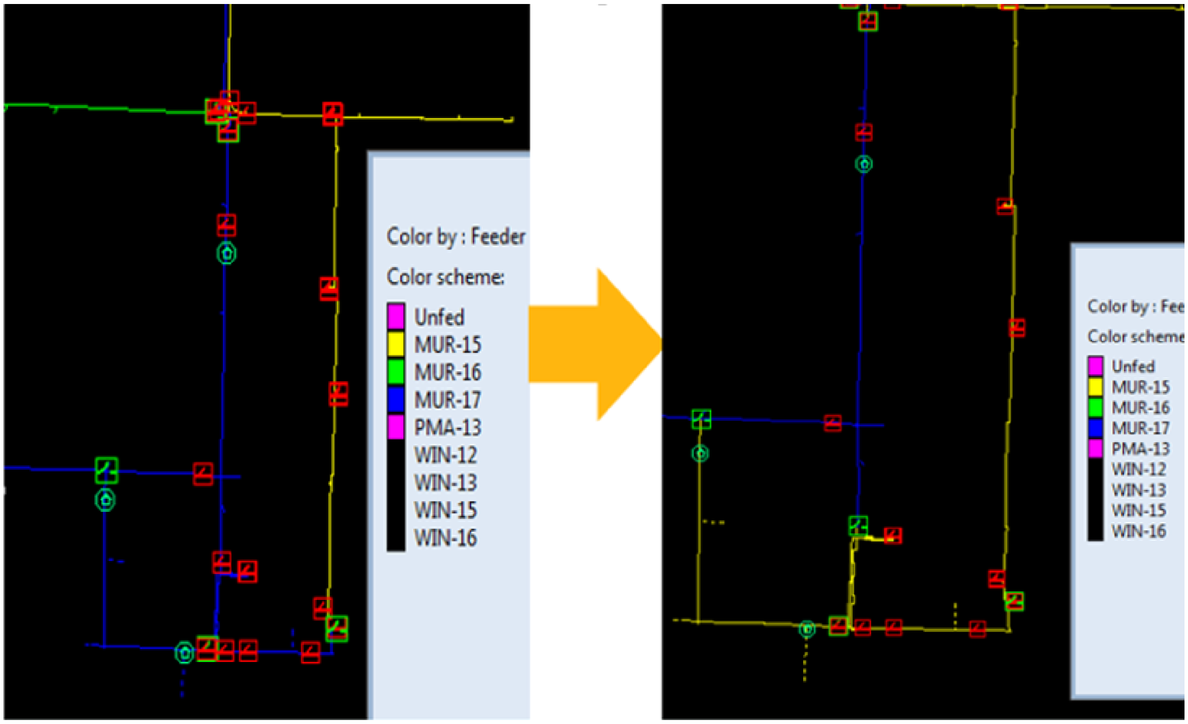
Shifting appropriate amount of load from Murden Cove – 17 to Murden Cove – 15 feeder without overloading Murden Cove – 15 greatly reduces the storage requirements for Murden Cove -17 feeder. This can be achieved by closing switch 17-811-P4 which ties MUR – 15 and 17 and opening switch 17-618. This switching operation does not create any loops and no load is unfed.

The storage requirement, post this switching operation, for Murden Cove – 17 reduces from 8 MW/45 MWH to 3.4 MW/15.2 MWH. However, this leads to an overload of MUR-15 feeder and a storage of 0.4 MW/0.4 MWH is required to mitigate this overload. Figure 6-2 below shows the configuration of Murden Cove 15 and 17 feeders and their loadings after the proposed load shifting operation. The final storage capacity requirements to address the Winslow tap outage are as follows:

- Site (1): PMA 13 – 3.2MW/ 9 MWH
- Site (2)[8]: MUR 16 – 4.4 MW/20 MWH
- Site (3)[8]: MUR 17 – 3.4 MW/15 MWH
- Site (4): MUR 15 – 0.4 MW/ 0.4 MWH

Therefore, the total storage requirements considering load shifting is 11.4 MW/44.4 MWH. The possible storage sites are shown below in Figure 6-3 and is discussed in detail in Section 6.1.3.

[8] Site (2) and Site (3) are possibly located on the WIN-13/ MUR-16 & WIN-15/ MUR-17 feeders to accommodate storage requirement for both MUR-16 and MUR-17.



Feeders for MURDEN COVE	Demand - MVA
MUR-13	9.218
MUR-15	5.959
MUR-16	14.082
MUR-17	17.788
MURDEN COVE Totals	47.029

Feeders for MURDEN COVE	Demand - MVA
MUR-13	9.218
MUR-15	10.63
MUR-16	14.082
MUR-17	13.438
MURDEN COVE Totals	47.308

Figure 6-2 Murden Cove 17 to 15 load shifting

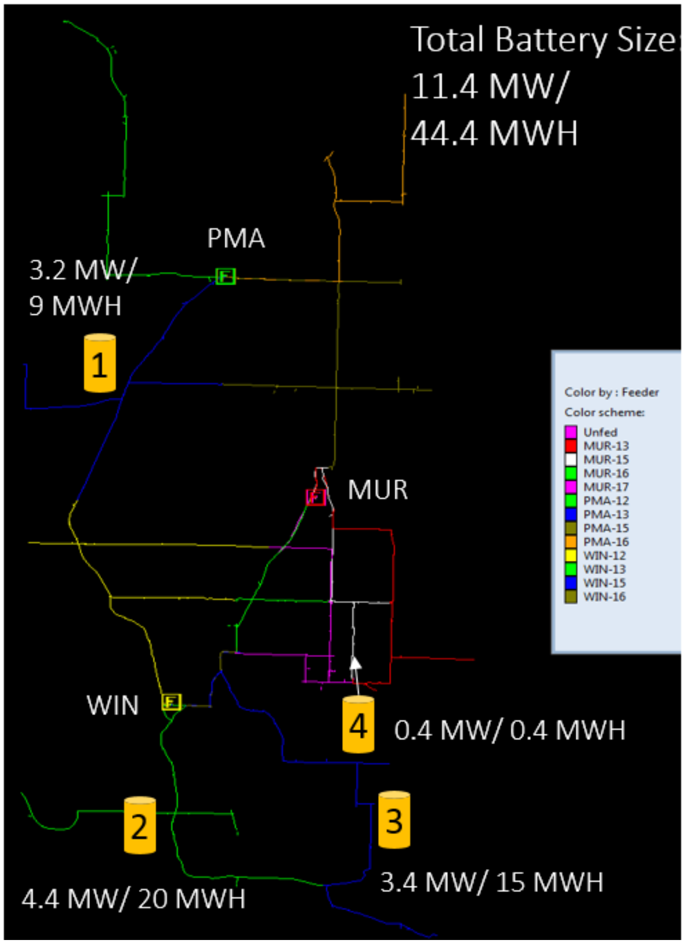


Figure 6-3 Storage Sizing for Transmission Reliability Needs considering distribution feeder capacity limits

In Figure 6-3 above, preliminary recommendations on battery sites are shown and described below:

- The battery requirements for Port Madison 13 feeder of 3.2 MW/9 MWH is shown as site (1) in the figure above.
- The battery requirements for Murden Cove 16 feeder of 4.4 MW/20 MWH is shown as site (2) in the figure above. Site (2) can be located either on Winslow 13 or Murden Cove 16 feeders appropriately to mitigate thermal overloads on all sections of the feeder and avoid reverse power flow as detailed in Section 6.1.3.
- The battery requirements for Murden Cove 17 feeder of 3.4 MW/15 MWH is shown as site (3) in the figure above. Site (3) can be located either on Winslow 15 or Murden Cove 17 feeders appropriately to mitigate thermal overloads on all sections of the feeder and avoid reverse power flow as detailed in Section 6.1.3.
- The battery requirements for Murden Cove 15 feeder of 0.4 MW/0.4 MWH is shown as site (4) in the figure above.

As observed from Figure 6-2 above, the Murden Cove Distribution transformer is loaded to 47 MVA which exceeds the 36 MVA capacity limit under Winter N-1 conditions. Storage needs for the distribution transformer is investigated in Section 6.1.2.

6.1.2 Storage Siting and Sizing to Mitigate Overloads in Murden Cove Distribution Transformer

Under the outage of Winslow transmission tap, the Murden Cove distribution transformer loading reaches 47 MVA, well above its emergency rating of 36 MVA[9]. A storage solution is investigated to mitigate this overload. The storage sizing is initially performed without the Ferry charging load, and then updated to reflect the base planning scenario with the Ferry load due the difference of the load profile of the ferry charging station from the system load.

Figure 6-4 shows the loading on Murden Cove distribution transformer without ferry load. The storage size required to mitigate the overload on Murden Cove distribution transformer for the most constraining 8 hour window is 11.3 MW/49 MWH. The storage state of charge is shown in Figure 6-5.

To reflect base planning scenario with the ferry load, storage requirements to accommodate ferry load at Murden Cove distribution station in addition to the existing load fed from the distribution station is described below.

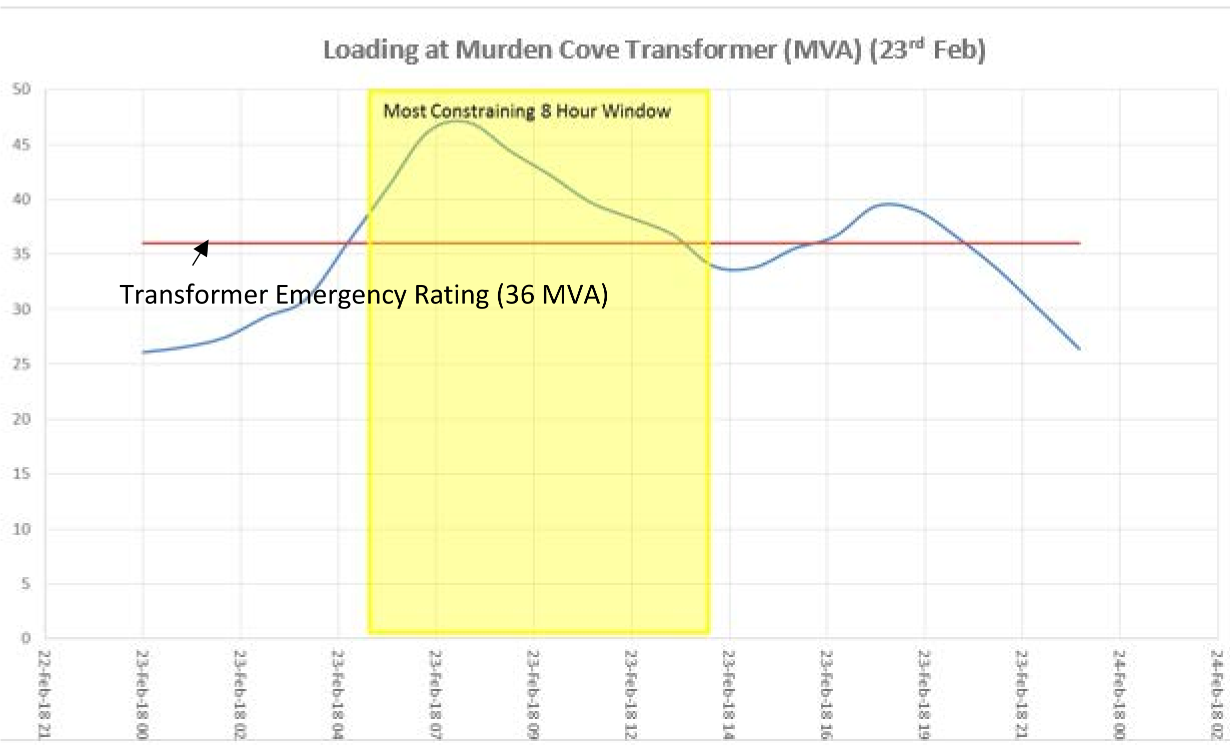


Figure 6-4 Murden Cove Transformer Loading without Ferry Load

[9] Based on the emergency rating standards of the transformer, the battery sizes may differ.

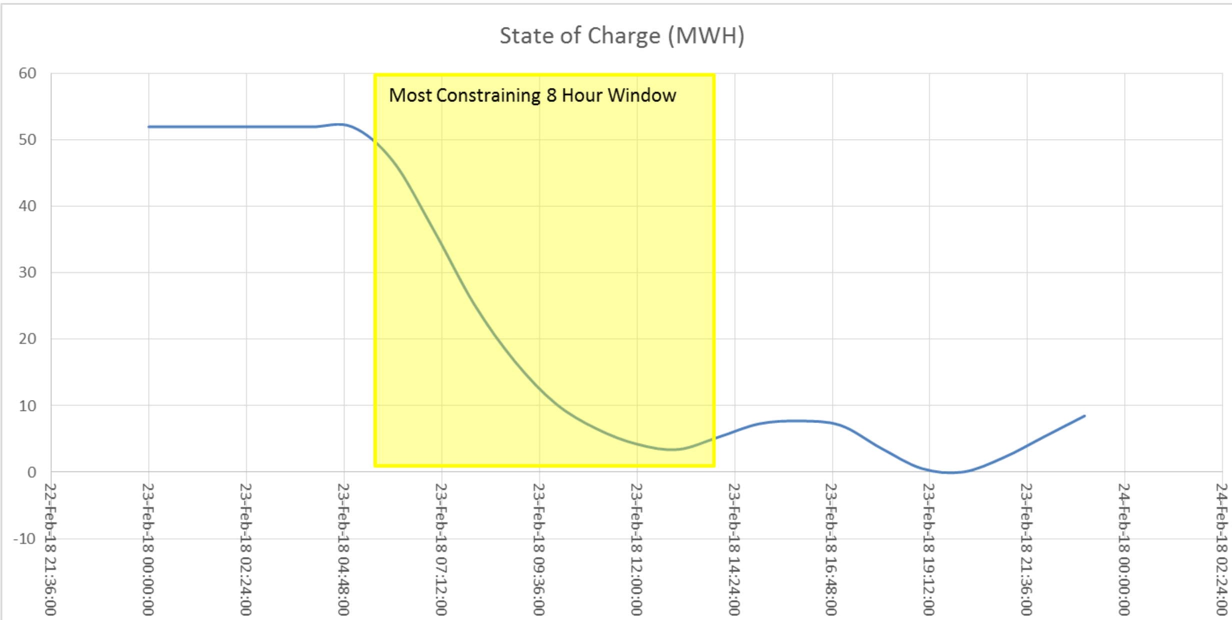


Figure 6-5 Storage State of Charge Requirements - Without Ferry Load

Considering the ferry load to be interconnected on a new feeder connected to the Murden Cove Substation, the storage size to mitigate the needs of Murden Cove Distribution Station needs to be upsized to accommodate the ferry load. In the year 2029, the ferry load is forecasted to be 10.2 MW. With one operation per hour and each operation lasting for 15 minutes at 10.2 MW, the energy consumption by the ferry load per hour is 2.55 MWH.

For the most constraining period of 23rd February 6 AM-2 PM, the loading on Murden Cove Transformer under Winslow Outage is shown above in Figure 6-4, with the threshold of 36 MVA (Transformer Limit). As observed from Figure 6-4 below, the load during the most constraining period of 6 AM – 2 PM is above the transformer limits almost all that time (6 AM – 1 PM). Therefore, there would not be a possibility of feeding the ferry load during this period from the Murden Cove distribution station.

Therefore to accommodate the ferry load additional storage capacity of 10.55 MW and 2.65 MWH for each constrained hour (considering 97% discharge efficiency) is required. Therefore, considering ferry load and a constrained period of 8 hours under Winslow tap outage, additional storage capacity needed is 10.55 MW/ 21.2 MWH for the Murden Cove distribution transformer.

Therefore considering ferry load, the total size requirement to mitigate the overloads on the Murden Cove Distribution Station Transformer for Winslow tap transmission outage is 21.85 MW/70.2 MWH i.e. aggregate of transformer storage need (11.3 MW/49 MWH) and ferry storage need (10.55 MW/21.2 MWH). The Bainbridge Island storage solution site and size requirements are shown in Figure 6-6.

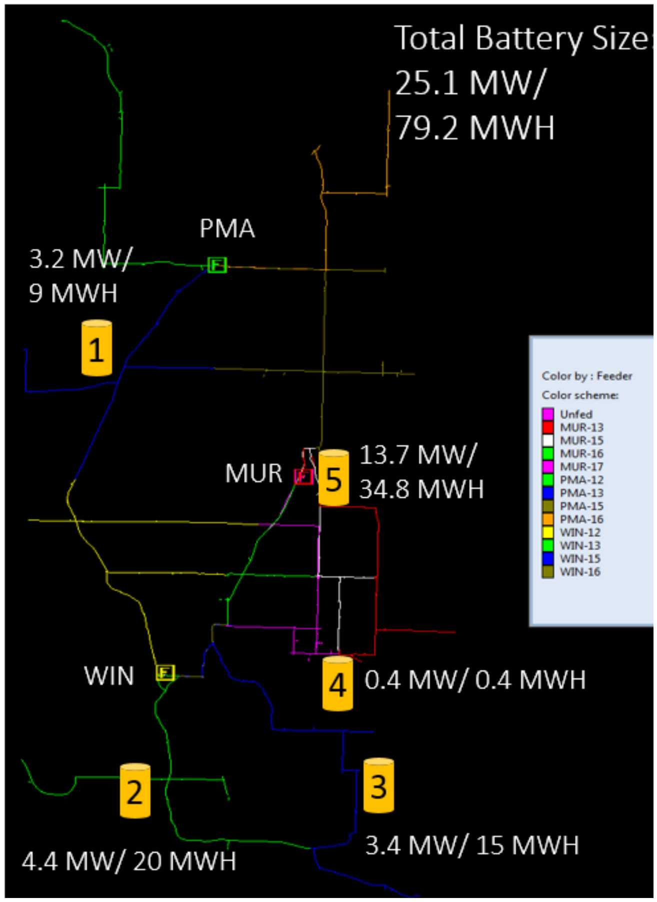


Figure 6-6 Bainbridge Island Storage Sizes and Sites to Address Transmission Reliability (Winslow Tap Outage)

In Figure 6-6 above, preliminary recommendations on battery sites are shown and described below:

- The battery requirements for Port Madison 13 feeder of 3.2 MW/9 MWH is shown as site (1) in the figure above.
- The battery requirements for Murden Cove 16 and 17 feeders of 4.4 MW/20 MWH and 3.4 MW/15 MWH respectively is shown as site (2) and site (3) in the figure above.
- Under outage of Winslow tap, the battery systems at site (2,3) are connected to the Murden Cove substation and can partially offset the Murden Cove substation requirements of 21.9 MW/ 70.2 MWH. Therefore, the remaining 14.1 MW/35.2 MWH is interconnected at the Murden Cove distribution station or its corresponding feeders to address the Murden Cove distribution station needs. This is represented as site (4,5) in the figure above.
- Site (4) (0.4 MW/0.4 MWH) needs to be interconnected to Murden Cove 15 feeder to mitigate the overloads observed and site(5) (13.7 MW/34.8 MWH) could be interconnected at Murden Cove substation and its corresponding feeders.
- Detailed siting of individual battery systems are discussed in the following section.

6.1.3 Storage Placement Options

Storage siting is investigated in detail in this section considering the loadings on different sections of the overloaded feeders. The storage site along the feeder is selected with the following objectives:

- Mitigate feeder overloads. A storage will reduce overloads upstream of its location and thus should be located downstream of all overloaded segments of the feeder.
- Avoid reverse power flows. A storage should not be located too far downstream of the substation that it can create reverse power flow on sections of the feeder, when discharged.

In the following plots, the feeder sections highlighted in red are heavily loaded considering a 9.5 MVA threshold (Feeder limit is 10.5 MVA. 1 MVA margin is considered). Therefore, the batteries need to be sited downstream of such sections to mitigate overloads. The sections highlighted in Yellow are lightly loaded sections considering the storage size requirements on these feeders. The sections highlighted in pink are the recommended interconnection sites for the storage sizes determined.

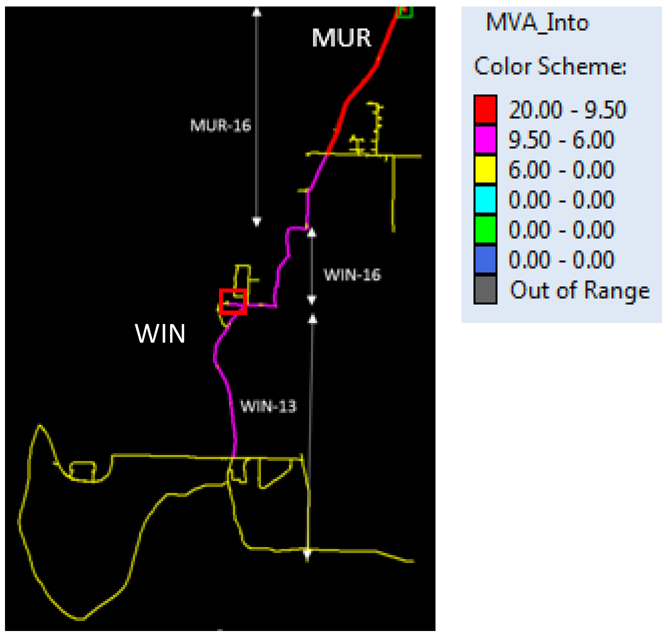


Figure 6-7 Murden Cove - 16 Storage Siting

Considering a storage requirement of 4.4 MW/20 MWH for MUR-16 and the storage operation at 0.8 power factor, the rated power output from the storage is 5.5 MVA. The 0.8 power factor is selected because there is KVAr demand from the supply side. The reactive power injection from the battery reduces the MW requirements of the battery and mitigates the loadings to the prescribed MVA limits. The storage needs to be sited at a location such that after the Winslow Tap outage and feeder switching, overloads need to be mitigated on all feeder sections without any reverse power flow. Considering these limitations, it is recommended that the storage need of 4.4 MW/20 MWH for MUR-16 be sited on the sections highlighted in Pink where the power flow is between 9.5 MVA and 6 MVA. This is approximately at a distance of 1 mile to 3.5 miles from the Murden Cove substation along the MUR-16, WIN-16 and WIN-13 feeders after the switching of Winslow 13 and 16 feeders on to Murden Cove 16 feeder after the outage of Winslow Distribution station.

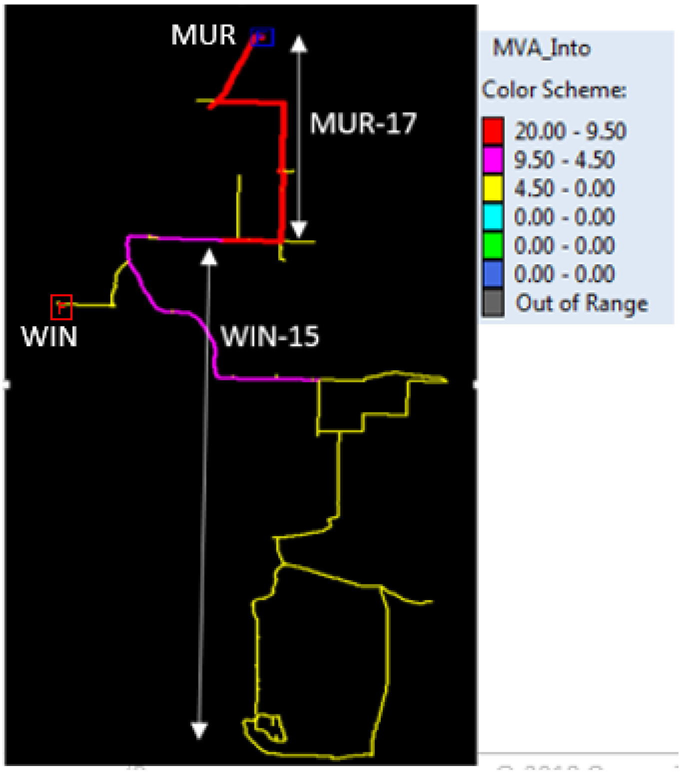


Figure 6-8 Murden Cove - 17 storage siting

Considering a storage requirement of 3.4 MW/15 MWH for MUR-17 and the storage operation at 0.8 power factor, the rated power output from the storage is 4.25 MVA. The storage needs to be sited at a location such that after the Winslow Tap outage and feeder switching, overloads need to be mitigated on all feeder sections without any reverse power flow. Considering these limitations, it is recommended that the storage need of 3.4 MW/15 MWH for MUR-17 be sited on the sections highlighted in Pink where the power flow is between 9.5 MVA and 4.5 MVA. This is approximately at a distance of 2.2 mile to 4.8 miles from the Murden Cove substation along the MUR-17 and WIN-15 feeders after the switching of Winslow 15 feeders on to Murden Cove 17 feeder after the outage of Winslow Distribution station.

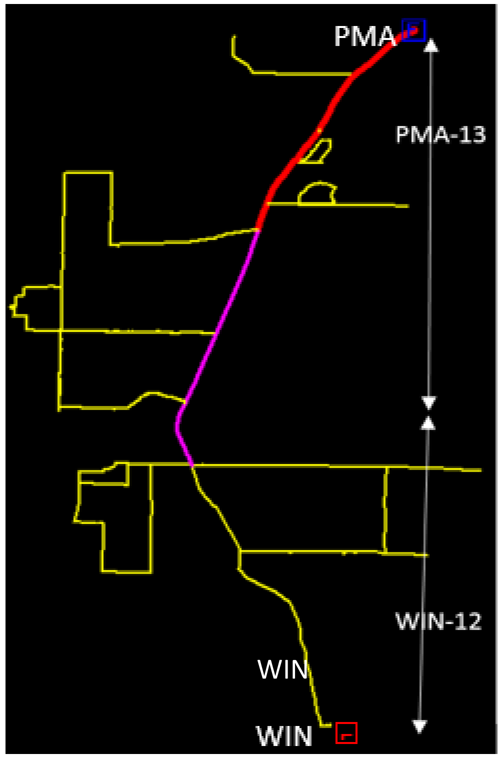


Figure 6-9 Port Madison 13 storage siting

Considering a storage requirement of 3.2 MW/9 MWH for PMA-13 and the storage operation at 0.8 power factor, the rated power output from the storage is 4 MVA. The storage needs to be sited at a location such that after the Winslow Tap outage and feeder switching and load shifting, overloads need to be mitigated on all feeder sections without creating reverse power flow. Considering these limitations, it is recommended that the storage need of 3.2 MW/9 MWH for PMA-13 be sited on the sections highlighted in Pink where the power flow is between 9.5 MVA and 4.5 MVA. This is approximately at a distance of 1.2 mile to 2.8 miles from the Port Madison substation along the PMA-13 and WIN-12 feeders after the switching of Winslow 12 feeder on to Port Madison 13 feeder after the outage of Winslow Distribution station.

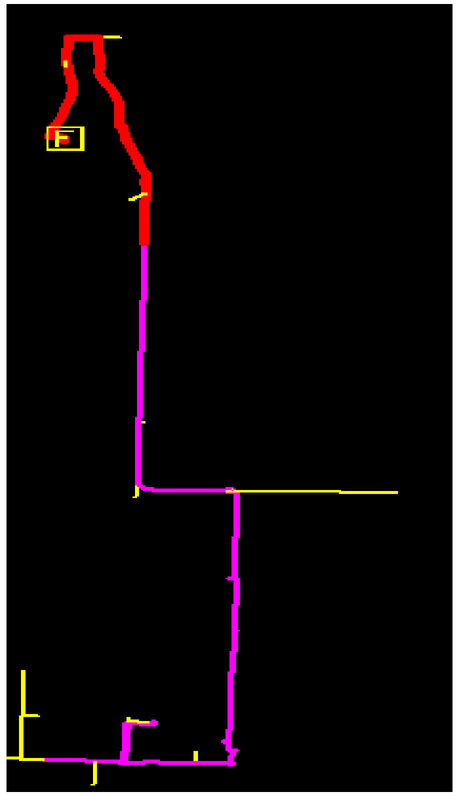


Figure 6-10 Murden Cove - 15 storage siting

Considering a storage requirement of 0.4 MW/0.4 MWH for MUR-15 and the storage operation at 0.8 power factor, the rated power output from the storage is 0.5 MVA. The storage needs to be sited at a location such that after the Winslow Tap outage and feeder switching and load shifting, overloads need to be mitigated on all feeder sections without creating reverse power flow. Considering these limitations, it is recommended that the storage need of 0.4 MW/0.4 MWH for MUR-15 be sited on the sections highlighted in Pink where the power flow is between 9.5 MVA and 1 MVA. This is approximately at a distance of 1 mile to 2.9 miles from the Murden Cove substation along the MUR-15 feeder after the recommended load shifting from MUR-17 to MUR-15.

Additionally, the 13.7 MW/ 34.8 MWh storage upsize required to mitigate the overloads on Murden Cove distribution transformer under Winslow outage and considering the ferry load, may be sited at the Murden Cove distribution station at the low voltage side of the distribution transformer.

Alternatively, the storage could be sited at any of the feeders at the Murden Cove Substation. However, considering the storage size requirements of 13.7 MW, to site the storage on any of the Murden Cove feeders, smaller size of the batteries to amount to a total of 13.7 MW/34.8 MWH is required to avoid reverse power flow on the feeders.

6.2 Storage Siting and Sizing for Substation Group Capacity Need

6.2.1 Storage Sizing for Substation Group Capacity Need

Considering the planning limit of the substation group utilization as per PSE solution criteria, the substation group capacity reaches the 84 MVA limit by the year 2021. Once installed, the storage is required fulfil its purpose for 10 years from the installation date, and thus the storage system should be designed to meet the system needs until Year 2031. The load on Bainbridge Island in the year 2031 is 92.1 MVA as per the Winter Normal Peak Load Forecast and the ferry load addition, and is the highest in the 2021 through 2030 period. Solution designed for the year 2031 is expected to meet the requirements for the 10 year period.

Figure 6-11 shows the load profile from December through February that is considered in this analysis, except for the Ferry charging load. Without the Ferry charging, the load shape exhibits a peak of 81.8 MVA on Feb 23, 2018. The Ferry charging load of 10.3 MW operating for 15 minutes in each hour will be incremental to the load profile.

Storage size requirements are determined by adding the loadings of the three distribution transformers at Port Madison, Winslow and Murden Cove. In the year 2031 and without the ferry load, the peak load totals 83.6 MVA.

Considering the ferry load profile, the hourly load on Bainbridge Island shown in Figure 6-11 is expected to increase by 10.3 MVA which would persist for 15 minutes each hour. With ferry, the load on Bainbridge Island is expected to violate the 84 MVA substation group capacity during 7 AM – 10 AM on the peak load day of FEB 23-2018. Figure 6-12 below shows the peak load for the constrained period on a 15 minute resolution with the ferry load. This profile was used to determine the storage capacity needs for substation group capacity.

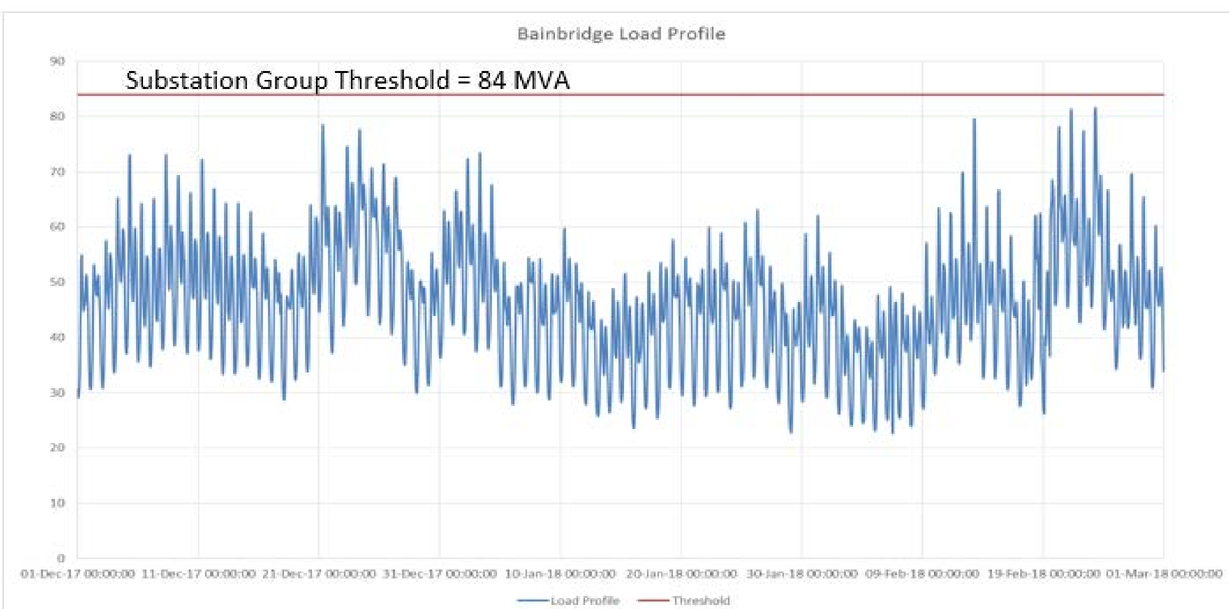


Figure 6-11 Bainbridge Island - Load Profile Without Ferry

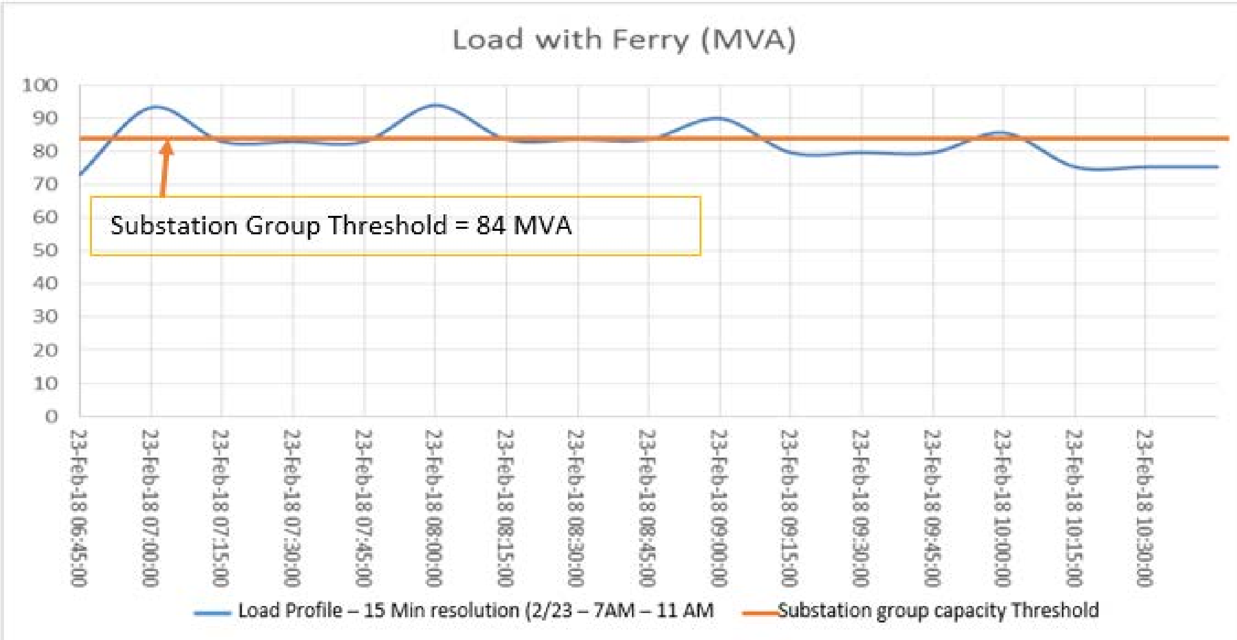


Figure 6-12 Bainbridge Island - Load Profile with Ferry (constrained Period)

Discharge is required from the storage if the load on the Island is greater than 84 MVA. As shown above (Figure 6-11) and from the calculated peak from the Synergi Electric Model, without the ferry load, there is no requirement for the storage until 2031. The storage discharge is required when the ferry load is operational during high load. Discharge from the storage is required when the load without the ferry exceeds 73.7 MVA, as hourly operation of ferry load would cause the load on the island to exceed 84 MVA.

Discharge from the storage would be required for 15 minutes in each hour when the ferry load is operational (Figure 6-12). The other 45 minutes of the hour, the storage can be charged back based on the available substation capacity considering 84 MVA threshold. The storage is assumed to be operated at 80% power factor.

The Storage State of Charge and storage MW output are shown in Figure 6-13, Figure 6-14 below for the most constraining period 23rd February (7 AM- 11 AM). The total Storage Size requirement is 9.7 MW/5 MWh, for substation group capacity needs, under the planning scenario with the ferry and with DSM.

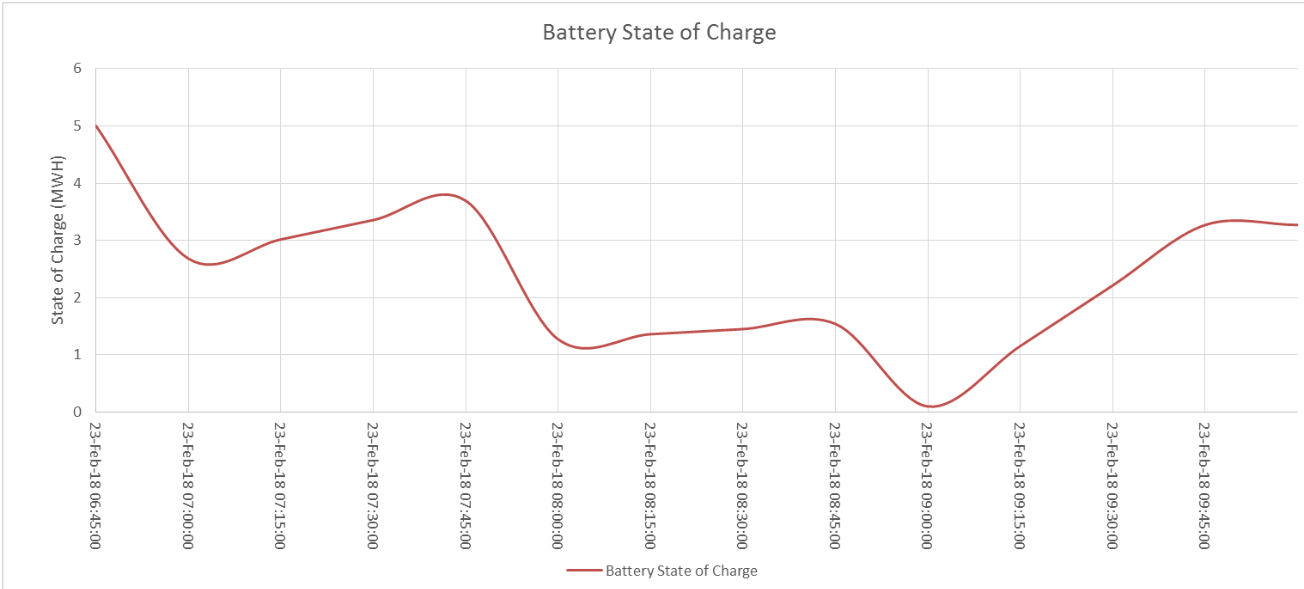


Figure 6-13 Storage State of Charge

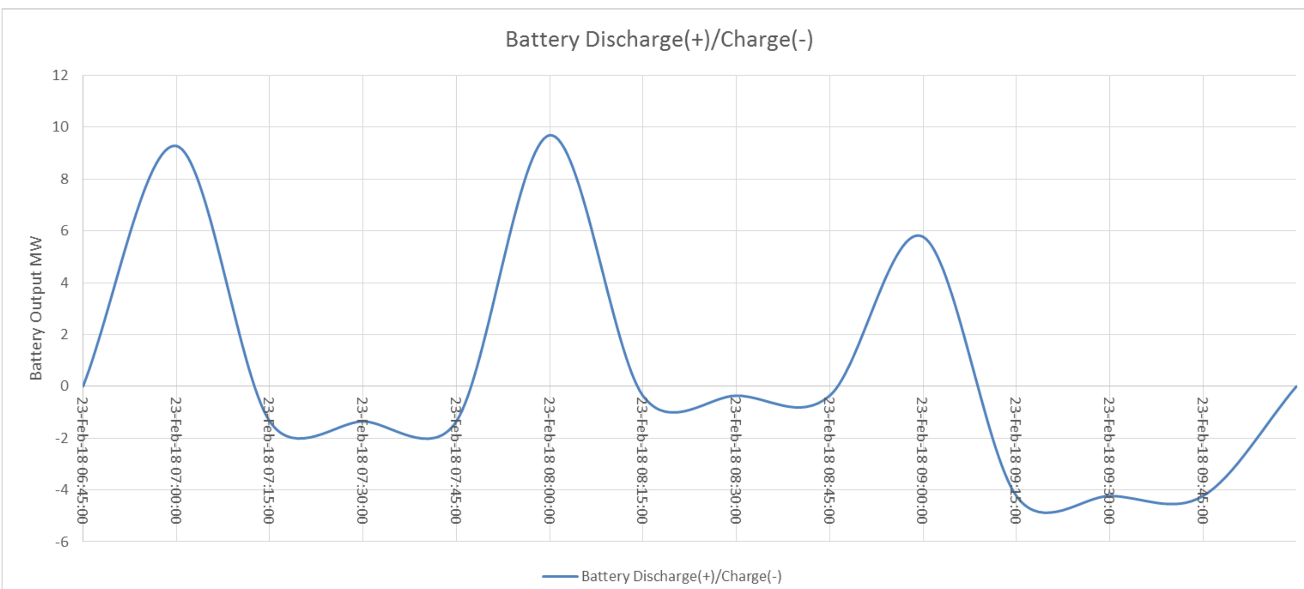


Figure 6-14 Storage Output

6.3 Storage Siting and Sizing for Winslow 13 Reliability Needs

The conventional project to address the Winslow 13 reliability need is to convert to underground a portion of the Winslow 13 feeder from the Winslow substation to the tie of Winslow 12 at an estimated cost of $643,000. Figure 6-15 below shows a portion of Winslow 12 and 13 feeders and the proposed upgrade is highlighted.

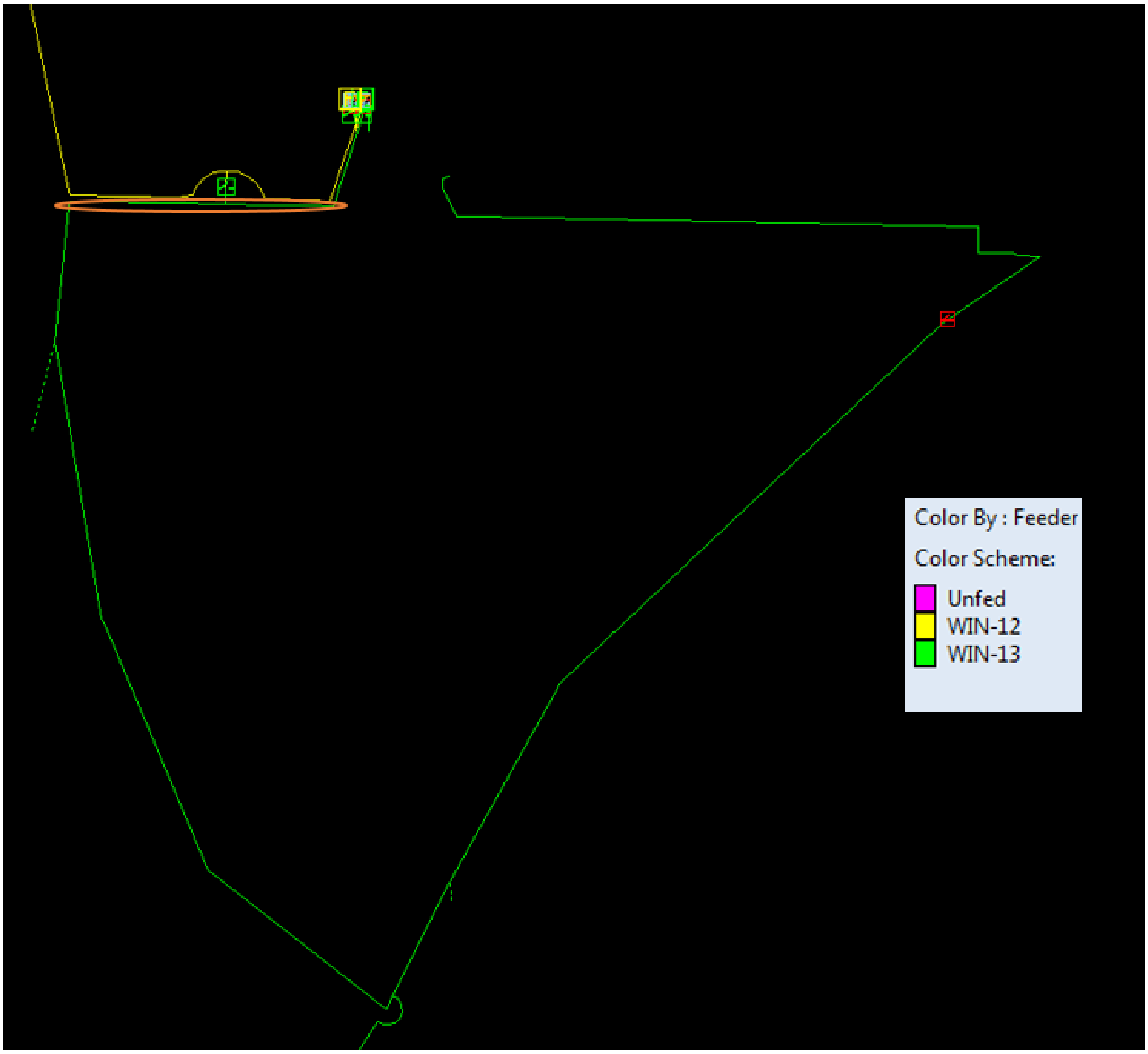


Figure 6-15 Winslow 13 proposed upgrade to Underground Section

As this upgrade is at the beginning of the feeder, this provides reliability to the entire feeder. Therefore, an equivalent storage solution is considered to support the load on the entire Winslow 13 feeder for 4 hours, which is the estimated restoration time. During the period of 2019-2029, the maximum feeder forecasted load is 393 Amps for the year 2019. The peak demand is estimated to be 8.33 MW, 2.8 MVAR.

Considering the load profile and a maximum of 4 hour outage duration, the total storage size requirements to mitigate the WIN-13 reliability needs are 8.6 MW/32 MWh.

It is worth assessing if the batteries that have been previously selected to mitigate the Transmission Reliability in section 6.1 can also mitigate the reliability needs of WIN-13 feeder.

- The 4.4 MW/20 MWh storage at Site 2 was required to mitigate the overload on Murden Cove - 16 feeder due to pick up of Winslow 13 and 16 feeders. As observed from Figure 6-7, the storage could be sited before/after the tie between Winslow 12 and 13 feeder and hence could be used to serve the reliability needs for Winslow 13 feeder.

- However, the 3.4 MW/15 MWh could not be sited on the Winslow 15 feeder at the tie point of Winslow 15 and 13 shown in Figure 6-8, and therefore, this storage cannot be used to serve the reliability needs of the Winslow 13 feeder.
- Therefore, an additional storage size of 4.2 MW/ 12 MWh is required on Winslow 13 feeder to carry the entire Winslow 13 feeder under an outage.

6.4 Summary of Storage Siting and Sizing Analysis

The storage-only solution for the 3 system needs requires 5 battery systems. The sizes and locations of these storage systems is summarized in Table 6-1.

Table 6-1: Summary of Battery Solution Siting and Sizing Analysis

			Battery Size		<---------*Needs* -------------->			<------------*Overloads*----------->				
ID	**Site**	**Location**	**Size MW**	**Size MWh**	**WIN-TAP**	**Sub. Group**	**WIN-13 Feeder**	**MUR-16**	**MUR-17**	**PMA-13**	**MC Sub Trafo**	**Placement Options**
1	1	PMA-13 /WIN-12	3.2	9	X					X		1.2-2.8 Miles from PMA sub, along PMA-13 or WIN-12
2	2	WIN-13	4.4	20	X		X	X			X	1.0-3.5 Miles from MC sub, along MUR-16, WIN-16, or WIN-13)
		WIN-13	4.2	12			X					WIN-13
3	3	MUR-17 /WIN-15	3.4	15	X				X		X	2.2-4.8 Miles from MC sub, along MUR-17 or WIN-15)
4	4	MUR-15	0.4	0.4	X				X		X	1.0-2.9 Miles from MC sub, along MUR-15
5	5	MC Sub	13.7	34.8	X	X					X	MC sub
		Total Battery Size	**29.3**	**91.2**	25.1MW/ 79.2MWh	Included in WIN-TAP	8.6MW/ 32MWh	4.4MW/ 20MWh	3.8MW/ 15.4MWh	3.2MW/ 9MWh	21.9MW/ 70.2MWh	Note: MC is Murden Cove Substation

6.5 Storage System Price Estimates

As the reliability needs for Winslow Tap is in the year 2018, storage is assumed to be installed in the year 2019. Additionally, the storage sizes for Winslow Tap Outage can be used to mitigate Substation capacity needs until the year 2031. The reliability need for Winslow 13 feeder could be addressed partially using the storage needs determined for Winslow Tap Reliability. An additional 4.2 MW/12 MWH storage is required on Winslow 13 feeder to carry the entire Winslow 13 feeder.

As each of these Storage systems are used to address multiple needs, it is assumed that the BESS is at an adequate State of Charge (SOC) when the need arises commensurate with the time of year and the nature of the system need. For example, for Winslow tap reliability, the storage is only required during specific periods of Winter Peak months; for substation capacity, the storage is only needed during specific hours of February; while for the Winslow 13 feeder reliability, the storage is expected to have a SOC based on the feeder loading at that time to ride through the 4 hour outage. The capacity of the storage systems beyond the system need can be exploited for additional benefits.

The storage costs are shown below for the storage-only solution to address the Winslow Tap Reliability needs, Substation Capacity needs and feeder reliability of Winslow 13. These are installed battery (Li-Ion) system costs and do not include additional interconnection costs, land and permitting costs and other costs associated with distribution automation.

Table 6-2 Storage System Costs[10]

Material		3.2 MW/9 MWH	4.4MW/20 MWH	3.4 MW/15MWH	14.1 MW/35.2MWH	4.2 MW/12 MWH
	10- Battery System	$2,342,891	$5,234,119	$4,050,567	$9,485,505	$3,140,471
	20- Container	$450,000	$675,000	$450,000	$1,125,000	$450,000
	30- Inverter	$375,000	$375,000	$375,000	$1,312,500	$375,000
	40-Transformer	$218,125	$218,125	$218,125	$640,000	$218,125
	50-MV SWGR	$200,000	$200,000	$200,000	$240,000	$200,000
	60-HVS Turnkey	$0	$0	$125,000	$0	$0
	70-EMS Hardware	$62,500	$81,250	$62,500	$143,750	$62,500
Labor + Travel Expenses						
	100-Engineering Cost	$24,571	$24,571	$24,571	$24,571	$24,571
	110-PM Cost	$144,000	$230,400	$144,000	$307,200	$144,000
	120-Commissioning	$85,714	$127,086	$100,343	$190,857	$93,029
	130-Expenses	$43,229	$59,743	$43,229	$75,229	$43,229
Civil Work						
	200-Construction	$235,063	$339,250	$235,063	$605,158	$235,063
	Total	$4,181,093	$7,564,544	$6,028,397	$14,149,770	$4,985,987
	Total Battery Price	$ 36,909,791				

[10] Battery system costs are based on Quanta Technology's bottom-up estimate methodology

6.6 Summary

The three system needs (transmission reliability, substation capacity, and Winslow-13 reliability) can be addressed using conventional T&D solutions, and alternatively using energy storage systems. The Storage solution will require the use of 5 storage systems as follows:

Table 6-3 Siting and Sizing of Storage-Only Solution

ID	Location	Storage-Only Solution	Needs
1	PMA-13/WIN-12	3.2 MW/ 9 MWH	Winslow Tap Reliability
2	WIN-13	4.4 MW/20 MWH 4.2 MW/12 MWH	Winslow Tap Reliability & Winslow-13 Feeder Reliability Winslow-13 Feeder Reliability (exclusive)
3	MUR-17/WIN-15	3.4 MW/ 15 MWH	Winslow Tap Reliability
4	MUR-15	0.4 MW/ 0.4 MWH	Winslow Tap Reliability
5	Murden Cove Distribution Station	13.7 MW/ 34.8 MWH	Winslow Tap Reliability& Substation Capacity Needs
	Total	**29.3 MW / 91.2 MWH**	**All 3 Needs**

Table 6-4 summarizes the different needs for Bainbridge Island and the corresponding storage solutions and their corresponding capital investment levels.

Table 6-4 Summary of Conventional, Storage-Only Solution

		Conventional T&D		**ALL-BESS Option**	
Need Driver	**Need Year**	**Solution**	**Costs**	**Storage Sizes (MW/MWH)**	**Costs**
Transmission Reliability – Winslow	Current	Transmission Loop	$12,300,000	25.1 MW/ 79.2 MWH	$31,923,804
Substation Group N-0 Capacity	2021	New Distribution Substation	$11,250,000	9.7 MW/ 5 MWH	$4,077,290*

Feeder Reliability (WIN-13)	Current	Conventional feeder reliability solution, $640k underground conversion	$640,000	8.6 MW/ 32 MWH	$12,550,531**
ALL		ALL Above	$24,190,000	29.3 MW/ 91.2MWh	$36,909,791
Upsizing For Degradation				29.3MW / 111 MWh***	$43,500,000

*- The battery sizes for Transmission Reliability for Winslow Tap can be used for Substation Group Capacity need as well. Therefore, this cost is not included in the total.

**- 4.4 MW/20 MWh battery sized for Transmission Reliability for Winslow Tap is used for Feeder Reliability of WIN-13. This portion of the cost is not included in the total.

*** The capacity of the energy storage system is upsized to mitigate the anticipated degradation over the 10 year planning horizon. For a nominal 2% annual degradation in storage capacity, the storage MWh capacity is upsized by 22% from the level required to address the system needs.

7 TASK 4: TECHNO-ECONOMIC EVALUATION

7.1 Analysis Methodology

The economic evaluation of the storage solutions as compared to the conventional T&D solutions requires:

- Lifetime modeling of the cost of each project from inception to retirement inclusive of project development activities and timeline, EPC, O&M, capacity management, replacement, and disassembly and recycling.
- Modeling of relevant utility's capital structure including debt and equity ratios and costs, and tax rate.
- Proper regulated asset base (RAB) accounting including treatment of depreciation for tax and book purposes.
- Useful life estimates: The conventional T&D solutions have an assumed book life of 45 years, while the energy storage technology is assumed to have a useful life of 15 years for Li-Ion technology (20 years for Flow technology).

We adopted the following methodology to compare the economics of the various solution alternatives:

1. The capacity of the energy storage system is upsized to mitigate the anticipated degradation over the 10 year planning horizon. For a nominal 2% annual degradation in storage capacity, the storage MWh capacity is upsized by 22% from the level required to address the system reliability needs.
2. The capital cost components of each solution alternative is calculated (conventional T&D, and energy storage).
3. However, because of the differences in asset life between the conventional component (45 years) and the storage component (15 years) of any solution, the cost of each component over the 10 year planning horizon is calculated and summed (using present value) to provide a total 10 year capital cost. This calculation utilizes a real economic carrying cost taking into account the company's weighted average cost of capital and the inflation rate.
4. The present value of the O&M costs over the 10 year planning horizon are calculated and summed for each solution.
5. The overall (capital and O&M) present value costs of all solutions are calculated and compared.

7.2 Economic Assumptions

7.2.1 Utility Capital Structure

The capital structure (debt and equity) of PSE was utilized in the study. A key parameter was calculated from the capital structure, namely the WACC (weighted average cost of capital) to be 6.97%, and was utilized in discounting cash flows to compare investments.

Financial Parameters	Value
Income Tax Rate	21.00%
Sales Tax	4.76%
Debt Ratio	51.50%
ESS Debt Repayment Period Yrs	10
T&D Debt Repayment Period Yrs	30
Solar PV Debt Repayment Period Yrs	20
Interest Rate	5.8100%
After-Tax Equity Cost	9.50%
Cost Escalation p.a.	2.50%
Price Escalation p.a.	3.00%
Inflation p.a.	2.50%
WACC	6.97%
Pre-Tax Cost of Capital	7.60%
Pre-Tax Return on Rate Base	8.82%
Pre-Tax Equity Cost	12.03%

7.2.2 Asset Depreciation Schedules

The following summarizes the depreciation schedules for tax and book purposes for various asset classes:

Depreciation Schedule (Yrs)	Book Straight Line	MACRS for Tax Purposes
Conventional T&D	45	15
Storage Systems	10	7

7.2.3 Capex and Opex

The capital cost of a fully installed and commissioned Li-Ion energy storage system in 2019 was assumed to have two parts, one for the AC power block (inverter, transformers, interconnection) at $250/kW, and the other for the DC energy block (batteries, structures, cables, … etc.) at $325/kWh. These cost rates approximate very well the detailed installed cost of the storage bill of materials that was utilized in Section 6. The cost of storage losses was calculated based on the technology's indicative roundtrip efficiency of 90%, and a prevailing average cost of energy of $30/MWh.

Conventional T&D solutions capex was estimated by PSE for each project. All estimates were assumed to be in 2018 dollars.

An inflation rate of 2.5% was taken to escalate the project cost. The annual O&M cost of conventional T&D projects was assumed to be 1.5% of the project's initial capex. The annual O&M cost of Li-Ion storage systems was assumed to be $10/kWh plus 1% of initial capex.

All O&M costs were escalated by 2.5% annually.

For this comparative analysis, several typical cost items in energy storage systems were not considered because they either fell outside the 10 year planning horizon, or the expected storage use cycles is uncertain, including:

- Inverter replacement was assumed every 10 years and to cost $100/kW.
- Cost of disassembly and recycling was assumed to be $50/kWh of storage capacity.

7.2.4 Life Cycles and Capacity Degradation

Storage capacity is assumed to fade with calendar and use, at a rate of 2% per year for a Li-Ion storage if utilized at an average rate of one full cycle per day. A lifecycle curve as a function of depth of discharge was assumed to have 4,500 for full cycles, and increases as the depth of discharge decreases.

7.2.5 Storage Size

The storage capacity is upsized at the installation time to account for the anticipated degradation over the 10 year planning horizon.

7.3 Economic Analysis Results Summary – Without Market Revenues

The economics of the two project alternatives are analyzed and compared in Table 7-1 over the 10 year planning horizon, without consideration of any potential market revenues that can be generated by the Storage-Only solution.

Table 7-1. Techno-Economic Analysis Summary

All Costs are Present Value ($M)	Conventional T&D Solution	Storage-Only Solution	Storage-Only Solution (Option)
Application	Distribution Capacity & Reliability	Distribution Capacity & Reliability	Distribution Capacity & Reliability (Excluding WIN-13 feeder reliability)
Project Need Date	2018	2018	2018
Storage Size MW/MWh			
Min Size to Meet System Needs	-	29.3MW / 91.2 MWh	25.1MW / 79.2 MWh
Upsized to Mitigate Degradation	-	29.3MW / 111 MWh	25.1MW / 97 MWh
Capital Investment –			
Conventional	$24.2[1]	-	-
Storage	-	$43.5	$37.7
Total	**$24.2[1]**	**$43.5**	**$37.7**
Capital Levelized Real Cost (over 10 years)	$10.0	$32.6	$28.2
O&M Cost (over 10 years)	$0.4	$1.6	$1.4
Total Cost (over 10 years)	**$10.4**	**$34.1**	**$29.6**
Cost Ratio	**100%**	**328%**	**284%**

[1]Costs are July 2018 Puget Sound Energy cost estimate based on similar past projects in other areas of PSE service territory. Does not include site-specific engineering

7.4 Economic Analysis Results Summary – With Market Revenues

The storage solution was optimized to address the grid needs during peak load periods, and therefore it will have under-utilized capacity during all other periods that can potentially be monetized through participation in other grid services.

Appendix B provides a detailed analysis of the potential revenue streams of the Storage-Only solution from providing system capacity and participation in energy price arbitrage services; while Appendix C provides a detailed analysis of the potential revenue streams of the Storage-Only solution (Option) from providing system capacity and participation in energy price arbitrage services.

7.4.1 Revenue Stacking Potential of the Storage-Only Solution

The present value over 10 years of providing system capacity and participating in energy arbitrage after fulfilling the 3 system needs is estimated optimistically in Appendix B to be 2.4M ($1.66M for energy price arbitrage and $0.75M for system capacity).

7.4.2 Revenue Stacking Potential of the Storage-Only (Option) Solution

The present value over 10 years of providing system capacity and participating in energy arbitrage after fulfilling the 2 system needs is estimated optimistically in Appendix C to be 2.1M ($1.5M for energy price arbitrage and $0.6M for system capacity).

7.4.3 Comparative Analysis with Market Revenues

The analysis in Section 7.3 showed the cost over 10 year for the conventional solution to be $10.4M and for the storage-only solution to be $34.1M. Adjusting the storage-only solution cost with the market revenues will alter the comparison slightly as follows.

Solution	Market Participation Level	Storage Solution Net Cost (over 10 years)	Ratio of Cost of Storage Solution to Conventional Cost
Storage-Only Mitigate 3 System Needs: - Win-Tap Reliability - Substation Group Capacity - WIN-13 Feeder Reliability	None System Capacity Only Energy Price Arbitrage Only System Capacity and Energy Price Arbitrage	$34.1M $33.4M $32.4M $31.7M	328% 321% 311% 305%
Storage-Only (Option) Mitigate 2 System Needs: - Win-Tap Reliability - Substation Group Capacity	None System Capacity Only Energy Price Arbitrage Only System Capacity and Energy Price Arbitrage	$29.6M $29.0M $28.1M $27.5M	284% 279% 270% 264%

The opportunity to participate as well as the cost of participation and market prices of the ancillary services and capacity markets over a 10 year period can be highly uncertain. However, the above cursory analysis provides an indicative view of the potential market revenues and cost comparison between the two solution alternatives.

8 CONCLUSIONS

This study explored the technical and economical efficacy of two alternative solutions to the Bainbridge capacity and reliability needs:

- **Conventional T&D solution**: The conventional solution proposed by PSE allows all substations to backup each other and supply the needed capacity for the future and includes 3 elements:
  - Build a 3 mile 115kV line and tie Winslow and Murden Cove substations.
  - Build a new 115/13 kV distribution substation.
  - Convert a section of WIN-13 feeder to underground.

- **Storage-Only Solution**: Five (5) energy storage systems, with a minimum combined capacity of 29.3 MW/91.2 MWh as follows:

Location	Storage-Only Solution
PMA-13/WIN-12	3.2 MW/9 MWH
WIN-13	8.6 MW/32 MWH
MUR-17/WIN-15	3.4 MW/ 15 MWH
MUR-15	0.4 MW/ 0.4 MWH
Murden Cove Distribution Station	13.7 MW/34.8 MWH
Total (minimum size)	**29.3 MW / 91.2 MWH**

The capital cost of the Conventional solution is estimated at $24.2M (estimate made by PSE in July 2018 based on similar past projects in other areas of PSE service territory – does not include site-specific engineering), while the capital cost of the Storage-Only solution is estimated at $43.5M. A detailed financial analysis shows the cost of the Storage-Only solution to be over 3 times that of the Conventional solution over the project planning horizon of 10 years.

		Conventional T&D		ALL-BESS Option	
Need Driver	**Need Year**	**Solution**	**Costs[1]**	**Storage Sizes (MW/MWH)**	**Costs**
Transmission Reliability – Winslow	Current	Transmission Loop	$12,300,000	25.1 MW/ 79.2MWH	$31,923,804
Substation Group N-0 Capacity	2021	New Distribution Substation	$11,250,000	9.7 MW/ 5MWH	$4,077,290
Feeder Reliability (WIN-13)	Current	Conventional feeder reliability solution, $640k underground conversion	$640,000	8.6 MW/ 32MWH	$12,550,531
ALL		ALL Above	$24,190,000[1]	29.3 MW/ 91.2MWh	$36,909,791
Upsizing For Degradation				29.3MW / 111 MWh	$43,500,000

[1]Costs are July 2018 Puget Sound Energy cost estimate based on similar past projects in other areas of PSE service territory. Does not include site-specific engineering.

The lifetime cost analysis of the Storage-Only solution shows it to be 3 times as expensive as the wire solution. Participation of the Storage-Only solution in the system capacity and energy price arbitrage services does not materially change its comparative cost to the wire solution.

9 APPENDIX A – LEVELIZED REAL COST ANALYSIS

This section presents one method of comparing the costs of two assets that have different useful lives.

Take for example a conventional transmission asset with a useful life of 45 years. Assuming a capital cost of the asset of $1M, and an annual maintenance cost of $15K that escalates at an inflation rate of 2.5% per year. One might want to calculate the appropriate cost of this asset for the first 10 years of its life.

The methodology that has been used in this report, the levelized real cost, converts the capital cost of the asset to a 45 year annuity payment that escalates annually at the inflation rate. Thus, the cost of the asset for the first year of operation is the annuity payment in the first year, and the cost of the second year grows up with the inflation rate and so on. The cost of the asset in the first year is calculated based on the weighted average cost of capital (WACC) of the asset owner so that the present value of the annuity payments is equal to the asset capital cost.

This method is also called the real economic carrying cost method, and can be calculated using the following formulas using Capital Recovery Factors (CFR) for each year as follows:

$$CFR_1 = \frac{(d-g)(1+d)^n}{(1+d)^n - (1+g)^n}$$

$$CFR_n = CFR_1\,(1+g)^{n-1}$$

Where:

d=discount rate (WACC); g=inflation rate; n=asset life

As an example, for the aforementioned $1M asset with $15k annual O&M, assuming a WACC of 6.97%, inflation rate of 2.5%, and asset life of 45 years, the CFR1 = 5.2%, and the present value of the first 10 years of asset capital cost is 41% of the asset capital cost, or $410K. The present value of the O&M cost is $120K for a total 10 year cost of $530k.

10 APPENDIX B – REVENUE STACKING POTENTIAL OF STORAGE-ONLY SOLUTION

The storage-only solution consisting of five (5) battery systems totaling 29.3MW/91.2MWh was designed to address three needs, namely, the Winslow-Tap outage, the substation group loading limit, and the Win-13 feeder outage. The Bainbridge Island system needs vary throughout the year with the load level, and correspondingly, the percentage of the battery size (MW and MWh) that is required to address these system needs will also vary. This provides a commercial opportunity to monetize the excess capacity of the storage solution during periods when the needs are not at their highest levels, in order to offset the cost of the storage investment.

Two monetize-able services that are potentially available to this storage system are system capacity and energy price arbitrage. The Integrated Resource Plan (IRP) of 2017 provides a basis for the valuation of these two potential revenue streams. System capacity is a contracted service and thus has a lower risk as compared to energy price arbitrage which depends on the daily volatility of the locational marginal prices (LMP). The first priority of utilizing the storage system is to address the local needs. Any excess capacity will be utilized to provide system capacity services, and finally any remaining excess capacity will be used to provide energy price arbitrage.

The analysis methodology that was followed in this study to quantify and optimize the revenue streams is summarized in the following 3 steps:

1. Determine the required storage capacity (MW and MWh) for each hour in a year to address the three local needs.
2. Assess the storage availability to provide the system capacity service.
3. Optimize the operating profits from energy price arbitrage.

10.1 Hourly Storage Requirements to Address Needs:

The storage solution consisting of five (5) storage systems was designed to address three needs. Two of which (Winslow-Tap outage and WIN-13 feeder outage) are contingent services that are only triggered after the onset of a defined grid outage, while the third need (substation group) is triggered whenever the load level exceeds a prescribed level and thus is not contingent. To address the two types of needs, the storage systems will have to discharge to address the substation group trigger while keeping enough energy (MWh) in reserve to potentially address a subsequent defined outage. Both the discharged MW and the reserve MWh vary hourly throughout the year depending on the load level on specific feeders and substations in the area, as was detailed in Chapter 6.

Figure 10-1 shows the percentage of the storage solution size that is required to address the substation group capacity requirement, while Figure 10-2 shows the required storage solution size (expressed as a percentage of the total planned solution size) that is required to address all three needs. The percentage size is conservatively computed as the higher of either MW rating percentage or MWh rating percentage. The analysis was conducted using the 2019 data which corresponds to the highest peak in the study horizon. The data is tabulated in columns corresponding to each of the 24 hours in a day, and in rows corresponding to each of the 12 months in a year. For example, at hour ending 8, the maximum discharge for all days in December to address the substation group capacity need will be 22% of the storage solution rating, and at the same time, the storage solution will have to maintain 65% of its rated energy capacity in reserve in anticipation of an outage in accordance with the Winslow-Tap or the Win-13 outage scenarios. Similarly, during June-Sept, the storage solution is not required to address any needs.

Hourly Max of Battery Requirements for Substation Group (N-0) : MW/MWh (%)

Max Co / Ro	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	All
1									5%																5%
2								31%	33%	20%	5%														33%
3																									
4																									
5																									
6																									
7																									
8																									
9																									
10																									
11																									
12								12%	22%	19%	10%														22%
All								**31%**	**33%**	**20%**	**10%**														**33%**

Figure 10-1: Storage Max Hourly Requirements for Substation Group Capacity Need by Month and Hour (taken as the higher of MW% or MWh%)

Hourly Max of Battery Requirements MW/MWh (%)

Max of Col / Row	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	All
1	12%	17%	18%	20%	22%	30%	42%	47%	49%	45%	43%	39%	33%	26%	26%	26%	29%	38%	41%	41%	37%	33%	17%	11%	49%
2	26%	37%	49%	61%	69%	83%	84%	79%	69%	58%	51%	49%	47%	47%	72%	71%	66%	61%	63%	59%	53%	48%	36%	22%	84%
3	10%	11%	12%	13%	15%	16%	30%	44%	46%	44%	35%	30%	17%	15%	13%	13%	14%	17%	20%	23%	19%	15%	10%	10%	46%
4	9%	9%	10%	12%	14%	16%	27%	45%	44%	30%	15%	11%	10%	10%	10%	16%	11%	11%	11%	11%	10%	9%	9%	9%	45%
5	8%	8%	8%	10%	11%	13%	21%	46%	49%	44%	40%	30%	17%	9%	10%	14%	16%	18%	29%	29%	28%	23%	9%	8%	49%
6	7%	7%	7%	7%	7%	7%	8%	8%	8%	8%	7%	7%	7%	7%	7%	7%	7%	8%	8%	8%	7%	7%	7%	7%	8%
7	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
8	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	7%	7%	7%	7%	8%	8%	8%	7%	7%	6%	6%	8%
9	5%	5%	5%	5%	7%	8%	9%	9%	9%	8%	7%	7%	7%	7%	7%	7%	8%	8%	9%	9%	8%	7%	6%	5%	9%
10	7%	7%	7%	9%	10%	12%	13%	25%	33%	25%	10%	10%	10%	10%	10%	10%	11%	11%	11%	10%	10%	9%	8%	7%	33%
11	12%	14%	16%	18%	20%	23%	39%	47%	47%	46%	44%	42%	40%	40%	35%	35%	34%	41%	39%	38%	35%	32%	20%	12%	47%
12	19%	26%	33%	40%	46%	56%	65%	65%	61%	55%	50%	47%	45%	42%	40%	41%	43%	44%	45%	45%	44%	42%	37%	25%	65%
All	**26%**	**37%**	**49%**	**61%**	**69%**	**83%**	**84%**	**79%**	**69%**	**58%**	**51%**	**49%**	**47%**	**47%**	**72%**	**71%**	**66%**	**61%**	**63%**	**59%**	**53%**	**48%**	**37%**	**25%**	**84%**

Figure 10-2: Storage Max Hourly Requirements for All 3 Needs by Month and Hour (taken as the higher of MW% or MWh%)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	88%	83%	82%	80%	78%	70%	58%	53%	51%	55%	57%	61%	67%	74%	74%	74%	71%	62%	59%	59%	63%	67%	83%	89%
2	74%	63%	51%	39%	31%	17%	16%	21%	31%	42%	49%	51%	53%	53%	28%	29%	34%	39%	37%	41%	47%	52%	64%	78%
3	90%	89%	88%	87%	85%	84%	70%	56%	54%	56%	65%	70%	83%	85%	87%	87%	86%	83%	80%	77%	81%	85%	90%	90%
4	91%	91%	90%	88%	86%	84%	73%	55%	56%	70%	85%	89%	90%	90%	90%	84%	89%	89%	89%	89%	90%	91%	91%	91%
5	92%	92%	92%	90%	89%	87%	79%	54%	51%	56%	60%	70%	83%	91%	90%	86%	84%	82%	71%	71%	72%	77%	91%	92%
6	93%	93%	93%	93%	93%	93%	92%	92%	92%	92%	93%	93%	93%	93%	93%	93%	93%	92%	92%	92%	93%	93%	93%	93%
7	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%
8	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	93%	93%	93%	93%	92%	92%	92%	93%	93%	94%	94%
9	95%	95%	95%	95%	93%	92%	91%	91%	91%	92%	92%	93%	93%	93%	93%	92%	92%	92%	91%	91%	92%	93%	94%	95%
10	93%	93%	93%	91%	90%	88%	87%	75%	67%	75%	90%	90%	90%	90%	90%	90%	89%	89%	89%	90%	90%	91%	92%	93%
11	88%	86%	84%	82%	80%	77%	61%	53%	53%	54%	56%	58%	60%	60%	65%	65%	66%	59%	61%	62%	65%	68%	80%	88%
12	81%	74%	67%	60%	54%	44%	35%	35%	39%	45%	50%	53%	55%	58%	60%	59%	57%	56%	55%	55%	56%	58%	63%	75%

Figure 10-3: Available Storage Capacity after Meeting System Needs

10.2 System Capacity Service:

The Puget Sound IRP in 2017 shows the system capacity price in 2018 through 2024 to be $3.79/kW-yr, and then jumps in 2025 to $78.19/kW-yr and stays at that level through 2037. The system capacity requirements are exclusively during December for each of the 10 hours between 6AM-11AM and 5PM-10PM.

An analysis of the local requirements in Figure 10-1 and Figure 10-2 and the hourly profile of the load in Bainbridge Island reveals the following observations:

- The load peaks in December during HE 8-11AM.
- The energy required to shave the peak load in December increases with the level of MW shaving. A 5 MW peak load shaving requires 3 hours of energy, while a 10MW peak shaving requires 4 hours, and further peak shaving beyond 15MW requires 10 hours.
- During December, the maximum MW discharge of the storage solution during the system capacity hours is 22% of the storage solution rating, while the maximum energy requirement is 65% of the storage rating. At any hour, the MW discharge in addition to the excess storage capacity above the requirement is available to provide the system capacity service. The minimum available percentage of the storage rating for system capacity services is 35%.
- During the 10 system capacity hours in December, the availability of the storage solution to provide system capacity service rises, as a percent of the storage solution rating, from 35% at 7AM to 58% at 10PM.
- The storage solution rating of 29.3MW and 91.2MWh provides only 3.11 hours of continuous discharge capability.
- If the storage aims to provide an equal level of system capacity at each of the 10 hours for each of the days in December, then the maximum level of participation in the system capacity service will be (3.11hr/10hr)x(35%)x(29.3MW) = 3.2MW, earning the full system capacity price. The present value of the system capacity service over 10 year is $0.63M.
- On the other hand, if the storage solution is viewed as a component of a portfolio of capacity solutions, and thus allowed to provide partial capacity for each hour, the storage can maximize

its participation by focusing on the last 3 hours in the day where it can participate by an average of 70% of its rating, or (56%)x(29.3) = 16.4MW, earning only 30% of the system capacity value (due to its limited energy capacity of 3hrs). The present value of providing system capacity over 10 year is $0.86M.

- Taking the average of the above two methods, to provide an estimated capacity value of $0.75M.

10.3 Energy Price Arbitrage:

During the hours when the storage is not required for reliability or not providing system capacity service, it has the potential to arbitrage the energy price by charging during periods of low prices and discharging during periods of high energy prices. The arbitrage potential is analyzed on a day-by-day basis, and only once a day at most to avoid excessive utilization of the storage life cycles. For a storage system with 3 hours of energy capacity, the first storage hour has the potential to generate the most profits because it can discharge at the highest price hour in a day and charge at the lowest price hour in the same day. The second hour of energy capacity will have to settle for the second best discharge and charge hours and thus generate less revenues. Adding all the arbitrage profits after deducting the cost of roundtrip losses provides an estimate of the maximum potential revenue from participation in this service.

The hourly locational energy prices (provided by Puget Sound according to the 2017 IRP) between 2018 and 2037 are averaged and summarized in Figure 10-4 by month and hour of the day, and color coded with red being highest and green being lowest. The average LMP is $56/MWh across the period with a high of $155/MWh and a low of $14/MWh. The average daily profile of the hourly prices is displayed in Figure 10-5 for a 5 individual years between 2019 and 2037 along with the average over all the years. The daily price profile shows a rising LMP level year over year, and a daily peak around hour-ending 19.

The daily arbitrage profit potential for each of the storage capacity hours is shown in Figure 10-6 in cumulative format for an average year between 2018 and 2037. The maximum arbitrage gross profit potential of the first storage capacity hour reaches as high as $70/MWh and can only be profitable during 290 days of the year, while the gross profit of the 4th storage capacity hour reaches a high of $50/MWh and stays profitable for only 200 days in a year. The annual potential profit from participating in energy arbitrage is shown in Figure 10-7. The maximum profit potential is $3.8/kW-yr for the first storage hour and drops to $1.9 for the 4th hour. The rise in arbitrage profits over time is shown in Figure 10-8 as the LMPs rise. The profits are organized into two groups, one when the storage is allowed to participate every day in the year while the second group restricts participation to only 200 days per year.

The Storage-Only solution, being a 3 hour battery, has the potential to earn $6.6/kW-yr ($2.6+$2.2+$1.8) in 2019, which increases to $10.6/kW-yr in 15 years. This totals an average of $252,000 annually, and a present value of $1.66M over 10 years.

Average LMP ($/MWh)																									
M/H	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Monthly
1	53	51	50	50	50	53	58	59	58	57	56	56	56	55	55	55	57	63	67	67	65	62	59	56	**57.0**
2	54	52	50	50	51	53	57	58	58	58	58	57	57	55	55	55	56	61	66	68	67	64	61	57	**57.3**
3	50	49	49	49	49	52	54	55	55	56	55	55	54	53	52	52	53	55	60	62	62	60	55	51	**54.1**
4	48	47	47	47	47	48	49	50	52	52	52	51	51	50	49	49	50	53	58	59	60	58	53	50	**51.2**
5	46	45	45	45	46	45	45	45	45	46	46	47	47	47	48	48	50	53	56	56	55	53	49	47	**48.1**
6	45	45	45	45	46	45	45	45	45	47	47	48	49	50	52	54	56	57	57	55	53	50	49	46	**49.1**
7	49	47	47	47	47	47	47	47	48	50	51	54	56	58	61	64	69	71	70	65	60	58	56	52	**55.1**
8	55	52	51	51	50	51	50	50	51	52	54	57	60	62	66	73	79	81	81	75	69	64	60	58	**60.4**
9	57	55	53	52	53	55	54	54	56	57	58	59	60	61	64	68	73	79	80	77	72	65	62	60	**61.9**
10	54	53	52	52	53	56	58	58	58	59	60	60	60	60	60	61	64	69	71	71	68	64	61	57	**59.9**
11	56	54	53	53	53	56	59	58	58	58	59	59	58	58	58	59	62	66	68	69	67	64	62	58	**59.4**
12	57	54	53	53	53	55	59	58	58	57	57	57	57	57	57	58	61	67	70	69	67	65	62	59	**59.2**
AVG	52	50	50	49	50	51	53	53	53	54	55	55	55	56	56	58	61	65	67	66	64	61	57	54	56
Min	14	14	14	14	15	15	16	18	20	20	20	20	21	21	21	22	21	20	20	20	20	20	16	16	14
Max	97	99	95	95	95	100	108	108	103	100	100	99	105	108	121	131	142	155	155	145	133	113	108	101	155

Figure 10-4: Average Locational Marginal Prices (LMP) by Month and Hour

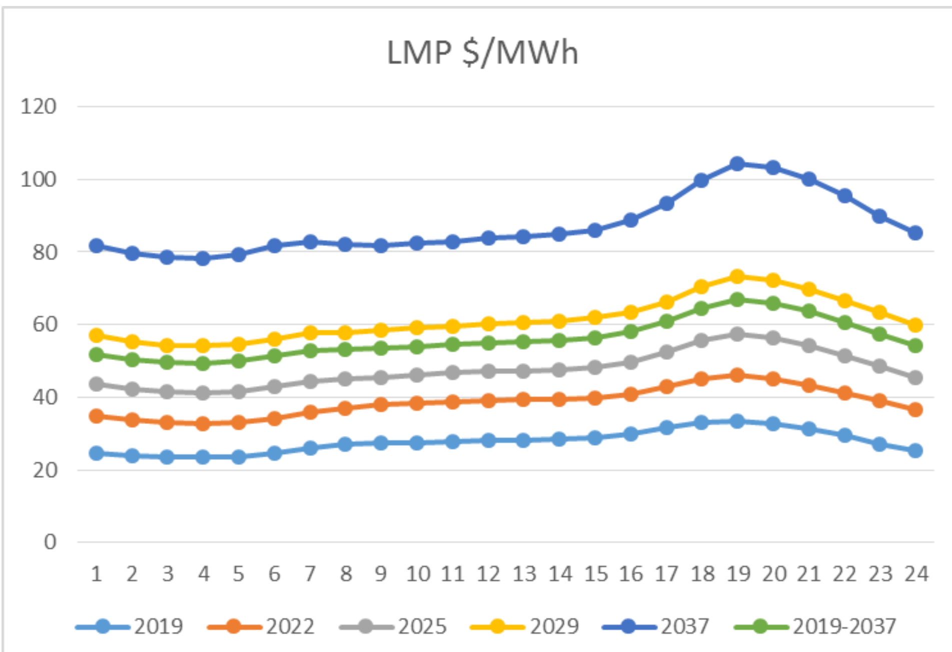


Figure 10-5: Average Daily Profile (24 hours)

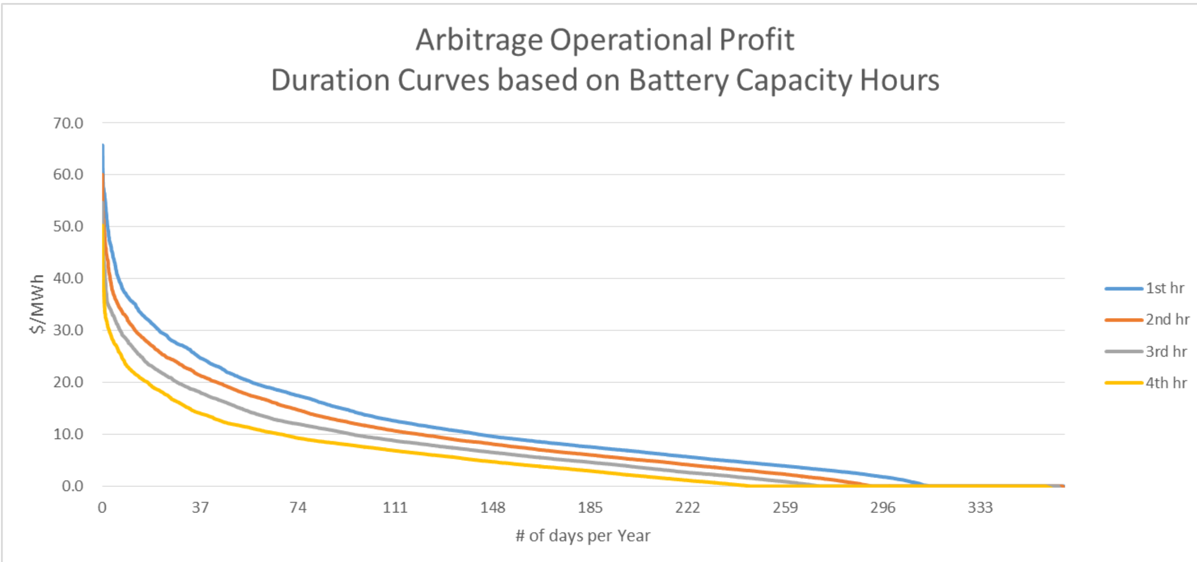


Figure 10-6: Cumulative Arbitrage Gross Profit for 1-4 Storage Capacity Hours

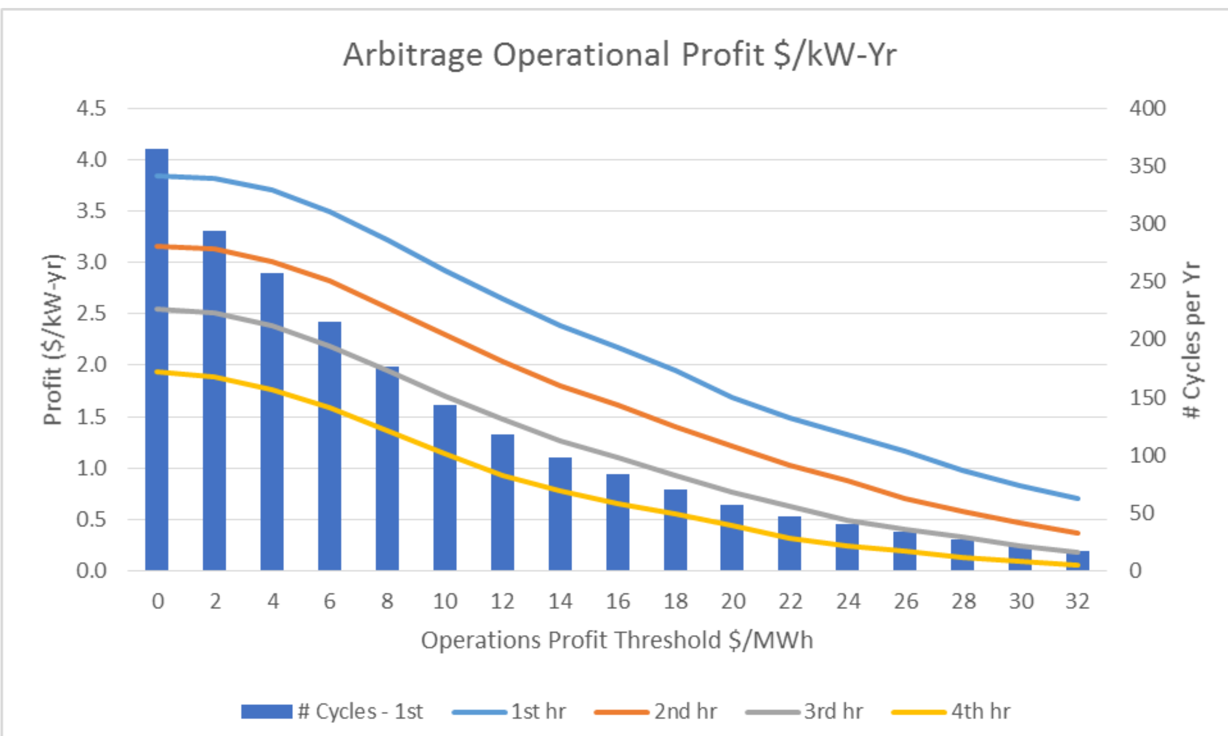


Figure 10-7: Arbitrage Gross Annual Profit for 1-4 Storage Capacity Hours

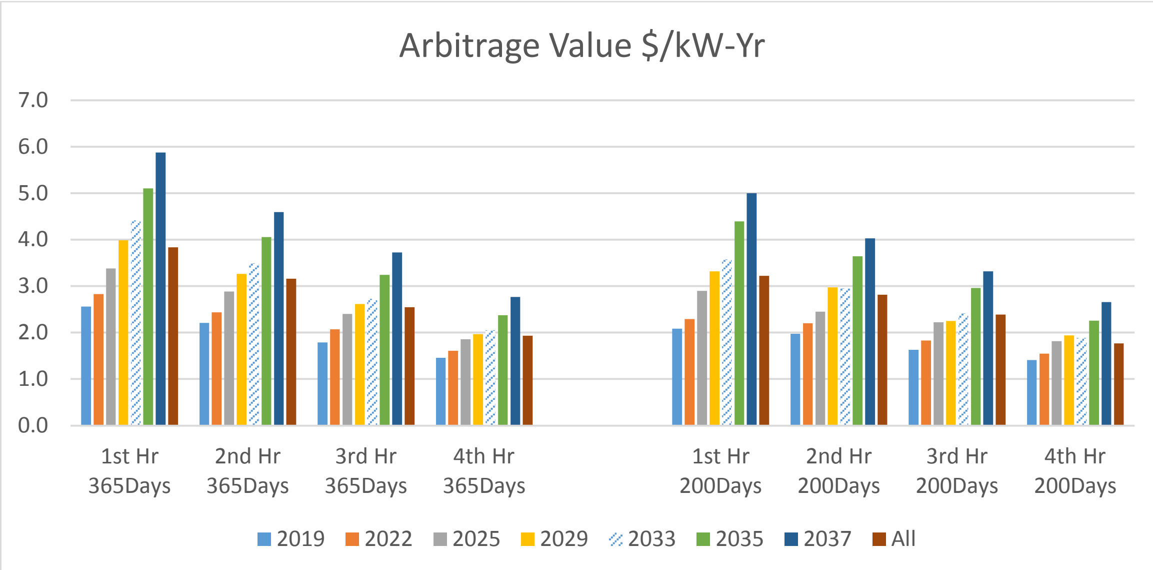


Figure 10-8: Annual Arbitrage Profit (2019 – 2037)

10.4 Optimized Revenue Stacking:

Beyond the reliability and capacity requirements, the analysis reveals that the storage solution has the potential to earn $2.4M, at most, in additional revenues when optimized using historical data (in present value over 15 years):

- System capacity $0.75M
- Energy Price Arbitrage $1.66M

Even if the revenue stacking could be optimized for system capacity services and energy price arbitrage, this revenue amount is not guaranteed and would be dependent on many other factors including perfect knowledge of market forward price curves, perfect equipment performance, and wholesale price growth in line with the IRP assumption.

11 APPENDIX C – REVENUE STACKING POTENTIAL OF STORAGE-ONLY (OPTION) SOLUTION

The storage-only (option) solution consisting of five (5) battery systems totaling 25.1MW/79.2MWh was designed to address two needs, namely, the Winslow-Tap outage, and the substation group loading limit. The Bainbridge Island system needs vary throughout the year with the load level, and correspondingly, the percentage of the battery size (MW and MWh) that is required to address these system needs will also vary. This provides a commercial opportunity to monetize the excess capacity of the storage solution during periods when the needs are not at their highest levels, in order to offset the cost of the storage investment.

In a similar manner to the analysis in Appendix B, two monetize-able services that are potentially available to this storage system are system capacity and energy price arbitrage. The Integrated Resource Plan (IRP) of 2017 provides a basis for the valuation of these two potential revenue streams. System capacity is a contracted service and thus has a lower risk as compared to energy price arbitrage which depends on the daily volatility of the locational marginal prices (LMP). The first priority of utilizing the storage system is to address the local needs. Any excess capacity will be utilized to provide system capacity services, and finally any remaining excess capacity will be used to provide energy price arbitrage.

The analysis methodology that was followed in this study to quantify and optimize the revenue streams is summarized in the following 3 steps:

4. Determine the required storage capacity (MW and MWh) for each hour in a year to address the two local needs.
5. Assess the storage availability to provide the system capacity service.
6. Optimize the operating profits from energy price arbitrage.

11.1 Hourly Storage Requirements to Address Needs:

The storage solution consisting of four (4) storage systems was designed to address two needs. One of which (Winslow-Tap outage) is a contingent service that is only triggered after the onset of a defined grid outage, while the second need (substation group) is triggered whenever the load level exceeds a prescribed level and thus is not contingent. To address the two types of needs, the storage systems will have to discharge to address the substation group trigger while keeping enough energy (MWh) in reserve to potentially address a subsequent defined outage. Both the discharged MW and the reserve MWh vary hourly throughout the year depending on the load level on specific feeders and substations in the area, as was detailed in Chapter 6.

Figure 11-1 shows the percentage of the storage solution size that is required to address the substation group capacity requirement, while Figure 11-2 shows the required storage solution size (expressed as a percentage of the total planned solution size) that is required to address both needs. The analysis was conducted using the 2019 data which corresponds to the highest peak in the study horizon. The data is tabulated in columns corresponding to each of the 24 hours in a day, and in rows corresponding to each of the 12 months in a year. For example, at hour ending 8, the maximum discharge for all days in December to address the substation group capacity need will be 14% of the storage solution rating, and at the same time, the storage solution will have to maintain 29% of its rated energy capacity in reserve in anticipation of an outage in accordance with the Winslow-Tap need. Similarly, during June-Sept, the storage solution is not required to address either need.

Hourly Max of Battery Requirements for Substation Group (N-0) : MW/MWh (%)

Max of Co																									
Row	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**All**
1									6%																6%
2								36%	38%	23%	6%														38%
3																									
4																									
5																									
6																									
7																									
8																									
9																									
10																									
11																									
12								14%	26%	23%	12%														26%
All								**36%**	**38%**	**23%**	**12%**														**38%**

Figure 11-1: Storage Max Hourly (MW) Requirements for Substation Group Capacity Need by Month and Hour

Hourly Max of Battery Requirements MW/MWh (%)

Max c Co																									
Ro	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**All**
1	6%	14%	15%	16%	16%	23%	36%	46%	50%	42%	37%	33%	25%	18%	18%	18%	21%	31%	34%	34%	29%	24%	8%		50%
2	24%	42%	57%	70%	79%	95%	96%	89%	74%	58%	51%	47%	44%	42%	63%	61%	57%	52%	57%	53%	48%	41%	27%	12%	96%
3	2%	3%	4%	4%	4%	4%	21%	40%	43%	38%	27%	23%	8%	4%		1%	3%	6%	12%	14%	10%	5%			43%
4	1%	2%	2%	2%	2%	2%	19%	39%	38%	22%	7%	1%				10%									39%
5							12%	41%	44%	39%	35%	24%	11%			4%	6%	10%	22%	22%	20%	15%			44%
6																									
7																									
8																									
9																									
10								17%	25%	17%															25%
11	5%	9%	10%	12%	13%	13%	31%	44%	45%	44%	39%	36%	33%	33%	27%	27%	26%	34%	32%	29%	27%	23%	11%		45%
12	13%	26%	36%	45%	51%	61%	70%	71%	66%	56%	51%	46%	41%	37%	34%	35%	38%	41%	41%	41%	39%	38%	29%	17%	71%
All	**24%**	**42%**	**57%**	**70%**	**79%**	**95%**	**96%**	**89%**	**74%**	**58%**	**51%**	**47%**	**44%**	**42%**	**63%**	**61%**	**57%**	**52%**	**57%**	**53%**	**48%**	**41%**	**29%**	**17%**	**96%**

Figure 11-2: Storage Max Hourly (MWH) Requirements for the 2 Needs by Month and Hour

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	94%	86%	85%	84%	84%	77%	64%	54%	50%	58%	63%	67%	75%	82%	82%	82%	79%	69%	66%	66%	71%	76%	92%	100%
2	76%	58%	43%	30%	21%	5%	4%	11%	26%	42%	49%	53%	56%	58%	37%	39%	43%	48%	43%	47%	52%	59%	73%	88%
3	98%	97%	96%	96%	96%	96%	79%	60%	57%	62%	73%	77%	92%	96%	100%	99%	97%	94%	88%	86%	90%	95%	100%	100%
4	99%	98%	98%	98%	98%	98%	81%	61%	62%	78%	93%	99%	100%	100%	100%	90%	100%	100%	100%	100%	100%	100%	100%	100%
5	100%	100%	100%	100%	100%	100%	88%	59%	56%	61%	65%	76%	89%	100%	100%	96%	94%	90%	78%	78%	80%	85%	100%	100%
6	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
7	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
8	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
9	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
10	100%	100%	100%	100%	100%	100%	100%	83%	75%	83%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
11	95%	91%	90%	88%	87%	87%	69%	56%	55%	56%	61%	64%	67%	67%	73%	73%	74%	66%	68%	71%	73%	77%	89%	100%
12	87%	74%	64%	55%	49%	39%	30%	29%	34%	44%	49%	54%	59%	63%	66%	65%	62%	59%	59%	59%	61%	62%	71%	83%

Figure 11-3: Available Storage Capacity after Meeting System Needs

11.2 System Capacity Service:

The Puget Sound IRP in 2017 shows the system capacity price in 2018 through 2024 to be \$3.79/kW-yr, and then jumps in 2025 to \$78.19/kW-yr and stays at that level through 2037. The system capacity requirements are exclusively during December for each of the 10 hours between 6AM-11AM and 5PM-10PM.

An analysis of the local requirements in Figure 11-1 and Figure 11-2 and the hourly profile of the load in Bainbridge Island reveals the following observations:

- The load peaks in December during Hour-Ending (HE) 8-11AM.
- The energy required to shave the peak load in December increases with the level of MW shaving. A 5 MW peak load shaving requires 3 hours of energy, while a 10MW peak shaving requires 4 hours, and further peak shaving beyond 15MW requires 10 hours.
- During December, the maximum MW discharge of the storage solution during the system capacity hours is 26% of the storage solution rating, while the maximum energy requirement is 71% of the storage rating. At any hour, the MW discharge in addition to the excess storage capacity above the requirement is available to provide the system capacity service. The minimum available percentage of the storage rating for system capacity services is 29%.
- During the 10 system capacity hours in December, the availability of the storage solution to provide system capacity service rises, as a percent of the storage solution rating, from 30% at 7AM to 62% at 10PM.
- The storage solution rating of 25.1MW and 79.2MWh provides only 3.16 hours of continuous discharge capability.
- If the storage aims to provide an equal level of system capacity at each of the 10 hours for each of the days in December, then the maximum level of participation in the system capacity service will be (3.16/10)x(29%)x(25.1) = 2.3MW, earning the full system capacity price. The present value of the system capacity service over 10 year is \$0.45M.

- On the other hand, if the storage solution is viewed as a component of a portfolio of capacity solutions, and thus allowed to provide partial capacity for each hour, the storage can maximize its participation by focusing on the last 3 hours in the day where it can participate by an average of 70% of its rating, or (61%)x(25.1) = 15.3MW, earning only 30% of the system capacity value. The present value of providing system capacity over 10 year is $0.75M.
- Taking the average of the above two methods, to provide an estimated capacity value of $0.6M.

11.3 Energy Price Arbitrage:

During the hours when the storage is not required for reliability or not providing system capacity service, it has the potential to arbitrage the energy price by charging during periods of low prices and discharging during periods of high energy prices. The arbitrage potential is analyzed on a day-by-day basis, and only once a day at most to avoid excessive utilization of the storage life cycles. For a storage system with 3 hours of energy capacity, the first storage hour has the potential to generate the most profits because it can discharge at the highest price hour in a day and charge at the lowest price hour in the same day. The second hour of energy capacity will have to settle for the second best discharge and charge hours and thus generate less revenues. Adding all the arbitrage profits after deducting the cost of roundtrip losses provides an estimate of the maximum potential revenue from participation in this service.

The hourly locational energy prices (provided by Puget Sound according to the 2017 IRP) between 2018 and 2037 are averaged and summarized in Figure 11-4 by month and hour of the day, and color coded with red being highest and green being lowest. The average LMP is $56/MWh across the period with a high of $155/MWh and a low of $14/MWh. The average daily profile of the hourly prices is displayed in Figure 11-5 for 5 individual years between 2019 and 2037 along with the average over all the years. The daily price profile shows a rising LMP level year over year, and a daily peak around hour-ending 19.

The daily arbitrage profit potential for each of the storage capacity hours is shown in Figure 11-6 in cumulative format for an average year between 2018 and 2037. The maximum arbitrage gross profit potential of the first storage capacity hour reaches as high as $70/MWh and can only be profitable during 290 days of the year, while the gross profit of the 4th storage capacity hour reaches a high of $50/MWh and stays profitable for only 200 days in a year. The annual potential profit from participating in energy arbitrage is shown in Figure 11-7. The maximum profit potential is $4.1/kW-yr for the first storage hour and drops to $2.1 for the 4th hour. The rise in arbitrage profits over time is shown in Figure 11-8 as the LMPs rise. The profits are organized into two groups, one when the storage is allowed to participate every day in the year while the second group restricts participation to only 200 days per year.

The Storage-Only solution, being a 3 hour battery, has the potential to earn $6.9/kW-yr ($2.7+$2.3+$1.9) in 2019, which increases to $11.4/kW-yr in 15 years. This totals an average of $230,000 annually, and a present value of $1.5M over 10 years.

Average LMP ($/MWh)																								
M/H	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**Monthly**
1	53	51	50	50	50	53	58	59	58	57	56	56	56	55	55	55	57	63	67	67	65	62	59	56	**57.0**
2	54	52	50	50	51	53	57	58	58	58	58	57	57	55	55	55	56	61	66	68	67	64	61	57	**57.3**
3	50	49	49	49	49	52	54	55	55	56	55	55	54	53	52	52	53	55	60	62	62	60	55	51	**54.1**
4	48	47	47	47	47	48	49	50	52	52	52	51	51	50	49	49	50	53	58	59	60	58	53	50	**51.2**
5	46	45	45	45	46	45	45	45	45	46	46	47	47	47	48	48	50	53	56	56	55	53	49	47	**48.1**
6	45	45	45	45	46	45	45	45	45	47	47	48	49	50	52	54	56	57	57	55	53	50	49	46	**49.1**
7	49	47	47	47	47	47	47	47	48	50	51	54	56	58	61	64	69	71	70	65	60	58	56	52	**55.1**
8	55	52	51	51	50	51	50	50	51	52	54	57	60	62	66	73	79	81	81	75	69	64	60	58	**60.4**
9	57	55	53	52	53	55	54	54	56	57	58	59	60	61	64	68	73	79	80	77	72	65	62	60	**61.9**
10	54	53	52	52	53	56	58	58	58	59	60	60	60	60	60	61	64	69	71	71	68	64	61	57	**59.9**
11	56	54	53	53	53	56	59	58	58	58	59	59	58	58	58	59	62	66	68	69	67	64	62	58	**59.4**
12	57	54	53	53	53	55	59	58	58	57	57	57	57	57	57	58	61	67	70	69	67	65	62	59	**59.2**
AVG	52	50	50	49	50	51	53	53	53	54	55	55	55	56	56	58	61	65	67	66	64	61	57	54	56
Min	14	14	14	14	15	15	16	18	20	20	20	20	21	21	21	22	21	20	20	20	20	20	16	16	14
Max	97	99	95	95	95	100	108	108	103	100	100	99	105	108	121	131	142	155	155	145	133	113	108	101	155

Figure 11-4: Average Locational Marginal Prices (LMP) by Month and Hour

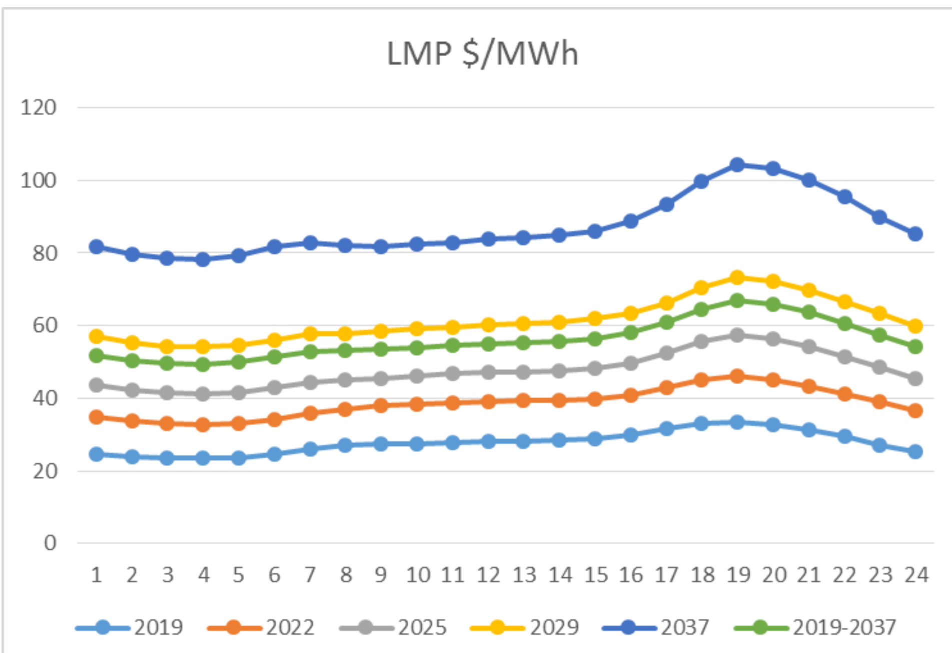


Figure 11-5: Average Daily Profile (24 hours)

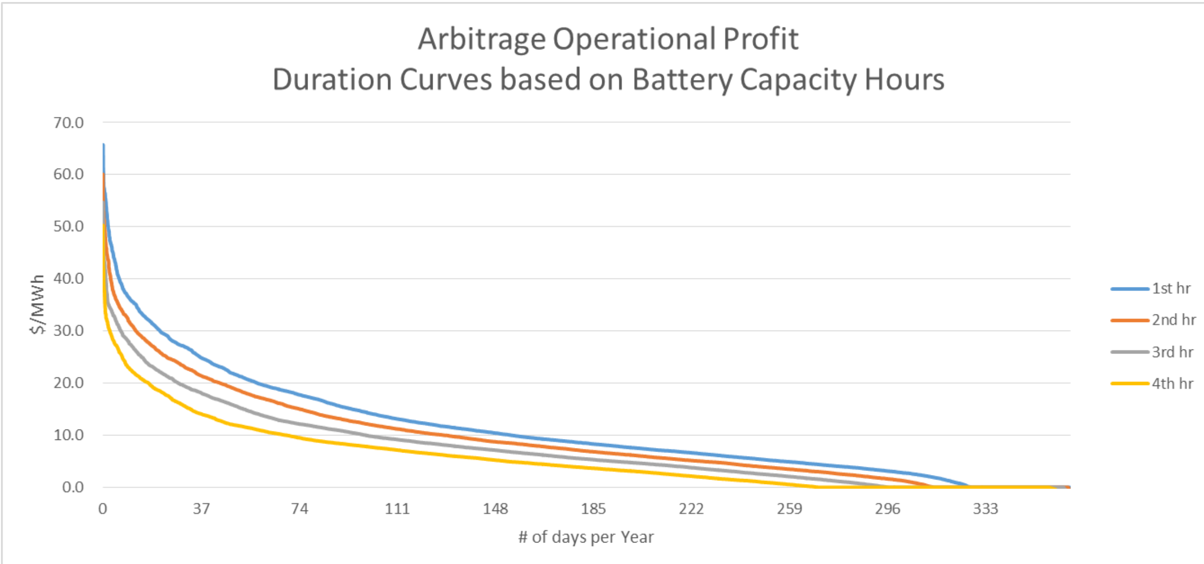


Figure 11-6: Cumulative Arbitrage Gross Profit for 1-4 Storage Capacity Hours

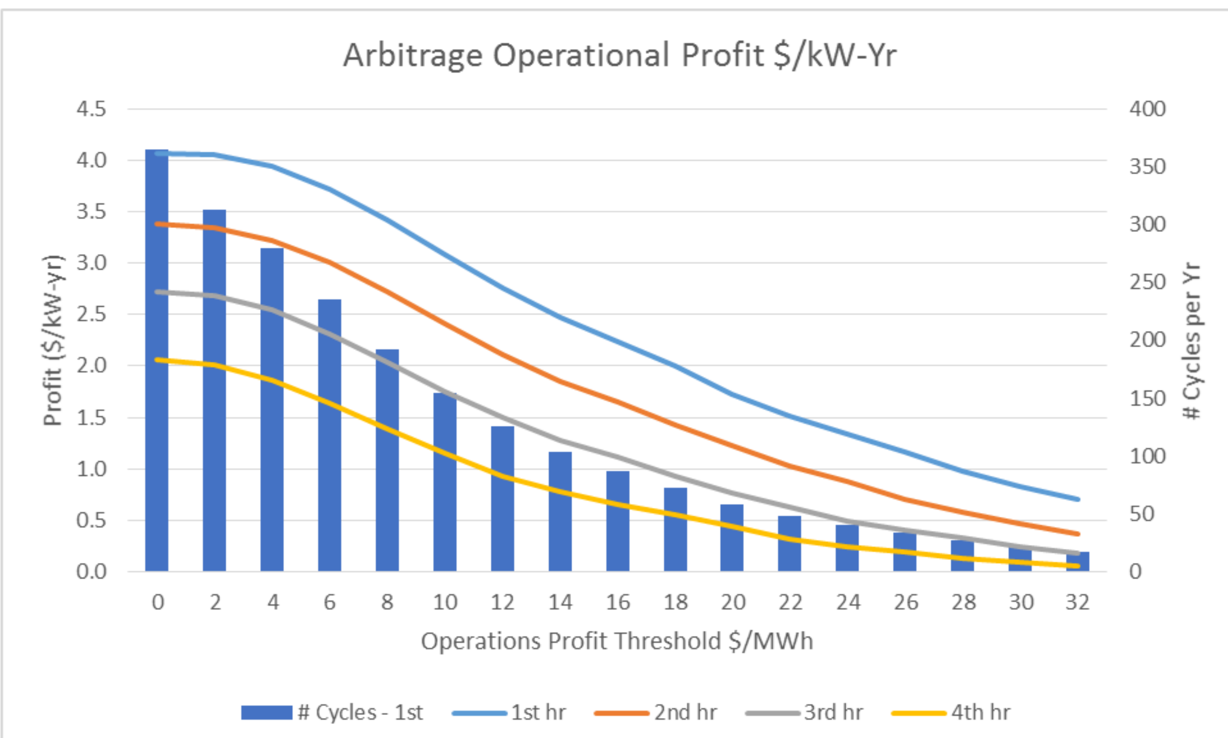


Figure 11-7: Arbitrage Gross Annual Profit for 1-4 Storage Capacity Hours

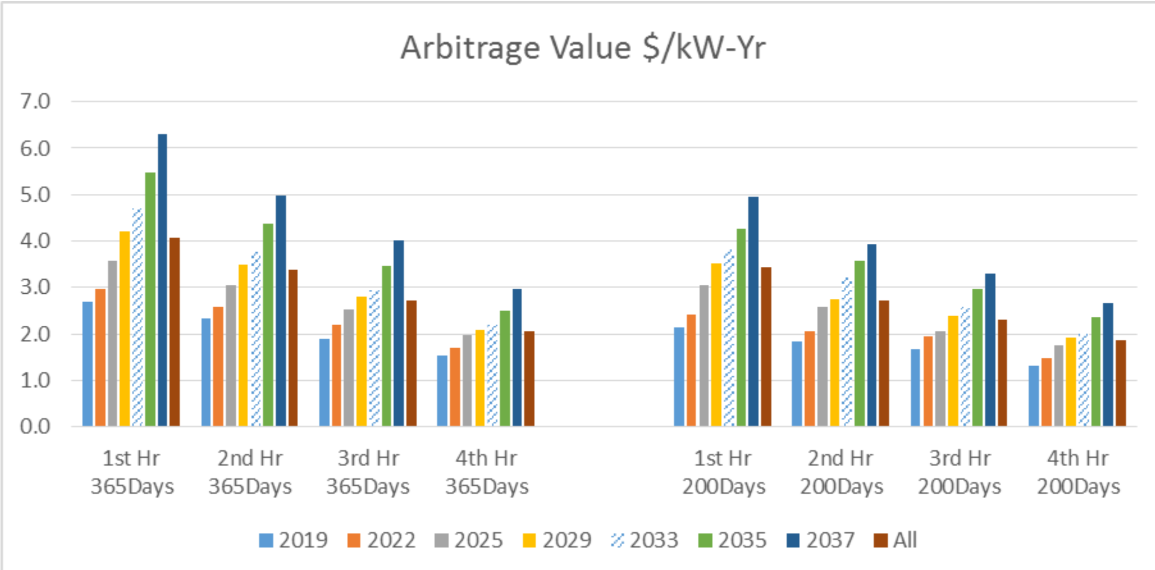


Figure 11-8: Annual Arbitrage Profit (2019 – 2037)

11.4 Optimized Revenue Stacking:

Beyond the reliability and capacity requirements, the analysis reveals that the storage solution has the potential to earn $2.1M, at most, in additional revenues when optimized using historical data (in present value over 15 years):

- System capacity $0.6M
- Energy Price Arbitrage $1.5M

Even if the revenue stacking could be optimized for system capacity services and energy price arbitrage, this revenue amount is not guaranteed and would be dependent on many other factors including perfect knowledge of market forward price curves, perfect equipment performance, and wholesale price growth in line with the IRP assumption.

Phifer, Kierra

From:	Perry, Matthew
Sent:	Tuesday, November 12, 2019 3:11 PM
To:	Morgan Smith
Cc:	Lombard, Barry; Nedrud, Jens - Transmission
Subject:	Underground transmission line process (PSE)

Dear Morgan,

On October 17, 2019, Puget Sound Energy (PSE) announced a package of projects to address to address electric reliability, aging infrastructure, electrification of the ferries, and increased demand for power on the island. The proposed solution is a unique solution developed for Bainbridge Island; it combines new technologies and traditional infrastructure.

One critical component to improving reliability is to build the "missing link" transmission line between Winslow and Murden Cove substations to create a transmission "loop" for the Island. This means each substation will be connected to two transmission lines. If one line goes out of service, the other line can still feed the substation and provide power to customers. Investing in this transmission infrastructure will make Bainbridge Island's electric grid more resilient for the future and reduce the impact of any single transmission outage by focusing on redundancy.

As PSE initiates its public engagement regarding the transmission loop, a question regularly brought up by our customers and Island residents is whether PSE can underground the transmission loop. We wanted to take this opportunity to outline the process by which a community can explore undergrounding transmission as an option.

Similar to when a City requests PSE to underground distribution lines (the lower voltage "neighborhood" power lines), who bears the cost burden for undergrounding transmission lines is outlined in a PSE tariff on file with the Washington Utilities and Transportation Commission (Electric Tariff G, Schedule 80). For transmission lines, the local community requesting or requiring the underground transmission line must pay the entire cost difference between overhead and underground lines. The City of Bainbridge Island, if it requests transmission undergrounding, would be responsible for the difference between the cost to construct and maintain an overhead line and the cost to design, construct and maintain an underground line. We have attached a general fact sheet that provides an overview of undergrounding transmission.

If the City is interested in exploring undergrounding of the transmission loop, the next steps are generally are as follows:

- PSE would meet with the City to discuss undergrounding, potential routes, potential impacts, additional costs, and challenges.
- PSE would retain at the City's cost a qualified independent third-party underground transmission expert to prepare a preliminary feasibility study. PSE would work with the underground expert to ensure that the final proposal meets the PSE electric system needs. The study report would generally include preliminary design elements, cost estimates, outline potential routes, process and timeline.
- Once the preliminary feasibility study is complete, if the City wants to pursue undergrounding the transmission loop PSE would work with the City to develop engineering, design, payment and services agreements; and other agreements as needed with PSE.

If the City would like to explore undergrounding options, PSE is happy to start the process outlined above. We appreciate your consideration, and we'll be reaching out to you to setup a meeting where we can discuss this further. In the meantime, should you have any questions, please reach out to me.

Sincerely,

Matt Perry	Barry Lombard
Government Relations Manager, PSE	Senior Project Manager, PSE

cc: Jens Nedrud, PSE

Matt Perry
Local Government Affairs & Public Policy Manager
PUGET SOUND ENERGY
Cell: (425) 478-7529
3130 S 38th St
Tacoma, WA 98409

PSE PUGET SOUND ENERGY

Puget Sound Energy
P.O. Box 97034
Bellevue, WA 98009-9734
PSE.com

July 23, 2021

Blair King, City Manager
City of Bainbridge Island
280 Madison Avenue N
Bainbridge Island, WA 98110

RE: Underground Transmission Line Process

Dear Mr. King,

On October 17, 2019, Puget Sound Energy (PSE) announced a package of projects to address to address electric reliability, aging infrastructure, electrification of the ferries, and increased demand for power on the island. The proposed solution is a unique solution developed for Bainbridge Island; it combines new technologies and traditional infrastructure.

On July 20, 2021, PSE presented at a Bainbridge Island City Council Study Session on the "Missing link" Transmission Line. The "Missing Link" is critical component to improving reliability is to build the "missing link" transmission line between Winslow and Murden Cove substations to create a transmission "loop" for the Island. This means each substation will be connected to two transmission lines. If one line goes out of service, the other line can still feed the substation and provide power to customers. Investing in this transmission infrastructure will make Bainbridge Island's electric grid more resilient for the future and reduce the impact of any single transmission outage by focusing on redundancy.

During the discussion, a few Councilmembers expressed interest on an Underground Transmission Line for the "Missing Link". PSE has also heard interest from community members during our public engagement regarding an underground transmission line. In response to the community interest, PSE will be hosting an information session with an underground transmission line expert to discuss the process and feasibility of installing transmission lines underground on August 16th from 5pm-6pm. We would welcome you, city staff and the City Council to attend this information session. <u>We also wanted to take this opportunity to outline the process by which a community can explore undergrounding transmission as an option.</u>

Similar to when a City requests PSE to underground distribution lines (the lower voltage "neighborhood" power lines), who bears the cost burden for undergrounding transmission lines is outlined in a PSE tariff on file with the Washington Utilities and Transportation Commission (Electric Tariff G, Schedule 80). For transmission lines, the local community requesting or requiring the underground transmission line must pay the entire cost difference between overhead and underground lines. The City of Bainbridge Island, if it requests transmission undergrounding, would be responsible for the difference between the cost to construct and maintain an overhead line and the cost to design, construct and maintain an underground line. We have attached a general fact sheet that provides an overview of undergrounding transmission.

If the City is interested in exploring undergrounding of the transmission loop, the next steps are generally are as follows:

- PSE would meet with the City to discuss undergrounding, potential routes, potential impacts, additional costs, and challenges.
- PSE would retain at the City's cost a qualified independent third-party underground transmission expert to prepare a preliminary feasibility study. PSE would work with the underground expert to ensure that the final proposal meets the PSE electric system needs. The study report would generally include preliminary design elements, cost estimates, outline potential routes, process and timeline.
- Once the preliminary feasibility study is complete, if the City wants to pursue undergrounding the transmission loop PSE would work with the City to develop engineering, design, payment and services agreements; and other agreements as needed with PSE.

If the City would like to explore undergrounding options, PSE is happy to start the process outlined above. We appreciate your consideration, and we'll be reaching out to you to setup a meeting where we can discuss this further. In the meantime, should you have any questions, please reach out to Kierra Phifer at Kierra.phifer@pse.com.

Sincerely,

Kierra Phifer
Local Government Relations Manager, PSE

Barry Lombard
Senior Project Manager, PSE

PSE PUGET SOUND ENERGY

PSE's electric power system

Comparison of overhead and underground transmission lines

Puget Sound Energy has more than 2,100 miles of high-voltage transmission lines throughout PSE's 6,000 square mile service area. These lines safely transport electricity generated by hydropower, natural gas, coal, wind and solar sources to transmission and distribution substations in local communities. Nearly all of PSE's high-voltage transmission lines are either 115 or 230 kilovolts (kV) and are typically supported on wood or steel poles.

Often we're asked whether we can underground transmission lines. PSE can build transmission lines underground. However, doing so requires cost sharing between PSE and the local community that requests it. That's because undergrounding is typically considered a local benefit, and it costs significantly more to build a power line underground. As a result, it is up to the local community to decide whether to invest in an underground line. In addition, there are several hurdles that must be overcome when it comes to undergrounding transmission lines.

230kV transmission lines

Underground and cost sharing

State regulations require PSE to first consider building overhead transmission lines because of their combination of reliability and affordability, both of which are important to our customers.

Underground transmission lines are considered a "local option" under applicable regulations, meaning the local community must pay the cost difference between building overhead and underground lines (rather than having the cost shared by PSE's 1.1 million customers). The requesting community would share the cost of the project from the preliminary feasibility and design to construction and maintenance.

Following is a comparison of overhead and underground transmission line costs.

Costs	
Overhead cost estimates*	**Underground cost estimates^**
• 115 kV: \$600K to \$2.9M per mile to construct • 230 kV: \$3M to \$4M per mile to construct	• 115 kV: \$9M to \$15M per mile to construct • 230 kV: \$20M to \$28M per mile to construct
Other overhead cost considerations	**Other underground cost considerations**
• Ongoing maintenance costs for vegetation • Costs less to maintain, repair, upgrade and relocate • Damages from car-pole accidents, trees and equipment failure occur more frequently, but cost less to repair • Costs are covered by all customers; no additional area costs to local customers is necessary	• Initial costs for vegetation removal and nominal ongoing maintenance costs • Costs more to maintain, repair, upgrade or relocate • Damages from tree roots and equipment failure occur less frequently, but cost more to repair • Local customers must pay the cost difference of undergrounding via area rates, including ongoing maintenance and repair

*These cost estimates include design, engineering, materials and construction. Additional costs, such as relocation of existing utilities, permitting and property rights are not included. Rebuilding existing overhead lines results in costs at the lower end of this range, while building new overhead lines results in costs at the higher end of this range.

^These cost estimates include design, engineering, materials and construction, and the ranges provided are for new underground transmission lines. Additional costs, such as relocation of existing underground utilities, permitting and property rights are not included, and all undergrounding costs can vary greatly depending on project-specific factors.

Other undergrounding challenges

While most communities decide not to invest in undergrounding based on the significant costs and competing investment priorities, there are other challenges to undergrounding transmission lines:

- **Environmental and neighborhood impacts:** Putting power lines underground can have significant environmental and neighborhood impacts. Undergrounding requires extensive vegetation removal, trenching and installation of large (typically 20 feet by 30 feet for 230 kV lines and 10 feet by 20 for 115 kV lines) access vaults every quarter to half mile, which can be very disruptive to neighborhoods and the environment. While some vegetation can remain under or beside an overhead line, vegetation must be completely removed along an underground transmission line route to ensure trees' root systems do not grow into the line.
- **Length of time for outage restoration:** Underground lines typically take longer to repair, and repairs are more difficult. When an overhead line fails, our crews can often repair it within hours. Repair of underground transmission lines can take days and even weeks, depending on the repairs that need to be made.
- **Maintenance challenges:** Overhead transmission line maintenance typically includes visual inspections, pole treatment and vegetation management. Underground transmission lines are more difficult to maintain due to their unique design and operating conditions. Underground cables are sensitive to changes in soil cover and aboveground changes, and patrolling is necessary to assess changes in soil depth, cover type, vegetation changes, or other issues that could impact the ability of the line to dissipate heat effectively.
- **Aesthetics:** While the majority of an underground transmission line is not visible above ground, vaults are typically installed every quarter to half mile and above-ground steel termination structures are installed at each end of the underground cable route.

Example of a steel underground termination structure. Photo courtesy of POWER Engineers, Inc.