CHAPTER 2. PROJECT ALTERNATIVES

2.1 WHAT DOES THIS CHAPTER COVER?

This chapter provides a description of project alternatives evaluated in the Draft Environmental Impact Statement (EIS). The alternatives described in this chapter were developed based on discussions between the partner Cities, the EIS Consultant Team, and Puget Sound Energy (PSE). This chapter also identifies alternatives considered but not evaluated in the Draft EIS because they did not meet PSE's project objectives. As required by the State Environmental Policy Act (SEPA), benefits and disadvantages of delaying PSE's project are described at the end of this chapter. The project includes numerous terms that may not be familiar to all readers. Words shown in *italics* when they first appear in the document are included in the Glossary following the Table of Contents.

2.2 WHAT ARE PUGET SOUND ENERGY'S PROJECT OBJECTIVES FOR ENERGIZE EASTSIDE?

Under SEPA, alternatives evaluated in an EIS must feasibly meet or approximate the project objectives. PSE, a regulated utility and the proponent for the Energize Eastside Project, developed the objectives of the proposal. Under SEPA, the objectives must be defined in a manner that does not preclude feasible alternatives that would have lower environmental costs (WAC 197-11-440(5)(b)).

As described in Chapter 1, the objectives for the project are to address a deficiency in transmission capacity on the Eastside that PSE expects will arise in the near future; find a cost-effective solution that can be implemented before system reliability is impaired; meet federal, state, and local regulatory requirements; and address PSE's electrical and non-electrical criteria for the project as outlined below. The transmission capacity deficiency PSE has identified is a product of the complex system that PSE uses to supply power to the Eastside, and the regulations PSE must follow as a utility provider making use of the regional electrical grid. As such, the criteria for what constitutes a viable solution are correspondingly complex.

The following is a list of project criteria from PSE's *Supplemental Eastside Solutions Study Report* (May, 2015) (Gentile et al., 2015). PSE's criteria are based on regulations for utilities and prudent, safe industry practices. They include 15 electrical criteria and 4 non-electrical criteria. The criteria are listed below, followed by a detailed explanation of each criterion in Sections 2.2.1 and 2.2.2. Background information regarding system contingencies and normal winter and summer load forecasts is provided in Sections 2.2.3 and 2.2.4.

Electrical Criteria Summary

The project would meet the following criteria:

1. Applicable transmission planning standards and guidelines, 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-2);
2. Within study period (2015– 2024);
3. Less than or equal to 95 percent of emergency limits for lines;
4. Less than or equal to 90 percent emergency limit for transformers;
5. Normal winter load forecast with [both] 100 percent and 75 percent conservation;
6. Normal summer load forecast with 100 percent conservation;
7. Adjust regional flows and generation to stress cases similar to annual transmission planning assessment;
8. Take into account future transmission system improvement projects that are expected to be in service within the study period;
9. Minimal or no re-dispatching of generation;
10. No load shedding;
11. No new *Remedial Action Schemes*;
12. No *Corrective Action Plans*;
13. Must address all relevant PSE equipment violations;
14. Must not cause any adverse impacts to the reliability or operating characteristics of PSE's or surrounding systems; and
15. Must meet performance criteria listed above for 10 or more years after construction with up to 100 percent of the emergency limit for lines or transformers.

Non-electrical Criteria Summary

The project would meet or approximate the following criteria:

1. *Environmentally acceptable* to PSE and communities;
2. Constructible by winter of 2017 - 2018;
3. Utilize *proven technology* which can be controlled and operated at a system level; and
4. Reasonable project cost, as defined in Section 2.2.2.4.

Collectively, these criteria were considered the fullest expression of PSE's objectives in developing solutions for the Energize Eastside Project. The electrical criteria listed are generally in line with criteria used in the electrical industry. Therefore, these criteria were used to identify reasonable alternatives for consideration in this EIS. The non-electrical criteria listed are typical of considerations made by utilities in project planning. While these are important in considering the solution, for this Phase 1 Draft EIS these criteria were generally not used to screen out alternatives.

Consideration of environmental impacts is part of the process for selecting alternatives under SEPA, in that alternatives considered in an EIS must approximate the proponent's objectives at a lower environmental cost. While the desired implementation schedule is important and reasonable, there are uncertainties associated with any of the alternatives including PSE's proposal that could delay implementation beyond these dates. With regard to what is considered proven technology, there is no clear-cut definition of what makes a technology proven. Therefore, a wide range of technologies that are in use at various scales have been evaluated, including some technologies that PSE does not currently utilize. For PSE, what constitutes reasonable cost is driven by PSE's responsibilities to deliver power at the lowest feasible cost to ratepayers. However, under SEPA, alternatives may be considered that are not the lowest feasible cost. For the Phase 1 Draft EIS alternatives, cost was not used to screen out any alternatives, in order to provide a more complete understanding of the environmental effects of alternatives before project-level alternatives are selected.

To clarify PSE's criteria for the community and decision-makers, PSE, the Eastside Cities, and the EIS Consultant Team developed brief explanatory descriptions for each criterion, provided in Sections 2.2.1 and 2.2.2. These descriptions were developed based on PSE documents and the EIS Consultant Team's familiarity with the power delivery system in western North America. The descriptions have been reviewed for accuracy and completeness by PSE and City staff with the five partner Eastside Cities that are leading this EIS process, and consulting electrical engineers on the EIS Consultant Team (Stantec).

2.2.1 Electrical Criteria

The electrical criteria used by PSE are briefly defined below.

2.2.1.1 Applicable transmission planning standards and guidelines, including mandatory NERC and WECC standards

These federal requirements mandate that PSE "shall demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands" under NERC performance categories. Essentially, PSE must plan the system to function in scenarios where customer demand may be at its highest and/or elements of the system may be out of service. Below are examples of the standards and guidelines used during the PSE planning process.

2.2.1.1.1 N-0 Thermal and Voltage Performance – NERC and WECC standards

This refers to system performance with all system components operating normally. The system must perform without violations (exceedances) of thermal and voltage limits with all systems operating and no contingencies occurring. A contingency refers to a system condition in which an equipment component is not operating normally and may be turned off or in limited operation, either as a result of an emergency or as part of scheduled maintenance or system improvements. Additional discussion of N-0 is providwed in Section 2.2.3.

2.2.1.1.2 N-1 Thermal and Voltage Performance – NERC and WECC standards

This refers to system performance with one contingency in the system. The system must perform without violations (exceedances) of thermal and voltage limits with one contingency occurring. Additional discussion of N-1 is provided in Section 2.2.3.

2.2.1.1.3 N-1-1 & N-2 Thermal and Voltage Performance – NERC and WECC standards

This refers to system performance with two contingencies in the system. This could be due to an emergency, as part of scheduled maintenance or system improvements, or a combination of circumstances. The system must perform without violations of thermal and voltage limits with two contingencies occurring. Additional discussion of N-1-1 and N-2 is provided in Section 2.2.3.

2.2.1.1.4 Use of Corrective Action Plans (CAPs) and Remedial Action Schemes (RAS) – NERC and WECC standards

See Sections 2.2.1.11 and 2.2.1.12 below.

2.2.1.1.5 Substation Planning and Security Guidelines

PSE’s Transmission Planning Guidelines state: “Transmission substations should be laid out for ultimate double 230 - 115 kV transformer bank configuration.” On November 20, 2014, the Federal Energy Regulatory Commission (FERC) issued Order 802 Critical Infrastructure Protection (CIP). That order states, “Physical attacks to the Bulk-Power System can adversely impact the reliable operation of the Bulk-Power System, resulting in instability, uncontrolled separation, or cascading failures.” On July 15, 2015, FERC issued a follow-up order to CIP-014. Paraphrasing from that order, certain registered entities are required to take steps (or demonstrate that they have already taken steps) to address physical security risks and vulnerabilities related to the reliable operation of the bulk power system. Owners or operators of the bulk power system must identify facilities that are critical to reliable operation. The owners or operators of those identified critical facilities shall develop, validate, and implement plans to protect against physical attacks that may compromise the operability or recovery of such facilities. Following the FERC direction, as well as prudent planning and operating standards, PSE limits the number of transformers at substations to two 230 – 115 kV transformer banks. In other words, based on security threats to the physical electric infrastructure, it is not reasonable or prudent to “put all your eggs in one basket.”

2.2.1.2 Within study period (2015 – 2024)

This refers to the 10-year study period during which potential solutions must meet the solution criteria. The study period is defined as the 10-year period between 2015 (the study year of the *Supplemental Eastside Solutions Study Report*) and 2024 (the final year of the WECC base cases used for the study).

2.2.1.3 Less than or equal to 95 percent of emergency limits for lines

PSE has two thermal operating limits: normal and emergency. The *normal operating limit* is a specific level of electrical loading that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life. The *emergency limit* is a specific level of electrical loading that a system, facility, or element can support or withstand for a finite period. The emergency rating is based upon the acceptable loss of equipment life or other physical or safety limitations for the equipment involved. If there is a violation of the emergency limit, a transmission line may not meet applicable clearance criteria and risk loss of mechanical strength due to overheating.

PSE's operating practice is to shift or *shed load*, or increase or decrease electrical generation, to avoid reaching an emergency limit. PSE utilizes 95 percent of the emergency limit as an indication of when PSE needs to start the process to study and upgrade the system to prevent violations of mandatory performance requirements and equipment degradation. The system operator receives an alarm when the transmission line reaches 95 percent of its emergency limit. If an alarm is triggered, the system operator takes steps to shift or shed load to prevent damage to the transmission line.

All PSE transmission lines of any voltage must remain equal to or below 95 percent of the emergency line-loading limit over the study period in order for a viable alternative to be considered a potential solution. This includes all periods of the year, whether the system is operating under normal or abnormal system configurations, or during light load or peak load conditions.

2.2.1.4 Less than or equal to 90 percent emergency limit for transformers

As discussed above, PSE has two thermal operating limits: normal and emergency. If there is a violation of the emergency limit in a transformer, it may overheat, causing a breakdown in internal insulation and leading to a transformer failure or reducing its operational life. Substation transformers are filled with oil to facilitate cooling and insulation. However, if the transformer overheats, the oil may catch fire or explode, which is a serious safety concern. PSE's operating practice is to shift or shed load or *dispatch generation* to avoid reaching an emergency limit. PSE uses a measure of 90 percent of the emergency limit for transformers as an indication of when PSE needs to start the process to study and upgrade the system to prevent violations of mandatory performance requirements and equipment loss of life. The system operator receives an alarm when a 230 to 115 kV transformer reaches 90 percent of its emergency limit. If an alarm is triggered, the system operator takes steps to shift or shed load, or dispatch generation to prevent damage to the transformer.

All 230 kV to 115 kV PSE transformers must remain equal to or below 90 percent of the emergency loading limit over the study period in order for a viable alternative to be considered a potential solution. This includes all periods of the year, whether the system is operating under normal or abnormal system configurations, or during light load or peak load conditions.

2.2.1.5 Normal winter load forecast with both 100 percent and 75 percent conservation

A normal winter load forecast represents a snapshot in time reflecting the highest expected load in winter for the given year of the forecast. The load is calculated for the coldest winter weather event with a 1 in 2 (50 percent) chance of occurring in a given year (also referred to as the two-year winter weather event). This would not be considered an average load, but a peak load. The peak load is used to ensure that the system can withstand the highest estimated loading under all system configurations and still reliably serve customers.

A 100 percent conservation level is the amount of reduction in load that PSE estimates could reasonably be attained through energy efficiency, *demand response*, and *distributed generation*. The 75 percent conservation level is the estimated amount of reduction in load multiplied by 0.75 to account for the possibility of achieving only 75 percent of the projected conservation. This factor addresses the potential that the level of conservation that is actually achieved may be inconsistent with the study model assumptions in some locations. Perfect precision cannot be attained without completely accurate data, and the 75 percent conservation level serves as a gauge to help planners understand the ramifications if the model does not precisely mimic a real-world scenario.

The "normal winter forecast with 100 percent conservation" is the peak load forecast for winter, taking into account the 100 percent conservation level for winter. The "normal winter forecast with 75 percent conservation" is the peak load forecast for winter, taking into account the 75 percent conservation level for winter. PSE needs both forecast scenarios to be met for a viable solution.

Load forecasts and conservation levels (reduction in load) are evaluated in detail in PSE's most recent Needs Assessment report and are based on several parameters, such as historical metering data and population statistics. Refer to the *Supplemental Eastside Needs Assessment Report* (PSE and Quanta Technology, 2015) for detailed information. Additional information on what is considered a normal winter load is provided in Section 2.2.4.

2.2.1.6 Normal summer load forecast with 100 percent conservation

A normal summer load forecast represents a snapshot in time reflecting the highest expected load in summer for the given year of the forecast. The load is calculated for the warmest summer weather event with a 1 in 2 (50 percent) chance of occurring in a given year (two-year summer weather event). One major difference between summer and winter peak loads is the different demand levels and use patterns associated with winter heating versus summer cooling. The 100 percent conservation level used in summer is different from the amount of reduction used for a 100 percent winter conservation level. The "normal summer forecast with 100 percent conservation" is the peak load forecast for summer, taking into account the 100 percent conservation level for summer. It is the peak expected load to be used in the study for summer conditions.

Additional information on what is considered a normal summer load is provided in Section 2.2.4.

2.2.1.7 Adjust regional flows and generation to stress cases similar to annual transmission planning assessment

In the course of conducting a load flow study to determine system constraints, many scenarios must be evaluated to simulate real-world possibilities. This is a requirement of the regional agencies (NERC and WECC) that govern the *power grid* in order to make sure it functions reliably for all utility customers. To that end, the transmission planning assessment is just one measure of system reliability. The load flow model itself is merely a mathematical simulation of all the components of the interconnected electric system. The model can only represent a snapshot of the system at a particular moment in time. To gain a full picture of system performance, many scenarios—sometimes called stress cases, sensitivity cases, or snapshots—must be reviewed. Each stress case adjusts both generation and regional flows. The combination gives a sense of real-world reaction to system operating conditions. The regional flows and generation levels used are based on a range of possible real-world conditions and are not a theoretical device to overwhelm the system. PSE studied both a minimal generation level stress case and a stress case that included an additional 1,000 megawatts (MW) of generation.

In addition, thousands of contingencies are evaluated. Contingencies are similar snapshots of the system that evaluate what happens when a transmission line or a transformer is out of service. The study also evaluates the possibility of two components being out of service at the same time. Light load periods as well as peak load periods present their own peculiar problems, and these too must be evaluated in snapshots. Finally, all of these snapshots begin to paint a picture for the planner of where the strengths and weaknesses of the system reside. This criterion requires that this type of stress case assessment must be performed for all solutions and a viable solution must work under all stress cases.

2.2.1.8 Take into account future transmission system improvement projects that are expected to be in service within the study period

The transmission system is constantly evaluated by each utility and the regional entities that unite them to ensure its performance and ability to provide electric power to customers. Each utility and regional agency proposes improvements as needed, such as the 230 kV transformer and transmission line PSE has proposed. When an improvement project has been identified by a utility, it is the utility's or regional authority's responsibility to accurately report the change to WECC so that it can be reflected in the future load flow models that WECC prepares. It is important to know not only the extent of the project, but also when it will be placed in service. One of WECC's responsibilities is to gather this information and prepare the models of specific configurations of generation and transmission in operation (also referred to as cases) based on specific year, load, and other conditions, and make these available to utility planners. However, it is PSE's or the other utility planners' responsibility to make sure that the models they use are correct. Part of that responsibility includes adjusting for any facility plans that may have changed after the WECC model is built, and adjusting for any facilities that may not yet be in service for the years that the utility planner is assessing.

2.2.1.9 Minimal or no re-dispatching of generation

Minimal or no re-dispatching of generation means that, in the normal course of study, PSE does not adjust the amount of generation coming from various generation sources to solve long-term problems. In a real-time scenario, generation is normally dispatched, which means a particular generation output level is set based on the needs of the local economy at a particular time period. Therefore, planners do not want a solution that involves ramping generation up or down to solve a long-term problem. In this case, dispatching generation has little or no impact on solving the transformer overloads on the Eastside, since there is no existing generation within the Eastside area, and ramping generation up or down outside of the Eastside area has little impact on Eastside transformer loading.

2.2.1.10 No load shedding

Load shedding is an intentionally engineered electrical power shutdown when electricity delivery is stopped for a period of time, usually during peak load. A rolling blackout, also referred to as rotational load shedding or feeder rotation, is an intentionally engineered electrical power shutdown when electricity delivery is stopped for periods of time over different parts of the distribution region. Load shedding or rolling blackouts are a last-resort measure used by an electric utility company to avoid a larger or more catastrophic outage of the power system. Load shedding is a type of demand response for a situation when the demand for electricity exceeds the power supply capability of the network. Load shedding, or rolling blackouts, generally result from one of two causes: insufficient generation capacity, or inadequate transmission infrastructure to deliver sufficient power to the area where it is needed.

As is typical of electric service providers, PSE does not use load shedding as a long-term solution to meet mandatory performance requirements. While NERC and WECC allow dropping load for certain contingencies, intentionally dropping *firm load* for an N-1-1 or N-2 contingency to meet federal planning requirements is not a practice that PSE endorses, because of the costs and inconvenience that outages impose on its customers.

What is **firm load**? Firm load is energy that a supplier is required by contract to provide without interruption (except during extreme emergencies).

2.2.1.11 No new Remedial Action Schemes

A Remedial Action Scheme (RAS) is designed to detect predetermined system conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping (shutting down) generation, shedding load, or reconfiguring a system. An RAS may accomplish objectives such as the following:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain acceptable voltages;
- Maintain acceptable power flows; or
- Limit the impact of cascading outages, system instability, or extreme events.

An RAS is normally administered automatically to control regional issues in the power system. PSE, like other utilities, develops and employs RASs to address short-term conditions that may arise as a result of problems on their system or on the regional grid.

This criterion requires that for a solution to be viable, no additional RASs would be needed. This is because use of RASs complicates the operation of the existing system, which adds risk and reduces predictability. An RAS is not considered a long-term solution to solve a local transmission deficiency.

2.2.1.12 No Corrective Action Plans

A *Corrective Action Plan* (CAP) is similar to an RAS. However, CAPs are usually corrective actions made manually by local system dispatchers and are intended to control local problems. In contrast, an RAS is typically administered automatically to control regional issues in the power system.

According to NERC, CAPs are temporary until a permanent solution is put in place. For a solution to be viable, no additional CAPs can be needed because they only complicate the operation of the existing system and do not provide a long-term solution.

2.2.1.13 Must address all relevant PSE equipment violations

PSE will only accept solutions that will solve any existing or future anticipated loading issues of PSE equipment. PSE's normal and emergency thermal operating limits, and potential consequences of violating those limits, are discussed earlier in this section.

2.2.1.14 Must not cause any adverse impacts to the reliability or operating characteristic of PSE's or surrounding systems

Under NERC and WECC guidelines, PSE cannot propose a project that will adversely affect the region, and it would be counterproductive for PSE to introduce a solution that raises other issues within its own system.

2.2.1.15 Must meet performance criteria listed above for 10 or more years after construction with up to 100 percent of the emergency limit for lines or transformers

If the proposed solution is needed by the winter of 2017 - 2018 and the solution is only viable until the end of the study period (2024), then PSE would need to start its next system improvement within a couple of years after the solution is put into service. PSE does not see this as realistic or prudent. A long-term solution must last through 2028, which is considered to be 10 years past the estimated 2018 in-service date. Additionally, the solution must not exceed 100 percent of the emergency limit for lines and transformers. Exceeding the 100 percent emergency limit will incur mandatory performance violations and equipment loss of life.

This criterion is established as a minimum period of time for a solution to be considered a long-term solution. Because of the standardized steps in voltage and equipment sizes (e.g., 115 kV and 230 kV), an alternative may exceed the 10-year minimum. Ideally, the best solution would exceed these minimum longevity requirements by providing options for future needed electric system reinforcements, such as an additional transformer, which could accommodate future growth beyond the 2028 timeframe.

2.2.2 Non-electrical Criteria

The criteria listed below reflect PSE's preferences regarding environmental concerns, project timing, degree of control and reliability of any solutions, and project cost. While these objectives are acknowledged as important, under SEPA and other permitting authority, the partner Cities generally did not weigh these equally with electrical criteria in selecting alternatives. This is because electrical criteria are generally non-discretionary, except in certain cases, such as system security. In contrast, non-electrical criteria are more discretionary. The partner Cities applied their own discretion in determining if an alternative was environmentally acceptable to carry forward in this Phase 1 Draft EIS, and did not eliminate any alternatives because of timing, unproven technology, controllability by PSE, or cost. These criteria, which are explained in greater detail below, may be considered in the project-level Draft EIS in Phase 2 of this EIS process.

2.2.2.1 Environmentally acceptable to PSE and communities

For PSE, environmentally acceptable means a solution that, through the environmental review process, would be found to minimize, to the extent practicable, the environmental impacts on the affected communities. This Phase 1 Draft EIS provides an evaluation of impacts for the range of alternatives so that citizens and decision-makers can understand the environmental tradeoffs.

2.2.2.2 Constructible by winter of 2017 - 2018

PSE studies show that Eastside customer demand will reach a point when the Eastside's electric transmission system capacity could experience a deficiency as early as winter 2017 - 2018. To be a viable solution, a project must be completed and in service by the identified target need date. For example, PSE's current schedule for the proposed 230 kV transformer and transmission line installation targets construction to begin in 2017, with project completion in 2018. Any delay in the schedule would push the in-service date beyond the 2018 winter timeframe, which would increase PSE's reliance on the use of CAPs and load shedding. PSE must prepare for project construction several years in advance because some specialized equipment can take up to 3 years to procure. Alternatives must be reviewed to ensure they are reasonably constructible by the in-service target date of 2018.

2.2.2.3 Utilize proven technology which can be controlled and operated at a system level

To PSE, *proven technology* means technology that has been successfully operated with acceptable performance and reliability within a set of predefined criteria. Proven technology must have a documented track record for a defined environment, meaning there are multiple examples of installations with a history of reliable operations. Such documentation must provide confidence in the technology from practical operations, with respect to the ability of the technology to meet the specified requirements.

"Controlled and operated at a system level" means a dispatcher at a local control center can turn resources on/off or reroute resources either manually or automatically from the dispatch center, or a dispatcher can instruct field personnel to do the same. This criterion rules out independent "behind-the-meter" resources that PSE could not call on as needed. Further, it means that PSE would need to conduct maintenance on, or inspections of, the resources to ensure that they are:

- Operational;
- Providing the capacity they are designed and intended to provide (referred to as *nameplate capacity*); and
- Available to be used when needed.

2.2.2.4 Reasonable project cost

What is a **rate base**? A rate base is a set of costs that PSE is allowed to recover over time through rates and fees charged to its customers. See the UTC website for more information: http://www.utc.wa.gov/regulatedIndustries/utilities/energy/Pages/financialDataForElectricCompanies.aspx

PSE has a legal obligation to deliver safe, dependable power, and an obligation to do so at a reasonable cost. PSE continually balances these obligations in determining the best solutions to solve problems facing the electric system. The Washington Utilities and Transportation Commission (UTC) also has an obligation to review all PSE projects to determine if the solution is reasonable and prudent. After a project is complete and before the costs are allowed to be placed into the *rate base*, PSE must prove to the UTC that the cost to build a project is prudent and reasonable to ratepayers. This means PSE must research and compare costs and benefits of multiple alternatives that can accomplish the desired objectives. This is not a simple lowest project cost test; it is a holistic review and analysis of factors such as projected duration of 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, as well as the dollar cost of the project. PSE has completed some of this evaluation already, and will continue to evaluate costs through the design and permitting phase of the project.

2.2.3 Understanding System Contingencies and their Frequencies

To understand the nature of the issue that PSE is proposing to address with the Energize Eastside Project, it is helpful to know about the frequency of conditions that produce the deficiency in transmission capacity that PSE has identified. This includes an understanding of how often there are equipment outages that affect the transmission system.

The PSE bulk electric transmission system includes approximately 2,100 components[1] that are included in its system model. Not all of these components affect the systems on the Eastside, but many components that are outside of the Eastside do affect how and where power flows into the Eastside. When everything is operating normally, the system is said to

[1] Transmission system elements include transmission lines 115 kV and above, transformers whose low side is 115 kV or above, generators connected to transmission, generator stepup transformers, reactive devices connected to transmission, substation bus sections at 115 kV and above, and circuit breakers at 115 kV and above.

be in an N-0 state. An N-1 outage condition can occur at any time when a single component trips or is taken offline. This occurs when a problem is detected or because some damage has occurred. It can also be a result of routine maintenance when a system component must be taken out of service (if possible, routine maintenance would not be scheduled during peak load periods or during bad weather). In a typical year, the PSE system operates in an N-1 condition about 350 - 360 days per year (almost every day). These conditions persist for approximately 60 percent of the time each year[2].

An N-1-1 outage condition is an N-1 outage followed by a period of time to manually adjust the system to a secure state, followed by a second N-1 outage. This occurs when a problem is detected or some damage occurs followed by an additional problem or damage event. However, it can also be a result of routine maintenance when a system component must be taken out of service, and the second N-1 outage occurs unexpectedly. Most days PSE operates in a mode where multiple elements are taken out of service across PSE's service territory. Most of these combinations do not cause customer outages the way the "N-1-1" outages do. In a typical year, the PSE system operates in an N-1-1 condition that causes customer outages about 15 to 30 times per year, each of which persists for approximately 4 to 12 hours[3], or less than 2 percent of the year[2].

An N-2 outage is when a single event trips multiple facilities, such as certain instances when all the breakers in a substation trip offline, leaving several circuits without power, or a problem occurs that affects both circuits of a double circuit transmission line (two transmission circuits located on one structure). This occurs when a problem is detected, or some sort of damage has occurred. It can also be a result of routine maintenance when multiple system components must be taken out of service. However, if at all possible, routine maintenance avoids multiple elements, and if necessary, would most likely not be scheduled during peak load periods or poor weather. In a typical year, the PSE system operates in an N-2 condition about 10 to 20 days per year, and persists for approximately 4 to 12 hours, or less than 1 percent of the year[2].

2.2.4 Understanding Normal Winter and Summer Load Forecasting

The normal peak weather events that PSE uses in its model to test its system are typical extended periods of either cold winter temperatures or hot summer temperatures, temperatures that have a 50 percent likelihood of occurring in a given year. For winter, this means a temperature of 23 degrees Fahrenheit or lower at the time of the system peak. For summer, this means a temperature of 86 degrees Fahrenheit or higher at the time of the system peak.

2.3 PROJECT ALTERNATIVES

This Phase 1 Draft EIS evaluates PSE's proposed Energize Eastside Project (a 230 kV overhead line), a No Action Alternative (as required by SEPA), and two other "action alternatives." These alternatives were developed by the partner Cities in cooperation with PSE, with the intent of providing options that could attain or approximate PSE objectives for

[2] These are estimates; PSE does not track outages in this format.
[3] This duration is an average and storm events can run much longer than 12 hours or shorter than 4 hours.

the project at a lower environmental cost. The **No Action Alternative** provides a benchmark against which the proposed project and other action alternatives can be compared. **Alternative 1** includes the 230 kV overhead lines but also includes options for locations, including underground and underwater options. **Alternative 2** includes a variety of solutions that would require very limited new transmission lines next to existing substations and would need to be implemented in combination in order to meet the project objectives. **Alternative 3** would involve installing enough 115 kV lines and transformers to address the project objectives without building 230 kV lines. Each alternative is described in more detail below.

2.3.1 No Action Alternative

The No Action Alternative is defined as those actions PSE would undertake to serve the project objectives without requiring issuance of state or local permits (something PSE could build or undertake immediately if the proposed project is not approved). The No Action Alternative represents the most likely outcome if the proposed project is not implemented, and it is considered the baseline condition.

The study area for the No Action Alternative is shown on Figure 1-4, which is the combined study area for all alternatives. The combined study area was used to describe the affected environment for this Phase 1 Draft EIS. The alternatives are located collectively within the following public land survey system townships and ranges: T25N / R6E, T25N / R5E, T24N / R6E, T24N / R5E, and T23N / R5E.

Based on U.S. Census and *Puget Sound Regional Council* population forecast data, PSE's analysis concluded that the population in PSE's service area on the Eastside is projected to grow by approximately 1.2 percent per year over the next 10 years and employment is expected to grow by 2.1 percent per year, resulting in additional electrical demand (Gentile et al., 2015).

How does PSE's conservation compare to other utilities? PSE's level of conservation is higher than other nearby utilities. For example, PSE expects to conserve about 500 MW cumulatively from 2013 to 2023, which represents approximately 15 percent of their projected average demand (load) of about 3,300 MW for that year (PSE, 2013). Seattle City Light (SCL) expects slower load growth than PSE, and total cumulative conservation from 2014 through 2023 to represent approximately 9 percent of average load (SCL, 2014). Snohomish Public Utility District (PUD), which expects load growth of approximately 2 percent per year, projects its total cumulative conservation since 2014 to represent approximately 9 percent of average load in 2024 (Snohomish PUD, 2013).

If electrical load growth occurs as PSE has projected, PSE's system would likely experience loads on the Eastside that would place the local and regional system at risk of damage if no system modifications are made. To address this risk in the near term, PSE would use CAPs (described in Section 2.2.1.12), which are a series of operational steps used to prevent system overloads or large-scale loss of customers' power. CAPs generally involve shutting off or reducing load on overloaded equipment and rerouting the load to other equipment. The CAPs are seen as temporary measures used to keep the entire system operating, but they can place large numbers of customers at risk of a power outage if anything else on the system begins to fail.

Under the No Action Alternative, PSE would continue to manage its system as at present. This includes maintenance programs to reduce the likelihood of equipment failure, and stockpiling additional equipment so that in the event of a failure, repairs could be made as quickly as possible.

Under the No Action Alternative, this EIS assumes that PSE would continue to achieve 100 percent of the company's conservation goals as outlined in its *2013 Integrated Resource Plan* (PSE, 2013), systemwide and for the Eastside. Conservation goals are achieved through a variety of energy efficiency improvements implemented by PSE and its customers. Conservation refers to electrical energy savings above and beyond state or local energy code requirements.

Table 2-1 shows PSE's projected conservation for its entire system and for the Eastside. For the Eastside in 2024, PSE projected that proposed conservation measures would address approximately 110 MW of peak usage, leaving a remaining Eastside load of 764 MW needing to be served during projected peak periods. The conservation measures would address approximately 13 percent of the peak load. PSE currently conserves approximately 21 MW, or 3 percent of the Eastside baseline peak load. For comparison, systemwide, PSE is estimated to have achieved system peak conservation of approximately 91 MW or approximately 1.9 percent of the system peak of 4,803 MW (peak load without conservation) in 2014 through 2015.

Table 2-1. Peak Load Addressed Through Conservation Measures by PSE Service Area and Year

PSE Service Area and Year	Peak Load Addressed Through Conservation Measures	Remaining Peak Load	Percent of Peak Load Addressed Through Conservation Measures
Eastside			
2015	21 MW	679 MW	3%
2024	110 MW	764 MW	13%
Systemwide			
2014-2015	91 MW	4,712 MW	1.9%

To achieve its electrical conservation goals, PSE expects to incentivize the following types of measures:

- Energy Efficiency: weatherization, efficient lighting, etc.;
- Fuel Conversion: converting from electric to natural gas;
- *Distribution Efficiency*: implemented on PSE *distribution systems*;
- Distributed Generation: customer *combined heat and power* (CHP), solar, wind, etc.; and

- Demand Response: *capacity savings programs*.

Energy efficiency is the largest contributor to total energy savings in PSE's conservation program, accounting for approximately 90 percent of total energy savings systemwide by 2024. Fuel conversion (from electric to natural gas) and distributed generation (smaller sources of power such as solar, wind, and other generation types) represent a small but growing component of PSE's conservation program, jointly comprising less than 10 percent of existing energy savings but projected to increase to approximately 14 percent of energy savings by 2024. Figure A-1 in Appendix A provides additional detail.

Distribution efficiency can include *conductor* replacement and *conservation voltage reduction*. Conductor replacement on existing lines could occur under the No Action Alternative as part of normal maintenance. However, these improvements would not substantially increase overall system capacity because capacity issues driving this project are typically associated with transformer overloads rather than conductor overloads. PSE would continue the current practice of using advanced systems, such as conservation voltage reduction, to improve system efficiency and reduce overall loading. Conservation voltage reduction refers to controlling PSE's distribution voltage at slightly reduced levels to conserve energy.

The other components of PSE's conservation program comprise relatively small percentages of their conservation target at present. Distributed generation and demand response are two of the components that are included in Alternative 2 and are discussed in further detail in Section 2.3.3.

There are no currently known new technologies that PSE would employ that could substantially affect the transmission capacity deficiency on the Eastside. Under the No Action Alternative, PSE would not be precluded from seeking out new technologies, however.

2.3.1.1 Construction

Under the No Action Alternative, construction activities would likely be limited to occasional conductor replacement, implementation of new technologies not requiring discretionary permits, and installation of distributed generation facilities under PSE's conservation program (e.g., solar panels, *wind turbines*, or rooftop generators). While conductor replacement could occur under the No Action Alternative, installation methods would likely involve the use of a single-man lift.

2.3.2 Alternative 1: New Substation and 230 kV Transmission Lines (Puget Sound Energy Proposal)

Under this alternative, PSE would install a new transformer somewhere near the center of the Eastside to convert 230 kV bulk power to 115 kV to feed the Eastside distribution system. The new transformer would be installed at or near one of three properties that are either adjacent to existing substations or have been purchased by PSE for future substations.

The study areas for each action alternative correspond to the areas where the project components would be constructed and operated. The Alternative 1 study area includes portions of Bellevue, Kirkland, Newcastle, Redmond, and Renton, and unincorporated King County (Figure 2-1). Alternative 1, Option D assumes in-water work within a portion of Lake Washington, including waterside areas along the shorelines of Beaux Arts Village, Bellevue, Clyde Hill, Hunts Point, Kirkland, Medina, Mercer Island, Renton, and Yarrow Point (Figure 2-1).

To supply the new transformer, two new 230 kV transmission lines would be constructed to bring power from existing 230 kV sources. PSE's Talbot Hill substation in Renton and Sammamish substation in Redmond are the closest existing 230 kV sources to the center of the Eastside, and are considered the southern and northern ends of this alternative. The Phase 1 Draft EIS considers that transmission lines could be placed in existing or new corridors, including adjacent to roads or highways. Because of the density of development on the Eastside, any new overland corridor would be likely to entail acquisition and removal of buildings.

For the Phase 1 Draft EIS, three basic types of 230 kV transmission lines are considered capable of meeting the project objectives: overhead (new as well as existing transmission lines), underground, and underwater (also referred to as submerged or submarine). The new 230 kV line could also be a combination of these types.

Solutions considered part of this alternative include "single circuit" lines as well as solutions that would allow for addition of a second 230 kV circuit on the same poles, in the same corridor, or in the same underground or underwater facility.

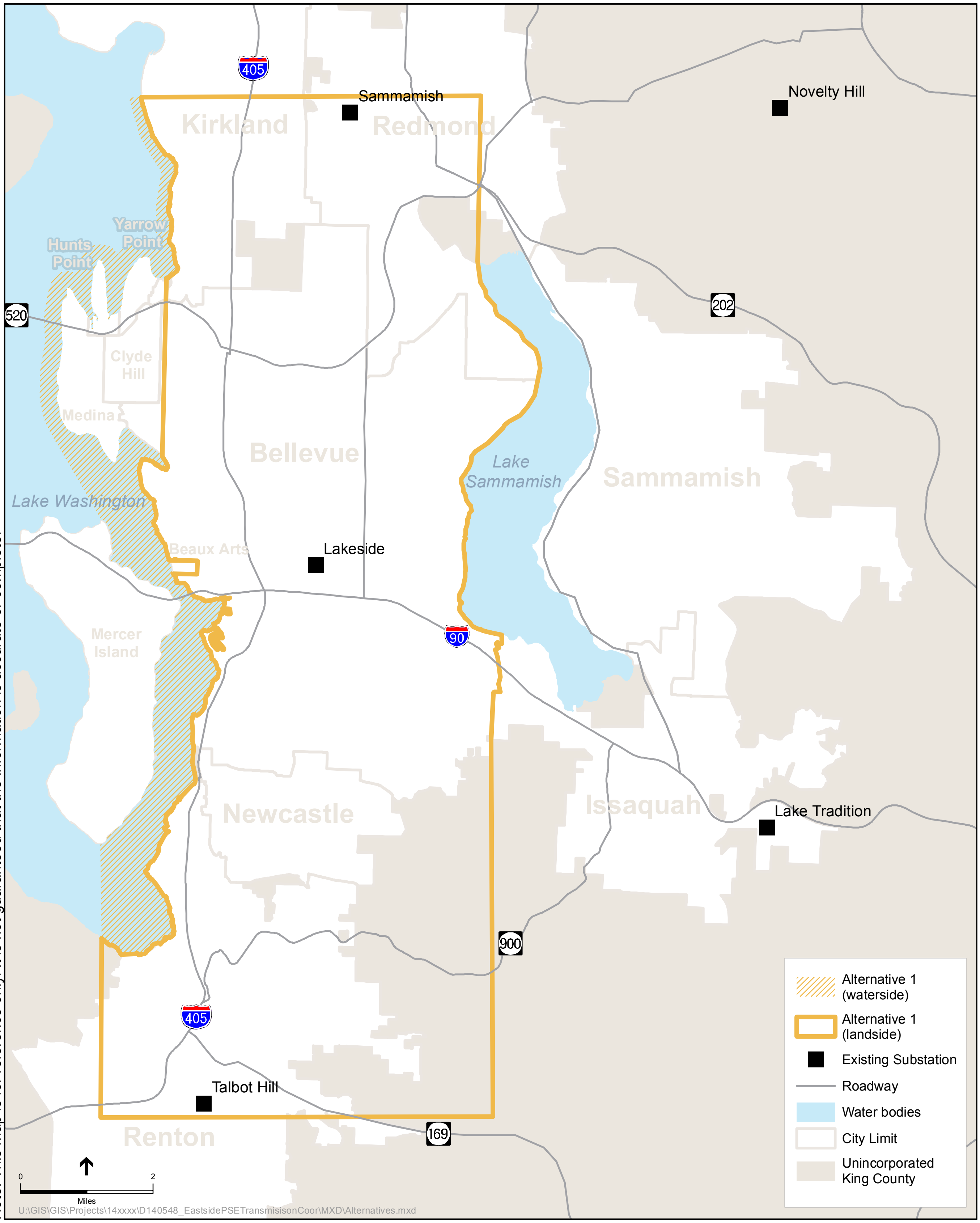
A single circuit transmission line includes three conductors (wires). A double circuit includes six conductors (See Figure 2-2 for a depiction of typical poles for single and double circuit transmission lines).

Operation of Alternative 1 would involve limited but regular maintenance along the transmission lines. Substation operation would involve regular site inspection and maintenance. All proposed equipment is subject to wearing out and would need to be replaced when this occurs, typically after several years of use. Replacement of conductors would be similar to the final steps of installation. Replacement of substation equipment would be similar to the final stages of construction, involving heavy trucks delivering equipment and cranes to remove and replace equipment.

The types of lines being considered for Alternative 1 have been categorized into four options as follows: **Option A**—new overhead transmission lines; **Option B** –use existing Seattle City Light (SCL) overhead transmission lines; **Option C**–underground transmission lines; and **Option D**–underwater transmission lines. These options are described in Sections 2.3.2.2 through 2.3.2.5.

For the Phase 1 Draft EIS, a study area was selected that assumes the 230 kV lines could be installed anywhere from Lake Sammamish to Lake Washington, plus a portion of Lake Washington for Option D (Figure 2-1).

Note: This map is for reference only. It is not guaranteed that the information is accurate or complete.



SOURCE: King County 2015; ESA 2015;
Puget Sound Energy 2015; WA Ecology 2014.

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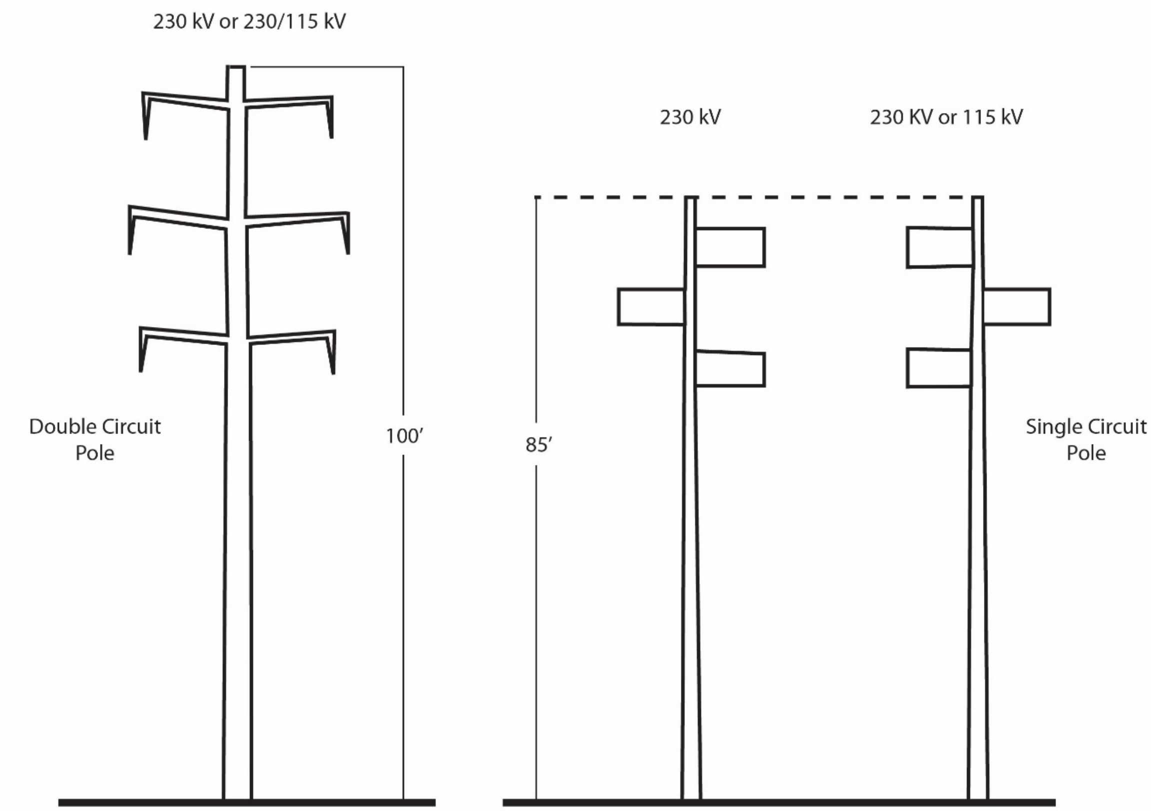
Figure 2-1

Alternative 1 Study Area

Figure 2-2. Typical Pole Dimensions for 230 kV Overhead Transmission Lines



2.3.2.1 Features Common to All Options

2.3.2.1.1 New Transformer

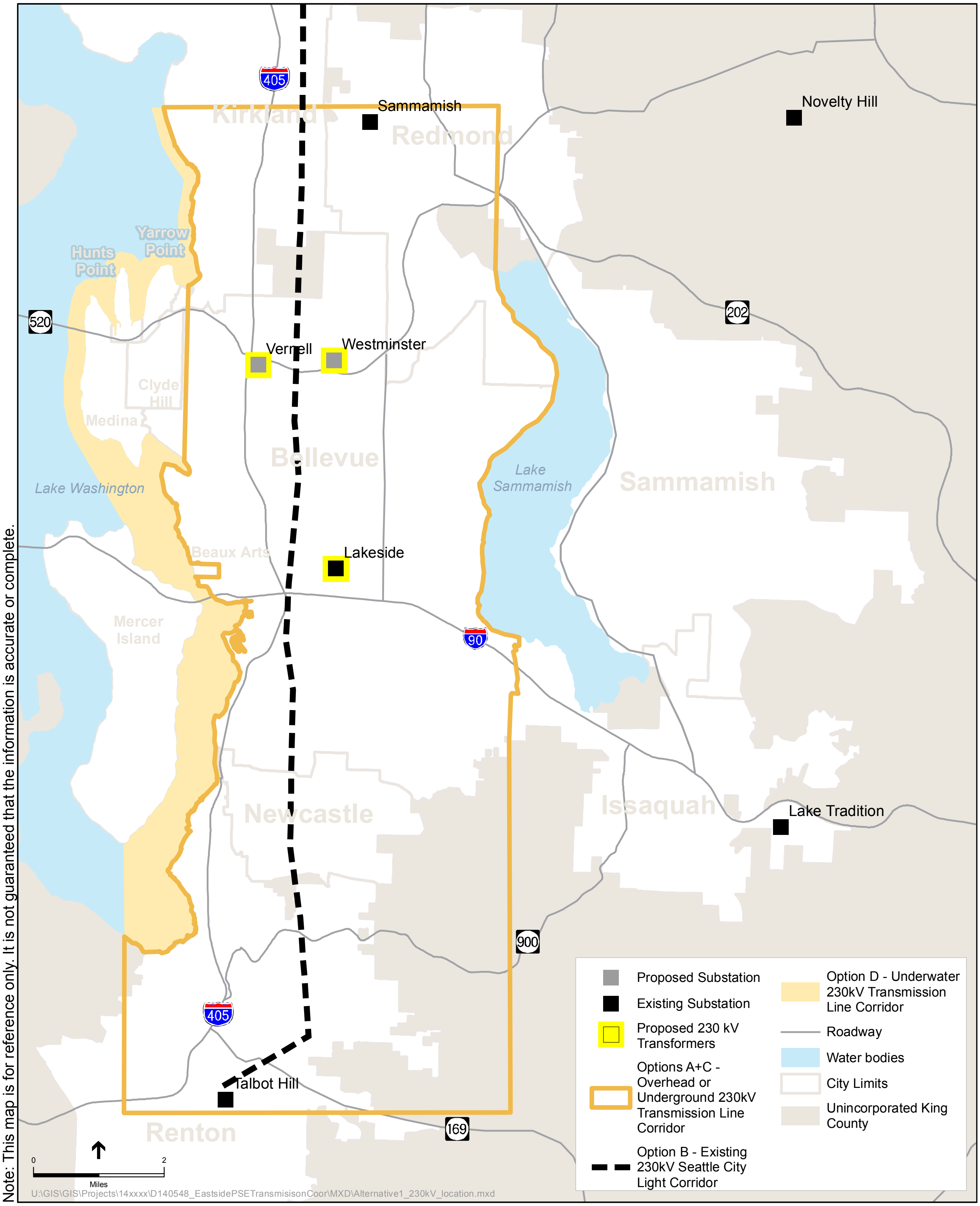
PSE currently owns three properties that have been designated as possible locations for future substations in the central portion of the Eastside. These substations could potentially serve the project objectives with a new 230 kV to 115 kV transformer (Figure 2-3).

Figure 2-3. Transformer

Potential locations could be adjacent to the existing Lakeside substation (Figure 2-4), or at one of two possible new substation sites referred to as Westminster and Vernell, all within Bellevue city limits (Figure 2-5). These sites are near multiple 115 kV lines, which would allow them the most efficient location to inject additional power to the Eastside. The property adjacent to the existing Lakeside 115 kV substation presents the most effective location from a systemwide perspective because of its immediate proximity to the existing 115 kV substation and multiple existing 115 kV lines. Both the Westminster and Vernell sites would require the addition of one or more new 115 kV lines.

Figure 2-4. Lakeside Substation

At any of these sites, development of a new 230 kV substation yard would be required. The substation yard would need to be large enough to accommodate the new transformer and associated electrical equipment such as circuit breakers, bus, and connections to the new transmission lines. The gravel yard would include the necessary foundations, access ways, stormwater drainage, and security fencing (typically 8-foot-tall chainlink, but other types of fencing may be used). In order to accommodate a new transformer and associated equipment, acquisition of property adjacent to the Lakeside substation site could be required. Both the Westminster and Vernell sites are owned by PSE, vacant and large enough for a new substation.



SOURCE: King County 2015; ESA 2015; WA Ecology 2014; Puget Sound Energy 2015.

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Figure 2-5
Alternative 1 - New Substation and 230 kV Transmission Line

2.3.2.1.2 Construction

Construction of a new substation would require clearing and grading to prepare the area for foundations to support the new transformer that converts the bulk power into the distribution system. The new transformer would also require supporting equipment that would be placed on a concrete pad in accordance with regulatory requirements and industry standards. The expansion of the substations would require construction of underground foundations to support the new transformer.

Construction for transformers would require delivery of the transformers to the site; grading of the site and creation of a foundation; and placement of the transformer on the foundation. Construction equipment required would include:

- Specialized oversize trucks and trailers;
- *Backhoes* or *excavators;*
- Concrete trucks; and
- Cranes or other specialty equipment to place transformers.

Use of oversize trucks would be restricted to certain hours to avoid or minimize traffic impacts. Additional information on construction equipment is included in Appendix B.

Construction of transformers would take up to 18 months. The duration of transformer construction would depend on location. Installation in a new facility with construction of a new substation yard would require the longest duration. Transformers and transmission lines could be constructed concurrently. Depending on site access and configuration, construction activities could require temporary street closures and detours.

Construction would also be required for new 230 kV transmission lines. Construction activities would vary by option and are described below. Temporary construction easements may be needed to build any of the options, and PSE would execute an agreement with the property owner for site access and site restoration during any such use.

2.3.2.2 Option A: New Overhead Transmission Lines

New overhead transmission lines may be located entirely within existing utility easements, or partially in new locations currently not dedicated to utility operations (such as along roadways or rail corridors, over or through private or other public property). This option would include a minimum of 18 miles of new overhead transmission lines (connecting in the most direct manner using PSE right-of-way from the Lakeside substation to the Talbot Hill and Sammamish substations). Additional transmission lines could be needed depending on the substation chosen and other route possibilities.

In the near term, one of the existing 115 kV lines between the Lakeside substation and the Talbot Hill substation may need to be rebuilt with a 115 kV line that provides a higher capacity. There would be little difference in conductor type (including size and appearance) between a high-capacity 115 kV line and a 230 kV line; therefore, the same line could potentially be used for a future 230 kV line. While there is not an immediate need for a second 230 kV circuit through the Eastside, there are cost efficiencies with installing a second circuit transmission facility in the same corridor as the proposed 230 kV line. PSE will consider this as part of efforts to identify the least costly infrastructure to serve its customers.

For overhead lines, an additional wire would be installed on top of the new poles for lightning protection. Any existing fiber-optic cable would need to be transferred to the new poles.

2.3.2.2.1 Overhead Transmission Line Locations

Figure 2-5 shows the area where installing a new 230 kV transformer and transmission line under Alternative 1, Option A would meet PSE's project objectives. Within this area, overhead lines could be constructed anywhere. PSE policy is to use its existing easements or rights-of-way wherever possible, but road and other utility right-of-way corridors (such as city streets, state and interstate highways, and some sections of the SCL corridor) are also possible locations. PSE may need to obtain new right-of-way to extend the transmission lines to a desired substation, or to avoid an area of potential impact elsewhere. Additionally, relocation of existing distribution or 115 kV lines may be needed in order to accommodate the new 230 kV line.

Specific pole locations would be determined based on site engineering. Pole locations would generally be based on tensioning needs for the wire (including where turns are needed along the route), underground obstacles at pole foundation locations, and allowable structural heights, all while attempting to use as few poles as possible. Consideration is also made to avoid placing poles in environmentally critical areas like wetlands and unstable slopes.

2.3.2.2.2 Pole Types and Heights for Overhead Lines

Poles would likely be steel or laminated wood monopoles; however, other designs such as H-frames using wood or steel poles could be used in some locations. Concrete poles are not commonly used in this region because they are more expensive than wood or steel. The diameter of the poles depends on height and would be greatest at the base. Typical in-line (tangent) poles would be 2 to 4 feet in diameter at the base, while typical corner and termination poles may need to be 4 to 6 feet in diameter at the base depending on the angle and the terrain. Termination poles and poles where the transmission line changes direction need to be larger than tangent poles to handle the asymmetrical weight and tension from the lines they are holding.

In order to meet *National Electric Safety Code* (NESC) and FERC/NERC requirements to prevent contact with the lines, adequate clearances must be maintained between each conductor, the ground, adjacent buildings, and trees. Pole height therefore would vary depending on the number of circuits, the arrangement of the circuits on the poles, topography, and surrounding land cover. Figure 2-2 shows the typical range of pole dimensions for 230 kV transmission lines. Generally, for a double circuit system, pole heights would range from 85 to 100 feet. In some configurations that could occur under Alternative 1, Option A, a double circuit would incorporate an existing 115 kV line with a new 230 kV line on poles similar to those shown in Figure 2-2. In special cases, such as crossing a ravine or highway, pole heights could be shorter or taller.

2.3.2.2.3 Construction

Under Alternative 1, Option A, new 230 kV transmission lines would be constructed along a minimum of 18 miles of corridor. Construction could occur within existing transmission or other utility easements, or in new locations currently not dedicated to transmission such as areas along road rights-of-way, rail corridors, or over or through private or other public property.

Clear zones. To ensure safe and reliable operation of overhead or underground transmission lines, the NESC specifies minimum horizontal and vertical clearance requirements for overhead lines, where trees and overhanging branches must be removed, and structures are generally prohibited (the *clear zone*). Existing 115 kV corridors on the Eastside vary in width, as do standards for 230 kV corridors. Because of this variability, generic assumptions were made based on standard practice in the industry (AEPOhio, 2014). These clear zone requirements typically determine transmission right-of-way (or easement) widths. Specific easement agreements may require more clearance.

For this Phase 1 Draft EIS, if a range of corridor widths is possible, the impact analysis assumes the worst case. In practice, PSE may be able to reduce the required clear zone, in which case impacts would be less than those assumed for this phase of the EIS.

The clear zone for an overhead 230 kV line could be approximately 120 to 150 feet wide. The transmission line could be located along existing 115 kV easements, which are typically 70 to 100 feet wide. Therefore, this analysis assumes that use of a 115 kV corridor could require the corridor to be widened by up to 50 feet. Section 2.3.5 summarizes the clear zone widths and other assumptions used for all alternatives in this EIS.

Coordination with Olympic Pipeline. If located along the existing 115 kV easement, construction of a 230 kV line has the potential to disrupt the Olympic Pipeline. Extensive coordination with the Olympic Pipe Line Company would be required during project design and construction to avoid disruption to the two lines, or to establish relocation procedures.

Pole installation. During construction, existing wooden poles and conductors would be removed, if present. The methods used to install new steel poles will depend on the type of pole used and both its physical and functional location. Poles can be directly embedded in the ground or utilize an anchor bolt cage, which is a drilled pier foundation that involves setting the anchor bolt cage in a poured column of concrete. Foundations for new 230 kV poles are typically *augered* (drilled) 4 to 8 feet in diameter with steel reinforcements that could extend 25 to 50 feet deep depending on the structure type. Steel poles are set and anchored to the foundations. In some cases, a caisson foundation is used for greater stability. (No foundations are used for wooden poles.) Approximately 100 pole foundations would need to be installed with a typical spacing between poles of 1,000 feet to extend the 18-mile distance between the Sammamish and Talbot Hill substations.

Transmission line installation. Once the pole is set in place, the transmission line (wire) would be installed (Figures 2-6, 2-7, 2-8, and 2-9). The wire-stringing operation requires equipment at each end of the section being strung. Wire would be pulled between these temporary pulling sites through pulleys at each structure. These pulling sites would be set up at various intervals along the right-of-way, typically 1 to 3 miles apart. Specific pulling sites would be determined close to the time the stringing activity takes place. Once the wire is strung, the stringing blocks (i.e., guide rollers) would be removed and the wire clipped into its final hardware attachment. Once poles are installed, surfaces around the new poles and in work areas would be restored.

Figure 2-6. Workers prepare to energize a transmission line (Gulf Power, 2015)

Figure 2-7. Workers Rebuilding a Transmission Line (Fischbach, 2014)

Figure 2-8. Installation of Transmission Line (Transelect, 2015)

Figure 2-9. Workers Rebuilding a Transmission Line (Fischbach, 2014)

Ground disturbance. Disturbance of site soils would be necessary for clearing and grading to prepare foundation pads as well as potentially a staging area and equipment access depending on the location of the transmission line. Construction would require temporary construction access roads. Installation of transmission lines under existing roadways could require excavation, construction, backfill, and pavement restoration within roadway rights-of-way.

Equipment. Construction equipment required for overhead transmission lines would include the following:

- Bulldozers;
- Backhoes;
- Trackhoes;
- Bucket trucks;
- Auxiliary rubber tire vehicles;
- Auger or vacuum trucks;
- Dump trucks;
- Concrete trucks or concrete pump trucks;
- Cranes;
- Line trucks;
- Conductor reel trailer for hauling conductor reels;
- Tensioner for applying tension to conductor coming off reels during pull; and
- Puller for pulling rope/hard line with attached conductor.

Length of Construction Period. Construction of overhead transmission lines would take approximately 12 to 18 months and could be constructed concurrently with the substation. If a new corridor were to be developed, the duration would likely be longer due to the need for more extensive clearing. Construction of a new corridor is also more likely to require demolition or removal of buildings, which would extend the duration of construction and could also result in temporary stockpiles of demolition debris.

Typically, the foundation for a steel transmission line pole involves work at a site for 1 to 3 days; setting the pole occurs in a day; and stringing the wires across the pole occurs within a day. These three stages of work can be separated by up to a month. Therefore, in any given location, construction activity would take place over 3 to 5 days within a period of up to 2 months. For wood poles, no foundation is set. Typically, the hole is prepared and the pole is set in a single day, with the wires installed up to a month later.

Other activities. Installation of new overhead transmission lines would require other construction activities that may include boring holes for geotechnical investigations, or relocating existing distribution and telecommunications facilities.

2.3.2.3 Option B: Use Seattle City Light 230 kV Overhead Transmission Lines

Alternative 1, Option B makes use of an overhead 230 kV transmission line belonging to SCL (see Figure 2-5). PSE has explored the idea of using the SCL line as an option; however, the SCL facility is not under PSE ownership, and SCL stated that it needs this line to serve its customers (Gentile et al., 2014). This option is included in this Phase 1 Draft EIS so that, if conditions change, this option will remain open.

System operational studies by PSE have shown that Option B would require significant modifications of the SCL line, including replacing most of the existing structures and all conductors, to provide the necessary capacity to meet PSE's identified need for the Energize Eastside Project. The present emergency ratings of the SCL lines are 426 megavolt amperes (MVA) in the summer and 526 MVA in the winter. In order for PSE to utilize these lines as the source for an additional 230 kV transformer on the Eastside, the present ratings are insufficient. If lines were upgraded by replacing only the conductor, then the assumed ratings for the reconductored lines are 692 MVA in the summer and 771 MVA in the winter. This would not be adequate to meet both SCL's needs and PSE's project objectives (Strauch, personal communication, 2015c). Therefore, if SCL were to grant use of this line, PSE would need to both tie into it and upgrade it. The next incremental increase in capacity would be to rebuild the SCL lines (replace structures and conductors), which could provide a line capacity of approximately 1,139 MVA in the summer and 1,366 MVA in the winter.

Option B would involve both of the SCL SnoKing-Maple Valley 230 kV transmission lines. It would also require connecting one double circuit 230 kV line to the Lakeside substation and connecting another double circuit 230 kV line to the Sammamish substation. The exact length of that alignment is not known, but the proximity of the Lakeside and Sammamish substations to the line suggests that each connection would be approximately 1 mile or less (Figure 2-5). This option would also require modifications to and expansion of several substations.

The rebuild of the SCL line was estimated by PSE to provide sufficient capacity for a period of less than 10 years, failing to meet electrical criteria #2 and #15 (Section 2.2.1), but it could otherwise attain or approximate PSE's objectives (Strauch, personal communication, 2015c).

2.3.2.3.1 Construction

Alternative 1, Option B would require replacing most of the existing structures of the SCL 230 kV lines. The SCL lines may need to remain in service; therefore, the replacement line may need to be constructed adjacent to the existing line and placed into service prior to removing the existing structures and conductor.

Construction activities needed would be similar to Alternative 1, Option A, except that it is assumed that the only new corridor needed would be the connection to the Lakeside substation. It is assumed that no additional clear zone would be required for the existing SCL 230 KV corridor. Activities would be concentrated along an approximately 15-mile-long corridor.

Due to the added complexity of rebuilding the SCL system while in operation, construction of transmission lines would last up to 24 months (Strauch, personal communication, 2015c).

Construction equipment required for Option B would be the same as described for Option A.

2.3.2.4 Option C: Underground Transmission Lines

Under Alternative 1, Option C, any portion of the alignments of new transmission lines considered for Option A could be placed underground.

The route alignment for new 230 kV underground transmission lines under Option C requires additional study because construction and operation of underground lines has different considerations than aboveground lines. It is possible that underground lines could be placed within PSE's existing 115 kV overhead line rights-of-way, public road right-of-way, or other right-of-way that PSE owns, purchases, or obtains rights to, when topography and operational considerations would allow it. PSE would maintain permanent access to the underground lines in order to make necessary inspections and repairs.

An underground transmission line would likely be a cross-linked polyethylene cable system consisting of stranded copper or aluminum conductor surrounded by insulation and a series of protective barriers. The outermost barriers are typically concrete or steel. Access *vaults* are needed periodically along an underground route to facilitate cable installation, maintenance, and repairs. Underground, reinforced concrete vaults (typically approximately 8 feet wide by 26 feet long) are usually spaced approximately every 1,500 to 2,500 feet along the route.

2.3.2.4.1 Construction

Underground transmission lines could be constructed through existing PSE 115 kV overhead transmission line rights-of-way, other utility rights-of-way (such as roadway or rail corridors), or new rights-of-way.

Installation techniques. Most underground installations are open-cut *trench* construction. The trench width for trench excavation would vary from 2 to 6 feet, plus temporary clearing for access roads and staging. The total work area would be approximately 30 feet wide. Trench depth is determined by future use of the area, location of other utilities, obstructions, and other factors. Additional excavation is done to construct access and splice vaults. Installation techniques for open-cut placement of transmission lines would likely include clearing and grading, excavation, and operation of large equipment. *Trenchless* methods could also be used.

Construction techniques for underground transmission lines largely depend upon the type of terrain and surface conditions:

- **Flat terrain –** Typically a temporary road is constructed along the full length of the trenching operation to provide the necessary construction access.
- **Rolling hills –** Where slopes are less than 10 percent, open trench construction is typically used. Slopes greater than 10 percent can limit access for construction equipment. In some cases access roads are cut into the hill or switchbacks are used to

climb steeper slopes. Horizontal directional drilling (HDD) or trenchless construction can sometimes be utilized to cross a series of hills.

- **Rock** - If bedrock is encountered, only trenchless methods such as directional boring would be used. PSE has indicated that explosives would not be used in urban areas or adjacent to the Olympic Pipeline. Because the project area is all considered urban, no blasting would occur.
- **Wetlands –** Open cutting can sometimes be used to cross wetlands; however, significant environmental controls are applied. In some cases, HDD can be used to span a wetland area.
- **Other obstructions –** There are other situations where open trenching is not practical. This includes crossing of streams, rivers, waterways, highways, railroad tracks, and other situations where open cutting is not allowed or practical. Various trenchless techniques or routing changes may be needed in these cases.

Equipment. Construction equipment required for excavation of trenches and cable pulling for underground transmission lines would include the following:

- Excavators or backhoes;
- Dump trucks;
- Bulldozers;
- Concrete mixers;
- Cranes;
- Conductor reel trailer for hauling conductor reels;
- Tensioner for applying tension to conductor coming off reels during pull; and
- Puller for pulling rope/hard line with attached conductor.

Construction of underground transmission lines would last 28 to 36 months. Construction of underground transmission lines would move in a linear fashion so that, in any given location, the duration of construction would be approximately 2 months.

2.3.2.5 Option D: Underwater Transmission Lines

Alternative 1, Option D involves constructing an underwater transmission line in Lake Washington. For the Phase 1 Draft EIS, a study area was selected that assumes cables could be installed within 1,000 feet of the eastern shoreline of Lake Washington from Kirkland to Renton, including the entire channel along Mercer Island (Figure 2-5). Underwater cable could be installed in Lake Washington provided that the appropriate equipment and materials could be transported to the lake.

Overland connections would be required to connect a submerged line to the Sammamish and Talbot Hill substations, and to a new transformer near the center of the Eastside. The underwater line would need to cross existing submarine cables in Lake Washington, requiring adequate spacing. Appropriate design steps would need to be taken to protect both existing and new cable systems.

2.3.2.5.1 Construction

Alternative 1, Option D would include installation of underwater transmission lines and overhead or underground transmission lines on land that would connect to the underwater portion of the line. In the south end of the underwater line, an overland connection could be accomplished in an existing transmission corridor. However, connecting the underwater line to the Sammamish substation or a new substation in the middle of the Eastside would require new corridors. For construction of overhead lines, refer to Option A, and for underground lines refer to Option C.

Underwater cables. PSE commissioned Power Engineers to prepare a report on an underwater option in one segment of Lake Washington. The report provides details and recommendations about what this option would entail (Power Engineers, 2015). The underwater cable system would likely be composed of three to six conductors spaced at least 16.5 feet apart from one another. Because of system demands, it was assumed that six cables would be needed. These cables could be buried 3 to 5 feet below the lake bottom, although in some areas that are deep enough to avoid potential conflicts with deep-draft vessels, cables may be laid directly on the lake bottom. Depending on the underlying conditions present, the installation of underwater transmission lines could be completed using trenchless methods such as horizontal directional drilling or trenching methods using special vessels to dredge the trenches.

In order to avoid potential impacts to the lake from inadvertent leaks, the cable would not be of the type that uses high pressure fluid-filled pipe. Additional information about laying submarine cable in Lake Washington can be found in the *Eastside 230 kV Project Lake Washington Submarine Cable Alternative Feasibility Report* prepared for PSE (Power Engineers, 2015).

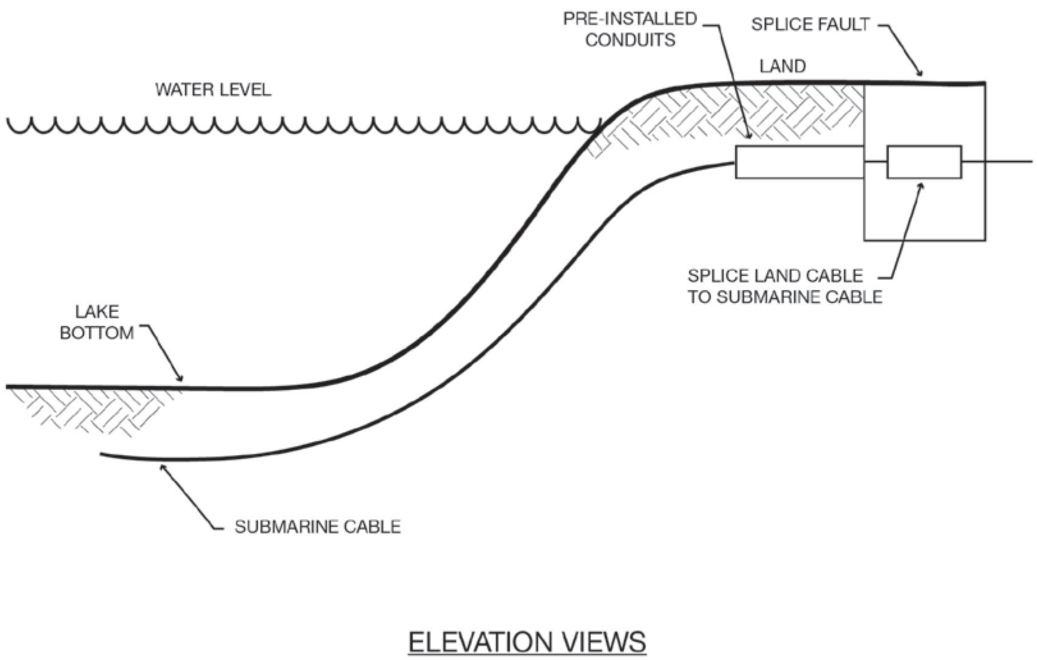
Overland lines. For Alternative 1, Option D, east-west overland transmission lines would be required at up to three locations:

- At the south end, extending from Talbot Hill to Lake Washington;
- From Lake Washington to a substation near the center of the Eastside; and
- At the north end, from the Sammamish substation to Lake Washington.

Overland connections could be via overhead lines as described for Alternative 1, Option A or underground as described for Option C.

Transition between underwater and overland lines. Shore landings where the underwater cables transition onto land would be constructed using *open-cut trenching*, *sheet piling*, and *dredging*. (Trenchless installation is possible but requires larger cable sizes and higher costs.) On the shoreline, splicing vaults are needed to connect the submerged cable to the overland portion of the transmission system. Figure 2-10 shows how a submarine cable would typically be attached to a land-based transmission line in a *splicing* vault.

Figure 2-10. Submarine Cable Landing via Open Trench (Power Engineers, 2015)



The number of splicing vaults is dependent on the design and the maximum length of cable that can be transported to and installed in Lake Washington. For a submerged transmission line that runs from Renton to Redmond, a minimum of three landing points for vaults would be needed, and it could be necessary to have one or more additional splice points on land, each of which would be similar in size to those described for underground cable in Alternative 1, Option C. At each landing point, up to six vaults would be needed to connect the underwater cables to the land cables (Power Engineers, 2015). Each of the cable runs would be physically separated with individual vaults and termination structures so that any two cables in a circuit could continue to operate if the third were taken down (de-energized) for maintenance activities. PSE would have to acquire property, remove vegetation and structures, install the vaults, and maintain access to the vault via a road that could accommodate commercial trucks. Since it is unknown exactly where or how submarine cables would be installed, worst-case assumptions have been used for installing the cables and shore landings.

Installation of upland cable transition points could require sheet or *soldier pile* driving and *cofferdams* in shoreline or nearshore areas, if trenchless techniques are not feasible or practicable to accomplish the offshore-to-upland transitions. It is expected that vibratory pile driving techniques would be adequate to install piles, which would substantially reduce the potential effects compared to impact pile driving methods.

Equipment. Construction equipment required for installation of underwater cables would include the following:

- Excavator or backhoe for open-cut and vault area trenching and loading dump truck;
- Dump truck for hauling spoils;

- Pile driver for sheet piles;
- Dredge for in-water conduit near shoreline;
- Concrete truck for poured-in-place vaults;
- Crane for lifting miscellaneous materials;
- Mixer truck and compaction grout pump to inject thermal backfill;
- Vacuum truck for site and street cleanup;
- Heavy-duty trucks for site deliveries of equipment and materials;
- Conductor reel trailer for hauling conductor reels;
- Tensioner for applying tension to conductor coming off reels during pull;
- Puller for pulling rope/hard line with attached conductor;
- Submarine cable laying barge designed to lay the cable in one continuous piece.

Additional information on construction equipment is included in Appendix B.

Installation of underwater transmission lines would require special vessels to dredge trenches in the lake bottom and lay cable (Figure 2-11) (Power Engineers, 2015). Because of the limitations on the size of vessels capable of passing under the I-90 floating bridge, multiple passes with a smaller vessel may be required for the complete installation of the cable system. Use of special vessels to dredge trenches in the lake bottom and lay cables in the trenches could restrict boat access in the work areas.

Materials would likely be transported via ship or barge from marine waters (via the Hiram M. Chittenden Locks) due to the size of transmission cables that would be needed. Truck delivery is considered infeasible because the longest cable segment that could be transported by truck is approximately 1,100 feet, due to highway weight limits.

Length of Construction Period. Construction of underwater transmission lines would take approximately 8 months. Additional time would be required to construct overhead or underground lines to connect to substations.

Figure 2-11. Typical Barge for 230 kV Cable Installation (Power Engineers, 2015)

2.3.2.6 Conservation

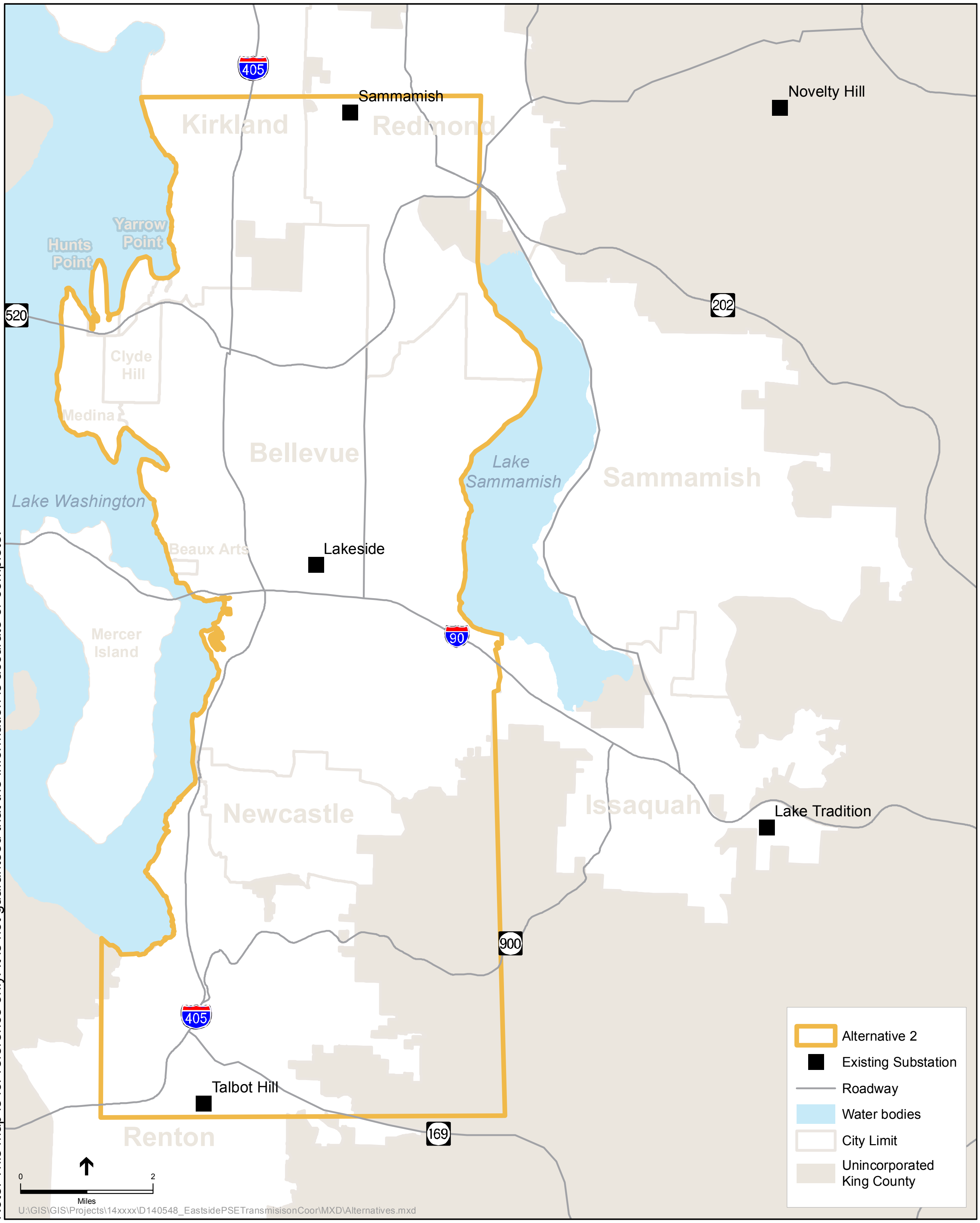
Under Alternative 1, PSE would continue the conservation efforts called out in its *2013 Integrated Resource Plan* (PSE, 2013), as described in the No Action Alternative. Alternative 1 is expected to result in the same levels of conservation as the No Action Alternative.

2.3.3 Alternative 2: Integrated Resource Approach

The focus of Alternative 2 is on energy conservation and use of technologies other than transmission lines to address the project objectives. Alternative 2 would address the projected deficiency in transmission capacity on the Eastside by reducing the growth in peak period demand through energy efficiency, storing and releasing energy when needed to address peak demand, and providing reliable additional peak period energy sources in the area where the transmission capacity is deficient.

The study area for Alternative 2 is shown on Figure 2-12. The Alternative 2 study area excludes in-water work, but includes potential project activity anywhere from the east side of Lake Washington to west side of Lake Sammamish. As described below, some components would need to be close to the center of this area to be effective.

Note: This map is for reference only. It is not guaranteed that the information is accurate or complete.



SOURCE: King County 2015; ESA 2015;
Puget Sound Energy 2015; WA Ecology 2014.

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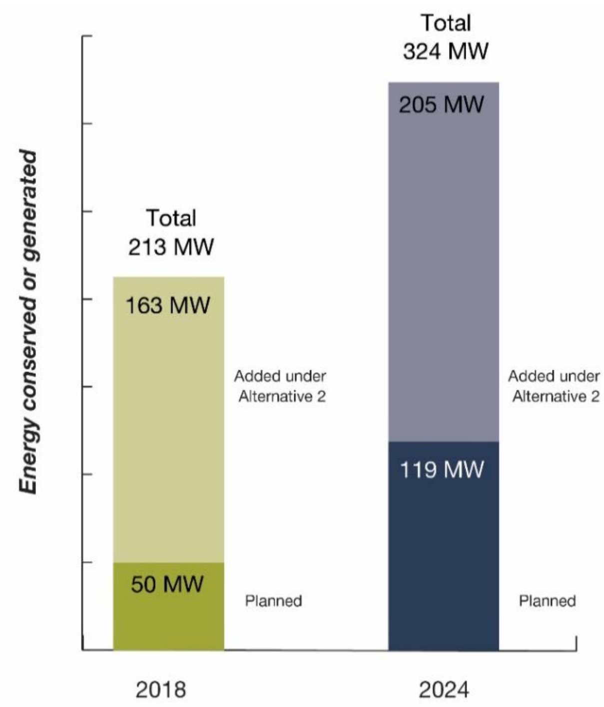
Figure 2-12

Alternative 2 Study Area

Determining the amount of non-transmission resources that would be needed to address the capacity deficiency that PSE has identified is complex because every solution has a different degree of effectiveness and reliability. For these reasons, it is not sufficient to look at the transmission capacity deficiency and replace that with an equal amount of non-transmission resources, such as energy efficiency or new generation. According to PSE projections, it would take 74 MW of additional transmission capacity to marginally meet the demand through 2018 (Gentile et al., 2015). However, to address the capacity deficiency in 2018 with non-transmission resources would take approximately 163 MW of additional conservation, storage, and new generation within the Eastside beyond the 50 MW of conservation planned in 2013 *Integrated Resource Plan* (Nedrud, personal communication, 2015; PSE, 2013) (Figure 2-13). To address the capacity deficiency in winter 2024 with non-transmission resources would take approximately 205 MW of additional conservation, storage, and new generation within the Eastside beyond the currently planned 119 MW of conservation (Figure 2-13). If growth continues as predicted, additional conservation or a system upgrade would be necessary to reliably serve the area beyond 2024.

Figure 2-13. Additional Non-Transmission Resources Needed to Meet Project Objectives in 2018 and 2024

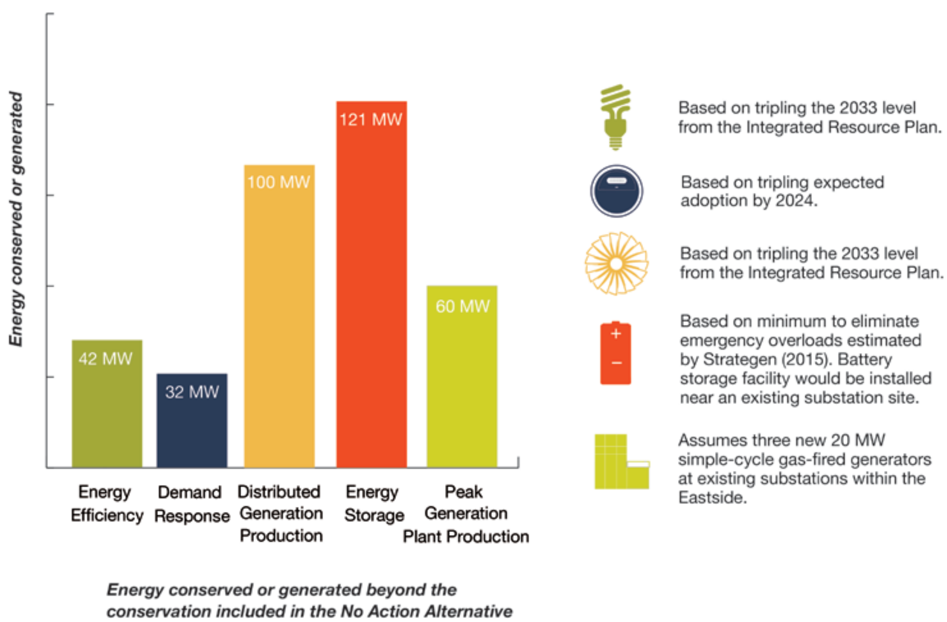


For comparison, PSE's current plan for the entire PSE service area (Figure 1-3) is to implement 852 MW of conservation by 2024. The Eastside represents approximately 14 percent of the total load for the PSE system, and therefore 14 percent of the total projected conservation (119 MW of conservation).

Alternative 2 would require close monitoring and management because it is based on the assumption that just enough conservation and new energy supply would be accomplished within the Eastside each year throughout the study period (2015 - 2024; electrical criterion #2) to avoid needing additional transmission capacity. This alternative could address the project need but results in uncertainty about how much infrastructure would be installed and how much additional supply would be needed each year. This alternative assumes that at the end of the 10-year study period, additional measures or facilities would be required to address future growth. The approach could be continued conservation efforts, but because of strict building codes already in place and the acceleration of retrofitting assumed under this alternative, the availability of additional capacity for conservation is uncertain. If conservation cannot address identified capacity needs, additional transmission or generation infrastructure could be required.

Alternative 2 assumes a mix of measures to accomplish conservation savings. In order to fully address the identified capacity need, Alternative 2 would include a combination of energy storage units, demand response devices, distributed generation, peak generation production, and energy efficiency improvements. These measures are described below. Figure 2-14 summarizes a theoretical mix of measures and anticipated energy conservation for each component. This figure is provided to illustrate the approximate magnitude of the effort required to meet the project need. The actual mix would depend on the success of each component adopted. Some, like energy storage, could be built by PSE, while others require voluntary participation by customers. The technical feasibility of each option within this approach would require further study to determine how much of each component is feasible, economical, and sufficiently reliable. For example, it could be more economical for PSE to install more peak generator plants than to incentivize customers to install as much distributed generation as is shown.

Figure 2-14. Example Mix of Energy Conservation, Storage, and Generation for Components of Alternative 2



2.3.3.1 Energy Efficiency Component

The energy efficiency measures under Alternative 2 would be the same as those described for the No Action Alternative, such as replacing older, inefficient appliances and lighting, and adding insulation and weatherproofing. Energy efficiency would reduce the total demand, thus lowering the peak load requirements. However, to meet the project objectives for Energize Eastside, these efforts would need to be substantially accelerated and expanded on the Eastside. The potential for additional energy efficiency on the Eastside is not currently known and would require additional evaluation. Stricter building energy code standards could accomplish part of the project objective but are not within the control of PSE. Therefore, building codes are not part of this alternative, but they could be considered by study area communities as a means to help ensure the success of this alternative.

Additional promotion and incentives would be necessary to encourage this higher level of conservation. For the Phase 1 Draft EIS analysis, it was assumed that the current energy efficiency incentive program could be accelerated and expanded for the Eastside (Figure 2-15). This analysis assumes PSE would need to accomplish approximately 42 MW of additional energy efficiency within the Eastside by 2024, over and above the approximately 45 MW of energy efficiency gains in the Eastside that PSE expects for that time period. It is recognized that this is an aggressive goal. PSE's *Integrated Resource Plan* (2013a) estimated PSE could achieve approximately 100 MW of additional energy efficiency during the period from 2024 to 2033 systemwide, which would equate to approximately 14 MW of energy efficiency gains on the Eastside during that time period. The additional energy efficiency assumed for Alternative 2 would be triple the amount that PSE estimated is achievable after 2024, and that additional energy efficiency would have to be accomplished before 2024.

Figure 2-15. Adding Insulation in an Existing Home (U.S. DOE, 2015a)

2.3.3.2 Demand Response Component

Demand response involves end-use electric customers reducing their electricity usage typically during peak load times, and sometimes involves shifting that usage to another time period. Typically this is done in response to a price consideration, a financial incentive, an environmental condition, or a reliability issue. Demand response requires special meters and control equipment that can be used to adjust electricity usage, usually adjusting automatically according to pre-agreed parameters (Figure 2-16). Some of the features of a demand response system could include the following:

Figure 2-16. Example Energy Monitoring System (Clauser, 2016)

- Meters that provide customers and PSE information about when and how much energy each customer is using, including on-line real-time information;
- Installation of in-home monitoring and control equipment that would allow PSE to control heating and cooling systems;
- Programmatic options to reduce peak demand during system emergencies, improve system reliability, and balance *variable-load resources*;
- Incentives for customers to curtail loads during specified events or pricing structures to induce customers to shift load away from peak periods; and
- Capability of sending a continuous wireless signal to the utility.

The *Integrated Resource Plan* (PSE, 2013) estimated that demand response systems would result in 116 MW systemwide reduction in capacity needed by 2024. Because the Eastside represents approximately 14 percent of the systemwide load, and assuming that adoption of demand response would be proportional on the Eastside to the rest of PSE service areas, it is assumed that approximately 14 percent of the systemwide reduction (16 MW of conservation by 2024) would occur on the Eastside under the No Action Alternative. In order to address the capacity deficiency projected for the Eastside, the program would need to be substantially accelerated and expanded within the Eastside in the next 10 years, at a rate that exceeds the rest of the system. For the Phase 1 Draft EIS, it is assumed that an additional 32 MW of demand reduction would need to be accomplished in the Eastside by 2024 (Figure 2-14). This would triple the expected rate of adoption of demand response in PSE's *Integrated Resource Plan* (2013a) to a total of 48 MW.

2.3.3.3 Distributed Generation Component

Distributed generation involves generating power on a customer's site. By producing power within the Eastside, distributed generation reduces the need for transmission of power through substations serving the Eastside. Distributed generation reduces costs and interdependencies associated with transmission and distribution and can shift control to the consumer.

2.3.3.3.1 Types of Facilities Included in EIS Analysis

In order to address the Eastside transmission deficiency with distributed generation alone, approximately 300 to 400 MW of capacity would be needed by 2024 depending on the geographic location of the generation (PSE, 2013; Strauch, personal communication, 2015a). While all distributed sources reduce the total amount of electricity that needs to be supplied through the transmission system, only a limited set of these resources, those that can be relied upon to produce power during periods of peak demand, would help to address the Eastside transmission capacity deficiency. For this analysis, distributed generation facilities were assumed to consist primarily of *gas turbines*, *anaerobic digesters*, *reciprocating engines*, *microturbines*, and fuel cells, with each system generating less than 10 MW. These types of facilities are discussed below, and are shown in Figures 2-17, 2-18, 2-19, 2-20, and 2-21).

New distributed generation resources would need to be capable of producing power when needed at peak times, such as during a winter cold snap or a summer warm spell, or they would need to be associated with an energy storage system that would allow use of the energy during peak periods. For an energy generating resource to be effective, it also has to be reliable, which means it must be well maintained and capable of producing a specified amount of energy when needed. To ensure adequate capacity even when some equipment is not working, a substantial degree of redundancy is needed in distributed generation resources. In addition, the distributed generation needs to be located at or near the load in order to be effective. This also contributes to the need for an overall higher capacity requirement. As with energy code requirements, cities could require these types of installations, but PSE must rely on voluntary installation.

Although these conditions suggest there could be difficulty implementing a robust distributed generation system sufficient to meet a substantial portion of the need, it is included in the Phase 1 Draft EIS because it is technically feasible and could address a portion of the need.

Figure 2-17. Gas Turbine (Simens, 2015)

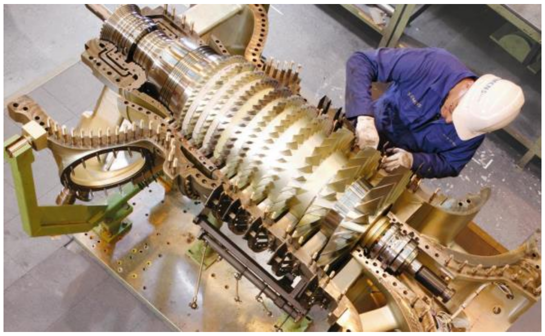


Figure 2-18. Anaerobic Digester (Biomass Energy Centre, 2015)

Figure 2-19. Reciprocating Engine (Madison Gas and Electric, 2015)

Figure 2-20. Microturbine (Capstone Turbine Corporation, 2015)

Figure 2-21. Fuel Cell (Soutter, 2012)

Gas Turbines. Gas turbines are machines that use hot gas to generate rotary mechanical power. They include a compressor, a combustion system, and a turbine. The compressor pulls air into the engine, pressurizes it, and moves it through to the combustion system. The combustion system injects fuel into the air to produce a hot, high-pressure gas. The high-pressure gas expands, moving through the turbine and causing the blades of the turbine to spin. This spinning action causes the connected generator to produce energy (Department of Energy, 2015).

Anaerobic Digesters. Anaerobic digesters use a collection of processes by which microorganisms break down biodegradable material (such as sewage, animal manure, and food waste) in the absence of oxygen, resulting in the production of biogas and digestate fuel. Biogas is a mixture of approximately 60 percent methane and 40 percent carbon dioxide that can be burned in a CHP unit to produce heat and electricity (Department for Environment, Food & Rural Affairs and Department of Energy & Climate Change, 2015).

Reciprocating Engines. Reciprocating engines are composed of an internal combustion engine and an electrical generator. The internal combustion engine burns fuel (diesel, propane, natural gas, or gasoline) to power the generator, which converts the power of the engine into electricity (Madison Gas and Electric, 2015).

Microturbines. Microturbines are small combustion turbines approximately the size of a refrigerator, with outputs of 25 kW to 500 kW. They are often composed of a compressor, combustor, turbine, alternator, recuperator (a device that captures waste heat to improve the efficiency of the compressor stage), and generator. They work much like a gas turbine, only on a smaller scale (Capehart, 2014).

Fuel Cells. Fuel cells are electrochemical devices that combine hydrogen and oxygen to produce electricity.

2.3.3.3.2 Generation Facilities Not Included in EIS Analysis

On-site energy generation can also include solar photovoltaic systems, wind turbines, and *small hydroelectric facilities*. These technologies were not included in Alternative 2 because they would contribute minimally to addressing the identified capacity deficiency.

Solar and wind power are typically less effective at addressing peak power needs because wind and sun may not be at their full potential during periods of peak demand.

A typical 6 kW rooftop solar photovoltaic system installed on a single-family residence generates 6,000 kWh per year. Currently, wind turbines on the Eastside are limited to two small-scale (approximately 1 MW) turbines, due to a lack of consistent wind.

Typically, winter peak system loading occurs in the morning and evening, when solar is less effective because of shorter daylight hours. Solar could help reduce summer peak loads but because additional capacity would continue to be needed for winter, the use of solar generation to address the transmission capacity deficiency would need to be matched by winter generation capacity and therefore would be redundant.

Because there are no identified locations on the Eastside where small hydroelectric facilities would be feasible, it was assumed that small-scale hydroelectric would not contribute to addressing capacity.

2.3.3.4 Energy Storage Component

The energy storage component considers the use of batteries installed within the Eastside that would charge during off-peak periods and discharge to the power supply system during peak demand times (Figure 2-22). Like distributed generation, energy storage would reduce the amount of electricity that must be delivered to the Eastside through the transmission system. While it is possible that home battery storage could occur in homes using technology that is currently being developed, this analysis considers a PSE-controlled facility capable of storing 121 MW, which would be adequate to eliminate emergency overloads (Strategen, 2015). This would require a site of approximately 6 acres and would need to be close to the center of the Eastside, ideally adjacent to an existing substation. Battery storage could be developed at one or more substations, but for this analysis, a total of 6 acres is assumed.

Figure 2-22. Battery Storage (Wood, 2014)

The feasibility of using energy storage combined with other previously identified alternatives was studied in March 2015 by Strategen Consulting, LLC. Results of this study can be found in the *Eastside System Energy Storage Alternatives Screening Study* (Strategen, 2015). Conclusions from that study stated the following:

- An energy storage system with power and energy storage ratings large enough to reduce normal overloads has not yet been installed anywhere in the world. For comparison, the largest operational transmission scale battery facility in the U.S. can provide 32 MW of power for about 40 minutes (Strategen, 2015). However, larger facilities are being developed in California and elsewhere.
- The Eastside system has significant constraints during off-peak periods that could prevent an energy storage system from maintaining sufficient charge to eliminate or sufficiently reduce normal overloads over multiple days.
- A system large enough to address the entire transmission capacity deficiency would need to deliver approximately 328 MW of electricity and store 2,338 (MWh) of power. A storage system of this size is not technically feasible because the existing Eastside transmission system does not have sufficient capacity to fully charge the system.
- Summer requirements were not evaluated because the limitations identified during the winter study indicated that energy storage would not be a feasible stand-alone alternative.

For these reasons, energy storage was considered a partial solution that would be implemented together with other demand-side reduction strategies.

2.3.3.1 Peak Generation Plant Component

Peak generation located within the Eastside would provide a source of electricity controlled by PSE that could be used to provide power at peak demand times to reduce the demands on the transmission system. This component would involve installing three 20 MW generators at existing substations within the Eastside. These could be any type of generator but the most likely type would be a *simple-cycle gas-fired generator* (Figure 2-23). These systems typically burn natural gas to turn a turbine that powers a generator, and are sometimes designed to also work with an alternate fuel that can be stored on-site. They can also be combined with heat recovery units to improve overall efficiency. These generators are referred to as peak generation plants.

Figure 2-23. Simple-Cycle Peak Generation Plant with 3 Gas-Fired Generators (Energy Capital Partners, 2015)

PSE evaluated using these types of generators alone to meet the project objective. PSE determined that 20 such generators (totaling 400 MW) would be needed because the farther the generator is located from the center of the Eastside, the less effective it becomes at addressing the identified capacity deficiency. Most of the substations on the Eastside are in residential areas, and these types of generators produce a high noise level that would be incompatible with those surroundings. For this reason PSE had eliminated this option from consideration. However, these are proven technologies that could possibly be sited in some locations and be compatible with adjacent uses, addressing a portion of the identified need. Therefore, Alternative 2 includes three 20 MW generators to be implemented in combination with the other components described for Alternative 2.

2.3.3.2 Construction

Construction of energy efficiency measures (such as weatherization and efficient lighting) would be limited and primarily focused on existing building upgrades.

Demand response is an end-user strategy that pertains more to customer usage patterns and requires little construction of new infrastructure. Construction would be limited to installation of meters and in-home monitoring systems and control equipment.

Distributed generation facilities (gas turbines, anaerobic digesters, reciprocating engines, microturbines, and fuel cells) would require minor construction activities primarily on residential and commercial sites. Some would be constructed at the same time as new buildings are being built, while others would be constructed independently. Facilities would range in size from small rooftop installations to larger facilities requiring up to 1 acre of space. Construction activities for larger facilities could require clearing and grading. Construction duration would vary depending on scale and technology.

The component of Alternative 2 that would require the most construction activity would be the energy storage component. Construction of battery storage facilities would last approximately 6 months and would require standard construction equipment similar to what is required for construction of a substation under Alternative 1. Construction for a battery storage facility would require clearing and grading adjacent to one or more existing substations. The battery storage facility or facilities would occupy approximately 6 acres in total.

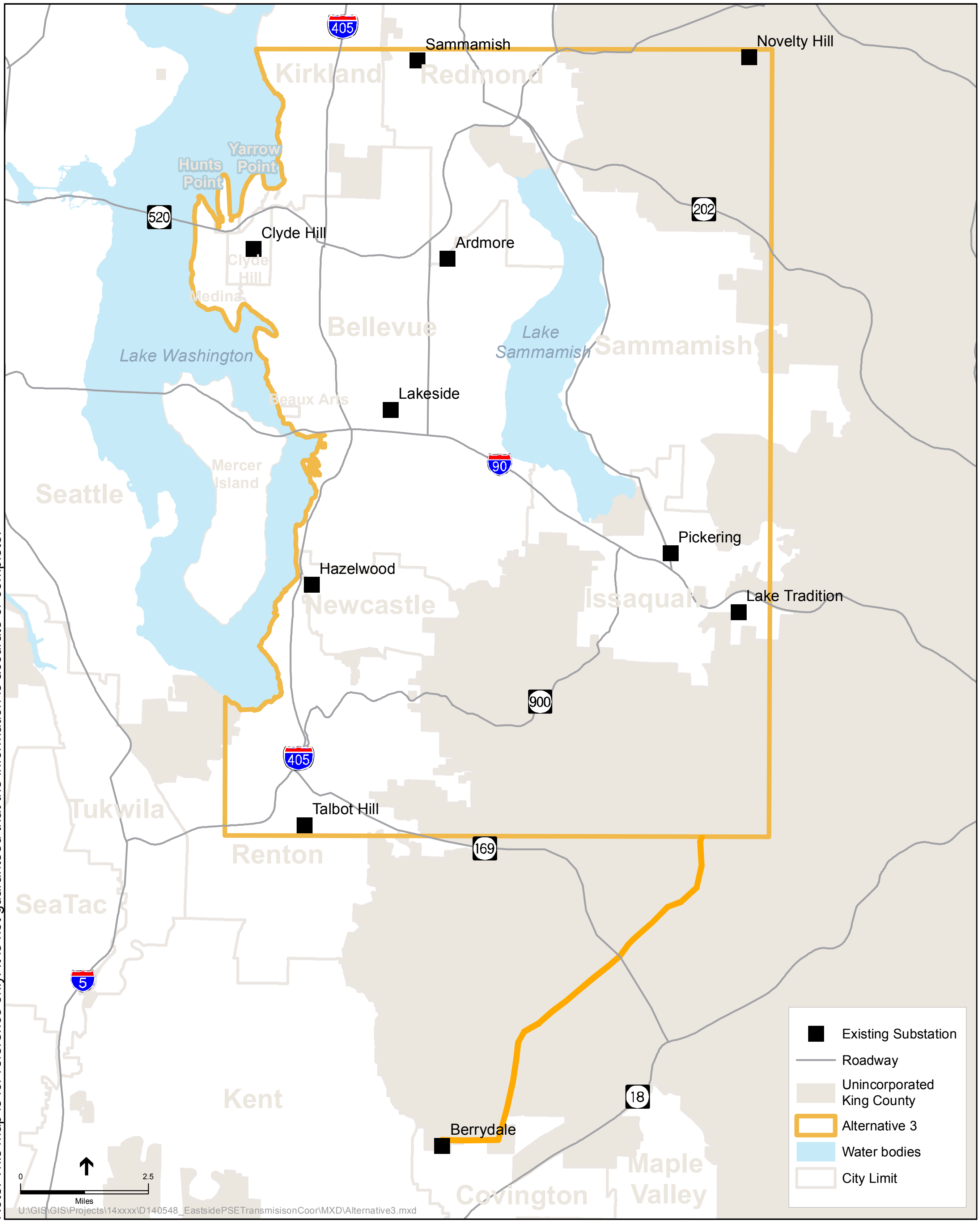
Construction of three gas-fired simple-cycle generators for the peak generation plant component would require construction similar to a substation, including trenching to access upgraded natural gas, water, and wastewater utility lines. Construction would occur within or adjacent to existing PSE substations. The construction duration would be approximately 12 months.

2.3.4 Alternative 3: New 115 kV Lines and Transformers

Under Alternative 3, new 115 kV transmission lines would be constructed in existing or new rights-of-way around a broad portion of the Eastside. Figure 2-24 shows the study area for Alternative 3. The Alternative 3 study area includes the same western boundary as Alternative 2 but extends eastward beyond Lake Sammamish and into the foothills of the Cascade Mountains. Portions of the cities of Sammamish and Issaquah are within the Alternative 3 study area.

The transmission lines would be similar to those described for Alternative 1, Option A, except that Alternative 3 would involve shorter poles, smaller foundations, and narrower rights-of-way. The corridor for the 115 kV transmission lines would be in existing corridors such as along roadways, requiring a clear zone 30 to 40 feet wide (refer to Table 2-3, in Section 2.3.5). Alternative 3 would involve construction of approximately 60 miles of new transmission line. Most of the corridor for Alternative 3 would be co-located or constructed adjacent to existing PSE transmission lines or other utility rights-of-way (roadways, rail corridors). New 115 kV transmission lines could be built along existing road rights-of-way that currently do not have overhead transmission lines. Figure 2-25 shows a conceptual routing of lines that PSE developed to estimate the extent of additional 115 kV transmission lines that would be need to meet the project objectives. In instances where there is not an adequate existing transmission corridor, construction would include vegetation clearing to ensure adequate clearance for the new overhead lines.

Operation of Alternative 3 would be similar to Alternative 1 and would involve limited but regular maintenance along the transmission lines. Substation operation would involve regular site inspection and maintenance. All proposed equipment is subject to wearing out and would need to be replaced when this occurs, typically after several years of use. Replacement of conductors would be similar to the final steps of installation. Replacement of substation equipment would be similar to the final stages of construction, involving heavy trucks delivering equipment and cranes to remove and replace equipment.



Note: This map is for reference only. It is not guaranteed that the information is accurate or complete.

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SOURCE: King County 2015; ESA 2015; Puget Sound Energy 2015; WA Ecology 2014.

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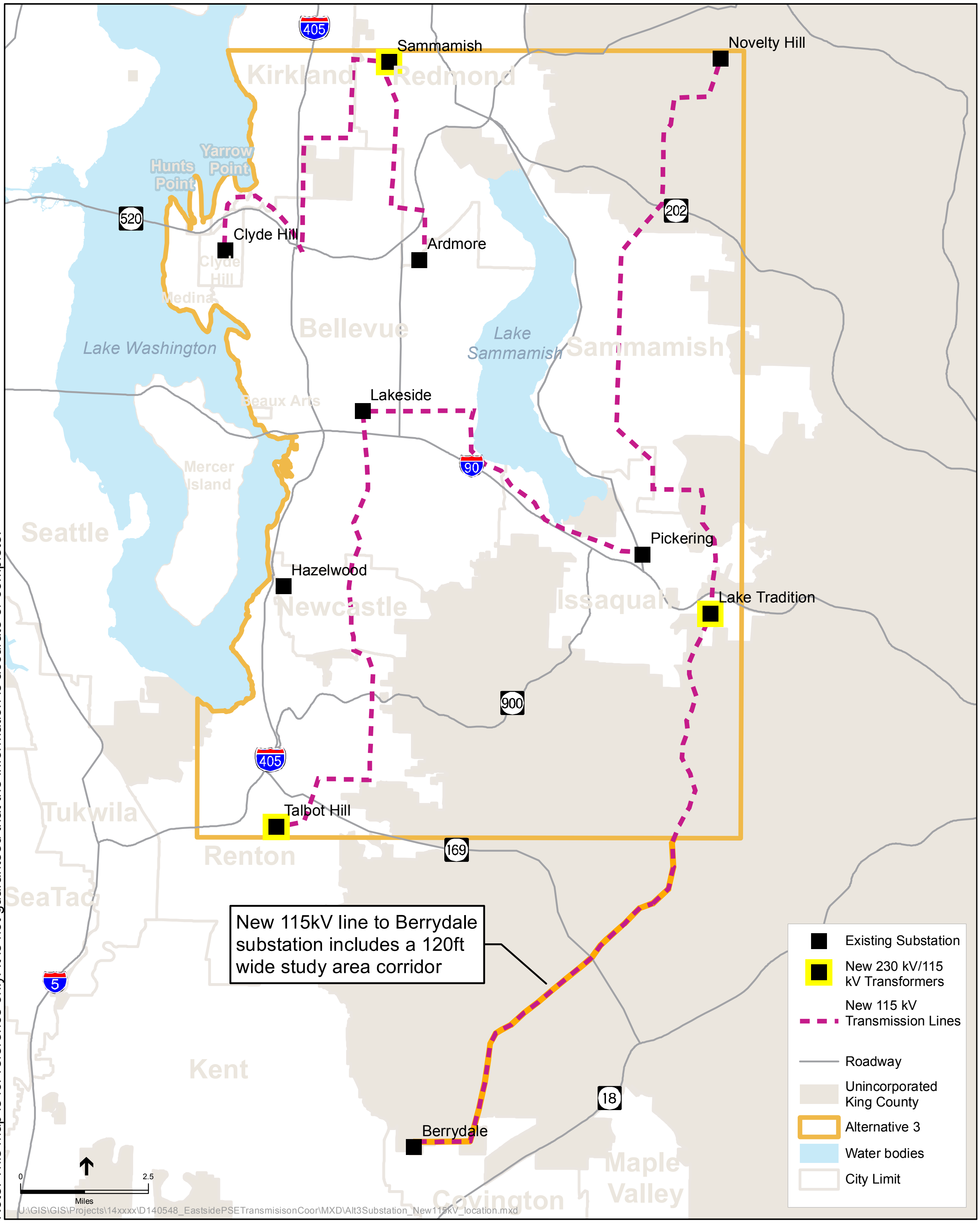
Figure 2-24

Alternative 3 Study Area

Note: This map is for reference only. It is not guaranteed that the information is accurate or complete.



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SOURCE: King County 2015; ESA 2015; WA Ecology 2014; Puget Sound Energy 2015.

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Figure 2-25

Alternative 3 - New 115 kV Lines and Transformers

Under Alternative 3, three new 230 kV to 115 kV transformers would be installed, one at each of the existing Lake Tradition, Talbot Hill, and Sammamish substations. In order to accommodate the additional transformers it is assumed, at a minimum, that the Talbot Hill substation would need to be expanded, and that additional security measures would be required at all three substations. At Sammamish and Talbot Hill, this would result in three 230 kV to 115 kV transformers being located in the same substation. PSE considers more than two transformers at a substation to be a high risk because damage to one substation with more than two transformers could take out a substantial portion of the capacity, so this alternative would not strictly meet PSE's current standards for substation design (electrical criterion #1). However, other utilities have developed and safely operated substations with three transformers, so this alternative has been included for the Phase 1 Draft EIS.

2.3.4.1 Construction

Substation. The construction methods for substation expansions and improvements would be the same as described in Alternative 1 (Section 2.3.2). Delivery of equipment would require special trucks and space for special equipment such as a crane. Table 2-2 provides a summary of the substation modifications that would be required to accommodate the new 115 kV lines. Some substations could accommodate the new lines, while five substations would require complete rebuilds and expansion for this alternative.

Table 2-2. Substation Modifications Required for Alternative 3

Substation	New 230/115 kV Transformer Required	New 115 kV Line Connections Required to:	Fits in Existing Substation Footprint	Notes
Sammamish	Install 3rd 230/115kV Transformer	Ardmore and Clyde Hill	No	Would need to expand the substation footprint by approximately 10 to 20%.
Lakeside 115 kV		Pickering and Talbot Hill	No	Requires substation yard expansion to fit additional buswork. Would not likely need to buy property, but would need to extend approximately 10 to 20% of the existing fence footprint.
Lake Tradition	Install 1st 230/115kV Transformer	Novelty Hill and Berrydale	Yes	Requires existing Bonneville Power Administration (BPA) 230 kV line to be extended to bring 230 kV to Lake Tradition substation.
Talbot Hill	Install 3rd 230/115kV Transformer	Lakeside and Hazelwood	No	Only enough space for one 115 kV line bay and three would be needed. Would need to expand the yard by approximately 5 to 10%.

Substation	New 230/115 kV Transformer Required	New 115 kV Line Connections Required to:	Fits in Existing Substation Footprint	Notes
Ardmore		Sammamish	Yes	Requires fourth line; should fit within the existing substation footprint.
Clyde Hill		Sammamish	No	Requires reconfiguring the substation. Preliminary rebuild designs have the substation increasing about 50 to 60% larger than existing yard.
Pickering		Lakeside 115 kV	Yes	
Berrydale		Lake Tradition	Yes	
Novelty Hill		Lake Tradition	Yes	
Hazelwood		Talbot Hill	No	Requires rebuilding the substation. A preliminary layout has the substation increasing about 200% larger than the existing yard. Additional property potentially needed.

Source: Strauch, personal communication, 2015a and 2015c

Transmission poles and lines. The exact number and locations of lines have not been determined. Figure 2-25 provides a conceptual layout of where new 115 kV lines would be required. A complete routing study would be done to evaluate the feasibility of any potential route. It is assumed that these lines would follow existing utility or road rights-of-way, and would either replace or be co-located with existing transmission and distribution lines wherever possible. This represents approximately 60 miles of new 115 kV lines. It is assumed these lines would be overhead lines. Additionally, an existing Bonneville Power Administration (BPA) 230 kV line would have to be extended to bring 230 kV to the Lake Tradition substation.

For a typical single circuit 115 kV system, without any distribution lines on the same poles, pole heights would generally vary from 60 feet to 75 feet depending on span length, structure configuration, and topography. However, in some instances taller poles may be required to span obstacles, meet right-of-way constraints, and address topographic variations. If co-location is required with existing 115 kV lines (a likely scenario, creating a double circuit), then pole heights would likely need to be up to 40 feet taller (approximately 100 feet total) in order to meet NESC requirements and right-of-way constraints.

Standard single circuit 115 kV lines are constructed on wood poles that are embedded directly in the ground and supported by guy wires as necessary. A hole is augured or created using a vacuum truck. The pole is placed, and the hole is backfilled with crushed rock. For locations that lack space or right-of-way for adequate guying, self-supporting poles may be utilized that are typically steel or laminated wood. *Insulators* are usually installed directly on the poles, followed by the conductor using the same general methodology as described earlier for the 230 kV system (Alternative 1).

Selection of appropriate pole material for 115 kV or 230 kV lines depends on height requirements, available space for guying, and location along the corridor. NESC requirements dictate the minimum separation between conductors. Turning and termination structures are typically under heavier structural loading and may require the use of down guys or self-supporting structures (i.e., glue-laminate or steel). The conductors for 115 kV would typically be smaller in diameter, but they would not be noticeably different in appearance from those used for 230 kV.

Length of Construction Period. Construction sequencing for overhead transmission lines would be similar to construction of Alternative 1, Option A, although some poles may be wood, which require less construction time than steel poles. Construction of transmission lines would last for 24 to 28 months. Along the transmission line, any given location would only see 3 to 5 days of construction activity spread over a period of 2 months. Three to four crews would each install an average of three poles per day.

Equipment. Construction equipment required for Alternative 3 would be similar to Alternative 1, Option A (see Appendix B).

2.3.4.2 Conservation

Under Alternative 3, PSE would continue the conservation efforts called out in its *Integrated Resource Plan* (PSE, 2013), as described in the No Action Alternative. Alternative 3 is expected to result in the same levels of conservation as the No Action Alternative.

2.3.5 Construction Summary Table

Table 2-3 shows a summary of construction details for each alternative, option, and component. See Appendix B for a list of construction equipment associated with all project alternatives.

Table 2-3. Construction Summary Table

Alternative/ Component	Construction Features	Construction Footprint	Construction Duration
No Action Alternative	Occasional conductor replacement, implementation of new technologies not requiring discretionary permits, and installation of distributed generation facilities under PSE's conservation program	N/A	N/A
Alternative 1 – New Substation (all options)	New substation yard with a new transformer and associated electrical equipment	• 3 to 4 acres	Up to 18 months
Alternative 1 – Option A: New Overhead Transmission Lines	New 230 kV transmission lines	• 18-mile corridor • 120- to 150-foot-wide clear zone • If located along existing easement, clear zone could be widened by 50 feet	• In any given location, 3 to 5 days within a period of up to 2 months • 12 to 18 months total
Alternative 1 – Option B: Existing SCL 230 kV Transmission Corridor	Complete rebuild of existing 230 kV transmission lines	• 15-mile corridor • Up to 2 miles for connector transmission corridors • No new clear zone along existing SCL corridor	Up to 24 months total
Alternative 1 – Option C: Underground Transmission Lines	Underground 230 kV transmission lines	• 30-foot-wide work area and permanent clear zone	• Approximately 2 months in any given location • 28 to 36 months total

Alternative/ Component	Construction Features	Construction Footprint	Construction Duration
Alternative 1 – Option D: Underwater Transmission Lines	Underwater 230 kV transmission lines	• Cable lines buried 3 to 5 feet below the lake bottom or directly on the lake bottom • Minimum of three landing points for vaults connecting to overland lines • Overland 230 kV transmission lines for approx. 8 miles to connect to substations	8 months
Alternative 2 – Energy Efficiency Component	Existing building upgrades	N/A	Limited
Alternative 2 – Demand Response Component	Installation of meters and in-home monitoring systems and control equipment	N/A	Limited
Alternative 2 – Distributed Generation Component	Minor construction activities primarily on residential and commercial sites	Facilities ranging from rooftop installations to up to 1 acre	Varying depending on scale and technology
Alternative 2 – Energy Storage Component	Installation of battery storage facilities	6 acres	6 months
Alternative 2 – Peak Generation Plant Component	Three gas-fired simple-cycle power generation facilities	• Construction would occur within or adjacent to existing PSE substations • Up to 1 acre each	12 months
Alternative 3 – New 115 kV Lines and Transformers	115 kV transmission lines	• 60 miles of corridor • 30- to 40-foot-wide clear zone	• In any given location, 3 to 5 days within a period of up to 2 months • 24 to 28 months total

2.4 ALTERNATIVES CONSIDERED BUT NOT INCLUDED

The following alternatives were identified through scoping but are not included for analysis in the Phase 1 Draft EIS for reasons explained below.

2.4.1 Use Existing BPA High-Power Transmission Line

Using the existing BPA line east of Lake Sammamish instead of installing a new 230 kV line in the Eastside is not being included in the Phase 1 Draft EIS because this source is outside the area that PSE has identified as being in need of more electrical power. To connect this source to the deficiency area would require new 115 kV line construction to marginally support the area. PSE considered several scenarios examining this potential solution. These included the following:

- Tapping the BPA Maple Valley – Sammamish 230 kV line and the SCL SnoKing – Maple Valley 230 kV line, and looping a new 230–115 kV Lakeside substation between the tapped lines.
- Using the 230 kV BPA Maple Valley – Sammamish Line to loop into Lake Tradition and installing a new 230–115 kV transformer at Lake Tradition to serve 115 kV load. The solution also included re-conductoring the SCL Maple Valley – SnoKing 230 kV with high-temperature conductors.
- Adding a 230–115 kV transformer at Lake Tradition and looping in BPA Maple Valley –Sammamish 230 kV line. Adding a third 230–115 kV transformer at Sammamish substation and assuming no new 115 kV lines are added to either substation.
- Adding a 230–115 kV transformer at Lake Tradition, looping in BPA Maple Valley – Sammamish 230 kV line, and adding a third 230–115 kV transformer at Talbot Hill substation. It was assumed that no new 115 kV lines were added to either substation.
- Adding a 230–115 kV transformer at Lake Tradition, looping in BPA Maple Valley – Sammamish 230 kV line, and adding a third 230–115 kV transformer at Sammamish substation. This assumed new 115 kV lines would be constructed to both substations.
- Adding a 230–115 kV transformer at Lake Tradition and looping in BPA Maple Valley –Sammamish 230 kV line, and adding a third 230–115 kV transformer at Talbot Hill substation. This assumed new 115 kV lines would be constructed to both substations.

All of these solutions were found to overload either transmission lines or transformers and therefore would not address all relevant PSE equipment violations (electrical criterion #13). See *Eastside Transmission Solutions Report*, October 2013 (updated February 2014), Tables 4.1 and 4.2, and Sections 4.6.3, 4.6.6, 4.6.8, 5.1.1, and 5.1.2 for more information (Gentile et al., 2014).

2.4.2 Upgrade/Adjust Existing Electrical System

Several changes and adjustments to the electrical transmission system were proposed as potential solutions. Several related to discontinuing the flow of electricity through the

Eastside to Canada during some peak demand periods. These were described in comments received during scoping regarding renegotiation of the Columbia River Treaty (which relates to river flows and electrical supply across the U.S. - Canada border), diverting power flowing from the south toward Canada to other transmission lines, or simply cutting off power flow to Canada altogether. Disconnecting the system from the region or not providing power to the rest of the region during peak periods is not included as an alternative because it was not considered viable for the following reasons:

- PSE has statutory and regulatory obligations that require being interconnected to the electric grid and that cannot be violated without penalties. Those obligations are with the FERC, NERC, WECC, ColumbiaGrid, and UTC (electrical criterion #1).
- This solution would also compromise PSE's ability to supply power and maintain reliability in an efficient and cost-effective manner; the generation that is owned and contracted for by PSE is generally outside PSE's service area and requires transmission lines to transport that power to PSE's service area. The diversity of the generation mixture provides security in the event that one kind of generation becomes limited (e.g., hydroelectricity in a year with low snowmelt or rainfall). Being part of the regional grid allows the dispatch of the least costly generating units within the interconnected area, providing an overall cost savings to PSE customers. Planned outages of generating and transmission facilities for maintenance can be better coordinated so that overall cost and reliability for the interconnected network is more efficient. Being interconnected also allows economies of scale for both transmission and generation facilities. Finally, this solution could reduce the supply of power to the Eastside, necessitating additional conservation, generation, or storage beyond that considered in the other alternatives in the EIS (electrical criteria #1 and 7).
- Disconnecting the north and south sections of the route at a central Bellevue substation to prevent non-Eastside load from being carried on this line during peak periods of demand on the Eastside would deprive the Eastside of power supply needed during these periods. Separating the system in central Bellevue from the regional grid would also not meet FERC mandatory reliability standards. This could be a CAP, which is temporary in nature and not a long-term solution, and does not bring a new source or new generation into the deficiency area (electrical criteria #1 and 7).
- Relying on BPA projects would not deliver the appropriate amount of power to the Eastside area because the BPA sources are outside the deficiency area and would address only wider regional problems, leaving a deficiency on the Eastside (electrical criterion # 7).
- Renegotiating the Columbia River Treaty is outside the purview of PSE and the Eastside Cities and would not help solve the problem as described previously (electrical criterion #1).

Other suggested solutions made during scoping include converting an existing alternating current (AC) line to a direct current (DC) power line, using "self-healing" lines, and changing conductor types and sizes.

Although switching to DC could potentially address the problem by marginally increasing the capacity of the lines, it would add complexity to the system that would reduce operational flexibility, which could have adverse impacts to the reliability and the operating characteristics of PSE's system. For example, if there was a problem within the DC portion of the system, it would not be possible to switch among other sources, as it is when the entire system is on AC. This alternative has not been included because avoiding such adverse impacts to reliability is one of PSE's stated electrical criteria (electrical criterion #1).

Suggested upgrades to the system (such as self-healing lines, up-conductoring, and installing transformers and inductors) would not improve reliability but would shift electrical load onto other components of the system, causing new deficiencies without addressing the transmission problem. Self-healing lines are automated switching systems that are triggered by adverse events in the system. They do not add capacity to the system, just speed in recovery from an adverse event. Inductors perform similarly, shifting load but not adding capacity. PSE examined up-conductoring in its solutions report and found that increasing capacity of 115 kV conductors led to transformers being overloaded (Gentile et al., 2014). Conversely, adding transformer capacity led to overloading lines. These solutions either do not meet the project objectives, or they offer a short-term solution that would not meet PSE's performance criteria for serving 10 years or more after construction (electrical criterion #1).

2.4.3 Larger Generation Facilities

Adding a large generation facility is not included as an alternative. To be effective, PSE found that the facilities would have to be located near the center of the Eastside area, such as near the Lakeside substation. This alternative is not included because the Cities determined that it does not meet SEPA requirements to provide a reasonable alternative that could feasibly attain or approximate a proposal's objectives at a lower environmental cost or decreased level of environmental degradation (WAC 197-11-440(5)(b)). Such a facility would likely have to be gas-fired to be capable of producing power reliably whenever it is needed.

PSE determined that at least 300 MW of power generating capacity would be needed and the most cost-effective way to generate that amount of power would be in a single plant. The 2013 Solutions Report (Gentile et al., 2014) found that small distributed generation and energy storage would have little impact on the problem unless a large number were developed, as described in Alternative 2, Integrated Resource Approach. Generation facilities at the 300 MW size would require gas and/or water infrastructure that is presently unavailable. These types of facilities also generate "atmospheric emissions and noise [that] would be extremely challenging" to permit in a feasible location that would not also require a significant new transmission line (Gentile et al., 2014).

Even if it were economically feasible to create multiple generation facilities of less than 300 MW, such as a series of plants generating 10 MW or more, they would need to be clustered close to the center of the Eastside to be effective, and would likely impose noise, air, and utilities impacts similar to or even greater than a single plant. Therefore multiple generation facilities of greater than 10 MW were not included for the same reason a single large generation plant was not included.

Smaller backup generators within the Eastside could potentially solve the peak demand; however, PSE did not find that there are currently enough generator owners willing to connect to the network to meet the project objectives (Gentile et al., 2014). PSE cannot compel owners of generators to connect to a network. In addition, increased usage of diesel generators would not meet present clean air regulations, and such facilities often have considerable noise impacts. This is not included as a stand-alone alternative because it does not meet PSE's performance criteria of serving 10 years or more after construction (electrical criteria #5, 6, and 15 and non-electrical criterion #3). However, providing a portion of the projected load by this method is examined as part of the distributed generation component of Alternative 2.

Generating more power outside of the Eastside area during peak periods, such as at PSE's existing peak generator plants, would not address the project objectives, because that would still require transmission to deliver power to the load area without risking damage to transmission equipment. This alternative is not included because it would not address the deficiency in the Eastside (electrical criteria #5, 6 and 14). Peak generator plants providing a portion of the projected load within the Eastside are considered under Alternative 2.

2.4.4 Submerged 230 kV Transmission Line in Lake Sammamish

The option of using a submerged line in Lake Washington is included in the Phase 1 Draft EIS. Scoping comments also suggested using Lake Sammamish for a submerged line. However, there are a number of technical issues that constrain the feasibility of a Lake Sammamish submerged line. These include the following:

- Submerged cables are typically delivered to a site by ship or barge. Large barges cannot access Lake Sammamish due to the weir at the outlet.
- Weight limits on highways would limit the length of cable reels to 1,100 feet, which would mean approximately 34 splices to reach the length of the lake.
- Highway transport may also be limited due to the 14-foot reel diameter.
- Underwater splices increase the risk of cable failure, while splices on land require construction of a vault at each splice. (Strauch, personal communication, 2015b)

Given these constraints, placing a cable in Lake Sammamish was deemed to not be a viable option.

2.4.5 Other Approaches

An alternative addressing a phased approach is not included because it would not address the quickly approaching transmission capacity deficiency during peak periods identified in the Eastside (electrical criterion #10).

Combining alternatives that provide partial solutions was suggested during scoping. Combinations of various solutions were considered. Alternative 2 includes suggested components that would directly address the transmission capacity deficiency in the Eastside that has been identified by PSE. Combinations with other components that would either increase the problem or have little or no effect, such as those listed above, were not carried forward.

Solving the Eastside deficiency requires a reliable alternative composed of one or more of the following:

- A new high-voltage energy source from the outside brought into the deficiency area;
- A new generation source or energy storage of sufficient size and duration installed within the deficiency area; and/or
- Reduction in electrical load during peak demand periods.

Alternatives that would violate PSE's Planning Standards and Guidelines (such as changing a transmission line from AC to DC) or that could harm other utilities in the region (such as disconnecting the Eastside from the regional grid during peak periods) would not become compliant by combining them with other alternatives (electrical criterion #1). Alternatives that would reduce the availability of power to the Eastside (such as limiting the flow of power from sources outside of the Eastside) would require even greater measures to compensate for the reduced power supply to the Eastside (such as new generation or storage, more conservation, or new transmission capacity) and as such would likely have greater impacts than the alternatives that are evaluated in the EIS (electrical criteria #1, 5, 6, and 14). Among the alternatives suggested, this leaves only the alternatives that will be studied and a few alternatives that provide temporary solutions, such as increasing the capacity of wires and transformers, or temporary rerouting of power during peak periods. Combining temporary solutions with the alternatives included in the EIS does not materially change the range of alternatives for the EIS, although such measures could reduce the severity or risk of impacts under the No Action Alternative.

Reducing the scope to include only Bellevue would require a generation facility within the Bellevue city limits, which is not included for the same reasons as indicated earlier under Larger Generation Facilities, or a solution similar to the Integrated Resource Approach (Alternative 2). Therefore, narrowing the scope to include only Bellevue will not be considered as a separate alternative.

2.5 BENEFITS AND DISADVANTAGES OF DELAYING THE PROPOSAL

Delaying the project would have the benefit of avoiding the impacts in the near future for the action alternatives described in the EIS. It is possible that by delaying the project, some of the expanded conservation measures described in Alternative 2 would be incorporated into development, reducing energy demand further than PSE has projected. Additional conservation could have the benefit of reducing greenhouse gas generation from electrical consumption on the Eastside. Delaying the project could allow technological advancements to occur in areas such as battery storage or generation, providing additional feasible alternatives to increased transmission capacity in the near term.

The disadvantages of delaying the project are that the risks of power outages (described in Chapter 1) that would be associated with the No Action Alternative could develop over time. It is also possible that the awareness of such risks would discourage development within the Eastside.