# Description of Proposal

energizeEASTSIDE

# Puget Sound Energy – Energize Eastside Conditional Use Permit Description of Proposal – North Bellevue Segment

Puget Sound Energy, Inc. (PSE) proposes the construction of a new substation in South Bellevue (the "Richards Creek substation") and the upgrade of approximately16 miles of two existing transmission lines operating at 115 kilovolt (kV) to 230 kV (herein referred to as 230 kV lines) and continued aggressive conservation (collectively the "Energize Eastside Project" or the "Project"). The new substation, upgraded lines, and aggressive conservation are needed to address electrical system reliability deficiencies identified during federally-required planning studies. This Project significantly improves reliability for Eastside communities, including the City of Bellevue (City), and will supply the additional electrical capacity needed for current and anticipated growth.

The existing system is not robust enough to maintain reliable service if the entire existing PSE Eastside electric system facility is taken out of service at one time. Therefore, the Energize Eastside Project will be constructed in two phases. This will allow PSE to keep the existing 115 kV facilities partially in-service during construction, which will allow PSE to maintain reliable service to all customers during construction. The Land Use Permits for the first phase (the "South Bellevue Segment") including a new substation and upgrading approximately 3.3 miles of existing lines) were issued by the City of Bellevue in 2019 (Permit Nos. 17-120556-LB and 17-120557-LO) and upheld by the City Hearing Examiner and King County Superior Court on appeal.

The second phase (the "North Bellevue Segment") is the focus of this application and includes upgrading approximately 5.2 miles of existing 115 kV lines with 230 kV lines between the Redmond/Bellevue city boundary and existing Lakeside substation. This upgrade includes replacing existing wooden H-frame poles (which have 2-3 poles each) with steel monopoles. After deliberate review and extensive stakeholder input, PSE proposes to undertake this work in the existing transmission line corridor rather than siting the project in Bellevue neighborhoods that currently lack a transmission line corridor. Within the existing utility corridor, the proposed pole locations for the rebuilt lines will generally be in the same locations as the existing poles. Use of the existing corridor (which has housed transmission lines since the 1920s and 30s) minimizes potential impacts to the environment (e.g., vegetation management, aesthetic impacts) and to adjacent uses to the fullest extent feasible.

Per Bellevue Land Use Code (LUC) 20.20.255(C), new or expanding electrical utility facilities require Conditional Use Permit Approval under Part 20.30B LUC and Part 20.20.255.E LUC. Note that a separate Critical Areas Land Use Permit has been submitted for the project under Part 20.25H LUC. The following section demonstrates PSE's compliance with the City of Bellevue's Conditional Use Decision Criteria (LUC 20.30B.140):

A. *The conditional use is consistent with the Comprehensive Plan; and*

**Response:** The proposed transmission line replacement is consistent with the City's Comprehensive Plan. As stated in the introduction to the Land Use Element of the Comprehensive Plan:

> *One of the fundamental roles of the Comprehensive Plan is to anticipate, guide, and plan for a growth in a way that helps the city achieve its vision. The plan is a tool to look ahead to the likely growth and ensure that the city's plans for land uses, infrastructure, and services are aligned.*

PSE has a statutory duty to provide safe and reliable power at a reasonable cost (see RCW 80.28.010(2)). The Energize Eastside Project is a key electrical infrastructure project needed to bring a 230 kV power source to the Eastside region, including the City of Bellevue - the region's largest city and job center. As required by the state Growth Management Act (GMA), one of the elements that must be addressed in the City's Comprehensive Plan is Utilities.

As stated in the Utilities Element, the City must plan for adequate provision of utilities consistent with the goals and objectives of the Comprehensive Plan, *taking into consideration the public service obligation of the utility involved*.

The expansion of the PSE Sammamish to Talbot Hill transmission corridor (which includes the North Bellevue segment) is shown on Map UT-7 of the Comprehensive Plan. PSE's North Bellevue segment proposal is accordingly consistent with the routing identified in the Comprehensive Plan.

As previously determined by the City, The UT Element in the Comprehensive Plan is directly applicable to PSE's proposal. The goals outlined in the Utilities Element are:

- *To develop and maintain all utilities at the appropriate levels of service to accommodate the city's projected growth.*
- *To ensure reliable utility service is provided in a way that balances public concerns about infrastructure safety and health impacts, consumer interest in paying a fair and reasonable price for service, potential impacts on the natural environment, and aesthetic compatibility with surrounding land uses.*
- *Utility facilities are permitted and approved by the city in a fair and timely manner and in accord with development regulations, to encourage predictability.*
- *New technology to improve utility services and reliability is balanced with health and safety, economic, aesthetics, and environmental factors.*

As explained in detail below, the Energize Eastside project fulfills both these goals and the Utilities Element's more specific Comprehensive Plan policies:

| General Utility System | |
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| **UT-3:** Use design and construction standards that are environmentally sensitive, safe, cost-effective, and appropriate.<br><br>**UT-8:** Design, construct, and maintain facilities to minimize their impact on surrounding neighborhoods. | **Response:** The proposed transmission line replacement will have temporary construction impacts on property owners where the utility corridor easements cross their property.<br><br>Construction impacts will be minimized to the greatest extent feasible through use of existing or historic access routes that were used for initial pole installation and/or maintenance activities. As required by state law, utility locates will be performed prior to ground disturbing activities to avoid any potential conflicts. Appropriate temporary erosion control measures will be used during work activities. A safe work area will be established around each pole removal and installation location, providing space for placing equipment, vehicles, and materials. PSE will also comply with all City codes relating to hours of construction and noise.<br><br>PSE will work with individual property owners to restore areas impacted during construction to its previous or an improved state. PSE will mitigate in-kind as required by applicable regulations when restoration is not possible. All applicable codes and standards will be followed during design and construction, including electrical, stormwater and erosion control, tree protection, and noise.<br><br>PSE's proposed use of the existing utility corridor minimizes impacts on surrounding neighborhoods by preventing impacts in new areas. The properties adjacent to the proposed project are already occupied by transmission lines and, to some extent, the adjacent vegetation is already maintained for this use. By locating replacement poles in proximity to existing pole locations, PSE's proposed line minimizes impacts, including vegetation and aesthetic impacts, to surrounding neighborhoods.<br><br>In addition, the use of steel monopoles instead of other designs regularly used to support high voltage transmission lines (including the "milk maid" designed used in the Seattle City Light corridor), reduces |

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| | potential aesthetic and ground disturbing impacts. |
| **Utility Coordination** | |
| **UT-18:** Coordinate with other jurisdictions and governmental entities in the planning and implementation of multi-jurisdictional utility facility additions and improvements. | **Response:** The proposed transmission line upgrade is a linear utility project that crosses through multiple jurisdictions (including the cities of Redmond, Bellevue, Renton and Newcastle; collectively "Partner Cities"). The north segment of this project will traverse Redmond and Bellevue while the south segment will traverse the cities of Bellevue, Renton and Newcastle. PSE has engaged in regular and significant outreach and to inform both Redmond and Bellevue about the proposed project, which continues today as an extension of the process reflected in the Phase 1 and Phase 2 Draft Environmental Impact Statements (DEIS), which were developed co-operatively by the Partner Cities. This conclusion is also support by the City's previous determination in evaluating the South Bellevue Segment that "Several UT policies call for planning and coordination to ensure reliable, sustainable, and quality service for the whole community. PSE has coordinated its system planning with the City and other agencies and is now proposing a project consistent with this system planning work and these policies." |
| **General Non City-Managed Utilities** | |
| **UT-45:** Coordinate with non-city utility providers to ensure planning for system growth consistent with the city's Comprehensive Plan and growth forecasts. | PSE is a non-city utility provider. The purpose of the Energize Eastside project is to bring a new 230 kV power source to the Eastside region to meet capacity and reliability needs as determined through PSE planning studies. The 230 kV power brought into Richards Creek substation will supply existing and future 230 kV transmission lines providing power to the entire Eastside region. The project will increase reliability as well as meet forecasted increases in electricity demands.<br><br>PSE also regularly coordinates with other non-city utilities, including monthly meeting |

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| | with the Olympic Pipeline company to discuss and coordinate on the Energize Eastside project. This ongoing coordination aids in PSE ensuring that its construction and operational planning is integrated with other co-located facilities. |
| **UT-47:** Defer to the serving utility the implementation sequence of utility plan components. | PSE is the electrical serving utility for Bellevue and has, due to operational and reliability concerns, proposed to permit the Energize Eastside project in two phases. The Bellevue utility plan focuses on developing and maintaining utilities at the appropriate levels of service in order to accommodate growth. The project falls under the electrical, non-city managed utilities, plan components. The Energize Eastside project will be permitted and constructed in two phases. This will allow PSE to keep the existing 115 kV facilities partially in service during construction, which will allow PSE to maintain reliable service to all customers during construction. |
| **UT-48:** Coordinate with the appropriate jurisdictions and governmental entities in the planning and implementation of multi-jurisdictional utility facility additions and improvements. | See response to UT-18. |
| **UT-49:** Require effective and timely coordination of all public and private utility activities including trenching and culvert replacements. | The new transmission lines would be constructed within PSE's existing 115 kV transmission line corridor. Anticipated construction coordination would need to occur with Olympic Pipe Line Company and Seattle City Light. No culvert replacements are proposed as part of the North Bellevue Segment. |
| **UT-64:** Require the reasonable screening and/or architecturally compatible integration of all new utility and telecommunications facilities. | **Response:** Transmission lines are exempt from screening requirements.<br>Transmission poles do not naturally blend in with the surrounding environment. PSE is proposing to offset the aesthetic impacts through: pole design and finish selection based on neighborhood context; replacing poles as close to existing pole locations as possible; consolidating two lines on one pole where feasible; reducing the overall |

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| | number of poles; and designing poles to the minimum height necessary based on topography, site context, and electrical design standards.<br><br>Pole finishes selected for North Bellevue include dull galvanized steel and naturally self-weathering (Corten).<br><br>Galvanized steel is a common choice for transmission poles because of its durability and low maintenance characteristics. The pole is coated with a layer of zinc that prevents the steel from rusting. Initially, the steel can have a shiny finish, but as the zinc weathers it becomes dull in appearance.<br><br>Galvanizing provides decades of protection for steel from corrosion. It is gray in color and is better suited for areas with minimal backdrop as to better blend in with the skyscape.<br><br>Corten is long-lasting and low maintenance. When the steel is exposed to moisture and air, a rust patina forms. As the structure rusts it becomes brown in appearance, and over time the patina darkens in color. Once the patina forms on weathering steel, a natural protective layer prevents corrosion. The use of Corten steel poles is very suitable, and often preferred, within forested areas because of their rust brown finish.<br><br>Please see the Pole Finishes Report submitted with the Conditional Use Permit (CUP) application for this project. |
| **UT-68:** Encourage the use of utility corridors as non-motorized trails. The city and utility company should coordinate the acquisition, use, and enhancement of utility corridors for pedestrian, bicycle, and equestrian trails and for wildlife corridors and habitat. | **Response:** The proposed transmission line upgrade is located within an existing corridor that was established in the late 1920s and early 1930s and is mostly composed of easements on private property. Residential and commercial development has occurred around the easement areas, limiting public access. Additionally, much of the corridor is either located within private backyards and is fenced off, preventing connectivity between properties, or is undeveloped with no public access. The Greenway Trail System crosses |

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| | beneath the utility corridor at the Lake Hills Connector. |
| **UT-69:** Avoid, when reasonably possible, locating overhead lines in greenbelt and open spaces as identified in the Parks and Open Space System Plan. | **Response:** The existing corridor runs parallel to the Kelsey Creek Park and crosses Viewpoint Park, the Highland-Glendale Property, Skyridge Park, and the proposed Richards Valley Greenway, which are identified in the Parks and Open Space System Plan. PSE's transmission corridor was established prior to the establishment of the City and prior to the designation of property for public park use. By locating the upgraded transmission facilities in the existing corridor, PSE is avoiding any new impacts to parks and open space. |
| **UT-72:** Encourage cooperation with other jurisdictions in the planning and implementation of multi-jurisdictional utility facility additions and improvements.<br><br>Decisions made regarding utility facilities shall be made in a manner consistent with, and complementary to, regional demand and resources, and shall reinforce an interconnected regional distribution network. | **Response:** See response to UT-18 above.<br><br>The purpose of the Energize Eastside project is to bring a new 230 kV power source to the Eastside region to meet capacity and reliability needs as determined through PSE planning studies. All of the Partner Cities, including those directly impacted by construction of the north segment, will experience increased reliability and the transmission system will be better able to meet forecasted increases in electricity demands. |
| **UT-75:** Prior to seeking city approval for facilities, encourage utility service providers to solicit community input on siting of proposed facilities which may have a significant adverse impact on the surrounding community. | **Response:** The PSE Energize Eastside team has engaged in public outreach since the project launched in December 2013. In 2014, PSE led a public route discussion process, shared information about the project with the public, and solicited and obtained considerable public input. PSE continues to inform the public about the project and connect with property owners regarding fieldwork efforts through mailers, emails, PSE's website, public testimony to decision-makers, and public meetings.<br><br>Throughout 2014, PSE worked with a Community Advisory Group (CAG) to identify and consider the values held by the community in evaluating different transmission line route options and potential substation locations. CAG members represented various interests, including potentially affected neighborhood |

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| | organizations, cities, schools, social service organizations, major commercial users, and economic development groups. The CAG looked at factors used to develop different route options, narrowed the route options based on values and constraints, and prepared route option recommendations for PSE's consideration. Throughout the CAG process, PSE held public open houses to inform the public of the CAG's work and hosted additional community meetings and events to share information, respond to questions, and learn more about community values and interests.<br><br>PSE has also provided numerous presentations and briefings to individual property owners, neighborhood groups, organizations, and other interested stakeholders. PSE regularly informs the public about the project and its development process through mailings, email updates, and a project website. To date, public outreach and involvement has included:<br><br>• 22 CAG-related meetings, including 6 public open houses, 2 question and answer sessions, and 2 online open houses at key project milestones<br>• 650+ briefings with individuals, neighborhoods, cities and other stakeholder groups<br>• More than 3,000 comments and questions received<br>• 40+ email updates to more than 1,500 subscribers<br>• 10 project newsletters to 55,000+ households<br>• Ongoing outreach to 500+ property owners, including door-to-door and individual meetings<br>• Participation in 16 EIS-related public meetings |

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| **UT-77:** Require all utility equipment support facilities to be aesthetically compatible with the area in which they are placed by using landscape screening and/or architecturally compatible details and integration. | The use of the existing utility corridor is the most effective method of ensuring area compatibility, as the proposed route replaces existing equipment rather than creating new corridors. In addition, the replacement of H-frame poles with fewer steel poles helps to reduce visual interference and can be considered an improvement from existing conditions. Pole finishes can also enhance integration with various settings. Please see the Pole Finishes Report submitted with the CUP application for this project.<br><br>PSE is also working closely with the City to identify City preferences on variables that may further increase compatibility with surrounding areas (e.g., pole color and pole height). |
| **Non City-Managed Utilities – Additional Electrical Facilities Policies** | |
| **UT-91:** Encourage the public to conserve electrical energy through public education. | PSE has led all northwest utilities in energy conservation since 1979. Its energy-efficiency programs have helped PSE customers conserve nearly 5 billion kilowatt-hours of electricity. PSE continues to develop and undertake aggressive conservation programs.<br><br>More information can be found in PSE's *Energy Efficiency 2018 Annual Report of Energy Conservation Accomplishments* at: https://www.pse.com/-/media/Project/PSE/Portal/Rate-documents/EES/ees_2018_annual_rpt_energy_conservation_accomplishments.pdf |
| **UT-94:** Require in the planning, siting, and construction of all electrical facilities, systems, lines, and substations that the electrical utility strike a balance between potential health effects and the cost and impacts of mitigating those effects by taking reasonable cost-effective steps. | **Response:** PSE has conducted studies on potential health effects of the proposed transmission line upgrade, which have been peer reviewed by City of Bellevue consultants through the State Environmental Policy Act (SEPA) review and drafting of an EIS for this project. In particular, the EIS looked at electric and magnetic fields (EMF) and pipeline safety.<br><br>As outlined in the *Final EIS (FEIS),* no unavoidable significant adverse impacts were identified that could result from the |

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| | Energize Eastside project related to health effects. |
| **UT-95:** Work with Puget Sound Energy to implement the electrical service system serving Bellevue in such a manner that new and expanded transmission and substation facilities are compatible and consistent with the local context and the land use pattern established in the Comprehensive Plan.<br><br>*Discussion: Where feasible, electrical facilities should be sited within the area requiring additional service. Electrical facilities primarily serving commercial and mixed use areas should be located in commercial and mixed use areas, and not in areas that are primarily residential. Further, the siting and design of these facilities should incorporate measures to mitigate the visual impact on nearby residential areas. These considerations should be balanced with the community's need to have an adequate and reliable power supply.* | **Response:** The City of Bellevue is made up of a mix of land uses that have developed around the utility corridor that was established in the late 1920s and early 1930s. The corridor is identified in the Utilities Element of the Comprehensive Plan on both Map UT-6 (Existing Electrical Facilities) and Map UT-7 (New or Expanded Electrical Facilities). An Alternative Siting Analysis (submitted with this CUP application) has been completed as required by the City of Bellevue LUC and Comprehensive Plan for transmission corridors identified as sensitive sites. Additionally, the upgrading of the transmission lines to 230 kV is included in the City's Comprehensive Plan.<br><br>The proposed transmission lines will be sited in the existing utility corridor and traverse a variety of land uses including commercial, institutional, single family residential, recreation, and parks/open space. The corridor predates the incorporation of the City and the existing land use patterns already integrate the utility facilities, keeping the proposed project compatible and consistent with local context and land use patterns.<br><br>This conclusion is confirmed by the FEIS, which found that impacts to land use will "be less-than-significant because [the proposed project] is consistent with City and subarea plans, and would not adversely affect existing or future land use patterns." FEIS at 14.1-9 – 10. |

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| **UT-96:** Require siting analysis through the development review process for new facilities, and expanded facilities at sensitive sites, including a consideration of alternative sites and collocation.<br><br>*Discussion: Sensitive facility sites are those new facilities and existing facilities proposed to be expanded where located in or in close proximity to residentially – zoned districts such that there is potential for visual impacts absent appropriate siting and mitigation. The city will update Map UT-7 to the extent needed to stay current with changes in Puget Sound Energy's system planning.* | **Response:** PSE has prepared a siting analysis as required for expanded facilities at sensitive sites. Please see the *Energize Eastside Alternative Siting Analysis* submitted with the CUP application for this project. |
| **UT-97:** Avoid, minimize, and mitigate the impacts of new or expanded electrical facilities through the use of land use regulation and performance standards that address siting considerations, architectural design, site screening, landscaping, maintenance, avoidable technologies, aesthetics, and other appropriate measures. | **Response:** The City of Bellevue and partner jurisdictions of Redmond, Renton, Kirkland, and Newcastle completed an FEIS that addresses anticipated impacts from the proposed Energize Eastside Project.<br><br>Avoidance, minimization, and potential mitigation measures are discussed in detail in the *Phase 2 Draft Environmental Impact Statement* for the Energize Eastside Project. Alternative technologies were analyzed in detail in the *Phase 1 Draft Environmental Impact Statement*.<br><br>PSE proposes mitigation that fully complies with all of the City's code requirements. Mitigation measures include, but are not limited to, revegetation, pole height reduction, and selection of pole finishes that are suitable to the context. PSE is also in discussions with the City to coordinate and ensure that any impact identified during the Partner Cities' State Environmental Policy Act review are avoided, minimized and mitigated to the extent feasible under the law (*i.e.,* any mitigation must be proportionate to identified impacts caused by the proposed project). |
| **UT-98:** Discourage new aerial facilities within corridors that have no existing aerial facilities. | **Response:** PSE is proposing to replace two existing aerial 115 kV lines with two 230 kV lines within an existing, established utility corridor. No new aerial facilities are proposed corridor as part of the project. |

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| **UT-99:** Work with and encourage Puget Sound Energy to plan, site, build and maintain an electrical system that meets the needs of existing and future development, and provides highly reliable service for Bellevue customers.<br><br>*Discussion: Providing highly reliable service is a critical expectation for the service provider, given the importance of reliable and uninterrupted electrical service for public safety and health, as well as convenience.*<br><br>*Highly reliable service means there are few and infrequent outages, and when an unavoidable outage occurs it is of short duration and customers are frequently updated as to when power is likely to be restored. A highly reliable system will be designed, operated and maintained to keep pace with the expectations and needs of residents and businesses as well as evolving technologies and operating standards as they advance over time.* | **Response:** PSE has prepared two studies that describe the need for the Energize Eastside Project: the Eastside Needs Assessment Report and the Supplemental Eastside Needs Assessment Report (Gentile et al., 2014, 2015). The deficiency in the transmission capacity on the Eastside is based on a number of factors. Key factors include: growing population and employment in the Eastside (including significant projected growth in Bellevue), changing power consumption patterns, and changing utility regulations that require a higher standard of reliability. PSE has concluded that the most effective and efficient solution to meet the need objectives is to site a new 230 kV transformer at a central location on the Eastside that will be fed from the Sammamish substation in Redmond from the north and the Talbot Hill substation in Renton from the south. This decision is consistent with the City's comprehensive plan, which requires not just reliable power, but "highly reliable" power. Additionally, PSE evaluates its system needs annually and continues to conclude that the Energize Eastside project is needed under current and foreseeable load scenarios.<br><br>Without adding transmission capacity, a deficiency during peak periods could develop on the Eastside as early as the winter of 2017-2018, with the potential for load shedding (forced power outages) <u>by the summer of 2018</u>. PSE now operates with the use of Corrective Action Plans, which include load shedding to address this deficiency. The proposed project is needed to meet the needs of the City's residents and businesses. |

## Environmental Element

The proposed transmission line replacement will have impacts on environmental resources within the City of Bellevue.

| **Environmental Stewardship** | |
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| **EN-12**: Work toward a citywide tree canopy target of at least 40% canopy coverage that | **Response:** Selective tree canopy will be removed as part of the transmission line |

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| reflects our "City in a Park" character and maintain an action plan for meeting the target across multiple land use types including right-of-way, public lands, and residential and commercial uses.<br><br>**EN-13**: Minimize the loss of tree canopy and natural areas due to transportation and infrastructure projects and mitigate for losses, where impacts are unavoidable. | upgrade. Strict federal clearance requirements must be met with the upgrade from a 115 kV transmission corridor to a 230 kV transmission corridor, resulting in additional vegetation management within the existing corridor.<br><br>To mitigate for loss of significant trees in the transmission corridor, PSE is proposing mitigation ratios that meet or exceed regulatory standards. PSE will work with individual property owners to replace trees and mitigate other vegetation impacts on private property. Where individual property owners decline to have new trees or shrubbery planted onsite, PSE will work with the City to place additional trees offsite.<br><br>PSE is required by federal standards to maintain safe clearances between vegetation and utility lines. The upgraded transmission lines will have to comply with PSE's 230 kV vegetation management standards, which generally require removal of trees located in the wire zone that have a mature height of more than 15 feet. Taller trees within the transmission right-of-way may also be affected depending on tree species, tree health, distance from the wires, and topography.<br><br>PSE has been meeting with property owners along the existing corridor to discuss tree replacement and will continue to work together to develop property-specific landscaping and tree replacement plans. It is anticipated that a number of trees cannot be replaced onsite due to property owners' preferences. In those cases, replacement trees will need to be planted outside the corridor. One benefit of offsite planting is the option to plant larger trees that will contribute to habitat quality and area aesthetics. Offsite options may include city parks, and neighborhood groups/HOAs. PSE will work with the City to identify other offsite areas that would benefit from these trees. PSE's goal is that the proposed project will result in a net increase in the number of trees, which should assist the City in achieving its tree cover goals. |

| **Water Resources** | |
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| **EN-19:** Retain existing open surface water systems in a natural state and restore conditions that have become degraded. | **Response:** The transmission line would cross 18 streams in the North Bellevue Segment (Kelsey Creek and streams EB02-EB18). However, the aerial crossings of the transmission line will not impact the streams or their buffers and no in-water work will occur. Impacts to buffers will be minimized and limited to pole foundations and selective vegetation management.<br><br>No natural open surface water systems in Bellevue will be affected by the project. Proposed mitigation for project impacts includes enhancement of Wetland A at the Richards Creek Substation (restoring degraded conditions) and purchase of credits from the Keller Farm Mitigation Bank (KFMB). Mitigation specifics are presented in the associated Critical Areas Report. |
| **EN-26:** Manage water runoff for new development and redevelopment to meet water quality objectives, consistent with state law. | **Response:** The transmission line upgrade, including pole replacements, will not result in changes to existing runoff patterns. |
| **Geo Hazards** | |
| **EN-30:** Regulate land use and development to protect natural topographic, geologic, vegetational, and hydrological features.<br><br>**EN-39:** Use specific criteria in decisions to exempt specific small, isolated, or artificially created steep slopes from critical areas designation.<br><br>**EN-40:** Minimize and control soil erosion during and after development through the use of best management practices and other development restrictions. | **Response:** All applicable City of Bellevue land use and clearing regulations, including LUC 20.25H.125 – Performance Standards, will be complied with as part of the Energize Eastside Project construction. Following the completion of geotechnical reports, there will be selective tree removal and approximately 48 poles will be removed from geo hazard areas and 16 new poles will be installed within geo hazard areas. Per the Bellevue code, areas that do not meet the 10 foot rise or 1,000 square feet threshold (including small engineered or manmade slopes) have been removed from the geo hazard analysis.<br><br>A temporary erosion and sediment control (TESC) plan will be developed for the project. Necessary best management practices (BMPs) will be used as appropriate, including chipping and scattering of removed vegetation. |

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| | Disturbance will be limited to the minimum necessary within geo hazard areas, including limiting equipment access and disturbance areas. All disturbed areas will be restored.<br><br>See the project Geotechnical Report (Appendix D to the Critical Areas Report) for further information. |
| **Fish and Wildlife Habitat** | |
| **EN-63:** Preserve and maintain fish and wildlife habitat conservation areas and wetlands in a natural state and restore similar areas that have been degraded.<br><br>**EN-67:** Prohibit creating new fish passage barriers and remove existing artificial fish passage barriers in accordance with applicable state law.<br><br>**EN-70:** Improve wildlife habitat especially in patches and linkages by enhancing vegetation composition and structure, and incorporating indigenous plant species compatible with the site.<br><br>**EN-71:** Preserve a portion of significant trees throughout the city in order to sustain fish and wildlife habitat. | **Response:** Impacts to fish, wildlife, wetlands and habitat conservation areas are discussed and analyzed in detail in the North Bellevue Critical Areas Report and Endangered Species Act Biological Evaluation associated with the proposed project. As explained in those documents, limited disturbance is anticipated within fish and wildlife habitat areas and wetlands. Existing poles within wetlands will be replaced outside of wetlands. Buffer impacts will be limited to the pole footprint and selective vegetation management activities required by federal clearance standards. Existing impact to wetlands would be removed by relocating 6 poles from wetland to non-wetland areas which will allow approximately 150 SF of wetland area to be restored. Following pole removal, the holes will be filled in with dirt and restored with an appropriate native wetland seed mix and left to naturally regenerate.<br><br>Proposed mitigation for project impacts includes enhancement of Wetland A at the Richards Creek Substation (improving wildlife habitat and native species/diversity) and purchase of credits from the KFMB. Mitigation specifics are presented in the associated Critical Areas Report. |
| **Critical Areas** | |
| **EN-84:** Use science based mitigation for unavoidable adverse impacts to critical areas to protect overall critical areas function in the watershed. | **Response:** The proposed mitigation for wetland and buffer impacts caused by the Energize Eastside Project will be mitigated using the best available science to the extent allowable in compliance with LUC 20.25H, the City of Bellevue's critical areas |

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| | code. Proposed mitigation, which includes enhancement of Wetland A at the Richards Creek Substation and purchase of credits from the KFMB, will result in measurable habitat improvements to critical area functions and values. Mitigation specifics are presented in the associated Critical Areas Report. |

### Subareas

The existing transmission corridor crosses through the following five Subareas identified in the Comprehensive Plan: Bridle Trails, Bel-Red, Wilburton/NE 8th St, Southeast Bellevue, and Richards Valley.

| **Bridle Trails Subarea** | |
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| *General Land Use* | |
| **Policy S-BT-1.** Protect Bridle Trails from encroachment by more intense uses to ensure that the Subarea remains an area of residential neighborhoods. | **Response:** The proposed transmission line upgrade will serve and improve reliability for PSE's residential customers in Bridle Trails and will not cause a change in adjacent uses from residential to non-residential uses. Additionally, the proposed project is located within an existing transmission line corridor that was established in the late 1920s and early 1930s and is mostly composed of easements on private property. PSE's proposed project is compatible with existing adjacent uses and will not cause long-term impacts to access to the existing trail or in any way interrupt residential uses now or in the future. Within the Bridle Trails Subarea, the future land use designation is Single-Family Residential. |
| *Natural Determinants* | |
| **Policy S-BT-5.** Protect and enhance the capability of Yarrow Creek, Valley Creek, and Goff Creek to support fish and other water-dependent wildlife.<br>*Discussion: This policy recognizes the role of these creeks in fisheries support and wildlife preservation. It is important to preserve the natural environment and to* | **Response**: The transmission line does not cross or occur within these stream buffers; therefore, no impacts would occur. |

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| *retain our native habitat for the aesthetic value and character of the community.* | |
| **Policy S-BT-7**. Where natural vegetation is removed, replacement with similar plant materials should be required. | **Response:** As set forth in PSE's North Bellevue Segment Vegetation Management Plan, to mitigate for loss of significant trees in the transmission corridor, PSE is proposing mitigation ratios that meet or exceed regulatory standards. PSE will work with individual property owners to replace trees on private property. |
| **Bel-Red Subarea** | |
| *General Land Use* | |
| **Policy S-BR-10**. Accommodate the continued operation of existing, and allow new, service uses that are compatible with planned future land uses. Accommodate existing service uses that are less compatible with residential and higher intensity, mixed use development (i.e., those that create noise, odor, fumes, aesthetic or other impacts), but preclude the new establishment of these types of service uses in transit nodes and in stand-alone residential areas.<br><br>*Discussion: This policy is to be implemented through the City's land use regulations. The services sector is quite broad, and includes uses such as health care, business and professional office, household repair, and auto repair. Many of these service uses have characteristics of general retail, are compatible with mixed use commercial and residential, and are encouraged in Bel-Red's future. A smaller sub-set of service uses, such as auto repair, auto dealers and boat dealers (particularly their service/repair components) and towing, display characteristics similar to light industrial uses. These types of uses are less compatible with transit nodes and stand-alone residential areas, and thus new uses of this type are precluded in these areas.* | **Response:** The proposed transmission line upgrade is located within an existing corridor that was established in the late 1920s and early 1930s and is mostly composed of easements on private property. The small portion of the North Bellevue segment that goes through the Bel-Red Subarea Plan boundaries has a future land use designation as General Commercial. |

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| *Environment* | |
| **Policy S-BR-27**. Protect and enhance wetlands and other designated critical areas in Bel-Red, through the use of development regulations, incentives, and possibly public funds.<br>*Discussion: Special attention is needed if Bel-Red's critical areas are to be protected and restored, given that much Bel-Red development took place before standards were adopted to identify and protect these sites.* | **Response:** None of the poles would be placed in wetlands, streams, or their respective buffers in the Bel-Red Subarea. |
| **Wilburton/NE 8th St Subarea** | |
| *Land Use* | |
| **Policy S-WI-1.** Protect residential areas from impacts of other uses by maintaining the current boundaries between residential and non-residential areas.<br>*Discussion: This plan establishes appropriate areas for non-residential uses. Beyond these areas, non-residential uses, except for those normally permitted in residential areas, (such as parks, churches, schools, utilities, and home occupations) should not be permitted to encroach into residential areas. This does not limit the potential for development that mixes residential uses with commercial, institutional or other uses in areas that are predominately non-residential.* | **Response:** The proposed transmission line upgrade is located within an existing corridor that was established in the late 1920s and early 1930s and is mostly composed of easements on private property. PSE's proposed project will be constructed and operated within the existing corridor, which will not be expanded. The project is a use that is compatible with and serves residential and non-residential but does not affect where these uses are developed. It will not affect the current boundaries between residential and non-residential uses. |
| *Natural Determinants* | |
| **Policy S-WI-16.** Protect and enhance streams, drainage ways, and wetlands in the Kelsey Creek Basin.<br>**Policy S-WI-17.** Prevent development from intruding into the floodplain of Kelsey Creek. | **Response:** The corridor will be enhanced with appropriate vegetation to provide stream and wetland habitat improvements. Project impacts, including those within the Kelsey Creek Basin, will be mitigated for through enhancement of Wetland A at the Richards Creek Substation and through purchase of credits from the KFMB. The associated Critical Areas Report provides additional information.<br>No impacts from the project are proposed within areas of special flood hazard, |

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| | including within the floodplain of Kelsey Creek. |
| *Community Design* | |
| **Policy S-WI-44.** Utilities should be provided to serve the present and future needs of the Subarea in a way that enhances the visual quality of the community (where practical). | **Response:** The purpose of the Energize Eastside project is to bring a new 230 kV power source to the Eastside region to meet capacity and reliability needs as determined through PSE planning studies and independently confirmed by City of Bellevue consultants. The 230 kV power brought into Richards Creek substation will supply existing and future power to the entire Eastside region. All of the Partner Cities, including those directly impacted by construction of the north segment, will experience increased reliability and the transmission system will be better able to meet forecasted increases in electricity demands.<br><br>In addition, the replacement of H-frame poles with fewer steel poles helps to reduce visual clutter and can be considered an aesthetic improvement from existing conditions. Pole finishes can also enhance integration with various settings. Please see the Pole Finishes Report submitted with the CUP application for this project. |
| **Southeast Bellevue Subarea** | |
| *Policies* | |
| **Policy S-SE-2.** Enhance or improve the existing residential character through landscaping, building orientation, and building design for all new development and physical improvements. | **Response:** The proposed transmission line upgrade is located within an existing corridor that was established in the late 1920s and early 1930s and is mostly composed of easements on private property. To mitigate for loss of significant trees in the transmission corridor, PSE is proposing mitigation ratios that meet or exceed regulatory standards. PSE will work with individual property owners to replace trees on private property, which provides an opportunity for residential customers to have improved landscaping throughout the corridor.<br><br>In addition, the replacement of H-frame poles with fewer steel poles helps to reduce |

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| | visual clutter and can be considered an aesthetic improvement from existing conditions. Pole finishes can also enhance integration with various settings. Please see the Pole Finishes Report submitted with the CUP application for this project. |
| **Richards Valley Subarea** | |
| *General Land Use* | |
| **Policy S-RV-1.** Enhance the natural environment within the industrial area by encouraging redevelopment to consider natural features in site design, including but not limited to reducing impervious surface, improving the functions of wetlands and stream corridors, incorporating natural drainage features, retaining trees, and restoring vegetated corridors. | **Response:** The corridor will be enhanced with appropriate vegetation to provide stream and wetland habitat improvements. Project impacts to wetlands and wetland/stream buffers will be mitigated for through enhancement of Wetland A at the Richards Creek Substation and through purchase of credits from the Keller Farm Mitigation Bank. The associated Critical Areas Report provides additional information. |
| *Natural Determinants* | |
| **Policy S-RV-5.** Retain the remaining wetlands within the 100-year floodplain along Richards Creek, Kelsey Creek, and Mercer Slough for drainage retention and natural resource park use.<br>*Discussion: It is important to preserve the natural environment and to retain the native habitat for the aesthetic value and character of the community* | Through careful project design, pole installations and associated permanent impacts have been avoided within wetlands. Additionally, no impacts from the project are proposed within areas of special flood hazard. |
| **Policy S-RV-6.** Protect and enhance the capability of Richards Creek, Kelsey Creek, and Mercer Slough and their tributaries to support fisheries along with other water-related wildlife. | **Response:** There are no direct impacts to any streams in the N Bellevue segment. Project disturbance, including temporary construction impacts, will not occur below the OHWM of Kelsey Creek or any other regulated stream within the project area. Temporary impacts will occur in the Valley Creek, Richards Creek, and Kelsey Creek drainage basins during construction in stream buffers as part of the following activities: pole installation and removal, and construction access route re-establishment/use. |

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| **Policy S-RV-7.** Retain and enhance existing vegetation on steep slopes, within wetland areas, and along stream corridors to control erosion and landslide hazard potential and to protect the natural drainage system. | **Response:** Proposed tree and vegetation removal is the minimum necessary to construct and operate the project. The corridor will be enhanced with appropriate vegetation to provide stream and wetland habitat improvements.<br><br>Clearing activities (including vegetation removal) within geo hazard areas will be minimized as applicable during construction, and stumps will be left in-place. Additional description and analysis of landslide hazard potential associated with the project can be found in the Bellevue North Segment Critical Areas Report (Appendix D). |
| *Utilities* | |
| **Policy S-RV-20.** Use common corridors for new utilities if needed.<br><br>*Discussion: If new power lines are needed in the Subarea, they should be developed in areas that already contain power lines, rather than causing visual impacts in new areas.* | **Response:** The Project is consistent with this policy because the existing 115 kV transmission lines within the Sammamish-Lakeside-Talbot Hill corridor will be upgraded to 230 kV instead of proposing the development of a new corridor. |
| **Policy S-RV-21.** Improve the appearance of public streets and power line rights-of-way. | **Response:** The transmission line corridor within the Richards Creek subarea is located in a Light Industrial land use district. There are currently numerous transmission lines and other utilities in the corridor.<br><br>The replacement of H-frame poles with fewer steel poles helps to reduce visual interference and can be considered an improvement from existing conditions. Pole finishes can also enhance integration with various settings. Please see the Pole Finishes Report submitted with the CUP application for this project. PSE will explore opportunities with the City. |
| **Policy S-RV-28.** Encourage the retention of vegetation during the clearing, grading, and construction processes to screen development from nearby residential neighborhoods. | **Response:** Applicable City of Bellevue land use and clearing regulations, including retention of vegetation, will be complied with as part of project construction. |

*B. The design is compatible with and responds to the existing or intended character, appearance, quality of development and physical characteristics of the subject property and immediate vicinity; and*

**Response:** The Energize Eastside Project is compatible with and responds to the existing character, appearance, quality of development and physical characteristics of the subject site and immediate vicinity. Because the Project is sited in an existing corridor shared with another utility (the Olympic Pipeline system), the Project will both improve reliability to adjacent uses and will not introduce a change in land use. It will consolidate the lines onto fewer poles, which, although larger, will not increase visual clutter and could reduce it in some areas. Various pole treatments will be employed to complement the natural environment, and vegetation management will maintain the general appearance of landscaping in a similar manner as the present. Although a number of trees will be removed, the remaining and proposed trees will partially screen views of the taller poles. Reinstallation of telecommunications facilities on the same transmission facilities following construction will ensure that there will not be an increase in the number of telecommunications facilities to the maximum extent feasible.

The transmission line corridor is an existing utility corridor that was established in the late 1920s and early 1930s. The current uses adjacent to the corridor developed over time as areas were annexed into the City and these areas became more dense and populated. As such, the utility corridor is part of the existing character of these areas. PSE is proposing to replace the existing 115 kV transmission poles with steel poles to accommodate 230 kV conductors. The poles will generally be installed in the same location or in close proximity to the existing poles. In most cases, the number of poles will be reduced from four to one or two. The consistency of the proposed transmission lines with other uses in the vicinity was confirmed by the FEIS, which found that impacts to land use will "be less-than-significant because [the proposed project] is consistent with City and subarea plans, and would not adversely affect existing or future land use patterns." FEIS at 4.1-9.

The FEIS found that impacts to the aesthetic environment on the North Bellevue segment would be less-than-significant. Contrast with the natural environment would be minimal because the 93-foot poles would, in most cases, be shorter than the surrounding vegetation or would appear shorter than surrounding vegetation due to vegetation density. In general, the topography does not affect the visibility of the transmission line along this segment because dense, tall vegetation obscures the view of the transmission line. Within the built environment, the poles would be approximately 40 feet taller than existing conditions, and the pole diameter would be wider than existing conditions, contrasting more with the surrounding houses and existing utility infrastructure. The new transmission line would have consistent form and height throughout the segment, and would reduce visual clutter by reducing the number of poles. FEIS at 4.2-18.

In many areas, PSE further proposes using a *delta* conductor configuration that uses less hardware rather than the existing rectilinear design. By limiting the area of visual impact and mirroring other natural elements, PSE can effectively mitigate aesthetic impacts and ensure consistency with adjacent uses.

*C. The conditional use will be served by adequate public facilities including streets, fire protection, and utilities; and*

**Response:** The transmission line upgrade is a utility and will consist of replacing two existing 115 kV transmission lines within an existing 100-foot wide corridor with two 230 kV lines in the same corridor. No new permanent access or other additional public facilities will be required to accommodate the upgraded lines.

D. *The conditional use will not be materially detrimental to uses or property in the immediate vicinity of the subject property; and*

**Response:** PSE's proposed project will improve the reliability of electrical services to uses adjacent to the upgraded transmission line poles. The north segment of the proposed transmission line upgrade will not be materially detrimental to uses or properties in the immediate vicinity. PSE proposes siting the north segment along the same corridor used by existing transmission lines. This corridor has been established for almost a century. Because adjacent land uses and properties already integrate transmission line facilities, they will not be materially impacted by replacement of the existing transmission line facilities.

Property owners closest to the transmission lines typically own and use the property beneath the transmission lines, subject to terms of the easement that was on the property when purchased. The presence of transmission lines generally does not impede property owners use and enjoyment of their property and the visual enjoyment of their property will remain largely unchanged, with the exception that the poles will be larger, made of metal rather than wood, and in slightly different locations. In some cases, the new pole configuration will mean fewer poles, and the lines will be higher above the line of sight for properties in the immediate vicinity, thereby reducing the visual impacts to some of the properties closest to the Project. PSE has also offered to work with each property owner to adjust the location of the new poles to the extent feasible for the convenience of individual property owners.

The consistency of the proposed transmission lines with other uses in the vicinity was confirmed by the FEIS, which found that impacts to land use will "be less-than-significant because [the proposed project] is consistent with City and subarea plans, and would not adversely affect existing or future land use patterns." FEIS at 4.1-9—10.

With respect to aesthetic impacts to properties in the vicinity of the proposed transmission line, the FEIS describes the north segment as follows:

> No scenic views from parks, trails, or outdoor recreation facilities would be significantly impacted. There are occasional views of the Cascades along the transmission corridor, views of the Olympics from Northup Way, and views of Mount Rainier along SR 520. Changes in the transmission infrastructure from 115 kV transmission lines to 230 kV transmission lines are not expected to negatively impact views from those locations because the change would occur within an existing transmission corridor, and the increase in height would move the wires farther above drivers' line of sight of visual resources. Impacts would be less-than-significant. FEIS at 4.2-19.

In general, studies have found that the effects on property values are highest for properties nearest the lines and tend to diminish over time after the project is constructed. Phase II DEIS at 3.10-2.

One more objective rubric for assessing harm to properties in the vicinity is the potential for the project to impact house values. Both the Phase I and Phase II of the DEIS confirmed that there would be no materially detrimental impact to house values resulting from PSE's proposed transmission line upgrade. Phase II DEIS at 3.10-1—2; and Phase I DEIS at Ch. 10 Land Use and Housing, 10-21—22 (which summarizes studies detailing economic impacts of transmission lines on housing values). This is especially significant as the studies reviewed contemplated the siting of a new transmission line, rather than a transmission line upgrade where similar utilities already exist. The DEIS's conclusions on economic impacts provides further evidence that PSE's proposed transmission line upgrade would not be materially harmful to properties in the immediate vicinity.

PSE has also proactively addressed potential safety concerns related to construction safety and the potential for interactions between the project and two collocated Olympic Pipeline petroleum pipelines. As proposed, PSE and pipeline safety expert DNV-GL have concluded that while there are safety risks for occupants of adjacent properties associated with the high voltage lines and the presence of the Olympic Pipeline system, these risks will not increase with the Project, and will likely be reduced. Additionally, DNV-GL modelling confirmed that fault potential, shock potential, and A/C interference (all of which are safety concerns in a collocated corridor) are all below industry safety standard thresholds.

E. *The conditional use complies with the applicable requirements of this Code.*

**Response:** The proposed transmission line upgrade complies with the applicable requirements of the City of Bellevue code as evidenced through the documentation provided by this CUP application.

## LUC 20.20.255.E: Electrical utility facility decision criteria:

1. *The proposal is consistent with Puget Sound Energy's System Plan;*

**Response:** The need for additional 230 kV capacity in the Eastside region was identified, and has been included in PSE's Electrical Facilities Plan for King County ("Plan"), since 1993. As explained in the Plan, "[t]he 230 kV sources for the 115 kV system in northeast King County are primarily the Sammamish and Talbot Hill substation. The loads on the 230- 115 kV transformers in these stations will be high enough to require new sources of transformation." Additionally, the "Lakeside 230 kV Substation project [now referred to as Energize Eastside] will rebuild two existing 115 kV lines to 230 kV between Sammamish and Lakeside [where PSE proposes the construction of the Richards Creek substation], and between Lakeside and Talbot Hill."

2. *The design, use, and operation of the electrical utility facility complies with applicable guidelines, rules, regulations, or statutes adopted by state law, or any agency or jurisdiction with authority;*

**Response:** Performance requirements for any integrated transmission system are heavily regulated at both the federal and regional levels. PSE's regulators include FERC, NERC, and WECC (the Federal Energy Regulatory Commission, North American Electric Reliability Corporation and Western Electricity Coordinating Council, respectively).

NERC is the regulatory authority certified by FERC to develop and enforce reliability standards. NERC has delegated the task of monitoring and enforcing the federal reliability standards to WECC, the regional entity that has authority over transmission in the western region.

The NERC standards mandate that certain forecasts and studies must be completed to determine if the system has sufficient capability to meet expected loads now and in the future. When completing transmission planning studies, contingencies are simulated to determine if the electric system meets the mandatory NERC performance requirements[1] for a given set of forecasted demand levels, generation configurations and levels, and multiple system component outages.

Federal regulations require that the appropriate planning be undertaken proactively. The probability that events which must be modeled may occur is not an element of NERC-compliant reliability planning. This conservative planning methodology is implemented to prevent large scale, cascading, transmission system blackouts, like those that have occurred in the recent past (for example, the 2003 Northeast blackout that affected 55 million people in the Northeast and Midwest regions of the United States and Canada).

The PSE transmission planning studies performed in 2013 and 2015 determined that thermal violations on transmission line and transformer equipment could occur under foreseeable scenarios within the next few years. The thermal violations are a result of modelling scenarios for several mandatory component outage contingencies that take into consideration peak demand (which is heavily dependent on seasonal temperatures and daily demand profiles) and levels of conservation. In essence, this is a requirement to have redundancy in the transmission system.

In an effort to stop PSE's Energize Eastside Project, a complaint was filed with the Federal Energy Regulatory Commission (FERC) against PSE and other utilities alleging the transmission reliability study methods utilized by PSE et al. were not consistent with NERC requirements (Attachment A). FERC dismissed all aspects of the complaint, stating:

> "Based on the record before us, we find that Puget Sound [PSE] and the other Respondents complied with their transmission planning responsibilities under Order No. 890 in proposing and evaluating the Energize Eastside Project." (FERC Docket No. EL15-74-000, Order Dismissing Complaint, Issued Oct. 21, 2015.)

The FERC response also concluded:

> "We agree with Puget Sound [PSE] and ColumbiaGrid that the Energize Eastside Project was properly classified a Single System Project because it was designed to address Puget Sound's projected inability to serve its own customers, ColumbiaGrid's Puget Sound Area Study Team did not find any Material Adverse Impacts associated with the project, and ColumbiaGrid included the project as a Single System Project in its most recent 2015 Biennial Plan. Accordingly, we find that the Energize Eastside Project was proposed and evaluated in accordance with the then-applicable transmission

[1] The transmission planning standards that were in effect in 2012-2013 were: TPL-001-3, TPL- 002-0b 2nd Rev (TPL-002-2b), TPL-003-0b 2nd Rev (TPL-003-2b), and TPL-004-2. TPL-001-3, TPL-002-2b, TPL-003-2b, and TPL-004-2 are being retired as they are replaced in their entirety by TPL-001-4. Enforcement of the new standards began January 1, 2015. Visit the NERC website at http://www.nerc.com/pa/Stand/Reliability Standards/TPL-001-4.pdf for more information.

planning requirements." (FERC Docket No. EL15-74-000, Order Dismissing Complaint, Issued Oct. 21, 2015.)

3. *The applicant shall demonstrate that an operational need exists that requires the location or expansion at the proposed site;*

The stated purpose of the Energize Eastside project is to address a transmission system deficiency between the Sammamish and Talbot Hill substations and to meet local demand growth and protect reliability in the Eastside of King County, roughly defined as extending from Redmond in the north to Renton in the south, between Lake Washington and Lake Sammamish, and including the City of Bellevue. The Project was identified in the City's Comprehensive Plan UT Element policies for non-City-managed utilities and is shown on Map UT-7 – New or Expanded Electrical Facilities.

Comprehensive Plan Policy UT-47 directs the City to defer to the serving utility, in this case PSE, regarding the implementation sequence of components of the utility's plan. In total, six separate studies performed by five separate parties have confirmed the need to address Eastside transmission capacity (20.20.255.E.4; D.3.b & c):

- Electrical Reliability Study by Exponent, 2012 (City of Bellevue)
- Eastside Needs Assessment Report by Quanta Services, 2013 (PSE)
- Supplemental Eastside Needs Assessment Report by Quanta Services, 2015 (PSE)
- Independent Technical Analysis by Utility Systems Efficiencies, Inc., 2015 (City of Bellevue)
- Review Memo by Stantec Consulting Services Inc., 2015 (EIS consultant).
- Assessment of Proposed Energize Eastside Project prepared for Newcastle, 2020 (MaxETA Energy, PLLC & Synapse Energy Economics, Inc.)

In addition to the above studies, PSE annually reanalyzes the need as part of PSE's mandatory requirements by NERC. These requirements are detailed in NERC standard TPL-001-4 Transmission System Planning (TPL) Performance Requirements. Per NERC requirements, PSE performs this annual planning assessment to analyze the electric system and reconsider previous transmission planning conclusions. All of the annual reviews conducted for 2016, 2017, 2018, and 2019 have confirmed PSE's previous determination that the Energize Eastside project is needed and that there is a transmission capacity deficiency and the transmission capacity deficiency in the Eastside, including Bellevue, will continue to get worse as load grows.

The Quanta-prepared Needs Assessment reports published in 2013 and 2015 and performed pursuant to the mandatory NERC transmission planning standards identified four major areas of concern:

1. Overload of PSE facilities in the Eastside area. Studies identified potential overloading of transformers at Sammamish and Talbot Hill substations, and several 115 kV transmission lines routing power to the Eastside area are at risk of overloading under certain conditions.

2. Small margin of error to manage risks from inherent load forecast uncertainties. PSE's planning studies rely in large part on load forecast data. Imbedded in PSE's load forecasts are several factors that include elements of risk. These include conservation, weather and block loads.

    - Conservation: To date, PSE customers have achieved 100 percent of the company's conservation goals, which are very aggressive within the industry. If 100 percent of conservation goals are not achieved, then the transmission system capacity will be surpassed sooner than expected.

    - Weather: PSE's load forecast assumes "every other year" cold weather. (Some utilities take a more conservative approach, using the coldest and hottest weather in five or ten years, as inputs to system performance studies[2].) If the region experiences weather extremes outside of those used in PSE's planning studies, electricity demand will surpass the transmission system capacity sooner than expected.

    - Block loads: These include large development projects that add significant load to the system. If block load growth increases more than anticipated, demand for electricity will surpass the transmission capacity sooner than expected.

3. Increased use and expansion of operational Corrective Action Plans (CAPs) to keep the system compliant. CAPs are a series of operational steps used to prevent system overloads or loss of customers' power. They are a short-term fix to alleviate potential operational conditions that could put the entire grid at risk. They protect against large-scale, cascading power outages; however, they can put large numbers of customers at increased risk of power outages. For example, to prevent winter overloads on the Talbot Hill transformer banks, PSE is already using operational CAPs, which increases outage risk to customers. As growth continues, additional CAPs will be needed. Per federal standards, operational CAPs are not intended to be long-term solutions to system deficiencies.

4. Impacts to interconnections identified by ColumbiaGrid. Though the need for Energize Eastside is driven by local demand, because the electric system is interconnected for the benefit of all it is a federal requirement to study all electric transmission projects to ensure there are no material adverse impacts to the reliability or operating characteristics of PSE's or any surrounding utilities' electric systems. ColumbiaGrid, the regional planning entity, produces a Biennial Transmission Expansion Plan that addresses system needs in the Pacific Northwest, including the PSE system.

PSE's 2015 Supplemental Needs Assessment Report confirmed the winter deficit findings in the 2013 Needs Assessment Report, stating that: *By winter of 2017-18, there is a transmission capacity deficiency on the Eastside that impacts PSE customers and communities in and around Kirkland, Redmond, Bellevue, Issaquah, Newcastle, and Renton...**By winter of 2019-20, at an Eastside load level of approximately 706 MW, additional CAPs are required that will put approximately 63,200 Eastside customers at risk of outages.*** The 2015 Needs Assessment also confirmed that by summer of 2018, there would be a transmission capacity deficiency on the Eastside and that **by summer of 2018, CAPs will be required to manage overloads under certain N-1-1 contingencies,**

[2] For example, ISO-NE plans to a 90/10 or one in ten year weather forecast.

**and the use of these CAPs will place approximately 68,800 customers at risk and could require 74 MW of load shedding, affecting approximately 10,900 customers at a time.**

To further study this, in 2015 PSE commissioned Nexant to simulate three scenarios of rotating outages that could be needed if no action is taken to upgrade the Eastside's transmission system. Nexant's Energize Eastside Outage Cost Study determined that if PSE must use corrective action plans that include rolling blackouts, more than 130,000 customers could be impacted as early as the summer of 2018, at a cost of tens of millions of dollars to the local economy. The City of Bellevue contracted with Utility System Efficiencies, Inc. (USE) to perform an Independent Technical Analysis (ITA) of the purpose, need and timing of the Energize Eastside project. This study confirmed the capacity deficiency in the Eastside area. The ITA was performed to verify the project need and PSE's study methods, as these were questioned by a small public opposition group (see **LUC 20.20.255.E: Electrical utility facility decision criteria** (2), above).

The ITA concluded that "PSE used reasonable methods to develop its forecast showing the Eastside area growing at a higher level [faster pace] than the county or system level". Additionally, the ITA addressed common questions about the project, including:

- Is the Energize Eastside Project needed to address the reliability of the electric grid on the Eastside? **The ITA determined, "YES."**

- If the load growth rate was reduced, would the project still be needed? **The ITA determined, "YES."**

- If generation was increased in the Puget Sound area, would the project still be needed? **The ITA determined, "YES."**

- Is there a need for the project to address regional flows, with imports/exports to Canada? **The ITA determined that by modeling zero flow to Canada, the project is still necessary to address local need**.

The City of Newcastle hired MaxETA Energy, PLLC and Synapse Energy Economics, Inc. (MaxETA and Synapse) to prepare a study reviewing this need. That study, completed June 28, 2020, concluded that there is a need ("…shows that there is a summer transmission capacity deficiency in King County under N-1-1 contingencies even at today's peak load level.")[3].

Since those studies, summer demand from PSE's customers has twice exceeded planning thresholds identified in these studies as putting PSE at risk of having to implement CAPs.[4] Because PSE's system now experiences summer loads that exceed planning thresholds, PSE undertakes CAP planning that includes the potential for intentional load shedding (i.e.,

[3] *Assessment of Proposed Energize Eastside Project*, MaxETA Energy, PLLC and Synapse Energy Economics, Inc., June 2020, Page 3 Key Findings

[4] On June 8, 2018, PSE sent letters to several cities on the Eastside including Bellevue stating that their peak customer demand projections, which were the basis for determining the need for the Energize Eastside project, had been exceeded in the summer of 2017. PSE indicated that the systemwide peak customer load in the summer of 2017 reached the levels earlier predicted for summer of 2018, exceeding the 3,625 MW threshold identified as the load level at which PSE's system is at risk of outages. This occurred in early August of 2017, following a brief period of unusually high daytime and nighttime temperatures.

intentional power outages) throughout its Eastside service area, including north Bellevue neighborhoods.

Load shedding is not a practice that PSE or many other responsible utilities use unless absolutely necessary. Since load shedding adversely impacts residential, commercial and industrial customers as well as surrounding cities, towns and neighboring communities, it is necessary and good utility practice to coordinate with cities, towns, municipal officials and emergency services, and to publicly inform those affected.

The geographic location of the Energize Eastside project is directly related to the operational need, local demand growth, and reliability considerations that PSE has identified and that the Project is designed to address. Specifically, the Project is located between Redmond and Renton, the two points where the system can connect to 230 kV bulk power on the Eastside. PSE explored dozens of other options for siting the Project in the Eastside. Based on its siting analysis, and consistent with the findings of the project's EIS, PSE found that locating the Project within an existing right-of-way has fewer impacts than creating a new right-of-way corridor, as well as being the location that provides the least costly way to develop the Project. The Project is therefore proposed in the existing 115 kV corridor connecting the Talbot Hill substation to the Lakeside substation.

Using the existing transmission line corridor provides the shortest path between the Sammamish substation in the north and the Talbot Hill substation in the south to the Lakeside substation area. Operationally, replacing the existing 115 kV lines with 230 kV lines utilizes an existing corridor without the need for creating a new one through areas that do not have transmission lines today.

4. *The applicant shall demonstrate that the proposed electrical utility facility improves reliability of the system as a whole, as certified by the applicant's licensed engineer;*

**Response:** PSE's transmission planning studies, listed above, demonstrate that under certain contingencies the delivery system on the Eastside could not continue to meet reliability requirements without significant infrastructure upgrades. PSE's 2013 Eastside Transmission Solution Report and 2015 Supplemental Eastside Transmission Solution Report addressed the needed reliability infrastructure upgrades to build a new 230-115 kV substation in the Bellevue area with a 230-115 kV transformer, upgrade the existing 115-kV lines to 230-kV lines, and provide aggressive conservation to provide the reliable improvements to the Eastside area. The new substation will allow existing 115 kV lines to distribute the power into Eastside communities. This would provide increased capacity and reliability for more than 100,000 customers on the Eastside, including north Bellevue.

Completing this infrastructure upgrade would eliminate PSE's reliance on operational CAPs. These CAPs could include intentional shedding of the load under certain conditions when re-dispatching the generation and/or sectionalizing the transmission system would not help in reducing the load beyond capacity limitations of the transmission equipment. Thus, ensuring reliable service to all the Eastside customers and beyond by preventing a large area outage.

All of the studies listed above are provided in the Alternative Siting Analysis. These studies were reviewed and confirmed by Jens Nedrud, Manager of System Planning, a Washington State licensed engineer. See Attachment B (containing PSE's 2021 Reliability Certification for Energize Eastside 230-kV Project (LUC 20.20.255.E.)).

5. *For proposals located on sensitive sites as referenced in Figure UT.5a of the Utility Element of the Comprehensive Plan, the applicant shall demonstrate:*

   a. *Compliance with the alternative siting analysis requirements of subsection D of this section;*

      See PSE's Alternative Siting Analysis.

   b. *Where feasible, the preferred site alternative identified in subsection D.2.d of this section is located in the land use district requiring additional service and residential land use districts are avoided when the proposed new or expanded electrical utility facility serves a nonresidential land use district;*

      As explained in the six studies assessing the need for Energize Eastside, PSE's proposed transmission line upgrade is responsive to projected growth in the Eastside generally and the City of Bellevue specifically. All land uses (including residential and non-residential uses) on the Eastside, including the land use districts in which the project is proposed to be sited will directly benefit from the reliability improvements (and the associated reduced risk of outages) that will follow project construction. Improvements to reliability as a result of the Project will also benefit the entire City and other communities surrounding Bellevue, including both non-residential districts and residential districts

      The Energize Eastside project provides additional transmission capacity needed to accommodate existing electrical demand and expected growth throughout the Eastside. Most of the population and employment growth in Bellevue to be served by the Project is expected to occur in non-residential zones and mixed-use zones. However, because transmission capacity must connect to the regional grid, it is not possible to construct the facility in a discrete zone or zones; the lines must cross several zones to reach the center of the Eastside, and the majority of the area it must cross is residentially zoned.

      Finally, consistent with City policies on utility corridors, PSE's proposal makes use of an existing shared utility transmission corridor. By using an existing transmission line corridor that passes through residential areas, it is not feasible to avoid residential areas and to the extent that residential land use districts are impacted, they are districts that already house PSE's high voltage transmission lines and are subject to PSE transmission line easements, which largely predate the construction of residential uses along the corridor.

6. *The proposal shall provide mitigation sufficient to eliminate or minimize long-term impacts to properties located near the electrical utility facility.*

   The FEIS identified limited unavoidable significant adverse impacts. PSE is committed to implementing avoidance, minimization, and mitigation identified through the SEPA review process where feasible to avoid and address any significant adverse impacts. PSE is committed to fully complying with all mitigation required by the City's code and permit conditions. Specifically, PSE will mitigate those impacts identified in the Critical Areas Report, as well as tree impacts that are necessary to meet federal transmission line operational standards. PSE will work with affected property owners, the City, and other stakeholders to replace trees in the most effective manner that meets the permit conditions.

F. *Design Standards:*

*In addition to the requirements set forth in Part 20.30B LUC, Part 20.30E LUC, Part 20.25B LUC (if applicable), and other applicable provisions of this section, all proposals to locate or expand an electrical utility facility shall comply with the following:*

1. *Site Landscaping. Electrical utility facilities shall be sight-screened as specified in LUC 20.20.520.F.2 or as required for the applicable land use district. Alternatively, the provisions of LUC 20.20.520.J may be used, provided this subsection does not apply to transmission lines as defined in LUC 20.50.018.*

**Response:** The proposed project in the North Bellevue Segment consists of a transmission line corridor. This requirement is not applicable within the transmission line corridor.

2. *Fencing. Electrical utility facilities shall be screened by a site-obscuring fence not less than eight feet in height, provided this subsection does not apply to transmission lines as defined in LUC 20.50.018. This requirement may be modified by the City if the site is not considered sensitive as referenced in Figure UT.5a [UT-7] of the Utility Element of the Comprehensive Plan, is adequately screened by topography and/or existing or added vegetation, or if the facility is fully enclosed within a structure. To the maximum extent possible, all electrical utility facility components, excluding transmission lines, shall be screened by either a site-obscuring fence or alternative screening.*

**Response:** This requirement is not applicable within the transmission line corridor.

3. *Required Setback. The proposed (including required fencing) shall conform to the setback requirement for structures in the land use district.*

**Response:** The Project will comply with water, sewer, and storm clearance and setback per BCC 24.02 and 24.04.

4. *Height limitations. For all electrical utility facility components, including transmission lines, the City may approve a request to exceed the height limit for the underlying land use district if the applicant demonstrates:*

   a. *The requested increase is the minimum necessary for the effective functioning of the electrical utility facility; and*

   **Response:** The request to exceed the height limit is the minimum necessary for the effective and safe functions of the transmission lines. The existing corridor is located within different zoning districts throughout the City, including residential and commercial. The replacement pole height will need to increase over the current pole height. NESC requires minimum clearance between each of the conductors and the ground, said distance based on operating temperature and loading to account for sag. These safety standards also require increased separation between the three conductors necessary for each circuit once upgraded to 230 kV. This increased conductor separation adds height to the poles. Poles are designed to meet the minimum height, required safety provisions, and design standards, all of which ensure effective functioning of the transmission line during all operational conditions.

*b. Impacts associated with the electrical utility facility have been mitigated to the greatest extent technically feasible.*

**Response:** As stated above and in the Alternative Siting Analysis, the location of the upgraded transmission lines minimizes impacts to adjacent properties by using an existing transmission line corridor that was established more than 80 years ago. Additionally, extensive engineering, which included design and operational parameters, was undertaken to minimize pole height to the extent practicable. This approach also allowed for a reduction in EMF, which in turn allowed for the lowest AC interaction with other utilities that share the corridor. Flexibility of pole finish has been accounted for in an effort to help minimize the contrast of the replacement poles with the dominant background.

# ATTACHMENT A
# FERC Order

153 FERC ¶ 61,076
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Philip D. Moeller, Cheryl A. LaFleur,
Tony Clark, and Colette D. Honorable.

Coalition of Eastside Neighborhoods for Sensible Energy,
Citizens for Sane Eastside Energy,
Larry G. Johnson,
Glenna F. White, and
Steven D. O'Donnell

v. Docket No. EL15-74-000

Puget Sound Energy,
Seattle City Light,
Bonneville Power Administration, and
ColumbiaGrid

ORDER DISMISSING COMPLAINT

(Issued October 21, 2015)

1. In this order, we dismiss a complaint (Complaint) filed by the Coalition of Eastside Neighborhoods for Sensible Energy, Citizens for Sane Eastside Energy, and individuals Larry G. Johnson, Glenna F. White, and Steven D. O'Donnell (collectively, Complainants) against Puget Sound Energy (Puget Sound), Seattle City Light, a department of the City of Seattle (Seattle), Bonneville Power Administration (Bonneville), and ColumbiaGrid (collectively, Respondents).

## I. **Background**

2. Puget Sound, Seattle, and Bonneville are members of ColumbiaGrid, a non-profit membership corporation whose purpose is to coordinate the operation, use, and expansion of the Pacific Northwest transmission system. Currently, however,

Puget Sound is the only Respondent that is an enrolled member in the ColumbiaGrid transmission planning region, established by certain parties to comply with Order No. 1000.[1] Puget Sound is planning to construct a transmission project consisting of approximately 18 miles of electric transmission lines and associated substation upgrades between the Cities of Redmond and Renton in the State of Washington (Energize Eastside Project). Specifically, the Energize Eastside Project will add a 230/115 kV transformer near Puget Sound's Lakeside Substation and rebuild the existing Sammamish-Lakeside-Talbot 115 kV lines to convert them to 230 kV lines. The exact location of the rebuilt 230 kV transmission lines will be determined after the completion of the state Environmental Impact Statement and local land use permitting processes, which are currently underway. The Energize Eastside Project will be located completely within Puget Sound's service territory. Puget Sound is planning to construct the project in order to accommodate projected local load growth that Puget Sound projects will create local transmission capacity deficiencies in the area beginning by the winter of 2017-18.

3. On June 9, 2015, Complainants filed the Complaint pursuant to section 206 of the Federal Power Act (FPA)[2] and Rule 206 of the Commission's Rules of Practice and Procedure.[3] Complainants allege that the Energize Eastside Project was promoted and implemented by Respondents in a manner that violates Order Nos. 890[4] and 1000. Complainants also assert that Respondents have violated Order No. 2000,[5] "contractual

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[1] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.* v. *FERC*, 762 F.3d 41 (D.C. Cir. 2014) (Order No. 1000).

[2] 16 U.S.C. § 824e (2012).

[3] 18 C.F.R. § 385.206 (2015).

[4] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009) (Order No. 890).

[5] *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001) (Order No. 2000).

obligations they have entered into with the Commission that incorporate the provisions and policies set forth in those Orders," and the terms of their Open Access Transmission Tariffs (Tariffs).[6]

4. Complainants argue that the Energize Eastside Project is a Bulk Electric System facility, as defined in Order No. 773,[7] based on the Commission's "bright line" test, because it is a 230 kV project.[8] They further argue that because the project meets more than one regional need – it is intended to meet both Puget Sound's local load needs and to provide additional transmission capacity to support 1,500 MW of power flow north to Canada in order to satisfy Bonneville's obligation to deliver power to Canada under the terms of the Columbia River Treaty[9] – it was subject to the requirements of Order No. 1000 and should have gone out to bid to third parties.[10]

5. Complainants argue that, under Order No. 1000, ColumbiaGrid was required to initially determine whether there is a transmission need on the regional system that would require a project such as the Energize Eastside Project. Complainants assert that, if ColumbiaGrid determined that there was such a need, it needed to inform its members and other interested stakeholders, allow them to propose solutions to resolve the transmission need, and then study those proposals and the associated load flow studies. Complainants further argue that, if ColumbiaGrid determined that the preferred solution met the goals of more than one entity, it needed to determine a fair allocation of the costs of the project.[11] Complainants assert that this process was not followed because Puget Sound alone determined that the Energize Eastside Project was necessary and

[6] Complaint at 1-2.

[7] *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Order No. 773, 141 FERC ¶ 61,236 (2012) (Order No. 773).

[8] Complaint at 6.

[9] *Id.*, J. Richard Lauckhart Aff. at P 18.

[10] *Id.* at 2, 6.

[11] *Id.*, J. Richard Lauckhart Aff. at PP 20-22.

conducted the associated load flow studies,[12] and ColumbiaGrid did not determine any regional cost allocation.[13]

6. Complainants conclude that Respondents have violated the regional planning process required by Order Nos. 890 and 1000 because they have violated the "single utility" rule, failed to properly ascertain the regional need for the Energize Eastside Project, failed to conduct their own environmental assessment of the project, and did not conduct industry-standard load flow studies to determine whether the Energize Eastside Project might be duplicative, less efficient, and more costly than better alternatives.[14]

7. In particular, Complainants assert that Order No. 1000's "single utility" rule required the Respondents to study the regional system as if a single utility owned all relevant generating, transmission, and distribution facilities.[15] Complainants argue that Respondents have not complied with this requirement because Puget Sound did not ask ColumbiaGrid to conduct regional power flow studies for the Energize Eastside Project, but instead, conducted inappropriate power flow studies of its own to determine if the project was necessary.[16] Complainants contend that if these studies were performed on a single utility basis, they would have logically looked at using existing Seattle transmission lines to address the transmission capacity deficiency.[17] Complainants note that Seattle allegedly refused to allow Puget Sound to use those lines because Seattle preferred to reserve those lines for its own use to meet its operating needs.[18]

8. Complainants argue that Respondents also circumvented the requirements of Order No. 1000 because ColumbiaGrid did not evaluate the potential negative environmental impacts of the Energize Eastside Project on its own[19] and Respondents

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[12] *Id.*, J. Richard Lauckhart Aff. at P 25.

[13] *Id.*, J. Richard Lauckhart Aff. at P 22.

[14] *Id.* at 2-3.

[15] *Id.*, J. Richard Lauckhart Aff. at P 49.

[16] *Id.*, J. Richard Lauckhart Aff. at P 25.

[17] *Id.* at 7.

[18] *Id.*, J. Richard Lauckhart Aff. at P 47, n.16; Attachment K.

[19] *Id.* at 8.

chose the Energize Eastside Project without giving any consideration to its environmental impacts or considering the environmental impacts of alternatives.[20]

9. Complainants also allege that the load flow studies Puget Sound conducted were flawed. In particular, they argue that the studies should not have included 1,500 MW of firm transmission to Canada because the transmission system has operated for over 50 years without the ability to deliver 1,500 MW to Canada.[21] Complainants contend that the Columbia River Treaty envisioned the construction of a new transmission line in order to facilitate the delivery of power to Canada that was contemplated in the treaty, but that Bonneville and its counterparty to the treaty, the British Columbia Hydro and Power Authority (BC Hydro), chose not to build this line. Complainants argue that, as a result, Bonneville put in place an operating procedure to curtail flows to Canada anytime such flows might cause overloads on transmission lines in western Washington. Thus, Complainants assert that the transmission system has operated without the ability to deliver the 1,500 MW of treaty power to Canada. Complainants argue, therefore, that the load flow studies for the Energize Eastside Project should have been conducted with no flow between Canada and the United States.[22]

10. In addition, Complainants assert that Puget Sound's load flow studies were flawed because they did not include 1,435 MW of output from eight Puget Sound-controlled natural gas generators located in western Washington. Complainants state that a load flow study performed by Utility Systems Efficiencies, Inc. (Utility Systems) for the City of Bellevue included some, but not nearly all, of this output. Complainants argue that this omission creates inappropriate results in the Puget Sound and Utility Systems load flow studies.[23]

11. Complainants also assert that Puget Sound's 2013 Integrated Resource Plan shows that it needs an additional 1,500 MW of generating capacity by 2018 in order to cover estimated peak load and provide an appropriate level of reserves. Complainants argue that Puget Sound has not determined where it will obtain this additional 1,500 MW of supply and that, therefore, Puget Sound will need to run all of its resources to cover peak load in 2018, including the natural gas plants that were excluded from the Puget Sound and Utility Systems load flow studies. Complainants contend that, as a result, the load

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[20] *Id.*, J. Richard Lauckhart Aff. at P 75.

[21] *Id.* at 4.

[22] *Id.*, J. Richard Lauckhart Aff. at PP 78-86.

[23] *Id.*, J. Richard Lauckhart Aff. at PP 37-44.

flow studies need to include the natural gas plants that were excluded from the Puget Sound and Utility Systems load flow studies.[24] Complainants also note that Puget Sound's 2013 Integrated Resource Plan did not address the possibility of building additional generating units in the area of the Energize Eastside Project to accomplish the dual objective of contributing to the need for 1,500 MW of additional generating capacity and addressing a potential transmission problem in the area.[25]

12. Complainants describe several alternatives to the Energize Eastside Project that they allege could be put in place at a lower cost and with lower environmental impact than the Energize Eastside Project.[26] Complainants also assert that ColumbiaGrid and its member utilities are not acting in compliance with Order No. 1000 because they have yet to agree on a ColumbiaGrid Planning and Expansion Functional Agreement (Planning Agreement) that brings them into compliance with Order No. 1000. Complainants acknowledge that the Planning Agreement and subsequent amendments have been accepted by the Commission, but they assert that ColumbiaGrid and its member utilities have not agreed on an Order No. 1000-compliant Planning Agreement because Bonneville has not yet made a compliance filing to fully conform its Tariff to the Commission's *pro forma* Tariff, as modified by Order No. 1000.[27]

13. Complainants request that the Commission order ColumbiaGrid to perform transparent and industry-standard load flow studies to determine whether the Energize Eastside Project meets a local transmission need and whether a more efficient, less expensive, and less environmentally destructive alternative exists.[28] Complainants assert that Puget Sound, Bonneville, and Seattle have already committed to have ColumbiaGrid perform such studies in their Order Nos. 890 and 1000 compliance filings and in the Planning Agreement.[29]

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[24] *Id.*, J. Richard Lauckhart Aff. at PP 90-92.

[25] *Id.*, J. Richard Lauckhart Aff. at PP 102-103.

[26] *Id.* at 5; J. Richard Lauckhart Aff. at PP 47, 95-104.

[27] *Id.*, J. Richard Lauckhart Aff. at PP 6-9; 11-15.

[28] *Id.* at 7.

[29] *Id.* at 5.

14. Complainants ask that the Commission order Puget Sound to "cease and desist from any further activity with respect to [the Energize Eastside Project], including seeking permits for it" once Complainants' requested load flow studies "show conclusively there is no local load reliability issue that would justify [the Energize Eastside Project] being built."[30]

15. Complainants further request that the Commission order Seattle and Bonneville to cooperate in restarting the project selection process at the ColumbiaGrid level, cooperate in properly performed load flow studies, and to not engage in any further acts that are subversive of the Order Nos. 890 and 1000 processes.[31]

16. Additionally, Complainants request that the Commission order Puget Sound, Bonneville, and Seattle to provide an Order No. 1000-compliant Planning Agreement. Complainants ask that, if these entities fail to provide an Order No. 1000-compliant Planning Agreement, the Commission direct them to form a Regional Transmission Organization (RTO) or Independent System Operator (ISO) to ensure Order Nos. 890 and 1000 compliance. Finally, Complainants state that, because ColumbiaGrid's method for selecting its board members is not fully compliant with the "independence" requirements set out in Order No. 2000, the selection method should be considered in consolidation with ColumbiaGrid's ongoing Order No. 1000 compliance proceeding in Docket No. ER15-429-000, *et al*.[32]

## II. <u>Notice and Responsive Pleadings</u>

17. Notice of the Complaint was published in the *Federal Register*, 80 Fed. Reg. 34,631 (2015), with answers, protests, and interventions due on or before June 29, 2015. Avista Corporation (Avista) filed a timely motion to intervene and comments. Puget Sound and ColumbiaGrid filed a joint motion to dismiss and answer. Bonneville filed a motion to dismiss Bonneville as a Respondent. Seattle filed a motion to dismiss and answer. Powerex Corp. (Powerex) filed a motion to intervene out-of-time.

18. On July 13, 2015, Complainants filed answers and, separately, a motion for order of default against Bonneville. On July 27, 2015, Seattle filed an answer to Complainants' answer. On July 28, 2015, Bonneville filed an answer to Complainants' answer and an answer to Complainants' motion for order of default. On August 11, 2015, Puget Sound

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[30] *Id.* at 7.

[31] *Id.* at 8.

[32] *Id.*

submitted supplemental information to its motion to dismiss and answer and Complainants submitted a letter objecting to the inclusion of that supplemental information in the record.

### A. Puget Sound and ColumbiaGrid Motion to Dismiss and Answer

19. Puget Sound and ColumbiaGrid argue that the Complaint should be dismissed because Complainants have failed to satisfy the Commission's rules for structuring a complaint, set forth in Rule 206 of the Commission's Rules of Practice and Procedure.[33] Specifically, Puget Sound and ColumbiaGrid assert that the Complaint does not "clearly identify the action or inaction which is alleged to violate applicable statutory standards or regulatory requirements,"[34] or "explain how the action or inaction violates the applicable statutory standards or regulatory requirements"[35] because the Complaint does not cite any particular portion or provision of Order Nos. 890 or 1000 that Respondents have allegedly violated. Puget Sound and ColumbiaGrid note that Order Nos. 890 and 1000 require the development of an Attachment K to Puget Sound's Tariff that satisfies those orders and thus, Attachment K, not Order Nos. 890 and 1000, defines the planning process that Puget Sound must carry out. Puget Sound and ColumbiaGrid further state that Puget Sound's Attachment K relies on the planning obligations set forth in the Planning Agreement, which was first approved by the Commission in 2007 and is used by ColumbiaGrid to facilitate the coordinated planning of multi-system transmission projects.[36] Puget Sound and ColumbiaGrid argue that the Complaint also does not cite any provision of Attachment K or the Planning Agreement that Respondents have allegedly violated. They assert that the Commission has previously dismissed complaints for failing to comply with these requirements.[37]

20. Puget Sound and ColumbiaGrid also argue that the Complaint fails to set forth the "business, commercial, economic or other issues presented by the action/inaction as such relate to or affect the Complainants,"[38] and to make a "good faith effort to quantify the

[33] Puget Sound and ColumbiaGrid Answer at 7.

[34] 18 C.F.R. § 385.206(b)(1) (2015).

[35] 18 C.F.R. § 385.206(b)(2) (2015).

[36] Puget Sound and ColumbiaGrid Answer at 4, 8.

[37] *Id.* at 7-8 (citing *Citizens Energy Task Force v. Midwest Reliability Org.*, 144 FERC ¶ 61,006, at P 38 (2013)).

[38] *Id.* at 9 (citing 18 C.F.R. § 385.206(b)(3) (2015)).

financial impact or burden (if any) created for the complainant as a result of the action or inaction."[39] Rather, Puget Sound and ColumbiaGrid state that Complainants generally assert that the Energize Eastside Project is "more costly" than their preferred alternatives, but they do not provide any information on the cost of the proposed alternatives. In fact, Puget Sound and ColumbiaGrid contend that Complainants merely assert that unnamed realtors have informed Complainants that their homes (whose number and present value are also unspecified) may decrease in value if the Energize Eastside Project is constructed and then argue, without further support, that local taxes will increase if the project is built.[40]

21. Puget Sound and ColumbiaGrid allege that the Complaint has also failed to indicate "the practical, operational, or other nonfinancial impacts imposed as a result of the action or inaction, including, where applicable, the environmental, safety or reliability impacts of the action or inaction."[41] Puget Sound and ColumbiaGrid assert that the Complaint merely states that the Energize Eastside Project is "environmentally unsound and hazardous" without any support other than noting that the project will be co-located with an existing pipeline and require routine tree-cutting.[42]

22. Puget Sound and ColumbiaGrid also note that Complainants are required to state "the specific relief or remedy requested,"[43] but that some of the relief requested in the Complaint cannot be granted. They explain that Complainants request that the Commission order Puget Sound to cease and desist from any further activity with respect to the Energize Eastside Project, including seeking permits for it; however, transmission construction, siting, and permitting fall within the purview of state and local jurisdictions, so it would be beyond the scope of the Commission's jurisdiction to direct Puget Sound to refrain from seeking state and local permits for the project.[44]

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[39] *Id.* at 9-10 (citing 18 C.F.R. § 385.206(b)(4) (2015)).

[40] *Id.*

[41] *Id.* at 10 (citing 18 C.F.R. § 385.206(b)(5) (2015)).

[42] *Id.*

[43] *Id.* at 11 (citing 18 C.F.R. § 385.206(b)(7) (2015)).

[44] *Id.*

23. In addition, Puget Sound and ColumbiaGrid assert that Complainants do not have standing to bring a complaint regarding Attachment K or the Planning Agreement; Attachment K describes the process by which Puget Sound coordinates with its transmission customers, neighboring transmission providers, affected state authorities, and other stakeholders, and Complainants do not fall within any of those categories because they are merely landowners in the area where the Energize Eastside Project will be built. Similarly, Puget Sound and ColumbiaGrid assert that Complainants are third-party non-signatories to the Planning Agreement and therefore do not have standing to bring a complaint regarding the Planning Agreement.[45]

24. Puget Sound and ColumbiaGrid argue that Complainants' allegations should be dismissed as impermissible collateral attacks on Commission Order Nos. 890, 1000, and 2000. They contend that Complainants' allegation that ColumbiaGrid's method for selecting its board members does not comply with the "independence" requirements set out in Order No. 2000 and Complainants' request that the Commission order Respondents to form an RTO or ISO are not relevant to whether Puget Sound complied with its transmission planning obligations. Puget Sound and ColumbiaGrid argue that, because ColumbiaGrid is not an RTO, the Order No. 2000 "independence" requirements are not applicable. Puget Sound and ColumbiaGrid also assert that Order No. 2000 did not mandate the creation of RTOs, and Order Nos. 890 and 1000 did not impose any specific requirements for the structure in which public utilities must implement the planning provisions that were to be incorporated into Attachment K. Therefore, they argue that Complainants' assertions regarding ColumbiaGrid's method for selecting its board members and their request that the Commission order Respondents to form an RTO or ISO are impermissible collateral attacks on Order Nos. 890, 1000, and 2000.[46]

25. Puget Sound and ColumbiaGrid also contend that Complainants collaterally attack Order Nos. 890 and 1000, and the Commission's orders accepting Puget Sound's compliance filings made pursuant to those orders, when they assert that the Energize Eastside Project should have gone out to bid to third parties and that Puget Sound should be required to abandon the project if new studies show there is no load reliability issue. Puget Sound and ColumbiaGrid assert that there is no requirement in Attachment K of Puget Sound's Tariff or the Planning Agreement that Puget Sound request bids or issue a request for proposals prior to any construction of a transmission facility. They also contend that the inclusion of any project, including the Energize Eastside Project, in a

[45] *Id.* at 11-13.

[46] *Id.* at 13-14.

ColumbiaGrid transmission plan is not a condition precedent to Puget Sound's decision to build a project.[47]

26. Puget Sound and ColumbiaGrid further argue that the Complaint should be dismissed for a lack of jurisdiction as it applies to ColumbiaGrid. They assert that the Commission has found that ColumbiaGrid does not own, operate, or control jurisdictional facilities necessary to qualify it as public utility under the FPA, and, therefore, ColumbiaGrid is not subject to section 206 of the FPA.[48]

27. In answering the Complaint, Puget Sound and ColumbiaGrid argue that, if the Commission considers the substantive issues raised by the Complaint, the Complaint must be rejected because Complainants have not demonstrated that Puget Sound has failed to comply with its Commission-approved transmission planning process contained in Attachment K of the Puget Sound Tariff and the Planning Agreement, nor have they demonstrated that the Respondents have violated Orders Nos. 890 and 1000.[49]

28. In support, Puget Sound and ColumbiaGrid assert that the Energize Eastside Project was originally conceived in 2006 and pre-dates the Order No. 1000 amendments to Attachment K of Puget Sound's Tariff; therefore, the Energize Eastside Project was subject to the Order No. 890 transmission planning requirements, not the Order No. 1000 requirements. They note that the Commission held that the Order No. 1000 requirements "apply to the evaluation or reevaluation of any transmission facility that occurs *after* the effective date of the public utility transmission provider's filing adopting the transmission planning and cost allocation reforms of the pro forma [Tariff] required by this Final Rule."[50] They state that Puget Sound's Order No. 1000 amendments to Attachment K of its Tariff did not take effect until January 1, 2015, and, therefore, that Complainants' allegations regarding supposed non-compliance with Order No. 1000 are inapposite.[51]

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[47] *Id.* at 15-16.

[48] *Id.* at 19.

[49] *Id.* at 19-20.

[50] *Id.* at 20-21 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 65) (emphasis added).

[51] *Id.*

29. Moreover, Puget Sound and ColumbiaGrid argue that Puget Sound complied with its then-applicable Order No. 890 transmission planning requirements for the Energize Eastside Project. They state that, pursuant to Puget Sound's Attachment K that was approved following Order No. 890, Puget Sound was required to develop an annual 10-year plan that identified new transmission facilities and facility replacements or upgrades that it was planning over the next 10 years. They explain that, pursuant to the then-applicable Planning Agreement, Puget Sound was required to advise ColumbiaGrid of any "Single System Projects" that it was planning on its system and submit those proposed projects to ColumbiaGrid. Puget Sound and ColumbiaGrid assert that Puget Sound complied with these requirements.[52]

30. Puget Sound and ColumbiaGrid state that, in accordance with Puget Sound's Order No. 890-compliant Attachment K, Puget Sound identified the Energize Eastside Project in each of its annual 10-year plans from 2009 to 2014, and posted all of those annual plans on its Open Access Same-Time Information System. They explain that Puget Sound notified ColumbiaGrid of the Energize Eastside Project as a Single System Project, as required by the Planning Agreement, and that ColumbiaGrid subsequently included the Energize Eastside Project in its Biennial Transmission Expansion Plans.[53]

31. Puget Sound and ColumbiaGrid argue that, contrary to Complainants' arguments, their studies properly included the 1,500 MW of transmission capacity associated with Bonneville's obligation to return power to Canada under the Columbia River Treaty. They assert that, when studying energy flows on the transmission system, transmission planners study the paths upon which energy flows rather than the contract paths upon which energy is commercially transacted and scheduled. They state that all flows of energy in the Puget Sound region, such as flows related to Bonneville's obligation to deliver power to Canada, affect the flows of energy on parallel transmission facilities like Puget Sound's facilities. Puget Sound and ColumbiaGrid argue that, to ensure transmission system reliability, Puget Sound's and ColumbiaGrid's studies considered a range of possible operating conditions, including one where Bonneville schedules 1,500 MW of energy on its contract path, and the effect those operating conditions have on Puget Sound's underlying transmission facilities. They assert that these assumptions are consistent with prudent utility practice because Bonneville's legal obligation to Canada exists, and it must be accounted for and anticipated in planning studies.[54]

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[52] *Id.* at 21-22.

[53] *Id.* at 27-28.

[54] *Id.* at 6, n.20.

32. Puget Sound and ColumbiaGrid argue that the Energize Eastside Project was properly classified a Single System Project. They state that Puget Sound's then-applicable Attachment K defines a Single System Project as "any modification of a single Transmission System that[:] (i) is for the purpose of meeting a Need that impacts only such single Transmission System; (ii) does not result in Material Adverse Impacts on any transmission system; and (iii) is included as a Single System Project in a Plan."[55] They explain that the Energize Eastside Project meets a "Need" that impacts only a single transmission system. They state that a "Need" is defined to include a projected inability of a transmission owner to serve its network load, native load customer obligations, or other existing long-term firm transmission obligations. Puget Sound and ColumbiaGrid assert that, in reports from 2013 and 2015, Puget Sound identified a need for transmission supply on Puget Sound's system in order to serve Puget Sound customers.[56]

33. Puget Sound and ColumbiaGrid state that Puget Sound introduced the Energize Eastside Project into ColumbiaGrid's existing Puget Sound Area Study Team transmission expansion planning process and the study team adopted the Energize Eastside Project in the team's expansion plan, without any finding of Material Adverse Impacts on any transmission system.[57] Puget Sound and ColumbiaGrid maintain that the Energize Eastside Project was included as a Single System Project in a "Plan." They state that "Plan" is defined as "at any time the then current Biennial Plan, as then revised by any Plan Updates." They assert that ColumbiaGrid explicitly included the Energize Eastside Project as a Single System Project in its most recent 2015 Biennial Plan.[58]

34. Puget Sound and ColumbiaGrid contend that ColumbiaGrid also complied with its remaining transmission planning responsibilities with respect to the Energize Eastside Project. They note that, in accordance with the Planning Agreement, ColumbiaGrid is required to develop a Biennial Plan, which must include those Single System Projects on a transmission system that have been submitted for inclusion in the Biennial Plan. Puget Sound and ColumbiaGrid assert that ColumbiaGrid has complied with this obligation because Puget Sound properly submitted the Energize Eastside Project to ColumbiaGrid

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[55] *Id.* at 23 (citing Puget Sound Attachment K § A.51; Planning Agreement § 1.51).

[56] *Id.* at 24-25.

[57] *Id.* at 25-27.

[58] *Id.* at 27.

for consideration, and ColumbiaGrid included the project as a Single System Project in its Biennial Plans.[59]

35. Finally, Puget Sound and ColumbiaGrid argue that, even assuming *arguendo* that the Energize Eastside Project is subject to the Order No. 1000 amendments to the Puget Sound Tariff and the Planning Agreement, the Commission has made clear that Order No. 1000 "do[es] not require that the transmission facilities in a public utility transmission provider's local transmission plan be subject to approval at the regional or interregional level, unless that public utility transmission provider seeks to have any of those facilities selected in the regional transmission plan for purposes of cost allocation."[60] Puget Sound and ColumbiaGrid assert that the Energize Eastside Project is a local load-serving project and that none of the Respondents is seeking to include the project in the regional plan for purposes of cost allocation; therefore, the Energize Eastside Project would not be subject to Order No. 1000's regional approval process.[61]

### B. Seattle Motion to Dismiss and Answer

36. Seattle explains that it is a department of the City of Seattle through which the city provides electric utility service. Seattle moves to dismiss the Complaint on the grounds that nothing in Order Nos. 890 or 1000 prevents a utility from building facilities in its service territory that are needed to serve load. Seattle also asserts that Complainants' references to Order No. 2000 are irrelevant to their claims because Order No. 2000 details the requirements applicable to RTOs, and there are no RTOs in the Energize Eastside Project's region.[62]

37. More specifically, Seattle argues that, in Order No. 890, the Commission expressly disavowed any intention to dictate which investments a utility would undertake, finding that "the planning obligations imposed in this Final Rule do not address or dictate which investments identified in a transmission plan should be undertaken by transmission providers."[63] Seattle further notes that Attachment K to the Puget Sound Tariff reflects the same concept, as the Tariff states that it "does not dictate or establish which

[59] *Id.* at 28-29.

[60] *Id.* at 21 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 65).

[61] *Id.*

[62] Seattle Answer at 2-3.

[63] *Id.* at 7 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 438).

investments identified in a transmission plan should be performed or how such investments should be compensated."[64]

38. Seattle maintains that Order No. 1000 expressly permits incumbent public utility transmission providers to develop and build local transmission facilities outside of the Order No. 1000 process, provided the project is located solely within the public utility's retail distribution service area, and is not proposed or selected in the regional transmission plan for purposes of cost allocation.[65] Seattle further explains that Order No. 1000 defined a "local transmission facility" as "a transmission facility located solely within a public utility transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation."[66]

39. Seattle asserts that the Energize Eastside Project falls within the Commission's definition of a "local transmission facility" since the transmission line is limited in length to 18 miles, the proposed route for the line sits entirely within Puget Sound's combined electric and gas service area, and Puget Sound has not opted to include the project in the ColumbiaGrid regional cost allocation process under Order No. 1000.[67] Seattle argues that, therefore, the Energize Eastside Project is the type of project the Commission made clear can be developed independently by an incumbent utility, without running afoul of Order No. 1000.[68]

40. Seattle further asserts that Complainants' claim that the Energize Eastside Project is a Bulk Electric System facility under the definition adopted in Order No. 773 is irrelevant. Seattle argues that the applicable scope of the Reliability Standards enforced by the North American Electric Reliability Corporation (NERC) has nothing to do with the scope of the transmission planning process under Order No. 1000.[69]

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[64] *Id.* (citing Puget Sound Tariff, Attachment K, Part II).

[65] *Id.* at 1-2.

[66] *Id.* at 7-8 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 63).

[67] *Id.*

[68] *Id.* at 9.

[69] *Id.* at 10.

41. Finally, Seattle points out that Order No. 1000 has no direct application to entities like Seattle that fall within the definition of a non-public utility under section 201(f) of the FPA.[70] Seattle explains that it is a non-public utility because it is a department of the City of Seattle and the City of Seattle is a city organized under a Charter authorized by the Washington State Constitution.[71] Seattle asserts that, in Order Nos. 890 and 1000, the Commission expressly declined to take action under section 211A of the FPA[72] to require non-public utilities to participate in the Order Nos. 890 and 1000 processes.[73]

### C. Bonneville Motion to Dismiss

42. Bonneville argues that it should be dismissed as a Respondent because the Complaint was filed pursuant to section 206 of the FPA, but the Commission has no jurisdiction over Bonneville pursuant to section 206.[74] Bonneville asserts that the Commission and several U.S. Circuit Courts have held that the Commission lacks jurisdiction over Bonneville pursuant to section 206.[75] Bonneville also notes that it is a party to a Memorandum of Agreement with Seattle and Puget Sound that memorializes the parties' plans to construct certain transmission projects, but that a subsequent letter agreement clarified that Bonneville is not participating in the Energize Eastside Project.[76]

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[70] 16 U.S.C. § 824 (2012).

[71] Seattle Answer at 2, 6, 11.

[72] 16 U.S.C. § 824j-1 (2012).

[73] Seattle Answer at 11 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 192; Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 815, 821; Order No. 1000-A, 139 FERC ¶ 61,132 at P 778).

[74] Bonneville Motion to Dismiss at 3-4.

[75] *Id.* at 4 (citing *Avista Corp.*, 143 FERC ¶ 61,255, P 2, n.4 (2013) ("[w]e recognize that Bonneville Power is not a public utility under section 201 of the FPA, 16 U.S.C. § 824 (2006), and is not subject to Commission directives made pursuant to FPA section 206;" *Bonneville Power Admin. v. FERC*, 422 F.3d 908, 924 (9th Cir. 2005) (*Bonneville*))).

[76] *Id.* at 2-3.

### D. Avista Comments

43. Avista supports the Puget Sound and ColumbiaGrid Answer and reiterates that the Complaint contains no allegations of any violations of any specific provision of Order Nos. 890 and 1000, or of Attachment K to Puget Sound's Tariff.[77] Avista also reiterates that Order No. 1000 planning requirements do not apply to the Energize Eastside Project because the project predates the January 1, 2015 effective date of the Order No. 1000 amendments to Attachment K of Puget Sound's Tariff.[78] Avista further asserts that Complainants' request that the Commission order Puget Sound, Bonneville, and Seattle to file an Order No. 1000-compliant Planning Agreement is moot because the Commission has already conditionally accepted Respondents' Planning Agreement, subject to a further compliance filing that remains pending before the Commission.[79]

### E. Complainants Answers and Motion for Order of Default

44. Complainants filed three separate answers to respond to the Puget Sound and ColumbiaGrid Answer, the Seattle Answer, and the Bonneville Motion to Dismiss, as well as a motion for Order of Default against Bonneville. In Complainants' answer to the Puget Sound and ColumbiaGrid Answer, they reiterate that the Energize Eastside Project is not a local load facility because it falls within the Bulk Electric System definition. Complainants also argue that the project should not be considered as a local load facility because its cost will be included in the rate for firm transmission service on the Puget Sound transmission system.[80] Complainants further contend that ColumbiaGrid has agreed to submit itself to the Commission's jurisdiction because it has signed the Planning Agreement and has a Commission-approved rate schedule on file with the Commission.[81] Finally, Complainants reiterate that Puget Sound's load flow studies were flawed because they included 1,500 MW of transmission capacity for Bonneville's delivery of power to Canada.[82]

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[77] Avista Comments at 3-4.

[78] *Id.* at 4.

[79] *Id.* at 5.

[80] Complainants Answer to Puget Sound and ColumbiaGrid Answer at 3-5.

[81] *Id.* at 12.

[82] *Id.* at 13-17.

45. In their answer to the Seattle Answer, Complainants argue that the Energize Eastside Project has been "selected in a regional transmission plan for purposes of cost allocation" because its cost would go into the rate for firm transmission service on the Puget Sound transmission system.[83] Complainants also reiterate that a "single-utility" approach would have identified Puget Sound's use of Seattle's transmission facilities as the solution to meet the need that the Energize Eastside Project is designed to address.[84] Complainants further contend that the Commission has jurisdiction over Seattle pursuant to section 211A of the FPA.[85] In addition, Complainants state that Seattle is subject to sanctions under section 211A because it does not have a Tariff on file with the Commission.[86]

46. In response to the Bonneville Motion to Dismiss, Complainants argue that section 211A of the FPA authorizes the Commission to enforce the requirements of Order No. 890 against even non-public utility transmission providers like Bonneville.[87] Complainants also argue that Bonneville has voluntarily submitted to the Commission's jurisdiction under Order No. 890 in exchange for reciprocity because Bonneville has signed the Planning Agreement and has an Attachment K to its Tariff on file with the Commission.[88]

47. In the motion for Order of Default against Bonneville, Complainants argue that, because Bonneville only moved to dismiss the Complaint and did not answer the Complaint, Bonneville should be considered in default under Rule 213(e) of the Commission's Rules of Practice and Procedure[89] and, as to Bonneville, all relevant facts stated in the Complaint should be deemed admitted.[90]

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[83] Complainants Answer to Seattle Answer at 6.

[84] *Id.* at 11-12.

[85] *Id.* at 13-14.

[86] *Id.* at 3-4.

[87] Complainants Answer to Bonneville Motion to Dismiss at 2, 4-7.

[88] *Id.* at 4, 10.

[89] 18 C.F.R. § 385.213(e) (2015).

[90] Complainants Motion for Order of Default at 1-2.

### F. Seattle July 27 Answer

48. Seattle argues that Complainants are incorrect in claiming that Seattle is out of compliance with the Commission's open access policies because it does not have a Tariff on file with the Commission. Seattle asserts that reciprocity does not require Seattle to file its Tariff with the Commission. Seattle explains that it satisfies the reciprocity condition by offering to provide transmission service under the terms of its publicly-available Tariff, but it is not required to file that Tariff with the Commission.[91]

49. Seattle also argues that Complainants are wrong in asserting that there is a basis for proceeding against Seattle under section 211A of the FPA. Seattle asserts that the Complaint was framed as a complaint under section 206, which has no application to Seattle, a non-public utility under section 201(f).[92]

### G. Bonneville July 28 Answers

50. Bonneville reiterates that the Complaint was filed under section 206 of the FPA, which does not apply to Bonneville, and that the Complaint fails to allege any violation on the part of Bonneville that falls within the Commission's jurisdiction. In response to Complainants' argument that section 211A authorizes the Commission to enforce the requirements of Order No. 890 against Bonneville, Bonneville argues that Complainants have not made any arguments that fall within the Commission's section 211A authority. Bonneville states that section 211A(b)(2) authorizes the Commission to issue a rule or order requiring an unregulated transmission utility, such as Bonneville, to provide transmission services "on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential."[93] However, Bonneville argues that Complainants do not make any allegation of non-comparable or discriminatory effects as required by section 211A. Bonneville asserts that, moreover, Complainants are not current or potential transmission customers of Bonneville, and thus could not have been denied any service on Bonneville's system or be treated differently than any other of Bonneville's customers.[94]

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[91] Seattle July 27 Answer at 3-4.

[92] *Id.* at 5.

[93] Bonneville July 28 Answer at 3-4 (citing 16 U.S.C. § 824j-1(b)(2) (2012)).

[94] *Id.* at 4.

51. Bonneville also disputes that it has voluntarily submitted itself to the Commission's jurisdiction. It states that, in *Bonneville*, the U.S. Court of Appeals for the Ninth Circuit rejected an argument that Bonneville had submitted itself to Commission jurisdiction by agreeing to abide by certain tariffs, and found that the Commission cannot exercise jurisdiction beyond what is authorized in the statute, regardless of whether the jurisdiction is exercised without objection or even with the consent of the relevant parties.[95]

52. Bonneville also filed an answer to Complainants' motion for Order of Default. Bonneville states that Rule 213(e) of the Commission's Rules of Practice and Procedure does not require the Commission to find an entity in default for failing to answer a complaint, but instead provides that any person failing to answer a complaint "may" be considered in default and the relevant facts "may" be deemed admitted as to that person. Bonneville argues that it should not be considered in default because the Commission's lack of jurisdiction over Bonneville under section 206 is well settled and, thus, it would be a waste of Bonneville's and the Commission's resources to require Bonneville to answer the Complaint. If the Commission finds that it has jurisdiction over Bonneville in this case, Bonneville requests that the Commission deny the motion for Order of Default and allow Bonneville additional time to file an answer.[96]

### H. Subsequent Pleadings

53. On August 11, 2015, Puget Sound filed a letter providing supplemental information to the factual assertions in its answer. On the same day, Complainants filed a letter asking the Commission not to make Puget Sound's letter part of the record.

## III. Discussion

### A. Procedural Matters

54. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2015), Avista's timely, unopposed motion to intervene serves to make it a party to this proceeding. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2015), the Commission will grant the late-filed motion to intervene of Powerex, given its interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

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[95] *Bonneville*, 422 F.3d at 924.

[96] Bonneville July 28 Answer to Motion for Order of Default at 3-5.

55. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2015), prohibits an answer to an answer unless otherwise ordered by the decisional authority. We will accept the answers in this case because they provided information that assisted us in our decision-making process.

### B. Substantive Matters

56. We will dismiss the Complaint with respect to Bonneville, Seattle, and ColumbiaGrid because the Complaint was filed pursuant to section 206 of the FPA, and Bonneville, Seattle, and ColumbiaGrid are not subject to the Commission's section 206 jurisdiction. Section 201 of the FPA specifies the scope of the Commission's jurisdiction under subchapter II of the FPA, which includes section 206. Section 201(f) provides that, "[n]o provision in this subchapter shall apply to, or be deemed to include, the United States, a State or any political subdivision of a State. . . or any agency, authority, or instrumentality of . . . the foregoing . . .unless such provision makes specific reference thereto."[97] Bonneville is a federal power marketing administration within the United States Department of Energy[98] and Seattle is a city organized under a Charter authorized by the Washington State Constitution;[99] section 206 of the FPA does not make any specific reference to include entities such as Bonneville or Seattle. Therefore, Bonneville and Seattle are not subject to the Commission's jurisdiction under section 206 of the FPA. The Commission has also found that ColumbiaGrid does not own, operate or control jurisdictional facilities necessary to qualify it as public utility under the FPA; thus, it is not subject to the Commission's jurisdiction under section 206 of the FPA.[100] Accordingly, we dismiss the Complaint against Bonneville, Seattle, and ColumbiaGrid.

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[97] 16 U.S.C. § 824(f).

[98] *See, e.g.,* Bonneville Motion to Dismiss at 3; *Avista Corp*., 143 FERC ¶ 61,255, at P 2, n.4 (2013) ("We recognize that Bonneville Power is not a public utility under section 201 of the FPA…and is not subject to Commission directives made pursuant to FPA section 206.").

[99] *See* Seattle Answer at 11.

[100] *See ColumbiaGrid*, 119 FERC ¶ 61,007, at PP 16, 27 (2007) ("NIPPC argues that the Commission should find that ColumbiaGrid is subject to the Commission's jurisdiction because ColumbiaGrid will perform certain jurisdictional services… We also disagree with assertions raised by NIPPC regarding the jurisdictional status of ColumbiaGrid… The current Planning Agreement does not cause ColumbiaGrid to own, operate or control jurisdictional facilities").

57. Complainants argue that the Commission has jurisdiction over Bonneville and Seattle in this matter pursuant to section 211A of the FPA.[101] We disagree. Section 211A provides that the Commission may issue a rule or order requiring an unregulated transmitting utility, such as Bonneville or Seattle, to provide transmission services "(1) at rates that are comparable to those that the unregulated transmitting utility charges itself; and (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential."[102] In Order No. 890, the Commission did not adopt a generic rule implementing section 211A with respect to all non-jurisdictional unregulated transmitting utilities[103] or invoke its authority under section 211A to require such non-jurisdictional entities to participate in the Order No. 890 planning processes, but instead found that it could exercise such authority on a "case-by-case" basis if there is an appropriate record.[104] Complainants have provided no basis for the Commission to exercise its authority under section 211A. The Complaint does not allege that Respondents are providing non-comparable, discriminatory, or preferential transmission services. Moreover, the Complaint does not allege that the Complainants are current or potential transmission customers of any Respondent; therefore, Complainants could not have received non-comparable or discriminatory transmission service from any Respondent, or have been treated differently from any other of Respondents' transmission customers.[105]

58. Complainants also argue that Bonneville, Seattle, and ColumbiaGrid have agreed to submit themselves to the Commission's jurisdiction because they are parties to the Planning Agreement and have tariffs or rate schedules on file with the Commission.[106]

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[101] *See* Complainants Answer to Bonneville Motion to Dismiss at 3-7; Complainants Answer to Seattle Answer at 13-14.

[102] 16 U.S.C. § 824j-1(b).

[103] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 192.

[104] *Id.* P 441.

[105] *See id.* P 192 ("A *potential customer* may file an application with the Commission seeking an order compelling the unregulated transmitting utility to provide transmission service that meets the standards of FPA section 211A.") (emphasis added).

[106] *See, e.g.,* Complainants Answer to Puget Sound and ColumbiaGrid Answer at 12; Complainants Answer to Seattle Answer at 13-15; Complainants Answer to Bonneville Motion to Dismiss at 10.

Complainants assert that it is "commonplace" and "axiomatic" in the law that "a party not otherwise subject to the jurisdiction of a governmental entity can nevertheless agree to submit itself to that jurisdiction."[107] However, courts have found that the Commission cannot exercise jurisdiction or authority that is not authorized by statute, even if the relevant parties voluntarily participated in Commission-approved markets and the parties consent to the jurisdiction.[108]

59. We also will dismiss the Complaint with respect to the remaining Respondent, Puget Sound. Rule 206 of the Commission's Rules of Practice and Procedure provides that a complaint must "[c]learly identify the action or inaction which is alleged to violate applicable statutory standards or regulatory requirements"[109] and "[e]xplain how the action or inaction violates applicable statutory standards or regulatory requirements."[110] We find that the Complaint fails to meet these requirements because the Complaint does not cite any specific provision of any Commission order or regulation, or any specific provision of the Puget Sound Tariff or Planning Agreement, that Respondents have allegedly violated. Instead, Complainants make vague allegations that Respondents have violated Order Nos. 890, 1000, and 2000, as well as the Puget Sound Tariff and Planning Agreement, without citing any specific provision of those orders, the Tariff, or the Planning Agreement that Respondents have allegedly violated. Thus, Complainants have not identified the "applicable statutory standards or regulatory requirements," that Respondents have allegedly violated. We cannot conclude that the Complaint has sufficiently identified the behavior that allegedly violates the applicable standards or requirements, or that it has sufficiently explained how there is such a violation, when Complainants have not even identified the applicable standards or requirements.

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[107] *See, e.g.,* Complainants Answer to Puget Sound and ColumbiaGrid Answer at 12; Complainants Answer to Bonneville Motion to Dismiss at 10.

[108] *See, e.g., Bonneville*, 422 F.3d 908, 924 ("[The Commission] cannot exercise jurisdiction or authority unless authorized by statute, regardless of whether the jurisdiction is exercised without objection or even with the consent of the relevant parties. . .Similarly, [the Commission] cannot expand its statutory authority to reach governmental entities/non-public utilities through § 206(b) simply because such entities voluntarily participated in markets approved by [the Commission] that involved [Commission]-jurisdictional wholesale sales of electric energy in interstate commerce.").

[109] 18 C.F.R. § 385.206(b)(1).

[110] 18 C.F.R. § 385.206(b)(2).

60. The Commission has previously dismissed complaints for failing to comply with these requirements. For example, in a case involving a complaint that alleged a violation of a NERC Reliability Standard, the Commission dismissed the complaint, finding that, "[i]f a complaint regarding an alleged violation of a Reliability Standard is to meet the threshold requirements of Rule 206, then the complaint must, at a minimum, set forth the specific provision of the Reliability Standard that is at issue."[111] The Complaint here similarly fails to provide that minimum level of specificity because it simply makes broad reference to Order Nos. 890, 1000, and 2000, the Puget Sound Tariff, and the Planning Agreement, and does not set forth any specific provision that is at issue.

61. In addition to the Complaint's procedural deficiencies, Complainants have not met their burden of proof under section 206 of the FPA to demonstrate that the Respondents' actions with respect to the Energize Eastside Project have violated any applicable requirement or are otherwise unjust, unreasonable, or unduly discriminatory, or preferential. Rather, contrary to Complainants' vague allegations that the Respondents have violated Order Nos. 890 and 1000, the record before us shows that Puget Sound and the other Respondents have complied with the applicable transmission planning requirements in those orders.

62. We agree with Puget Sound and ColumbiaGrid that the Energize Eastside Project was properly evaluated under the then-applicable Order No. 890 transmission planning requirements. The Commission has stated that Order No. 1000 does "not require that the transmission facilities in a public utility transmission provider's local transmission plan be subject to approval at the regional or interregional level, unless that public utility transmission provider seeks to have any of those facilities selected in the regional transmission plan for purposes of cost allocation."[112] The Commission has further explained that "Order No. 1000 does not prevent an incumbent transmission provider from meeting its reliability needs or service obligations by choosing to build new transmission facilities that are located solely within its retail distribution service territory or footprint and that are not selected in a regional transmission plan for purposes of cost allocation."[113] The record before us shows that the Energize Eastside Project is located completely within Puget Sound's service territory, that it was included in Puget Sound's local transmission plan to meet Puget Sound's reliability needs, and that neither Puget Sound, nor any other eligible party, requested to have the project selected in the

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[111] *Citizens Energy Task Force v. Midwest Reliability Org.*, 144 FERC ¶ 61,006, at P 39 (2013).

[112] Order No. 1000-A, 139 FERC ¶ 61,132 at P 190.

[113] *Id.* P 425.

regional transmission plan for purposes of cost allocation;[114] therefore, the project is not subject to the Order No. 1000 regional approval process, and is instead subject to the Order No. 890 transmission planning requirements.

63. Based on the record before us, we find that Puget Sound and the other Respondents complied with their transmission planning responsibilities under Order No. 890 in proposing and evaluating the Energize Eastside Project. As required by the Attachment K of Puget Sound's Tariff that was approved following Order No. 890, Puget Sound identified the Energize Eastside Project in its annual 10-year plans. Puget Sound also notified ColumbiaGrid of the Energize Eastside Project as a Single System Project, as required by the then-applicable Planning Agreement, and ColumbiaGrid subsequently included the Energize Eastside Project in its Biennial Transmission Expansion Plans.[115] We agree with Puget Sound and ColumbiaGrid that the Energize Eastside Project was properly classified a Single System Project because it was designed to address Puget Sound's projected inability to serve its own customers, ColumbiaGrid's Puget Sound Area Study Team did not find any Material Adverse Impacts associated with the project, and ColumbiaGrid included the project as a Single System Project in its most recent 2015 Biennial Plan. Accordingly, we find that the Energize Eastside Project was proposed and evaluated in accordance with the then-applicable transmission planning requirements.

64. Complainants argue that the Energize Eastside Project has been "selected in a regional transmission plan for purposes of cost allocation," and therefore is subject to the Order No. 1000 regional approval process, because its cost would go into the transmission rate for firm transmission service on the Puget Sound transmission system.[116] However, Complainants' argument confuses two separate issues. The regional cost allocation contemplated in Order No. 1000 involves allocating the costs of a transmission facility across a region. Including the cost of the Energize Eastside Project in Puget Sound's rate for firm transmission service on its system affects only Puget Sound's transmission rate and does not mean that the project was "selected in a regional transmission plan for purposes of cost allocation."

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[114] *See, e.g.,* Puget Sound and ColumbiaGrid Answer at 5, 21; Seattle Answer at 9.

[115] Puget Sound and ColumbiaGrid Answer at 27-28.

[116] *See* Complainants Answer to Seattle Answer at 6.

65. Complainants also assert that development of the Energize Eastside Project should have gone out to bid to third parties pursuant to Order No. 1000.[117] However, Complainants are incorrect because Order No. 1000 does not require project developers to be selected using a competitive bidding process[118] and there is no requirement in Puget Sound's Tariff or the Planning Agreement that Puget Sound issue a request for proposals or request bids prior to any construction of a transmission facility.

66. Complainants request that the Commission order Puget Sound "to cease and desist from any further activity with respect to [the Energize Eastside Project], including seeking permits for it."[119] Regardless of Complainants' arguments, we could not grant this requested relief because much of the "activity with respect to" the project, such as transmission siting and permitting, is not subject to the Commission's jurisdiction.

67. Complainants argue that the Energize Eastside Project is not a local load-serving project that is exempt from Order No. 1000 because it is a Bulk Electric System facility, as defined in Order No. 773.[120] This argument is inapposite. The Bulk Electric System definition was developed by NERC for use in determining the scope of NERC Reliability Standards and related obligations. Specifically, the definition of Bulk Electric System includes transmission facilities that are 100 kV or higher, with exceptions, such as local distribution facilities.[121] Order No. 1000 does not require that transmission planning regions use this Bulk Electric System definition to determine whether a transmission project is subject to the Order No. 1000 regional planning process. Instead, Order No. 1000 provides public utilities with the option to "use flexible criteria in lieu of 'bright line' metrics when determining which transmission projects are in the regional

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[117] *See, e.g.*, Complaint at 2.

[118] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 259, 321 & n.302 ("[T]he public utility transmission providers in a region may, but are not required to, use competitive solicitation to solicit projects or project developers to meet regional needs…[T]he Commission declines to adopt commenter suggestions to mandate a competitive bidding process for selecting project developers.").

[119] Complaint at 7.

[120] *See, e.g., id.* at 6; Complainants Answer to Puget Sound and ColumbiaGrid Answer at 4-5.

[121] Order No. 773, 141 FERC ¶ 61,236 at PP 45, 52, 56.

transmission plan."[122] Consistent with this option, ColumbiaGrid's regional planning process does not use the voltage of a transmission project as a threshold metric to determine whether the project should be in the regional plan. Nevertheless, the Energize Eastside Project is not subject to the Order No. 1000 regional approval process because it is located completely within Puget Sound's service territory, it was included in Puget Sound's local transmission plan to meet Puget Sound's reliability needs, and neither Puget Sound, nor any other eligible party, requested to have the project selected in the regional transmission plan for purposes of cost allocation. Whether or not the Energize Eastside Project falls within the Bulk Electric System definition does not affect this conclusion.

68. Complainants discuss alleged flaws in the load flow studies that Puget Sound conducted for the Energize Eastside Project. However, Complainants do not demonstrate that the studies violated any applicable transmission planning requirements or were otherwise unjust, unreasonable, or unduly discriminatory or preferential. Complainants do not cite anything that would require Puget Sound to use the study inputs and assumptions that Complainants prefer instead of the inputs and assumptions that Puget Sound used. Complainants state, without citation, that Puget Sound was obligated to ask ColumbiaGrid to conduct power flow studies for the project pursuant to a 2012 Order No. 1000 compliance filing.[123] They also assert that the studies did not comply with the "single utility" rule set forth in Order No. 1000.[124] However, as discussed above, any Order No. 1000 requirements are not applicable to the Energize Eastside Project. Beyond this, Complainants merely assert that Puget Sound's load flow studies were not "industry-standard," produced "tortured results," and used "undisclosed and dubious inputs."[125] Complainants do not explain what the "industry-standard" for such load flow studies is, and do not cite to anything demonstrating that Puget Sound's study inputs and assumptions were flawed beyond Complainants' mere allegations that they are

[122] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 223; Order No. 1000-A, 139 FERC ¶ 61,132 at P 283 (affirming that public utility transmission providers, in consultation with stakeholders, may apply either flexible criteria or bright-line metrics when determining which transmission facilities are in the regional transmission plan).

[123] *See* Complaint, J. Richard Lauckhart Aff. at P 25.

[124] *See id.* at 7, J. Richard Lauckhart Aff. at PP 49-50.

[125] *See id.* at 2-3; J. Richard Lauckhart Aff. at P 25.

flawed.[126] Moreover, Puget Sound has demonstrated that its needs assessments identified a transmission capacity deficiency, that the Energize Eastside Project was included in its annual transmission plans to address the deficiency beginning in 2009, that the project was reviewed by ColumbiaGrid's Puget Sound Area Study Team and not found to have any Material Adverse Impacts, and was included in ColumbiaGrid's Biennial Transmission Plans.[127] Accordingly, we do not believe that Complainants' allegations that Puget Sound's load flow studies were flawed provide any basis for the Commission to grant any of Complainants' requested relief.

69. Complainants also allege that ColumbiaGrid's method for selecting its board members is not fully compliant with the "independence" requirements set out in Order No. 2000. This allegation is inapposite because the Order No. 2000 "independence" requirements apply to RTOs, and ColumbiaGrid is neither an RTO nor ISO.[128] Accordingly, the "independence" requirement of Order No. 2000 does not apply to ColumbiaGrid.

70. Finally, Complainants request that the Commission order Puget Sound, Bonneville, and Seattle to provide the Commission with an Order No. 1000-compliant Planning Agreement, or, in the alternative, order those entities to form an RTO to ensure Order No. 890 and Order No. 1000 compliance.[129] Order No. 2000 encouraged the voluntary formation of RTOs, but did not require entities to form RTOs.[130] Therefore, Order No. 2000 does not support Complainants' argument that the Commission can order Puget Sound, Bonneville, and Seattle to form an RTO or ISO. Additionally, Complainants' request that the Commission order those Respondents to file an Order No. 1000-compliant Planning Agreement is also misplaced. Respondents have already

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[126] *CAlifornians for Renewable Energy, Inc. v. Pac. Gas & Elec. Co.*, 142 FERC ¶ 61,143, at P 18 (2013) ("rather than bald allegations, [complainants] must make an adequate proffer of evidence including pertinent information and analysis to support its claims.") (quoting *Ill. Mun. Elec. Co. v. Cent. Ill. Pub. Serv. Co.*, 76 FERC ¶ 61,084, at 61,482 (1996)).

[127] *See, e.g.,* Puget Sound and ColumbiaGrid Answer at 5, 26-27.

[128] *See, e.g., id.* at 14; Avista Comments at 3, n.5.

[129] *See* Complaint at 8.

[130] Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 30,995 ("we find it appropriate in this instance to adopt an open collaborative process that relies on voluntary regional participation to design RTOs.").

filed the Planning Agreement with the Commission to facilitate compliance with Order No. 1000 and the Commission has conditionally accepted the Planning Agreement, subject to a further compliance filing, which remains pending before the Commission.[131] Any concerns that Complainants have regarding the compliance of Respondents' Planning Agreement with Order No. 1000 are more properly considered in that proceeding. Moreover, Complainants Coalition of Eastside Neighborhoods for Sensible Energy and Citizens for Sane Eastside Energy have filed a motion to intervene and protest in that ongoing proceeding,[132] and have not explained why timely resolution of their concerns regarding Order No. 1000 compliance cannot be achieved in that forum.[133]

71. Given our determinations above, we will deny Complainants' motion for Order of Default against Bonneville. As Bonneville notes, Rule 213 does not require the Commission to find an entity in default for failing to answer a complaint, but provides that the Commission "may" make such a finding.[134] Given that the Commission does not have section 206 jurisdiction over Bonneville in this proceeding, we find that Bonneville is not in default for not answering the Complaint.

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[131] *See Avista Corp.,* 151 FERC ¶ 61,127, at P 2 (2015).

[132] Coalition of Eastside Neighborhoods for Sensible Energy, *et al.*, Motion to Intervene and Protest, Docket No. ER15-429-001, *et al.* (filed July 6, 2015).

[133] *See* 18 C.F.R. § 385.206(b)(6) (2015) (providing that a complaint must "[s]tate whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the complainant is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum.").

[134] 18 C.F.R. § 385.213(e) ("[a]ny person failing to answer a complaint *may be* considered in default, and all relevant facts stated in such complaint *may be* deemed admitted.") (emphasis added).

<u>The Commission orders</u>:

(A) The Complaint is hereby dismissed, as discussed in the body of this order.

(B) Complainants' motion for Order of Default is hereby denied, as discussed in the body of this order.

By the Commission.

( S E A L )

Nathaniel J. Davis, Sr.,
Deputy Secretary.

# ATTACHMENT B
# Certification of Need

PUGET SOUND ENERGY
The Energy To Do Great Things

Puget Sound Energy
P.O. Box 97034
Bellevue, WA 98009-9734

PSE.com

March 10, 2021

Heidi Bedwell
Environmental Planning Manager
City of Bellevue
450 110th Avenue NE
Bellevue, WA 98004

**RE: Reliability Certification for PSE's Energize Eastside Project (LUC 20.20.255.E)**

Dear Ms. Bedwell:

Puget Sound Energy, Inc. (PSE) proposes the construction of a new 230-115 kV substation in the Bellevue area and to upgrade the existing 115 kV lines to 230 kV lines to provide a reliable source of electricity to the new substation. As detailed below, PSE hereby certifies that this proposed electrical utility facility would provide increased capacity and reliability for more than 100,000 Eastside customers in the cities of Bellevue, Redmond, Kirkland, Newcastle, and Renton and will improve the reliability of PSE's system as a whole.

PSE as studied the need for the proposed electrical utility facility for more than a decade. PSE followed and continues to follow mandatory planning assessment standards by North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) to assess the need. In 2009, PSE's annual NERC required planning study indicated that there was a need for additional transmission capacity in the Eastside area. Given the significant consequences of the situation we had identified, PSE went outside the company for a qualified third-party review of PSE's work. The 2013 and 2015 Eastside Needs Assessments, completed by Quanta Technology, confirmed that by winter of 2017-18 and summer 2018, there would be a transmission capacity need on the Eastside of Lake Washington which impacts PSE customers and communities including Newcastle.

In fact, PSE's actual summer system peak demand for power in 2017 exceeded our summer peak demand forecasted for 2018 — one year earlier than expected. Again, in August 2018, the Eastside's actual summer peak demand exceeded the demand that was forecasted for 2020 – two years earlier than expected. This actual peak demand data confirmed that the transmission deficit on the Eastside is not a forecasted point in the future but is a current and existing system capacity deficit.

PSE's 2009 conclusion has been re-confirmed each year in our annual transmission planning assessments. During these assessments, PSE reconsiders previous transmission planning conclusions as required by NERC. All of PSE's annual reviews have concluded that that the

Energize Eastside project is needed for PSE to comply with NERC planning criteria and maintain the reliability of electrical services to Newcastle, Renton, Bellevue and Redmond and the system as a whole.

The need for the Energize Eastside project has also been confirmed by independent third-party review undertaken by the City of Bellevue, the Partner Cities who drafted the Project Environmental Impact Statement (EIS) and, in 2020, by the City of Newcastle. The City of Bellevue commissioned its own study to peer review PSE's Energize Eastside transmission planning studies and to look at local vs. regional need. This study was performed by Utility Systems Efficiencies (USE). During the EIS process, the Partner Cities hired yet another company, Stantec, to peer-review PSE's methods of assessing project need. Both USE (independently for Bellevue alone) and Stantec (collectively on behalf of all the EIS Partner Cities) confirmed that PSE and Quanta's work was done correctly in assessing the need for the Energize Eastside project. All of Bellevue's independent reviews of the need for the proposed electrical utility facility have confirmed that the project is needed to comply with NERC reliability criteria.

Completing this infrastructure upgrade would eliminate PSE's reliance on operational corrective action plans (CAPs). These operational CAPs could include intentional load shedding under certain conditions and/or sectionalizing the transmission system to reduce the load to prevent exceeding capacity limitations of the transmission equipment. Thus, the construction of the proposed electrical utility facility will aid in ensuring reliable service to all the Eastside customers and beyond and by preventing a large area outage.

Should you have further questions, please feel free to contact Brad Strauch, Energize Eastside Infrastructure Program Manager at 425-456-2556.

Sincerely,

Jens Nedrud, Professional Engineer (PE)
Manager System Planning
PUGET SOUND ENERGY

# ATTACHMENT C

# Assessment of Proposed Energize Eastside Project

# Prepared for the City of Newcastle by MaxETA Energy, PLLC and Synapse Energy Economics, Inc.

# Assessment of Proposed Energize Eastside Project

Technical review with respect to Section 18.44.052 of the City of Newcastle Municipal Code

Prepared for the City of Newcastle

June 2020 Update[1]

MaxETA Energy, PLLC

MaxETA Energy, PLLC:
Jorge Camacho, PE

Synapse Energy Economics, Inc.

Synapse Energy Economics, Inc:
Kenji Takahashi
Asa Hopkins, PhD
David White, PhD

[1] This core update contains data furnished by PSE in May 2020.

1032 15th ST NW, Suite 204, Washington, DC 20005 | 202.794.5015

# Contents

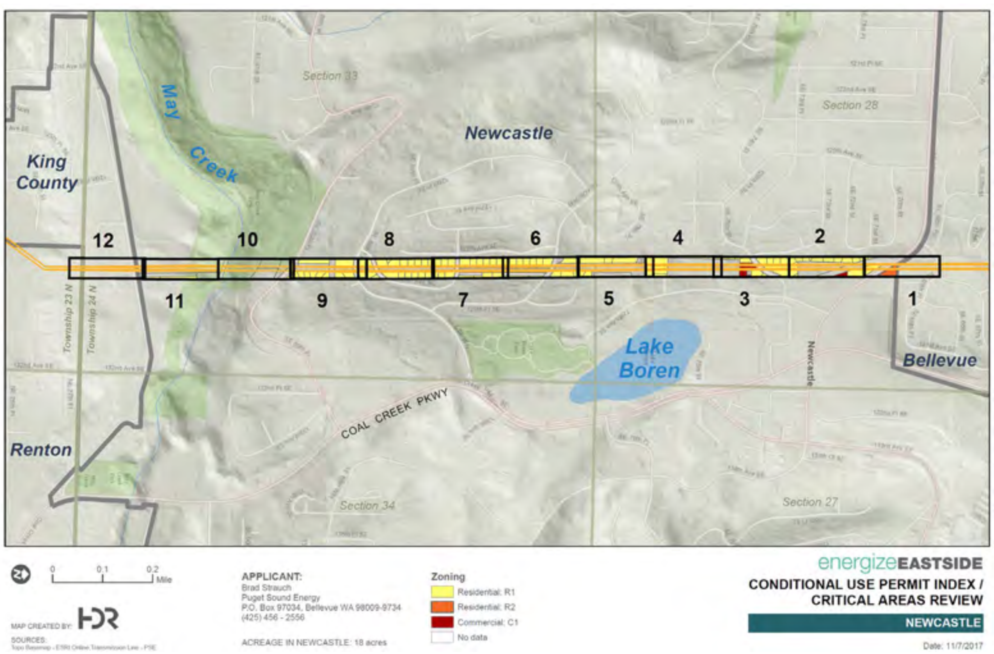
# 1. EXECUTIVE SUMMARY

<u>Background</u>

Puget Sound Energy (PSE) is projecting rapid load growth in the Eastside area near Lake Washington in Washington State. As a result, the utility identified the need to upgrade its substation and transmission infrastructure as early as 2008. To meet this need PSE proposed the Energize Eastside project in 2013, which entails building a new substation and upgrading transmission lines. PSE also investigated alternatives to building the substation, including energy conservation, batteries, and solar panels. However, the company concluded that such alternatives would not sufficiently address reliability concerns caused by the expected load growth.

As part of the Energize Eastside project, PSE applied to the City of Newcastle for a Conditional Use Permit (#CUP17-002) for a Regional Utility Facility. PSE asked to upgrade its electric transmission facilities for approximately 1.5 miles in the existing utility corridor, Willow 1, that spans approximately 1.5 miles in Newcastle; see Figure 1 below.

**Figure 1. PSE proposed Energize Eastside electric transmission route, Newcastle**




*Source: PSE Site Plans, Energize Eastside Project, November 2017.*

The upgrades in Newcastle are part of a large transmission project plan[2] that extends from the Sammamish transmission substation in Redmond to the Talbot Hill transmission substation in Renton (Figure 2). This plan was proposed to address several identified contingency[3] deficiencies in transmission capacity that PSE claims are triggered by summer and winter peak demand in King County. The proposed Energize Eastside project would build a new electric substation, the Richards Creek substation in Bellevue, and upgrade existing transmission lines in Redmond, Bellevue, Newcastle, and Renton.

**Figure 2. PSE proposed Energize Eastside electric transmission facilities and route**


*Source: Energize Eastside Project Newsletter Summer 2017*

In parallel with two other local communities affected by the project, the City of Newcastle is investigating PSE's Eastside filings to assess the need for the Energize Eastside project and to determine whether to provide the utility a city permit to allow PSE to upgrade its transmission infrastructure. MaxETA and Synapse Energy Economics were hired by the City of Newcastle to aid this investigation.

<u>Methodology</u>

As part of this need assessment, MaxETA and Synapse team assessed:

a) Whether PSE's load forecast methodology and assumptions, as well as forecast results, are reasonable and technically sound;

b) Whether there is a regional need for additional transmission capacity to maintain reliability;

c) Whether PSE has taken all necessary and cost-effective measures (including demand-side measures) to prevent an operational need from arising.

MaxETA and Synapse team reviewed various publicly available reports prepared by PSE as well as additional data obtained from PSE regarding historical and updated forecasted loads, conservation, and other demand-side resources.[4] The team also carried out a load flow model analysis to evaluate regional

[2] Energize Eastside, https://energizeeastside.com/.
[3] Contingency – an event where one or more electric facilities suffer an outage.
[4] See Section 4, Reviewed Material.

load conditions under contingencies, including whether the regional capacity thresholds estimated by PSE are reasonable.

Key Findings

- Our assessment of power flows finds that current or projected electric peak demand arising solely from the City of Newcastle does not trigger an operational need for the proposed transmission expansion.[5] However, our analysis shows that the current summer electric peak demand in King County has already triggered an operational need for the proposed transmission expansion to address system contingency scenarios and ensure the security of the Bulk Electric System.[6]

- Our power flow model assessment finds that the regional capacity thresholds in King County estimated by PSE are reasonable.

- The PSE load forecast approach follows a standard industry practice, although it has some limitations regarding the way it identifies and incorporates demand-side resources.

- Our review of historical summer peak loads and the capacity thresholds in King County provided by PSE shows that there is a summer transmission capacity deficiency in King County under N-1-1 contingencies even at today's peak load level. We further find that this capacity deficiency for the summer season has been 13 to 20 percent (or 200 to 300 megawatts, or MW) above the area's capacity threshold.

- Our review of historical winter peak loads and the capacity thresholds in King County shows PSE's winter peak load actually has been declining over the past several years. While we found that PSE's own winter load forecast is above the capacity threshold, we cannot conclude based on the data we analyzed whether there is a clear need for transmission capacity expansion for serving winter peak loads. PSE's past winter peak load forecasts have over-predicted winter peak loads and the current forecast does not appear to fully incorporate either the declining trend seen in winter peak over the last decade or potential emerging conservation opportunities.[7]

- PSE has adequately conducted transmission planning that seeks to prevent a facilities outage from becoming a customer interruption.

[5] This finding addresses a question posed by Newcastle. It is outside the scope of this evaluation to determine if the question posed by Newcastle is consistent with municipal code requirements.
[6] An unsecured Bulk Electric System could impact the reliability of electric service in Newcastle.
[7] By its very nature, load forecasting is a forward-looking planning tool.

Conclusions

PSE has demonstrated that the proposed transmission upgrades are needed to safeguard the operational reliability of the electric system as a whole.[8] To maintain system security, power systems are operated so that overloads do not occur either in real-time or under any statistically likely contingency. Not securing the bulk electric system to operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies could affect the electric supply reliability in Newcastle. This peer review verified that under specific contingencies (N-1-1 and N-2) the as-is bulk electric system serving Newcastle is already susceptible and operationally reliant in the implementation of Corrective Action Plans (CAPs).This means that PSE's application has met the threshold for approval described in Newcastle City Code C-5 under NMC 18.44.052 Utility facilities – Regional: "[t]he applicant shall demonstrate that an operational need exists that requires the location or expansion at the proposed site."

The current transmission deficiency can be cured by upgrading one of the 115kV transmission lines between the Talbot Hill and Sammamish substations to 230kV and installing an additional 230kV/115kV 325MVA transformer at the proposed Richards Creek substation in Bellevue. Upgrading the second 115kV transmission line that currently travels through the same corridor, Willow 1, to 230kV is consistent with good system planning, particularly because the facilities to support these higher voltages will already be deployed.

[8] Electric system as a whole is also referred to as Bulk Electric System.

Recommendations

We recommend that the Conditional Use Permit to PSE to upgrade the identified approximately 1.5 miles of existing 115kV lines with 230kV lines come with a condition: PSE should conduct an independent design assessment of the overhead transmission facilities traversing Newcastle to verify compliance with the clearance safety rules for the installation and maintenance of overhead electric supply of the 2017 National Electrical Safety Code (NESC), ANSI C2 Part 2. [9] We also recommend that the City of Newcastle send field inspectors during the transmission line upgrades to ensure compliance with the 2017 NESC.

[9] https://apps.leg.wa.gov/WAC/default.aspx?cite=296-45-045

# 2. INTRODUCTION AND NEWCASTLE MUNICIPAL CODE REVIEW

Puget Sound Energy's (PSE) past and current load forecasts show continued growing electric load in the Eastside area near Lake Washington in Washington State. The utility examined the expected growing demand in detail and identified the need to upgrade its substation and transmission facilities as early as 2008. In 2013, the PSE proposed the Energize Eastside project to address this load growth issue, including a proposal to build a new substation and upgrade transmission lines. PSE also investigated alternatives to building new substation and transmission facilities, specifically energy conservation, demand response, batteries, and solar panels. However, PSE's studies concluded that such alternatives would not sufficiently address reliability concerns caused by the expected load growth.

In parallel with two other local communities affected by the project, the City of Newcastle is investigating PSE's Eastside filings to assess the need for the Energize Eastside project and to determine whether to provide the utility a city permit to allow PSE to upgrade its transmission infrastructure. MaxETA and Synapse Energy Economics were hired by the City of Newcastle to aid this investigation.

The City of Newcastle requires that "[p]roposals that include new or expansions to existing utility facility – regional shall demonstrate compliance with" several criteria under NMC 18.44.052 ("Utility facilities – Regional") in addition to the conditional use permit criteria listed in NMC 18.44.050. For the purposes of NMC 18.44.052, expansions include "a modification of an existing regional utility facility by an increase in the size, height, impervious coverage, floor area, or parking area of the facility by greater than 10 percent."

Among others, our review specifically investigates whether PSE as an applicant to the City of Newcastle has complied with the following criteria under NMC 18.44.052:

> C-5. The applicant shall demonstrate that an operational need exists that requires the location or expansion at the proposed site;
>
> C-6. The applicant shall demonstrate that the proposed utility facility – regional improves reliability to the customers served and reliability of the system as a whole, as certified by the applicant's licensed engineer;

To find answers to these code requirements, this independent consultant report assesses:

a) Whether PSE's load forecast methodology and assumptions, as well as forecast results, are reasonable;

b) Whether there is a regional need for additional transmission capacity to maintain reliability; and

c) Whether PSE has taken all necessary and cost-effective measures (including demand-side measures) to prevent an operational need from arising.

# 3. Overview of Eastside Needs Assessment and Eastside Project

## 3.1. History of Eastside Needs Assessments

Since 2008, PSE has conducted numerous studies on the reliability of its transmission facilities to meet future peak load conditions and needs for transmission facility expansion. These studies identified a variety of concerns, and the studies conducted in recent years identified and examined solutions to the concerns in detail.

Earlier studies include the 2008 Initial King County Transformation Study, 2009 PSE TPL Planning Studies and Assessment, and the 2012 PSE TPL Planning Studies and Assessment.[10] These studies found that "potential thermal violations may occur on facilities from Talbot Hill Substation to Sammamish Substation," as noted in a 2013 study commissioned by PSE called the "2013 Eastside Needs Assessment."[11]

More recent studies focused on transmission facilities in the Eastside area and examined both the transmission needs as well as solutions. The studies that focused on the need for the transmission facilities are:

- 2013 Eastside Needs Assessment Report ("2013 Needs Assessment") prepared by Quanta Technology
- 2015 Supplemental Eastside Needs Assessment Report ("2015 Supplemental Needs Assessment" or "2015 Needs Assessment") prepared by Quanta Technology

Notably the 2013 Eastside Needs Assessment found that there would be a transmission deficiency in the winter of 2017–2018 and in the summer of 2018. More specifically, these key findings are as follows:

- "For the Winter peak at approximately 5,200 MW (2017–18 in the model) there are two 115 kV elements with loadings above 98% for Category B (N-1) contingencies and five 115 kV elements above 100% for Category C (N-1-1 & N-2) contingencies."
- "For the Summer peak at approximately 3,500 MW (2018 in the model), there are two 230 kV elements above 100% and two 115 kV elements above 93% loadings for Category B (N-1) Contingencies. There are also three elements above 100% loading and one above 99% loading for Category C (N-1-1) contingencies."[12]

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[10] Descriptions of these studies are provided on page 23 of the 2013 Eastside Needs Assessment.
[11] Quanta Technology 2013. Eastside Needs Assessment Report – Transmission System King County.
[12] Quanta Technology 2013. Page 8.

The 2013 Needs Assessment also found that a summer load level of need (3,340 MW) could occur as early as 2014. However, the study emphasizes that the PSE summer load level where King County starts to have significant issues is at about the 3,500 MW level projected for 2018.[13]

The 2013 Eastside Needs Assessment report also indicated the need to expand the use of Corrective Action Plans ("CAPs") to manage these overloads. CAPs are implemented according to the regional entity's procedures to remedy a specific system problem using a list of actions and an associated timetable for implementation. These actions include:[14]

- Installation, modification, retirement, or removal of transmission and generation facilities and any associated equipment
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violation
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan
- Use of rate applications, Demand Side Management (DSM), new technologies, or other initiatives
- If situations arise that are beyond the Transmission Planner or Planning coordinator that prevent CAP implementation in the required timeframe:
    - Non-Consequential Load Loss
    - Curtailment of Firm Transmission Service

PSE does not advocate for the use of CAPs as a solution to an identified need.[15] As a temporary operational alternative, NERC Standard TPL-001-4 allows curtailment and loss of load for specific contingencies to meet performance requirements. However, it is best practice to avoid the use of these operating procedures.

The 2013 Needs Assessment also indicated the overloads could be more severe if peak loads were higher as a result of other factors, such as extreme cold weather conditions, higher load growth due to local economic conditions, or lower conservation achievements relative to PSE's conservation targets.

The 2015 Supplemental Needs Assessment verified that there was still an expected transmission capacity deficiency in the Eastside area in the winter of 2017–2018 and in the summer of 2018. This

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[13] Quanta Technology. 2013. 2013 Eastside Needs Assessment, page 8, 9, 13 and 70; Quanta technology. 2015. 2015 Supplemental Eastside Needs Assessment Report, page 18.

[14] NERC Standard TPL-001-4 R2.7

[15] 2015 Supplemental Eastside Solutions Study Report.

study further identified that the summer capacity deficit is worse than what was identified in the 2013 Needs Assessment. The 2015 study found expected needs to use CAPs and load shedding to mitigate the system deficiency while the 2013 study found CAPs would be required, but not load shedding.[16]

To address these potential transmission deficiency problems, PSE carried out numerous studies to examine potential solutions including traditional supply-side solutions and non-wires solutions such as energy efficiency, demand response, and batteries: [17]

- 2013 Eastside Solutions Study Report (Updated February 2014), prepared by Quanta Technology
- 2014 PSE Screening Study, prepared by E3
- 2014 Eastside 230 kV Project Underground Feasibility Study, prepared by Power Engineers
- 2015 Supplemental Eastside Solutions Study Report, prepared by Quanta Technology
- 2015 Eastside System Energy Storage Alternatives Study, prepared by Strategen
- 2015 Lake Washington Submarine Cable Alternative Feasibility Study, prepared by Power Engineers
- 2018 Eastside System Energy Storage Alternatives Assessment Update, prepared by Strategen

## 3.2. PSE's Latest Eastside Contingency Load Threshold Analysis

The 2013 Eastside Needs Assessment Report includes a heat map that PSE claimed is a depiction of electric load density. However, we note that this map shows the most densely populated areas in and around the Eastside (see Figure 3) which do not necessarily coincide with electric demand. We conducted power flow models in the Northwest area serving the South King county zone using historical and projected peak demand for King County.[18] We ran the models employing the base cases provided by the Western Electricity Coordinating Council (WECC) and varying key sensitivities while maintaining the projected peak demand constant to evaluate regional grid conditions under various contingency events.

For Summer 2018, our load flow analysis verified that under N-1-1 contingencies the 230/115kV transformers at the Sammamish substation will overload when modeled using reasonable transformer series resistances and reactances and MVA operational limits. However, we also found that realistic increases in peak demand arising solely from the City of Newcastle, primarily served by the Hazelwood substation in the South King County zone, have negligible effect in the thermal transformer overloads identified for the Sammamish substation.

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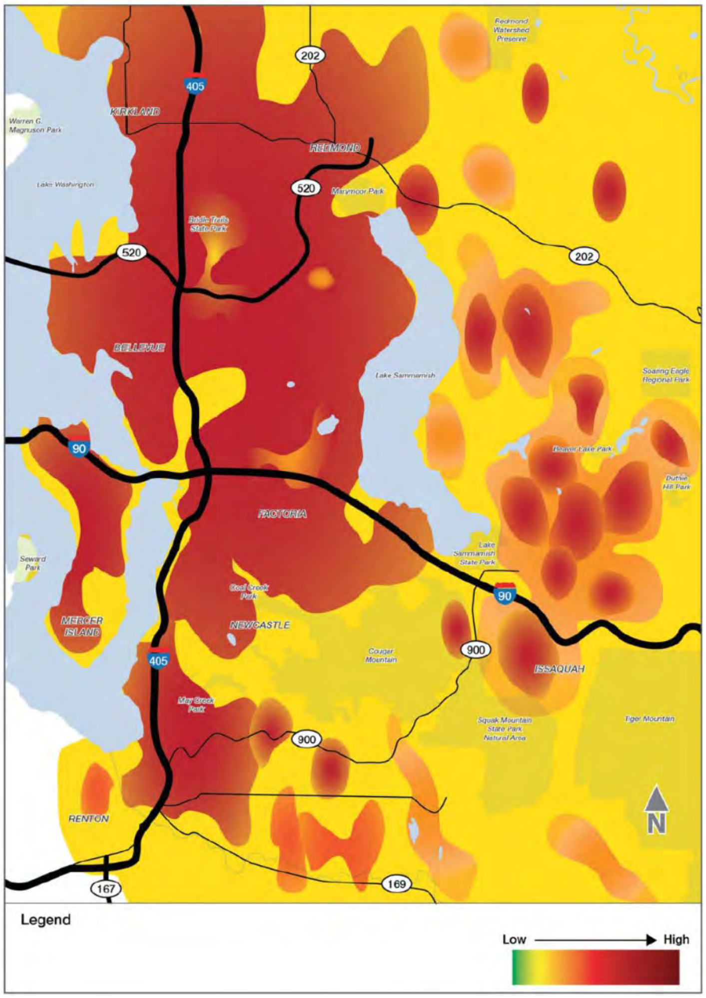
[16] Quanta Technology. 2015, page 4.

[17] These studies are available at https://energizeeastside.com/.

[18] An assessment of historical and projected peak demand is discussed in Section 5, for summer peak loads, see Figure 10 in Section 5.

**Figure 3. Modified heat map**




*Source: 2013 Eastside Needs Assessment Report depicts population density.*

We were able to verify that under several contingencies certain facilities of the bulk electric system serving Newcastle will overload. The operational need arises from having to comply with NERC reliability standards that safeguard the security of the bulk electric system and not due to the discrete electric peak demand in Newcastle. We want to highlight that Newcastle will experience electric supply reliability issues if the bulk electric system is not secured.

Page 18 of the 2015 Supplemental Needs Assessment references 3,340 MW of area summer load as a threshold above which PSE's transmission facilities will be overloaded under extreme system contingency events. Table 6-12 from the 2013 Eastside Needs Assessment further justifies the 3,340 MW as a level of concern by demonstrating equipment is overloaded to 100 percent of emergency rating during N-1-1 contingency at 3,340 MW of area summer load. In 2017, PSE switched to Electric Power Research Institute's PTLOAD program to calculate load limits for transformers because the existing in-house software was unmaintainable. The PTLOAD program is a widely accepted tool in the industry for rating transformers. With the new software, PSE adjusted its level of concern downward to

3,125 MW in the summer. The level of concern load level difference between 2013 and 2019 is mainly due to a change to a more widely accepted method of determining the individual transformer ratings. The latest estimate of the level of concerns by PSE is provided in Table 1 below for the PSE's entire service territory and for King County. Our load flow analysis confirmed that these load thresholds are reasonable.

**Table 1. PSE's revised load thresholds**

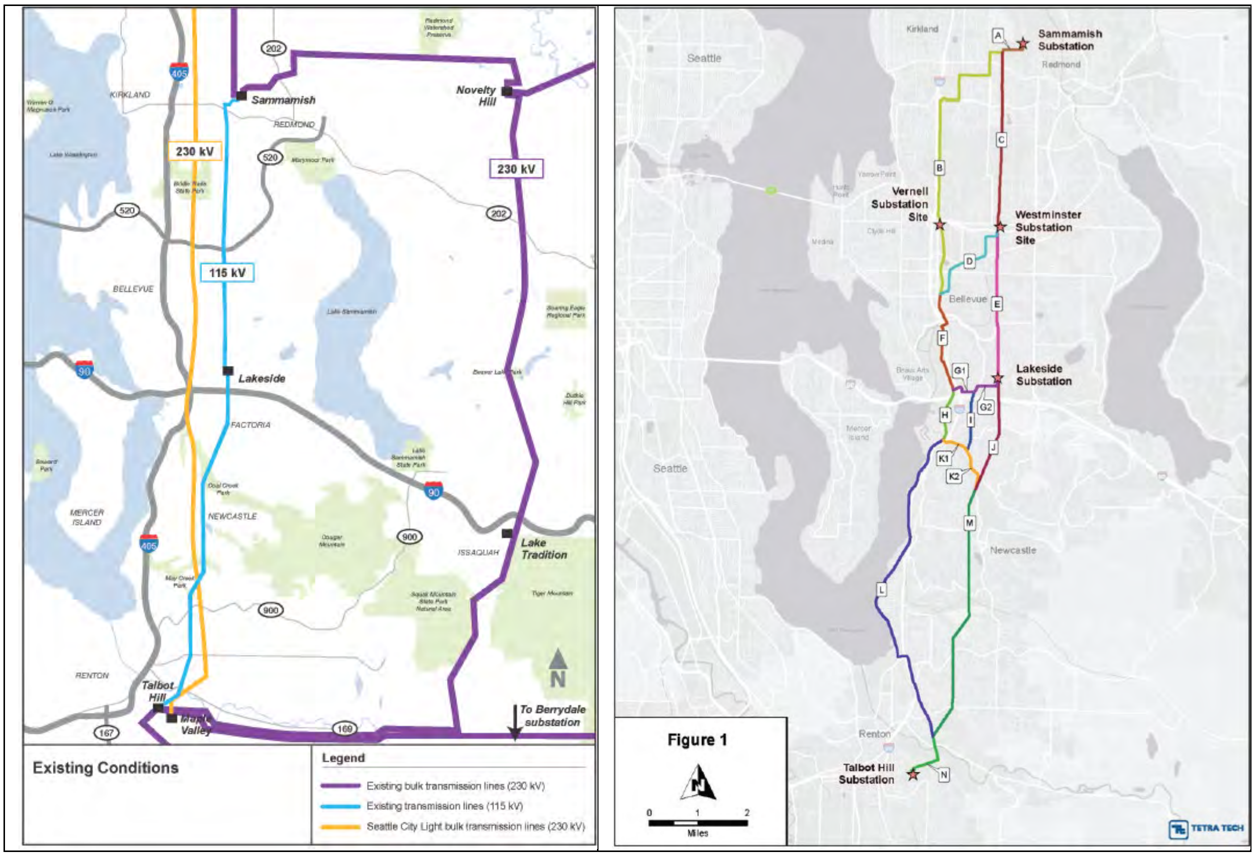
| | Summer (MW) | Winter (MW) |
|---|---|---|
| **PSE Area Load (Native + Transportation)** | 3125 | 5000 |
| **King County (Native + Transportation)** | 1594 | 2436 |

*Source: PSE Data Request Response – September 9, 2019; Note: These load levels were calculated by scaling 2018 TPL seasonal caseloads until the emergency rating exceeded 100 percent during N-1-1 contingency.*

## 3.3. Description of Proposed Eastside Project

PSE identified several contingency[19] deficiencies in its transmission capacity that are triggered by summer peak demand in King County. To address these deficiencies, PSE proposes a transmission expansion plan[20] that extends from the Sammamish transmission substation in Redmond to the Talbot Hill transmission substation in Renton (Figure 4). The proposed Energize Eastside project will also build a new electric substation, the Richards Creek substation in Bellevue, and upgrade existing transmission lines in Redmond, Bellevue, Newcastle, and Renton. PSE claims that these upgrades and new facilities are needed to ensure the bulk electric system continues to perform reliably under several contingencies.

**Figure 4. Energize Eastside project's proposed upgrade to the Sammamish-Talbot Hill 115kV transmission line (blue line left) to 230kV and new substation, the Richards Creek substation, in Bellevue**




*Source: Tetra Tech (December 2013) Eastside 230kV Project Constraint and Opportunity Study for Linear Site Selection.*

[19] Contingency – an event where one or more electric facilities suffer an outage.

[20] Energize Eastside, https://energizeeastside.com/.

# 4. LOAD FORECASTS AND NEED ASSESSMENT

## 4.1. PSE Load Forecast Methodology

The PSE load forecast approach follows a standard industry practice, although it has some limitations regarding the way it incorporates demand-side resources. PSE uses typical econometric models to forecast energy and peak loads over a 20-year time period. PSE's forecasting approach mainly consists of a regional economic and demographic model and a billed sales and customers model. The former uses both national- and county-level data to produce a forecast of various economic and demographic factors (*e.g.*, employment, types of employment, unemployment, personal income, population, households, building permit, etc.). The latter model takes the outputs from the former model and projects the number of customers by class as well as the energy use per customer by class. This model then multiplies the number of customers and energy use per customer to arrive at the billed sales forecast by class.

PSE uses another regression model to estimate electric peak loads based on observed monthly peak system demand and monthly weather normalized delivered demand.[21] It is not clear how much historical data are used in PSE's load forecast models, but one report produced by a consultant for Bellevue (Bellevue Consultant report) stated that key historical statistics are available for the entire system from 2000 and for King County and Eastside area from 2006.[22]

PSE's current forecasts are produced for each county. However, PSE also produced a forecast specific to the Eastside area in the 2013 and 2015 Eastside Needs Assessment studies. The Bellevue Consultant report noted that PSE started to produce county-by-county forecasts starting in 2015. The report also noted that for the 2013 and 2015 Eastside Needs Assessment studies, PSE produced the Eastside-specific forecast from the King County forecast using census tract data.[23] However, our data request to PSE revealed that PSE has not updated its forecast for the Eastside area since then, despite the fact that the Eastside was the most critical area of the Needs Assessment studies.[24]

PSE also makes some further adjustments to its load forecasts. Most notably, PSE reduces annual energy and peak load demands to account for the cost-effective amount of energy conservation (also called demand-side resources) identified in PSE's integrated resource plan (IRP) process.[25] The 2013 and 2015 Eastside Needs Assessment studies included several conservation scenarios, including one scenario called 100% Conservation (including 100 percent of the conservation potential estimated in the most recent IRP) and a 75% Conservation scenario. PSE has been including the impacts of electric vehicles in

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[21] PSE. 2017. 2017 PSE Integrated Resource Plan, Chapter 5.

[22] Utility System Efficiencies, Inc. 2015. Independent Technical Analysis of Energize Eastside, prepared for the City of Bellevue, Page 19.

[23] Utility System Efficiencies, Inc. 2015. Page 15.

[24] PSE response on June 14, 2019 to Newcastle Consultants' data request on May 15, 2019.

[25] PSE. 2017. 2017 PSE Integrated Resource Plan, Chapter 5, page 5-2.

its load forecast since its 2017 IRP.[26] PSE also includes the impacts of specific new construction projects in its near-term load forecasts, but correctly transitions those projects out of the forecast over several years to reflect the fact that new construction is included in the econometric projections of the base load forecast.

## 4.2. PSE Evaluation of Conservation and Other Demand-Side Resources

As mentioned above, PSE commissioned several studies to examine the potential of energy conservation and other demand-side resources as NWAs to the Energize Eastside project. These studies specifically examined whether there are sufficient demand-side resources available to reduce peak loads to the levels below critical thresholds under transmission contingency events (*e.g.*, N-1-1 conditions). Below we briefly summarize each of the key studies. Appendix A lists these studies as well as other studies we reviewed.

- **2013 Eastside Needs Assessment by Quanta Technology**: As mentioned above, in order to examine the need for transmission expansion, this study analyzed the impact of energy conservation measures on peak load forecasts based on the most recent IRP. The study assessed the capacity overloads for the entire PSE system and for the Eastside area with various conservation levels including a 100% Conservation scenario. The study identified system overloads by 2017–2018 for winter peak and as early as 2014 for summer peak under normal weather conditions, assuming 100 percent of the energy conservation estimated in the recent IRP. The study is not clear regarding which version of the IRP was used to develop conservation estimates, but it is likely that the study used PSE's 2013 IRP given the timing of the study.

- **2015 Supplemental Eastside Needs Assessment by Quanta Technology**: This report updated the load forecasts and reassessed the need for transmission capacity expansion in the Eastside area. The report indicates no changes to its energy conservation assumptions or methodologies. Unlike the 2013 study, this report clearly indicates that it used conservation targets from the 2013 IRP, although Quanta did not include the active demand response from that IRP because PSE did not implement active demand response following the IRP's publication.[27]

- **E3 study**: In early 2014, E3 assessed the potential for NWAs in King County to defer the proposed transmission upgrades in the Eastside area, including energy efficiency, demand response, and distributed generation.[28] Using additional avoided benefits of deferring the transmission upgrades, the study assessed as NWAs incremental amounts of cost-effective demand-side resources beyond the level of resources selected in PSE's 2013 IRP. The study found a total of 56 MW of incremental demand-side resource potential (30 MW from energy efficiency, 25 MW from demand response, and 1 MW from distributed generation) in King County. The study concluded that these demand-

[26] PSE. 2017. 2017 PSE Integrated Resource Plan, Chapter 5, page 5-37.

[27] Quanta Technology. 2015. Page 7.

[28] E3. 2014. 2014 PSE Screening Study.

side resources are not sufficient to defer the transmission need because the region will be 75 MW short with PSE's 100% Conservation scenario or 100 MW short with its 75% Conservation scenario (which also acts a proxy for the higher load growth scenario or extreme winter conditions). The study focused on winter peak loads, apparently because winter peak is the main focus of the 2013 Needs Assessment. Detailed examination of this study is outside of the scope of our analysis. However, it is not clear to us whether the amount of demand-side resources identified in this study is still valid today, mainly because the study is more than six years old and because potential amounts likely have changed since then.

- **Strategen 2015:** PSE commissioned Strategen to evaluate the feasibility of electric battery storage as an incremental measure to the additional demand-side resources identified by the E3 study.[29] The study examined annual hourly load data and determined that Talbot Hill substation was the substation with the most significant normal and emergency overloads that occur during the winter period. Assuming the demand-side resource results from the E3 study, the study examined load flows of the network transmission system and determined the battery sizes necessary to resolve normal overload reductions in the short term (Baseline), emergency overload elimination (Alternative #1), and normal overload elimination in the long term (Alternative #2). The resulting battery sizes are 328 MW, 121 MW, and 544 MW respectively.[30] The study also examined the technical feasibility and cost-effectiveness of large-scale batteries and concluded that batteries are not technically feasible under the Baseline and the Alternative #2 scenarios due to the excessive size of the batteries, siting limitations, long project timeline, and limited transmission system capacity to charge the batteries. The study then found that while the Alternative #1 (121 MW battery for resolving 34 MW of emergency overload) is technically feasible and cost-effective with a benefit-cost ratio of 1.13 and a $264 million net present value cost estimate, this scenario does not meet PSE's reliability requirements. However, we note it is likely that the estimated battery sizes are overestimated for addressing winter peak loads because the historical winter peak loads have been substantially lower than projected in the past. Nevertheless, the study's results for addressing the summer peak overloads are likely still applicable.

- **Strategen 2018**: PSE commissioned Strategen to conduct a new study updating the Strategen 2015 study to consider changes to substation equipment ratings, PSE's updated load forecasts in 2017, and recent advancements in the energy storage market.[31] This study analyzed the feasibility of two scenarios: (a) the Interim Solutions that meet the Winter 2018/2019 and Summer 2019 overload constraints and (b) the Complete Solution that meets PSE's 2027 forecasted need. The conclusions of this study are mostly consistent with the findings of the Strategen 2015 study. The 2018 Strategen Study found that energy storage is still not a practical solution to meet the expected

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[29] Strategen. 2015. Eastside System Energy Storage Alternatives Screening Study.

[30] These estimates take into account battery degradation factors and the study's finding that only 20 percent of the battery capacity is effective in reducing load at the substation and the rest of the battery outputs are expected to affect loads in other substations due to the interconnected nature of the network transmission system.

[31] Strategen. 2018. Eastside System Energy Storage Alternatives Assessment - Report Update.

Eastside transmission overloads. The study found that required battery systems would be substantially more expensive than the proposed transmission upgrades and would require large land areas (*e.g.*, 19 times the size of Tesla's Hornsdale facility in Australia, the world's largest currently installed system). The study also found that the largest system constraints have shifted from Talbot Hill substation for the winter peak period to Sammamish substation for the summer peak period. The required system size for the Complete Solution is 549 MW to serve the expected summer peak load in 2027. However, our review of PSE's latest load forecasts (discussed in the following section) reveals that the summer peak gap is about 460 MW in 2027 without demand response, solar PV, and other distributed generation (See Figure 10 in this section). Thus, it is likely the Strategen 2018 study overestimated the size and cost of battery options.

- **Latest conservation estimate**: PSE's latest load forecasts include the impacts of the 100% Conservation scenario that is consistent with the latest Conservation Potential Assessment included as Appendix J to the 2017 IRP, with the exception of demand response and distributed generation. This conservation potential includes PSE's energy efficiency programs, distribution efficiency (*e.g.*, conservation voltage reduction) and savings from codes and standards. Based on data from PSE, we found that PSE assumes 361 MW of winter conservation potential for 2023 (224 MW from energy efficiency programs, 132 MW from codes and standards, and 4 MW from distribution efficiency) while PSE's IRP selected 374 MW of conservation for the same year.[32]

[32] PSE. 2017. 2017 PSE Integrated Resource Plan, Chapter 1, Figure 1-4; File "Newcastle DR Q1 partG.xlsx" obtained from PSE data response on September 10, 2019 to Newcastle Consultants' data request on August 8, 2019.

## 4.3. PSE Winter Peak Load and Needs Assessment

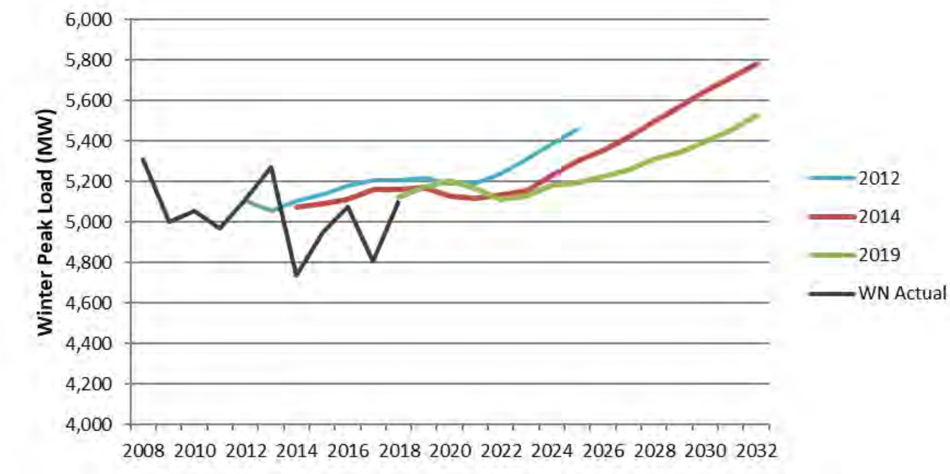
We conducted a review of historical winter and summer peak loads and the winter and summer peak load forecasts that PSE has made over the last several years. We obtained PSE's latest historical load data and load forecast through the data request process and compared them with PSE's previous analyses provided in the 2013 and 2015 Needs Assessment report. This sub-section focuses on our assessment of PSE's winter peak load estimates.

Figure 5 presents PSE's load forecasts for its service territory made in 2012, 2014, and 2019 along with weather-normalized actual winter peak loads (*i.e.*, loads adjusted for the specific weather impacts seen each year). These loads represent loads including the demand-side resource potential estimated in PSE's IRPs except peak load impacts from any demand response or distributed generation. These load data are also adjusted for PSE's transmission-level customers that are not included in PSE's corporate load forecasts.[33] This figure shows that the historical winter peak loads have been lower than what PSE's load forecasts have projected in the past, except in 2012.[34] It is also important to note that there has been a slight declining trend in the historical weather-normalized peak loads over the past 10 years. The annual average growth rate over the past 10 years is -0.4 percent. PSE did not project this decline. In fact, PSE's forecasts show increasing loads into the future years, and past forecasts showed increasing load during the time period when actual loads have declined. In addition, newer forecasts show lower peak loads than previous forecasts, and the time at which peak loads are projected to rise substantially appears to be shifting into the future with each forecast.

[33] We assume 270 MW of peak load for transmission-service customers per page 8 in the 2015 Supplemental Needs Assessment.

[34] This finding reflects updated weather normalized winter peak demand of PSE entire service territory furnished by PSE in May 2020.

**Figure 5. PSE entire service territory: winter peak load forecasts and actual peak load**




*Source: Compiled from PSE load forecast documents and discovery responses—WN Actual is weather-normalized actual peak load.*

PSE's load forecasts have historically over-projected loads relative to actual loads. This was noted by Washington Utilities and Transportation Commission (WUTC) in its "Acknowledgement letter attachment" to PSE's 2017 IRP. In this letter WUTC noted, "historically, PSE's load forecasts have been overly optimistic" and included an assessment of PSE's load forecasts by the Lawrence Berkeley National Laboratory in terms of average annual growth rate of energy (AAGR) as shown in Table 2 below.[35]

**Table 2. PSE's projected and actual average annual growth rate of electric energy**

| Period | LSE-Projected AAGR | Actual AAGR |
|---|---|---|
| **2006-2014** | 1.75% | -0.19% |
| **2012-2014** | 1.90% | -1.19% |

*Source: WUTC Acknowledgement letter to PSE's 2017 IRP.*

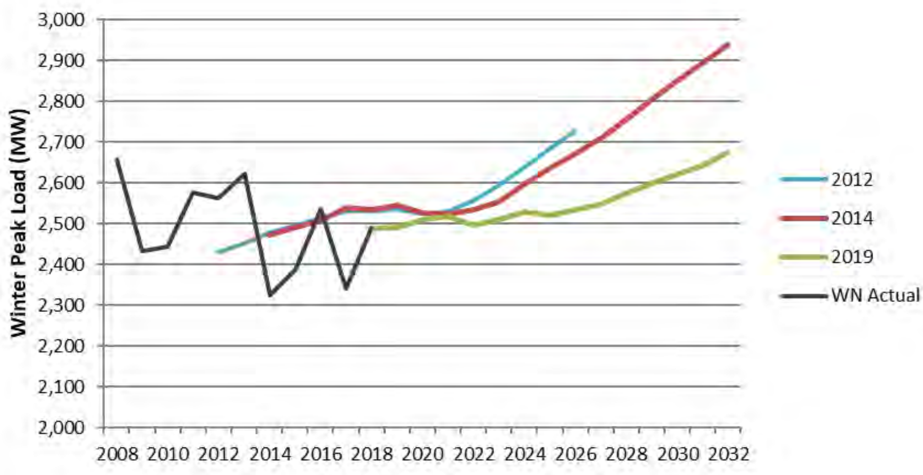
Historical loads and PSE's peak load forecasts for King County also show similar trends to what we have observed in PSE's entire jurisdiction, as shown in Figure 6. Both the historical loads and projected loads in this figure include additional peak loads expected from transmission-level customers.[36] Historical

[35] Washington Utilities and Transportation Commission (WUTC). 2018. Acknowledgement letter attachment: Puget Sound Energy's 2017 Electric and Natural Gas Integrated Resource Plan, Dockets UE-160918 and UG-160919. Page 11. Available at https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=1743&year=2016&docketNumber=160918.

[36] We assumed 81 MW of peak loads from those customers per PSE's data response on September 9, 2019 to our data request on August 8, 2019.

weather-normalized peak loads have been lower than forecasted weather-normalized peaks in four of the five most recent years (from 2014 to 2018 except 2016).[37]

**Figure 6. PSE King County: winter peak load forecasts and actual peak load**




*Source: Compiled from PSE load forecast documents and discovery responses. WN Actual is weather-normalized actual peak load.*

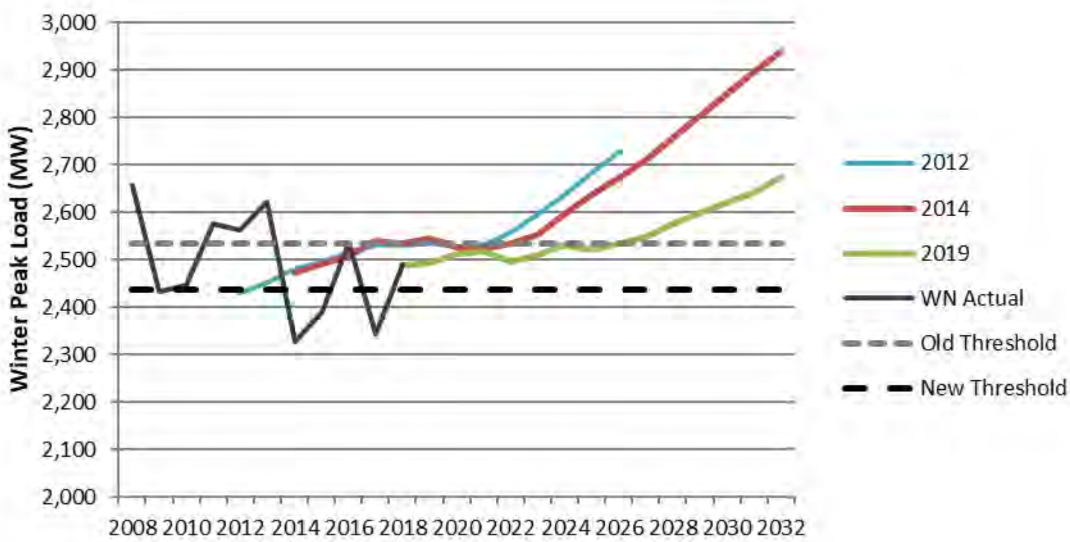
Finally, we examined the potential for winter transmission capacity constraints in King County—that is, whether and to what extent King County currently has or is expected to have any transmission capacity deficiency based on PSE's projections. We compared King County's current and projected winter peak loads with PSE's estimates for peak load thresholds. In other words, we examined the load levels of concern above which PSE's transmission facilities (*i.e.*, Talbot substation for the winter peak) are expected to experience capacity deficiency under contingency events (*i.e.*, N-1-1 conditions). This analysis is presented in Figure 7. Our analysis focuses on King County because PSE identified load constraints in the Eastside area and because PSE has not produced any updated historical loads or forecasts for the Eastside area since the 2015 Supplemental Needs Assessment, despite the fact that the Eastside was the most critical area of the Needs Assessment studies.

Figure 7 includes two separate estimates for load thresholds, labeled as "Old Threshold" and "New Threshold." The "Old Threshold" represents a load threshold (or a level of concern) that was estimated in the 2013 and 2015 Eastside Needs Assessment report, scaled from the full PSE service territory to King County. During our investigation of the needs for the Eastside, we learned that PSE switched to EPRI's PTLOAD software to characterize its transformers. This change resulted in a reduction in the MW threshold, primarily due to different assumptions regarding the performance of grid components that are built into the PTLOAD model. The "New Threshold" in Figure 7 reflects this new estimate. For the PSE service territory, the thresholds were reduced from 5,200 MW to 5,000 MW for the winter period

[37] This finding reflects updated weather normalized winter peak demand of PSE King County service territory furnished by PSE in May 2020.

(representing a 4 percent reduction) and from 3,340 MW to 3,125 MW for the summer period (representing a 6 percent reduction).[38] For King County, the new peak load thresholds are 2,436 MW for the winter and 1,594 MW for the summer. Because the 2013 and 2015 Needs Assessment reports did not provide any load threshold for King County, we estimated the "Old Threshold" for King County by taking the ratio of load threshold changes at the level of PSE's service territory.

**Figure 7. PSE King County: winter peak load estimates vs. peak load thresholds**




*Source: Compiled from PSE load forecast documents and discovery responses. WN Actual is weather-normalized actual peak load.*

A comparison of the loads in Figure 7 reveals that the recent actual winter peak loads have been lower than the Old Threshold, but were above the New Threshold in 2016 and 2018.[39] PSE's latest load forecast developed in 2019 shows projected load levels above the new load threshold starting in 2018, although only by about 50 to 80 MW (or 2 to 3 percent) over the next few years. The average annual growth rate over the past decade is -0.65 percent. As with the case of the system-wide peak load forecasts, PSE did not project this declining peak load in its past forecasts. PSE's latest forecast still shows an increasing winter peak trend. While the 2018 peak load is above the New Threshold, we are not convinced that the loads will remain above the New Threshold because PSE's winter peak load forecasts have historically over-projected winter peak loads. The current forecast may have a bias in projecting higher peak loads and not fully reflecting historical winter peak trends, just like the gap the WUTC identified between the annual electric sales forecasts and actual sales from 2006 to 2014 as mentioned above. Further, there is a possibility that future loads may not increase as much as PSE is projecting or even could be lower than the New Threshold if PSE follows the WUTC's recommendation

[38] PSE data response on September 10th to Newcastle's August 8th data request 4(b).

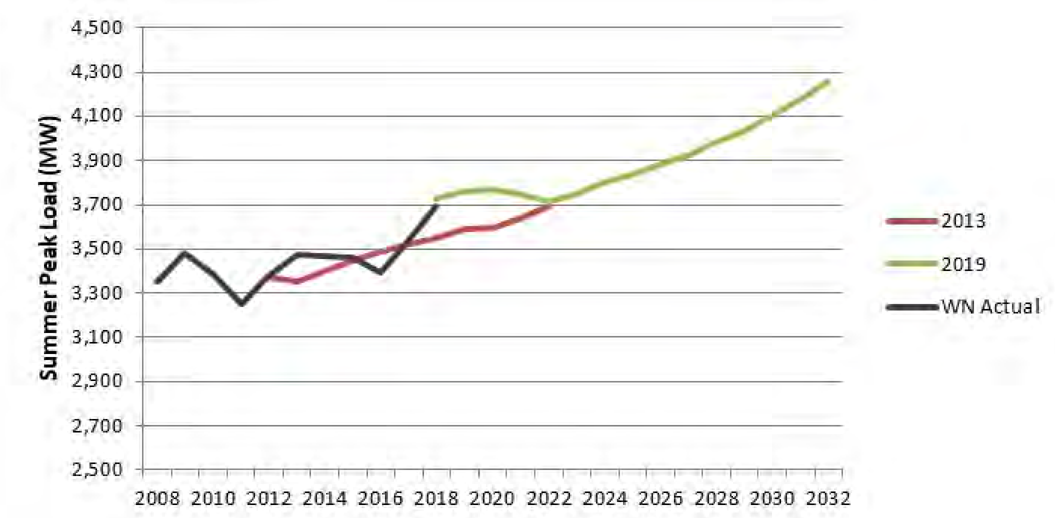
[39] This finding reflects updated weather normalized winter peak demand furnished by PSE in May 2020.

that "PSE should assume in years 11 through 20 that a reasonable level of emerging retrofit conservation measures will be available in the market at cost-effective rates even though they cannot be accurately identified or predicted now."[40]

## 4.4. PSE Summer Peak Load and Needs Assessment

PSE's summer peak loads present a very different story than the winter peak loads. Figure 8 presents PSE's load forecasts for its entire service territory made in 2013 and 2019, along with weather-normalized actual, historical summer peak loads through 2018 (*i.e.*, loads adjusted for annual specific weather impacts). As with the winter peak load estimates, the summer peak load estimates include loads for PSE's transmission level customers.[41] The load forecasts also represent loads adjusted for 100 percent of the demand-side resource potential estimated in PSE's IRPs. This figure shows that, unlike the historical winter peak loads, the historical summer peak loads have been increasing over the past several years, as forecast by PSE in 2013. Further, unlike PSE's winter peak forecast, the load for the first year for each forecast matches closely with the weather-normalized actual, historical loads (*i.e.*, year 2012 and 2018).

**Figure 8. PSE service territory: summer peak load forecasts and actual peak**



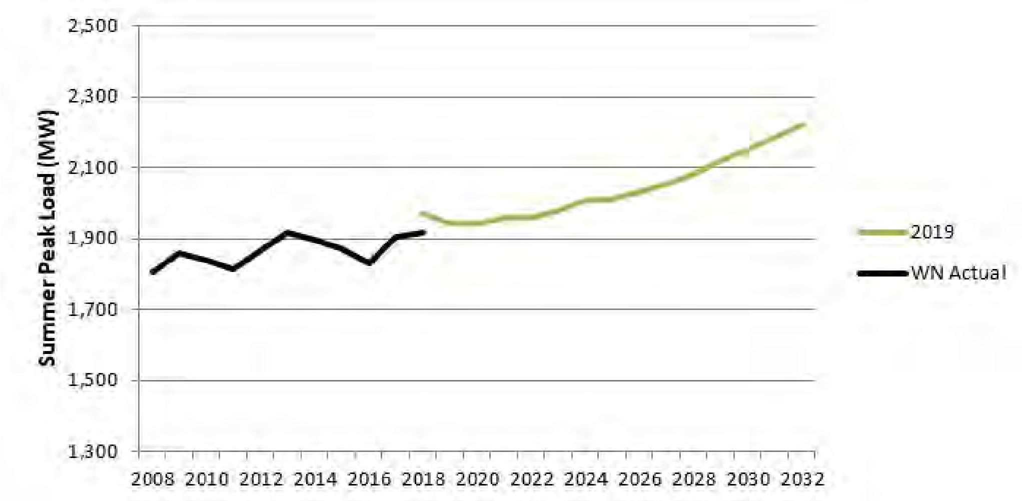

*Source: Compiled from PSE load forecast documents and discovery responses. WN Actual is weather-normalized actual peak.*

[40] WUTC. 2018. Page 11.

[41] We assume 270 MW of peak load for transmission-service customers per page 8 in the 2015 Supplemental Needs Assessment.

Historical and forecasted summer peak loads for King County show similar trends to the loads for PSE's entire service area, as shown in Figure 9.[42] Summer peak loads have been gradually increasing over the past several years, and PSE's forecast shows a growing peak load trend into the future. This figure includes just one forecast (made in 2019) because PSE's Eastside Needs Assessment studies did not analyze summer peak loads at the King County level, but instead focused on winter peak loads for the Eastside area as well as for the entire service territory.[43]

**Figure 9. PSE King County: summer peak load forecasts and actual peak load**




*Source: Compiled from PSE load forecast documents and discovery responses. WN Actual is weather-normalized actual peak load.*

Finally, we examined the potential of summer capacity constraints in King County. Figure 10 presents this review by providing a comparison of the summer peak loads with peak load thresholds (the load levels of concern in King County at which key transmission facilities will be overloaded under contingencies (*i.e.*, N-1-1)). As mentioned above in the winter peak load discussion, PSE revised its previous load threshold calculation methodology. Its new estimate is shown as "New Threshold" (1,594 MW) in Figure 10. Because the 2013 and 2015 Needs Assessment reports did not provide any load threshold for King County, we estimated the "Old Threshold" for King County based on the ratio of load threshold changes at the PSE's service territory level. At the total system level, the 2013 and 2015 Needs Assessment reports found system overloads could occur as early as 2014 and become more serious by Summer 2018.[44]

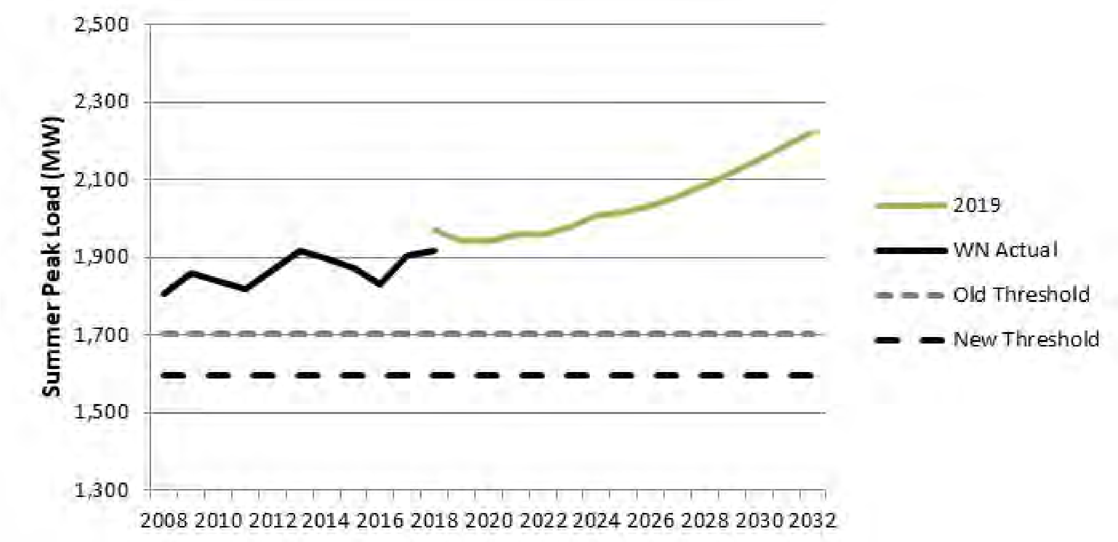
[42] We assume 81 MW of peak loads from transmission-service customers based on PSE's data response on September 9, 2019 to our data request on August 8, 2019.

[43] As mentioned previously, our analysis focuses on King County because PSE has not produced any updated historical or forecasted load estimates for the Eastside area despite the focus of its Needs Assessment reports being on the Eastside area.

[44] Quanta Technology. 2013, page 8, 9, 13 and 70; Quanta Technology. 2015, page 18 to 19.

A comparison of the load thresholds in Figure 10 reveals a more severe situation than found in the 2013 and 2015 Needs Assessment for the summer peak period: King County's summer peak loads have been exceeding the level of load concerns under N-1-1 contingencies both at the old and new threshold levels. More specifically, the peak load levels in King County have been 13 to 20 percent (or 200 MW to 300 MW) above the new threshold (assuming PSE's latest threshold is accurate). Given this current severe condition, we do not need to rely on load forecasts to determine the capacity needs because it would be infeasible to acquire sufficient demand-side resources to reduce this substantial gap within just a few years. At the current load levels, we have to conclude that there is an operational need to expand the transmission capacity in the region.

**Figure 10. PSE King County: summer peak load estimates vs. peak load thresholds**




*Source: Compiled from PSE load forecast documents and discovery responses. WN Actual is weather-normalized actual peak load.*

# 5. ASSESSMENT OF THE PROPOSED EASTSIDE PROJECT

## 5.1. The Proposal

PSE's proposed Energize Eastside project consists of upgrading the 115kV transmission lines to 230kV lines in the existing Willow 1 transmission line corridor and the construction of the Richards Creek substation in Bellevue. Our assessment finds that the upgraded transmission facilities proposed to traverse approximately 1.5 miles through Newcastle serve an operational need to safeguard the security of the bulk electric system.

## 5.2. Operational Need

We conducted a power flow analysis of PSE's transmission system with a focus on the Eastside project using the PowerWorld power flow model. Our analysis found that the facilities supplying the Eastside are currently experiencing a transmission capacity constraint that is especially pronounced during the summer in the Northwest area serving the South King County zone. A part of PSE's transmission planning responsibilities is to ensure the reliability of the transmission system it operates. This includes no long-term reliance on operating procedure corrective action plans.

Power systems are operated so that overloads do not occur either in real-time or under any statistically likely contingency. Contingencies can consist of several actions or elements, such as an outage of a single transmission line or an outage of several lines, a number of generators, and the closure of a normally open transmission line. The North American Electric Reliability Corporation (NERC) develops and enforces standards to ensure the reliability of power systems in North America. The Transmission Planning Standard (TPL) defines system performance requirements under both normal and various contingency conditions. The NERC transmission planning standards currently subject to enforcement are NERC TPL-001-4 and TPL-007-3.[45] We used these requirements to analyze PSE's transmission system, which is part of the Western Interconnection bulk electric system. The analyzed contingencies included (1) no contingencies, (2) events resulting in loss of a single system element, and (3) events resulting in loss of two or more system elements.

Under several contingencies, our power flow analysis verified that transformers at the Sammamish and Talbot Hill substations experience overloads when modeled using reasonable simulation parameters and MVA limits for normal and emergency operations. If these overloads are left unaddressed, Newcastle may experience reliability issues with its electric supply.

Electricity is primarily served to customers through distribution substations that are close to the loads. The city of Newcastle is primarily served by the Hazelwood Substation in the South King zone of the

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[45] North American Electric Reliability Corporation. n.d. "Mandatory Standards Subject to Enforcement." Available at https://www.nerc.net/standardsreports/standardssummary.aspx.

Northwest area. Based on the power flow analysis we conducted to verify the claims of transmission constraints used to justify the proposed facility upgrades, we found that increasing the load served by the Hazelwood substation had little effect in the flows through the Sammamish transmission substation. We conclude that the operational need claimed by the utility is not triggered by peak demand solely arising from Newcastle, but instead the operational need results from the requirement to secure the system at a regional level and comply with NERC reliability standards for the bulk electric system. We note that if the bulk electric system fails, Newcastle will be without electric supply unless island-able distributed generation (*i.e.*, generation near load centers) is available. Our review did not identify significant distributed generation capacity in the Newcastle area.

There is a possibility that the power flow through the Northern Intertie to PSE’s territory is affecting the summer peak situation in King County. Our power flow models verify that even with the Northern Intertie adjusted to zero flow, the Talbot Hill 230kV/115kV transformer on circuit #2 would still be overloaded when accounting for secondary contingencies. Note that the Northwest system that serves King County has interchange schedules with several other systems including BC Hydro, and during the summertime most of the interchanges are power imports into the Northwest area. The Northwest–BC Hydro interchange transfers take place through the High Voltage Northwest transmission system. Our assessment found that these transfers have minimal impact on the transmission power flows that supply the distribution facilities that feed the load centers of the Eastside.

## 5.3. Reliability Improvement

Electric utilities commonly experience facilities outages, either planned or unplanned. A well-planned system will feature redundancy and absorb these outages to maintain continuity of supply to customers and ensure service reliability in the Eastside.

In order for Newcastle to benefit from this level of reliability, PSE proposed to upgrade the existing 115kV line in the Willow 1 transmission line corridor (Figure 11 and Figure 12, next page) to 230kV lines. Under this proposal, residents in Newcastle would see the higher transmission towers needed to comply with the 2017 National Electrical Safety Code.

**Figure 11. Existing two 115kV electric transmission facilities on H-frame poles travel in existing transmission corridor through Newcastle around SE 80th Way, Newcastle, WA 98056**


*Source: Google Earth, retrieved September 2019. Note: City of Newcastle Public Notice of Proposed Land Use Action is visible.*

**Figure 12. Current 115kV electric transmission facilities around 12828 SE 80th Way, Newcastle, WA 98056**


*Source: Google Earth, retrieved September 2019.*

We highlight that a dual 230kV transmission line operated by Seattle City Light (SCL) already travels through Newcastle (Figure 13 below).

**Figure 13. Seattle City Light 230kV Transmission Line at Donegal Park [SE 74th ST, Newcastle, WA 98056]**


*Source: Google Earth, retrieved September 2019.*

# 6. KEY FINDINGS, CONCLUSIONS, AND RECOMMENDATIONS

## 6.1. Key Findings

Power flow cases analysis shows that the current summer electric peak demand in King County has already triggered an operational need for the proposed transmission expansion under system contingency scenarios.

Our power flow model assessment finds that the regional capacity thresholds in King County estimated by PSE are reasonable.

Our assessment of PSE's load forecasting methodology finds that the PSE load forecast approach follows a standard industry practice, although it has some limitations regarding the way it incorporates demand-side resources.

Our assessment of PSE's historical peak loads found that PSE's winter peak load actually has been declining over the past several years. While our assessment did not find a need at today's load level using the Old Threshold used in PSE's studies (the 2013 and 2015 Quanta studies), the 2018 load was above the New Threshold that PSE developed using revised methodology in 2016.

While we found that PSE's own winter load forecast is above the load threshold for concern in King County, we cannot conclude based on the data we analyzed whether there is any clear need created by the winter peak load for transmission capacity expansion in the future. PSE's past winter peak load forecasts have been over-predicting winter peak loads. The current forecast does not appear to fully incorporate the declining trend in weather-normalized winter peaks. Further, the current forecast does not appear to have incorporated the WUTC's recommendation to assume that in the longer term "a reasonable level of emerging retrofit conservation measures will be available in the market at cost-effective rates even though they cannot be accurately identified or predicted now."[46]

On the other hand, based on PSE's latest estimate for load thresholds in King County, which our power flow analysis verified, we found there is a summer transmission capacity deficiency in King County under N-1-1 contingencies even at today's peak load level. We further found that the capacity deficiency for the summer season has been 13 to 20 percent (or 200 MW to 300 MW) above the area's capacity threshold.

[46] WUTC. 2018. Page 11.

## 6.2. Conclusions

PSE demonstrated that the proposed transmission upgrades are needed to safeguard the operational reliability of the electric system as a whole. To maintain system security, power systems operators need to ensure overloads do not occur either in real-time or under any statistically likely contingency. Not securing the bulk electric system to operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies can affect the electric supply reliability in Newcastle. This peer review verified that under specific contingencies (N-1-1 and N-2) the as-is bulk electric system serving Newcastle is already operationally stressed. This means that PSE's application has met the threshold for approval dictated by Newcastle City Code C-5 under NMC 18.44.052 Utility facilities – Regional: "[t]he applicant shall demonstrate that an operational need exists that requires the location or expansion at the proposed site."

The current transmission deficiency can be resolved by upgrading one of the 115kV transmission lines between the Talbot Hill and Sammamish substations to 230kV and installing an additional 230kV/115kV 325MVA transformer at the proposed Richards Creek substation in Bellevue. Upgrading the second 115kV transmission line that currently travels through the same corridor, Willow 1, to 230kV is consistent with good system planning, given that facilities to support these higher voltages will already be deployed.

## 6.3. Recommendations

### Transmission solutions

We recommend that the Conditional Use Permit to PSE to upgrade the identified approximately 1.5 miles of existing 115kV lines with 230kV lines be conditioned on conducting an independent design assessment of the overhead transmission facilities traversing Newcastle. That assessment should verify compliance with the clearance safety rules for the installation and maintenance of overhead electric supply of the 2017 National Electrical Safety Code (NESC), ANSI C2 Part 2. [47] We also recommend that the City of Newcastle sends field inspectors during the transmission line upgrades to ensure compliance with the 2017 NESC.

[47] https://apps.leg.wa.gov/WAC/default.aspx?cite=296-45-045

# Appendix A. Reviewed Material

We reviewed the following materials in order to evaluate PSE's filings against the City of Newcastle's code requirements.

- Quanta Technology (2013) Eastside Needs Assessment
- Quanta Technology (2013) Eastside Solutions Study Report
- Quanta Technology (2015) Supplemental Eastside Needs Assessment
- Quanta Technology (2015) Supplemental Eastside Solutions Study Report
- Energy and Environmental Economics (2014) PSE Screening Study
- Strategen (2015) Eastside System Energy Storage Alternatives Screening Study
- Strategen (2018) Eastside System Energy Storage Alternatives Assessment – Report Update.
- PSE (2017) 2017 PSE Integrated Resource Plan
- PSE's Annual Report of Energy Conservation Accomplishments
- PSE (2019) Overview of Integrated Resource Plans and Cost-Effective Conservation in Washington
- Portland General Electric 2019 Draft Integrated Resource Plan
- Navigant (2017) 2017 IRP Demand-Side Resource Conservation Potential Assessment Report, Appendix J to PSE's 2017 Integrated Resource Plan
- Utility System Efficiencies, Inc. (2015) Independent Technical Analysis of Energize Eastside for the City of Bellevue, WA
- CADMUS Group (2013) Comprehensive Assessment of Demand-Side Resource Potentials (2014-2033)
- November 2017 Newcastle Site Plans, Variance and Non-Variance
- Tetra Tech (December 2013) Eastside 230kV Project Constraint and Opportunity Study for Linear Site Selection
- PSE (2017) Newcastle Alternative Siting Analysis

# ATTACHMENT D

## South Bellevue CUP Hearing Examiner Decision

**BEFORE THE HEARING EXAMINER**
**FOR THE CITY OF BELLEVUE**

| | | |
|---|---|---|
| In the Matter of the:<br><br>**Conditional Use Permit Application for the South Bellevue Segment of the Energize Eastside Project**<br><br>**PUGET SOUND ENERGY**, Applicant | ) | DSD File No. 17-120556-LB<br><br>FINDINGS OF FACT, CONCLUSIONS, AND DECISION |

## I. SUMMARY of DECISION.

The applicant has met its burden of proof to demonstrate that a preponderance of the evidence supports the conclusion that its application for a Conditional Use Permit (CUP) merits approval. Accordingly, the pending Conditional Use Permit application is approved, subject to conditions.

## II. BACKGROUND and RELEVANT CODE PROVISIONS.

There is no dispute that a conditional use permit is mandated for this project because the application is for new or expanding electrical utility facilities proposed on sensitive sites described and depicted on Figure UT.5a (revised to Map UT-7) of the Utilities Element of the City of Bellevue Comprehensive Plan. *(LUC 20.20.255.C; Staff Report, pages 7-8, and Attachment F, a copy of Comp. Plan Map UT-7).*

In this matter, the Hearing Examiner has jurisdiction to conduct an open record public hearing regarding the Conditional Use Permit application at issue. Under applicable City codes, a CUP is a Process I land use decision processed in accord with LUC 20.35.100-140.



BELLEVUE HEARING EXAMINER'S OFFICE
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As explained in LUC 20.35.140.A, the Hearing Examiner *shall approve* a project or approve with modifications if the applicant has demonstrated that the proposal complies with the applicable decision criteria of the Bellevue City Code, and the applicant carries the burden of proof and must demonstrate that a preponderance of the evidence supports the conclusion that the application merits approval or approval with modifications. In all other cases, the Hearing Examiner shall deny the application. The preponderance of the evidence standard is equivalent to "more likely than not."[1]

***Conditional Use Permit Decision Criteria:*** The decision criteria for a Conditional Use Permit is found in LUC 20.30B.140, which explains that the City may approve or approve with modifications an application for a conditional use permit if:

A. The conditional use is consistent with the Comprehensive Plan; and

B. The design is compatible with and responds to the existing or intended character, appearance, quality of development and physical characteristics of the subject property and immediate vicinity; and

C. The conditional use will be served by adequate public facilities including streets, fire protection, and utilities; and

D. The conditional use will not be materially detrimental to uses or property in the immediate vicinity of the subject property; and

E. The conditional use complies with the applicable requirements of this Code.

***Additional Criteria for Electrical Utility Facilities:*** Because the proposal is to construct or expand electrical facilities, the provisions of the City's Land Use Code specifically addressing Electrical Utility Facilities, found in LUC 20.20.255.E, must be satisfied. Prior to submittal of any Conditional Use Permit application, a detailed Alternative Siting Analysis was required. See LUC 20.20.255.D. In addition to the requirements set forth above for a Conditional Use Permit, as detailed in Part 20.30B LUC, all proposals to locate or expand electrical utility facilities shall comply with the following:

1. The proposal is consistent with Puget Sound Energy's System Plan;

2. The design, use, and operation of the electrical utility facility complies with

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[1] *In re Pers. Restraint of Woods,* 154 Wn.2d 400, 414 (2005).

applicable guidelines, rules, regulations or statutes adopted by state law, or any agency or jurisdiction with authority;

3. The applicant shall demonstrate that an operational need exists that requires the location or expansion at the proposed site;

4. The applicant shall demonstrate that the proposed electrical utility facility improves reliability to the customers served and reliability of the system as a whole, as certified by the applicant's licensed engineer;

5. For proposals located on sensitive sites as referenced in Figure UT.5a of the Utility Element of the Comprehensive Plan, the applicant shall demonstrate:

a. Compliance with the alternative siting analysis requirements of subsection D of this section;

b. Where feasible, the preferred site alternative identified in subsection D.2.d of this section is located within the land use district requiring additional service and residential land use districts are avoided when the proposed new or expanded electrical utility facility serves a nonresidential land use district;

6. The proposal shall provide mitigation sufficient to eliminate or minimize long-term impacts to properties located near an electrical utility facility. See LUC 20.20.255.E.

## III. ASSOCIATED PERMIT.

Given the scale of the project, a Critical Areas Land Use Permit (CALUP), which is a Process II Administrative Land Use Decision, was also required. The Director approved the CALUP as explained in the same Staff Report issued for the pending Conditional Use Permit. The CALUP was not appealed, so it was not on review as part of the Hearing Examiner's public hearing process. Specifically, the City thoroughly reviewed application materials for, duly noticed, sought and considered public feedback for, and issued a Critical Areas Land Use Permit for aspects of the South Bellevue Segment of the applicant's Energize Eastside Project, under File No. 17-120557-LO. Under the City's code, the CALUP approval is subject to appeal before the Hearing Examiner. Again, no appeal was filed, so the Critical Areas permit stands without modification, as issued, and serves as support for the Conditional



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Use permit addressed in this Decision.[2] All findings, conclusions and conditions of approval in the CALUP are now beyond review. Any appeal of this Decision cannot be used to collaterally attack any aspect of the CALUP or determinations made therein. See *Wenatchee Sportsmen Ass'n v. Chelan County,* 141 Wn.2d 169, 182, 4 P.3d 123 (2000), and *Habitat Watch v. Skagit County,* 155 Wn.2d 397, 410–11, 120 P.3d 56 (2005).

## IV. RECORD AND EXHIBITS.

Exhibits entered into evidence as part of the record, and an audio recording of the public hearing, are maintained by the City of Bellevue, and may be examined or reviewed by contacting the Clerk in the Hearing Examiner's Office.

Throughout the hearing process, some participants were represented by counsel. Matt McFarland and Cheryl Zakrzewski from the Bellevue City Attorney's Office represented city staff who generated the Staff Report and oversaw preparation of environmental review documents included in the record; Erin Anderson and Sara Leverette, from the Van Ness Feldman law firm, represented the applicant, Puget Sound Energy; Richard Aramburu represented CENSE (Coalition of Eastside Neighborhoods for Sensible Energy); and Larry Johnson represented CSEE (Citizens for Sane Eastside Energy).

***Exhibits:*** The Record includes all pre-hearing orders, motions, and briefs filed or issued prior to the public hearing, copies of which are maintained by the Clerk for the Hearing Examiner's Office, and all exhibits described and numbered on the attached Exhibit List. In sum, the record for this matter is somewhere near 15,000 pages.

***Hearing Testimony:*** The following individuals presented testimony under oath at the duly noticed public hearing for the underlying application, which spanned several days, beginning on the evening of March 28th, continuing through March 29th, April 3rd, and April 8, 2019.

*The following individuals provided testimony at some point on* ***March 28th:***

For the City of Bellevue:

Heidi Bedwell, Environmental Planning Manager, and Liz Stead, Land Use Director

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[2] As a Process II Decision, the CALUP had a 14-day appeal deadline, which expired on February 7, 2019. *See LUC 20.35.250.A.3.* Any appeals would have been included in the Hearing Examiner's public hearing process for the project. There were none. *See Staff Report for details on relevant dates, including date of issuance and appeal deadline listed on page 2.*

For the Applicant, PSE:

Dan Koch, PE, Director of Electric Operations; Elizabeth Koch, PE, Director of Planning for PSE; and Jens Nedrud, PE, Manager of Electrical System Planning for PSE.

General Public: Ms. Cofield; Mr. Anderson; Ms. Hirshci; Mr. Bannon; Mr. Alavi; Mr. Dachnahl; Mr. Wallace; Mr. Oleson; Mr. Anderson; Ms. Hansen; Ms. Akiyama; Ms. Smith; Mr. Borgmann; Mr. Funk; Mr. Sutton, Mr. Wagner, Mr. Shay, Mr. Townsend, Mr. Gilchrist, Mr. Yu, Mr. Finkbeiner, Ms. Trescases, Mr. Davis, Mr. Kasner, Dr. Kaner, Ms. Kapela, Ms. Swenson, Ms. Ma, Mr. Fleck, Ms. Talneja.

For CENSE:

Robert McCullough and Dean Apostol.

*The following individuals provided testimony at some point on* ***March 29th:***

For the applicant, PSE:

Lowell Rogers, re: pipeline safety issues; and David Kemp, re: effects of transmission lines on adjacent pipelines.

General Public:

Mr. Halverson, Ms. Jacobson, Mr. Woosley, Ms. Sander, Mr. Joe, Mr. O'Donnell, Ms. Kim, Ms. Dean, Mr. Jaeger, Ms. Keller, Ms. Fischer, Mr. Allred, Mr. Davis, Mr. Zimmerman, Mr. Johnson, Mr. Derdowski, Mr. Rumega, Ms. DeMund, Mr. Elworth, Ms. Elworth, Ms. Stronk, Ms. Ossenkop, Mr. Albert, Mr. Cliff, and Ms. Lopez.

For the applicant, PSE:

Tom Priestley, re: visual impacts.

For CENSE:

Mr. Marsh and Karen Esayian, with legal arguments presented by Mr. Aramburu.

For CSEE:

Mr. Lauckhart, with legal arguments presented by Mr. Johnson.

For the City of Bellevue:

Wolfgang Fieltsch, re: pipeline safety issues.

*Testimony on **April 3rd** provided the applicant and staff the opportunity to offer rebuttal testimony to any comments or evidence submitted during the course of the hearing.*

Rebuttal testimony from the applicant, PSE:

> Mr. Nedrud, Ms. Koch, Mr. Rogers, Mr. Thatcher, Mr. Strauch, and Mr. Koch.

Rebuttal testimony from City staff:

> Mr. Johnson, who managed the EIS process from start to finish, Ms. Stead, and Ms. Bedwell, all of whom confirmed that they heard nothing through the course of the hearing that would change their opinions reflected in the EIS and/or Staff Report; and legal arguments from Mr. McFarland.

***April 8th** was the date used for closing Arguments presented by counsel for the applicant, city staff, CENSE and CSEE.*

Given the size of the record and the volume of opposition comments received throughout the process, the Examiner sought to read every exhibit with attention and a fair mind. This involved site visits, to better appreciate comments from local residents, research, and reviewing a lengthy record of public outreach and feedback, administrative reviews, and a multi-phase set of environmental documentation that culminated in a Final EIS, which included detailed review on specifics presented in this pending CUP application. This was not a "small and simple" matter. Instead, it required considerable time and focus. All participants were advised at the close of the hearing that generating a Decision for this application would take significant time and attention. Having completed such review and mindful of the legal standards involved, this Decision is now in order.

## V. FINDINGS of FACT.

Based on the entire Record, estimated to be around 15,000 pages, the undersigned Examiner issues the following Findings of Fact. Any statements contained in previous or following sections of this Decision that are deemed to be Findings of Fact are hereby adopted as such and incorporated by reference.

1. In September of 2017, Puget Sound Energy, Inc. (PSE) applied to the City of Bellevue for a Conditional Use Permit and a Critical Areas Land Use Permit for the construction of a new substation and 230 kilovolt (kV) transmission lines that will be located within the Bellevue City Limits. *(DSD 000002, 000006, and 000007).*

2. The project elements that are at issue in this application are known as the "South Bellevue Segment" of PSE's Energize Eastside Project.

3. The larger "Energize Eastside Project" is the PSE proposal to construct a new substation in Bellevue (the "Richards Creek substation") and to upgrade 16 miles of two existing 115 kV transmission lines with 230 kV lines running from Redmond to Renton.

4. The Staff Report explains that PSE is applying for permits to construct the Energize Eastside Project in two phases. PSE has applied for permits for the first construction phase of the total Project in Bellevue, unincorporated King County, the City of Newcastle, and the City of Renton. *(DSD 000006).*

5. The first phase of the Energize Eastside Project in Bellevue (the "South Bellevue Segment") is fully addressed and analyzed in the 151-page Staff Report, which includes a detailed summary of public comments received *(DSD 000086-000102),* and ten attachments described as follows:

A. Project Plans
B. Alternative Siting Analysis
C. PSE South Bellevue Segment CUP Analysis
D. Independent Technical Analysis of Energize Eastside (USE2015)
E. Vegetation Management Plan
F. Comprehensive Plan, Map UT-7
G. Comprehensive Plan Policy Analysis
H. Photo Simulations
I. Critical Areas Report
J. Pole Finishes Report-City of Bellevue (South)

With all attachment materials included, the "Final Combined Staff Report", as it labeled in the electronic project files, exceeds 1,500 pages. *(DSD 000001-001510).*

6. The South Bellevue Segment includes construction of a new "Richards Creek" substation and upgrading 3.3 miles (the Bellevue portion) of existing 115 kV transmission lines with 230 kV lines between the existing Lakeside substation and the southern city limits of Bellevue. The remainder of the south portion of the Project continues through Newcastle, unincorporated King County, and Renton. Bellevue only has permitting authority for work proposed in its jurisdiction. The Project and PSE's specific proposal for the South Bellevue Segment involves the replacement of existing wooden H-frame poles with steel monopoles. Within the existing utility corridor, the proposed pole locations for the rebuilt lines will generally be in the same locations as the existing poles. *(DSD 000006).*

7. There is no credible dispute that the 3.3 miles of transmission line upgrades that will be part of this South Bellevue Segment are to be constructed within an existing corridor that was established in the late 1920s and early 1930s, and that current uses, including homes and

various commercial uses, were developed over time after the original utilities (including PSE powerlines) were installed. In the 1960s, the PSE lines were upgraded from 55 kV to 115 kV, which included replacement of original poles with H-frame poles. *(DSD 000232, part of Attachment B to Staff Report, Alternative Siting Analysis)*. Maintenance has occurred over time, and in 2007, PSE replaced or reframed approximately 200 H-frame structures on the existing corridor. *(Final EIS, at Sec. 2.2.1.2.2 re: Overview of the New 230 kV Transmission Lines, included in the Record at DSD 005445-5446).* As part of the proposed Energize Eastside Project, the existing, H-frame structures would be replaced primarily with a combination of single-circuit and double-circuit steel monopoles, with some wood poles remaining, particularly near substations. *Id.* The applicant notes that it identified the need to upgrade the lines within the same corridor to the next higher transmission voltage (230 kV) in the early 1990s, and that the 230 kV upgrade concept has been included in the Bellevue Comprehensive Plan since such time period. *(DSD 000233; Testimony of PSE witnesses).*

8. The Richards Creek substation, which is needed to step down voltage from 230 kV to 115 kV, will be constructed directly south of PSE's existing Lakeside switching station. The new substation will be located on parcel 102405-9130 (13625 SE 30th Street), currently used as a PSE pole storage yard. The parcel is 8.46 acres in size and contains critical areas (steep slopes, wetlands, and streams). Access to the substation site is from SE 30th Street. *(DSD 000006).*

9. Despite some comments, arguments, and requests to the contrary, the City of Bellevue only has jurisdiction over segments of the Energize Eastside Project that lie within the Bellevue City Limits. And, the Hearing Examiner only has jurisdiction to review this pending application, not possible, future applications for other segments in the City that have not been filed. Accordingly, the Examiner's review has been limited to the 3.3 miles of transmission line upgrades and the new Richards Creek Substation that are proposed within the City of Bellevue, collectively known as the South Bellevue Segment.

***Purpose and Need for project.***

10. The Staff Report credibly explains that the purpose of the Energize Eastside Project is to meet local demand growth and to protect reliability in the Eastside of King County, roughly defined as extending from Redmond in the north to Renton in the south, and between Lake Washington and Lake Sammamish. There is no dispute that it is PSE's responsibility to plan and operate the electrical system while complying with federal standards and guidelines. *(DSD 000008-11; Testimony of Ms. Koch, PSE's Director of Planning, and Ex. A-7, copy of Ms. Koch's written remarks provided at the public hearing).* Ms. Koch thoroughly explained current federal, regional, and state mandates and regular system audit requirements that electric utilities must meet.

11. PSE defines its broad objectives for the Energize Eastside Project as follows:

- Address PSE's identified deficiency in transmission capacity.
- Find a solution that can be feasibly implemented before system reliability is impaired.
- Be of reasonable Project cost.
- Meet federal, state, and local regulatory requirements.
- Address PSE's electrical and non-electrical criteria for the Project. *(DSD 000008).*

12. Electricity is currently delivered to the Eastside area through two 230 kV/115 kV bulk electric substations – the Sammamish substation in Redmond and the Talbot Hill substation in Renton – and distributed to neighborhood distribution substations using 115 kV transmission lines *(see Staff Report, Figure II-1)*. Although numerous upgrades have been made to PSE's 115 kV systems (including new transmission lines), the primary 115 kV transmission lines connecting the Sammamish and Talbot Hill substations have not been upgraded since the 1960s, and no 230 kV-to-115 kV transformer upgrades have been made at these substations. *(DSD 000008-11).*

13. Since then, the Eastside population has grown from approximately 50,000 to nearly 400,000. Both population and employment growth are expected to continue, but at a slower pace of around 2% per year, according to Puget Sound Regional Council (PSRC) estimates. A report prepared for PSE projects that electrical customer demand on the Eastside will grow at a rate of approximately 2.4% per year through 2024. *(Id.).*

14. As required by federal regulations, PSE performs annual electric transmission planning studies to determine if there are potential system performance violations (transformer and line overloads) under various operational and forecasted electrical use scenarios. These studies are generally referred to as "reliability assessments." *(Id., and Testimony of PSE witnesses).*

15. The need for additional 230 kV-to-115 kV transmission transformer capacity and 230 kV support in the Eastside was identified in the 1993 annual reliability assessment, and has been included in PSE's Electrical Facilities Plan for King County (System Plan) since that time. In 2009, PSE's annual reliability assessment found that if one of the Talbot Hill substation transformers failed, it would significantly impair reliability on the Eastside. *(DSD 000010).*

16. Replacement of a failed 230 kV transformer can take weeks, or even months, to complete depending on the level of failure and other site-specific parameters. Since 2009, other reliability deficits have been identified. These include concerns over the projected future loading on the Talbot Hill substation and increased use of Corrective Action Plans

(CAPs) to manage outage risks to customers in this portion of the PSE system. *(DSD 000010).*

17. Between 2012 and 2015, PSE and the City of Bellevue commissioned three separate studies by two different parties that confirmed the need to address Eastside transmission capacity *(DSD 000010)*:

- City of Bellevue Electrical Reliability Study prepared by Exponent, 2012.
- The Quanta Eastside Needs Assessment Report, 2013.
- The Quanta Supplemental Eastside Needs Assessment Report, 2015.

18. The Quanta Eastside Needs Assessment Report and Supplemental Eastside Needs Assessment Report, performed by Gentile (with Quanta Technology) for PSE in 2013 and 2015, respectively, confirmed that if growth in demand continued as projected, then the Eastside's existing grid would not meet federal reliability requirements by the winter of 2017/2018 and the summer of 2018 without the addition of 230 kV-to-115 kV transformer capacity in the Eastside area. *(DSD 000010-11).*

19. More significantly, and enhancing the credibility of reports submitted by the applicant, the City of Bellevue commissioned a separate study to evaluate PSE's system, which also confirmed the need for the Energize Eastside Project. And, as part of the EIS prepared for the Energize Eastside Project, Stantec Consulting Services Inc. also reviewed PSE's analysis and determined that PSE's approach to the needs assessment determination followed standard industry practice. *(DSD 000011; Staff Report, Attachment D, "USE" [Utility System Efficiencies, Inc.] Report, 'Independent Technical Analysis of Energize Eastside for the City of Bellevue, WA', dated April 2015; and Stantec Review Memo on the Eastside Needs Assessment Report, July 2015, included in the Record at DSD 000550-559, and referenced throughout the hearing).*

20. In June 2018, PSE notified the City of Bellevue that the actual peak demand in the summer of 2017 was equal to the peak demand projected for summer 2018, and warned that during peak summer demand periods CAPs would be in place that include intentional load shedding (rolling blackouts) for Eastside customers. *(DSD 000011; Testimony of Mr. Koch, PSE Director of Electric Operations).*

21. The application materials and materials referenced in the Staff Report provide a more-detailed explanation regarding the use of load shedding. *(Quanta, Supplemental Needs Assessment Report, at DSD 000453).* PSE recognizes that applicable federal and regional agencies allow dropping "non-consequential" load for certain contingencies, but does not endorse the practice of intentionally dropping load for serious contingencies in order to meet federal planning requirements. *(Id.).* All electrical loads modeled in the Needs Assessment work performed for PSE was considered "firm load" and PSE does not consider any of its

firm requirements to be non-consequential. This is the practice of most utilities. It is also consistent with the views of virtually all community officials who do not consider intentionally blacking out segments of customers as a responsible way to operate a modern electricity delivery system. *(Id.).*

22a. At the public hearing, several opponents questioned Mr. Koch's warning, because they haven't seen any of the rolling blackouts occur. It appeared as though they viewed his concerns about potential blackouts to be idle threats of doom to generate support for the project that they oppose. The Examiner finds that Mr. Koch, Mr. Nedrud, Ms. Koch, and other PSE witnesses appeared credible and forthright during their testimony presented at the public hearing. Even after hearing challenges and dismissive remarks about their opinions and work related to this project, Mr. Koch, Mr. Nedrud and other PSE witnesses appeared thoughtful and genuinely concerned that the current PSE system could soon be forced to use load-shedding (rolling blackouts) to address problems arising from peak demand on existing substations and powerlines, negatively impacting Bellevue residents and businesses.

22b. At the hearing, Mr. Koch provided a personal account of a meeting that he attended in Woodinville on July 24, 2018, with Emergency Management personnel, during which time the PSE transmission system in that location experienced a rapid cascade of events, one planned de-energization for a work-detail, one involving a squirrel that tripped off a line, all followed by a pole-top fire, resulting in what is known in the industry as an "N minus 1 minus 1 minus 1" (N-1-1(-1)) situation that forced PSE to "drop load" in order to prevent damage to equipment, i.e. the sequence of events caused PSE to intentionally black-out some customers for a period of time because the transmission system exceeded its limits in the area. While this project will not address the problems up in that part of King County, he offered the example to demonstrate that PSE must plan for many unexpected things, not just an occasional tree falling, but many events that, when happening at the same time, cause undue stress on transmission capacity, resulting in unreliable power supply, and possible blackouts. *(Testimony of Mr. Koch, and Ex. A-3, a copy of his written remarks provided at the public hearing).*

23. Following a request for additional information from the City, PSE explained that it did not perform any analysis on the electrical loads for the August 2017 dates, but that increased air conditioning was a likely contributor. PSE's planning-level modeling found that both summer and winter peak customer load were driving the need for additional transmission capacity. (Additional information regarding PSE's determination of operational need is discussed in Section VIII.C of the Staff Report in connection with Electrical Utility Facilities Decision Criteria LUC 20.20.255.E.3). *(DSD 000011).*



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24. At the public hearing, PSE witnesses explained how powerlines lose efficiency when they are overheated, and that when severe overloads/overheating occurs, some loads may need to be lowered or turned off to prevent "sparks", fire, other substantial failures in the electrical system. This is obviously the case during summer months – when high air temperatures combined with heavy electrical loads needed to power infrequently-used but increasingly-common air conditioners, fans, as well as regular system users – all stress the existing electrical transmission system. PSE witnesses explained how hotter lines cannot carry the same loads as they can during cooler weather, making the system less efficient during such hot weather events. Opposition comments that generally challenged the "project need" because there has not been enough discussion and analysis of system loads during summer months were not as credible or reliable as testimony provided by the applicant witnesses, who have the professional training, education, and background to reasonably ascertain that overheated powerlines can cause serious problems. Common sense supports their concerns that extreme heat in summer months, or even like that experienced recently during the past month with area temperatures in the high 80s and low 90s, poses a very real risk of failure for a system that has not been upgraded for decades to address increased demand caused by significant growth in the Eastside of King County.

25. The record includes ample information and evidence to support the need for the pending project. More recent explanations and justifications pointing to risks/overloads that can occur during hot weather only add to the evidence supporting the need for upgraded powerlines in Bellevue and the Eastside. PSE's planning-level modeling found that both summer and winter peak customer load were driving the need for additional transmission capacity. None of the project opponents provided testimony or evidence of comparable weight or substance as that provided by the applicant or the analysis provided in the Staff Report.

26. Arguments and comments challenging the need for the project because most study information is focused on high demand during cold weather events, and recent winter demand has not been as high as originally forecasted, were not convincing and do not serve as a basis to deny the pending application. This is largely because such arguments fail to recognize that just because the system hasn't failed yet, does not mean that it cannot at some point in the near future, and the consequences could be severe for Bellevue residents and businesses. PSE witnesses credibly described steps they have taken to address peak demand during winter, as well as summer, to avoid the need to use rolling blackouts. As the applicant has directed attention throughout the record, prudent planning is required by applicable state and federal utility system regulations to assure electrical system reliability. Hoping for warmer winters and cooler summers, or speculating about future battery options, or the generosity of a neighboring utility to help in a pinch, is not enough. No action is not a reasonable approach. Not long ago, it was commonly thought that the tolerance for being without power was about

2-3 days. Nowadays, for the vast majority of people, it is little more than the life of a cell phone battery. *(Testimony of Mr. Koch; Ex. A-3).*

27. Some comments challenged the "need" for the project, arguing that carrying power for loads headed to Canada or other distant locations could be or are already carried by other powerlines; or that simple, local emergency generators could be fired up to produce additional power supply, all somehow clearing up capacity in or generating additional power supply needed for the existing lines, and obviating or delaying the urgency for new lines as proposed in this application. These comments and related arguments run contrary to the City's unrebutted, independent consultant report on the topic, which provided the following relevant and highly persuasive conclusions regarding the existing 115 kV powerlines and facilities currently located along the Energize Eastside corridor, which specifically includes the South Bellevue Segment at issue in this matter:

> *[A]n overloaded electrical system overheats. During peak load periods, operators use CAPs to turn off (referred to as opening) lines from either Sammamish or Talbot Hill substation to reduce heating on certain system transformers and lines so that they will not be destroyed. They may be able to keep the Eastside area supplied with electricity, but in doing so large areas of the Eastside may only be fed from one source. If something happens to that source, such as a tree falling into a line, or a car accidentally taking out a pole, or a piece of equipment fails due to fatigue, at that moment the last viable connection to a power source is gone and the lights go out. Even worse, as load continues to grow, or the area hits the coldest winter or hottest summer on record, the operator will be left with a decision: who will have power and who will not. Until the peak period is over, in order to reduce overloads to an acceptable level, large portions of the Eastside area could be left without power. A further possible consequence would be that hospitals, nursing homes, fire departments, police stations and other critical support services must run on emergency power or are without power. In this situation the event has become not just an inconvenience but a hazard.*
>
> *There are a lot of questions surrounding the probability of these events occurring on the Eastside. Most people are likely unaware of how many times an outage is imminent or narrowly avoided. Attempting to specifically predict these events is nearly impossible because of the number of potential scenarios and permutations. Is it an extreme peak? Are 100% conservation levels being met? Is there a system component out for repair? Has an accident removed a piece of equipment from service? Has a natural or man-made disaster occurred that no*

*one thought would ever happen? Was the forecast wrong and loads grew faster than expected? The permutations are endless.*

*Regional electrical reliability is important to local communities. Without a reliable regional backbone, energy generated by a wide variety of sources could not be efficiently delivered to the population areas that need it. All the utilities in the Northwest bear some responsibility to keep the transmission system in working order. However, a local utility's main role is its customers and each has a legal duty to provide electricity to customers in its service area.*

*The local utility has two roles to play. On the community level, it needs to provide an adequate infrastructure of facilities and equipment that can reliably deliver energy to its local customers. As a regional player, the utility provides its customers access to the larger interconnected system while making sure its system is as reliable as its regional neighbors' systems and not a detriment to the whole.*

*The Energize Eastside Project is designed to bring the needed infrastructure to supply the local need. Any regional benefits that it provides would be added benefits of a stronger regional source, but these are not the primary reasons why the project has been proposed. The transmission capacity deficiency is driven primarily by local rather than regional growth. If the entire region surrounding the Eastside was eliminated or disconnected from Sammamish and Talbot Hill substations, and replaced with an independent 230 kV source of power at both ends, the result would be the same. The Eastside 230 -115 kV system as it exists cannot supply the projected load under all circumstances, with the required levels of reliability that the community and neighboring utilities expect. (Stantec Report, at DSD 000557-558).*

28. Mr. Nedrud credibly testified that opposition comments relied too heavily on consumption data instead of peak-demand data, which PSE must plan for. He emphasized that the issue is not just about one or a few "what-if" scenarios, but many, and that the through-put in existing lines is just too small. He described how "peak-generators" intended to provide additional power supply would be of no value if the existing lines are too small to carry the load during peak-demand situations. *(Testimony of Mr. Nedrud on April 3rd).*

29. Responding to challenges and complaints that the data used by PSE to demonstrate "need" for the project is now too old, from 2015 or so, Mr. Nedrud credibly testified that PSE has gone back to review whether deficiencies exist using more current data. He confirmed

that PSE analyzed data again, in December of 2016, 2017, and 2018, and that updated data from each time period showed peak-demand exceeding system capacity. *Id.*

***Environmental Review and Public Engagement.***

30. The Staff Report explains, and Department witnesses testified, that the City of Bellevue, in cooperation with the "Partner Cities" of Kirkland, Newcastle, Redmond, and Renton, conducted an environmental review of the entire Energize Eastside Project over the course of several years. The Partner Cities stipulated that the City of Bellevue would act as the SEPA lead agency. The culmination of the environmental review process was the Final Environmental Impact Statement (EIS) issued on March 1, 2018. The Final EIS built upon the previous Phase 1 Draft EIS and Phase 2 Draft EIS, released in January 2016 and May 2017, respectively. *(DSD 000074, and DSD 005404).*

31. PSE and the Partner Cities agreed to the rigorous two-phase environmental review. (*DSD 000012).* During Phase I of the environmental review, the Partner Cities evaluated a broad range of potential technological alternatives to address the identified transmission facility deficit. Phase I review assessed the feasibility and environmental impacts of wire solutions (i.e., overhead, underground and underwater transmission lines, including using Seattle City Light's existing corridor in the City of Bellevue) and non-wire solutions (ranging from battery storage, distributed solar and the construction of natural gas peak shaving facilities, among others). *Id.* As PSE witnesses summarized at the public hearing, running high power transmission lines under Lake Washington presents expensive and time-consuming challenges, and using City Light transmission lines is not a viable option for several reasons discussed in the Phase I EIS, including without limitation because it would mean that PSE would have to perform an entire "rebuild" of the existing City Light structures and all conductors along the entire line, and create a new connector-route leading to PSE substations. *(Testimony of Mr. Nedrud; and Ph. I EIS, Sec. 2.3.2.3 discussion of Option B, to use Seattle City Light 230kV Overhead Transmission Lines, at DSD 011181).*

32. Following the elimination of Project alternatives that were infeasible or failed to meet the Project's purpose and need, Phase II focused on analyzing the potential environmental impacts of route options for the overhead line alternative. *Id.* The Phase II Draft EIS and Final EIS analyzed 14 routing alternatives including a north, central and south Bellevue segment. *(DSD 005435, listing routing alternatives).* The EIS analyzed two central Bellevue routing alternatives (including two by-pass routes that do not cross the East Bellevue Community Council's ("EBCC's") jurisdiction) and four routing alternatives for the south segment. *Id.*

33. The Partner Cities' analysis confirmed that, of all alternatives and route options analyzed, construction of an upgraded transmission line in the existing corridor best addressed project need while limiting costs and environmental impacts. *(DSD 005472, FEIS at 2-45, which reads in relevant part: "At this time, [other than a transmission line upgrade] there are no currently known, widely accepted technologies that PSE would employ that could feasibly and reliably address the transmission capacity deficiency on the Eastside"; and DSD 000014-15 (describing how siting limits environmental impacts).*

34. Following the publication of the Phase II DEIS, PSE changed its preferred route alternative from the "Willow 2" route to the "Willow 1" route, the analysis of which provides the basis for this CUP application. PSE explained that it undertook this change in response to data showing that the Willow 1 route, which follows the existing transmission line corridor, was the safest, least impactful route. *(See PSE discussion of its preferred site alternative at DSD 000240-41; and PSE Response Brief to Motion to Continue, dated Feb. 11, 2019).*

35. All of the option routes considered through the EIS and alternate site review process, including Willow 1, traverse residential land use districts, but PSE determined that utilizing the existing corridor would minimize impacts associated with the Project on surrounding areas. As noted in the Staff Report and confirmed by Department and PSE witnesses at the public hearing, PSE's decision to use the existing corridor minimizes tree removal as compared to establishing a new corridor and allows for better assessment of potential interactions with the co-located Olympic pipeline. The existing corridor also minimizes the creation of new impacts to adjacent uses, including residential uses. As properties adjacent to the transmission line corridor currently have utility facilities in their viewsheds and neighborhoods, the Willow 1 route has lower impacts compared to establishing a new corridor. *(DSD 000044).*

36. The Alternative Siting Analysis (included in the Record as Attachment B to the Staff Report) contains sufficient information regarding the methodology employed, the alternative sites analyzed, the technologies considered, and the community outreach undertaken to satisfy the requirements of LUC 20.20.255.D. The Analysis includes numerous appendices addressing Project need, public outreach and input, and tracks the extensive environmental review undertaken in connection with the Project. The Analysis also explains how, by constructing the proposed transmission line facilities in the existing 115 kV transmission line corridor and selecting the Richards Creek substation, site compatibility impacts are limited by this preferred alternative. See LUC 20.20.255.D.2.d. Therefore, PSE's Alternative Siting Analysis complies with the provisions of LUC 20.20.255.D. *(See discussion at DSD 000044).*

37. As noted in the Staff Report, an EIS is the most detailed form of environmental review required under SEPA and is prepared when an agency determines that it is probable that a project would have significant environmental impacts. The Phase 1 Draft EIS assessed a range of impacts and implications associated with broad alternatives for addressing PSE's objectives in a non-project, or programmatic, EIS. *(DSD 000074).*

38. The environmental review undertaken by the Partner Cities and memorialized in the Phase 2 Draft EIS and Final EIS considered the impacts on the environment of the entire Energize Eastside Project throughout each jurisdiction – extending from Redmond in the north to Renton in the south. The Phase 2 Draft EIS incorporated the Phase 1 Draft EIS by reference and presented a project-level environmental review. *(DSD 000074).*

39. Based on the results of the Phase 2 Draft EIS analysis, PSE refined the proposed route of the transmission lines and associated Project components. The Final EIS assessed PSE's project level proposed alignment (referenced as "Willow 1") and considered environmental impacts of the entire Energize Eastside Project in light of this proposed alignment (see Chapters 1, 2, 4, 7, and 8 of the Final EIS). *(DSD 000074).*

40. While environmental analysis in the Staff Report focused on the impacts reviewed for the portions of the Project currently under consideration in connection with the two Bellevue Permits (specifically this CUP, and the associated, unchallenged Critical Areas permit, identified as Permit Nos. 17-120556-LB and 17-120557-LO), the environmental review in the Final EIS was not limited to any segment or portion of the Energize Eastside Project. Instead, the Final EIS presented a comprehensive environmental assessment of the entire Energize Eastside Project, including a full analysis of potential impacts and cumulative impacts associated with the construction and operation of PSE's proposed alignment. *(DSD 000074).*

41. Staff properly found and concluded that the Energize Eastside Project Final EIS and supporting documentation fulfill SEPA requirements for the pending proposal and the larger Energize Eastside Project and, consistent with BCC 22.02.020 and WAC 197-11-635, incorporated such documentation into the Staff Report by reference. *(DSD 000074).*

42. The Examiner concurs. The Final EIS, and the multi-year public outreach process undertaken by the Partner Cities, fulfills applicable SEPA review requirements for the project addressed in this permit.

43. The Final EIS reflects analysis of the South Bellevue Segment based on the application details at issue in this matter. Again, it also includes a full analysis of potential impacts and cumulative impacts associated with the construction and operation of the entire

Energize Eastside Project and PSE's proposed alignment. The Final EIS facilitated broad public participation and informed decision-making for both requested permits, the unchallenged CALUP and the Conditional Use Permit addressed herein. The review process for the South Bellevue Segment is the antithesis of any alleged failure to study, failure to disclose, or improper "segmentation" or "piecemealing" as some opponents argued.

44. For instance, the Final EIS explains: *"For the Richards Creek substation site and the Bellevue South and Newcastle Segments, the analysis included a review of the project design as presented in the permit applications submitted to Bellevue and Newcastle (PSE, 2017b and PSE, 2017c, respectively). The results below have been revised relative to the Phase 2 Draft EIS, incorporating the more detailed information in the permit applications on pole locations and critical areas (including wetlands, streams, and their buffers). The conclusions regarding significant impacts on land use, however, are the same as presented in the Phase 2 Draft EIS." (DSD 005495).*

45. Instead of using a "general" study, or guesstimate as to what average impacts on views and other aspects of the environment might be, as one might come to expect from a very broad environmental review document, the impacts on views for the Energize Eastside Project were analyzed by "segment" – which is the level of detail that specific neighborhoods frequently demand. See *Impact Analysis by Segment in the Final EIS, at DSD 005524*, which reads in part: *"The following pages summarize the potential impacts on scenic views and the aesthetic environment for PSE's Proposed Alignment, presented for the Richards Creek substation and by segment. For the Redmond, Bellevue North, Bellevue Central, and Renton Segments, the analysis included a review of refined project design details for PSE's Proposed Alignment and updated simulations, with results revised relative to the Phase 2 Draft EIS to reflect the new information. For these segments, the new information and analysis have not altered the conclusions presented in the Phase 2 Draft EIS regarding significant impacts to scenic views and the aesthetic environment."*

46. The Final EIS fully disclosed and discussed how the new transmission line project would be developed in segments or phases. See for example the explanation provided in the Sec. 2-37 of the Final EIS, at DSD 005464, which expressly informs the reader, the public, and decision-makers, as follows:

> "**Construction Phasing and Schedule.** Construction of the transmission lines would typically take approximately 12 to 18 months (over two construction phases) and would be constructed concurrently with construction of the Richards Creek substation. Under certain conditions, construction can be accelerated or slowed down depending on the number of crews working at the same time. The project is expected to be built in phases, with the south end (from the Talbot Hill substation to the proposed Richards Creek substation) being the first phase, followed by the north phase as soon as design, permitting, and energization of the south phase would allow. The project needs to be built in two construction phases to keep the Lakeside substation energized,

> thereby keeping the transmission system on-line to serve customers. During the construction of the south phase, the Lakeside substation will be served from the north and likewise, once the south phase is complete, it will be used to serve the Eastside while the north half is constructed."

47. Opposition arguments that challenged the pending application as improper "segmentation", "piecemealing", an undisclosed last-minute change, a strategic surprise, and the like, are factually incorrect. The Final EIS used to inform the public and decisionmakers in reviewing the pending application fully discloses that the South Bellevue Segment can function independently, and that the new transmission line will be developed in phases. It also explains a public benefit rationale for PSE's proposed phased construction schedule for the Energize Eastside Project – keeping the transmission system on-line to serve customers during construction.

48. PSE notes that the public review for its Energize Eastside Project has included the following community outreach efforts *(See DSD 000043-44; DSD 000249-252; and PSE Response Brief to Motion to Continue, dated Feb. 11, 2019):*

- 22 Community Advisory Group-related meetings, including six public open houses, two question and answer sessions, and two online open houses at key project milestones (four CAG meetings, three Sub-Area meetings, and an open house took place in Bellevue);
- Nearly 650 briefings (~320 in Bellevue) with individuals, neighborhoods, cities and other stakeholder groups;
- More than 300 comments and questions received, with more than 1,000 from Bellevue residents;
- 40+ email updates to more than 1,600 subscribers, with 775 residing in Bellevue;
- 10 project newsletters to 55,000+ households (20,000+ of which are in Bellevue);
- Ongoing outreach to 500+ property owners, including door-to-door and individual meetings, including approximately 130 parcels in Bellevue; and
- Participation in 16 EIS-related public meetings, five of which took place in Bellevue.

49. The Staff Report includes a detailed listing of public notices and public meetings conducted over the last few years regarding the construction of a new transmission line to connect the Talbot Hill and Lakeside substations, including the proposed Richards Creek substation addressed in this permit. *See DSD 000086-87.* Staff confirmed that public noticing requirements for the pending application were fully satisfied.

50. About 50 local residents, business owners, community leaders and interested citizens testified at the public hearing portion regarding the CUP application, and many live in neighborhoods that already have powerlines in their viewshed if they look at their windows or drive along streets in their community. Given the size of the crowd in the room when the

hearing opened, the Examiner granted a request to allow Bellevue residents the opportunity to speak first, followed by people from other places. Most people observed the hearing rules. People offered a wide-range of comments, with project supporters focusing on the need for reliable power in the City, and opponents repeating themes and issues raised in written comments analyzed throughout the EIS process and in the Staff Report. Several of the public witnesses spoke twice.

51. A large share of the public comments opposing the project focused on pipeline safety concerns. The applicant and staff properly note that pipeline safety issues are some of the most detailed topics addressed in mitigation measures and conditions of approval proposed in the FEIS and the Staff Report. Many of the opposition comments and presentations made during the public hearing focused on the "need" issue, with little pushback given to portions of the Staff Report that address how the project can be designed and conditioned to comply with applicable city standards for such facilities. Many opponents questioned whether any alternatives or routes ever really needed to be studied in the first place, reasoning that if there's no real need, then there is no reason for the project.

52. As noted in previous findings, "need" was analyzed over the past few years, and one thing has not and shows few signs of changing – Bellevue and the Eastside are booming. Even if growth were to grind to a halt, the rapid pace of growth and demand since the 115kv lines along the corridor were last substantially improved, decades ago, makes challenges to "need" and assertions that "demand just does not support the project" problematic.

53. Doing nothing, and simply maintaining the status quo, is not a responsible choice. The Phase 2 Draft EIS concluded that "Under the No Action Alternative, PSE would continue to manage its system in largely the same manner 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. *Implementation of the No Action Alternative would not meet PSE's objectives for the proposed project, which are to maintain a reliable electrical system and to address a deficiency in transmission capacity on the Eastside. <u>Implementation of the No Action Alternative would increase the risk to the Eastside of power outages or system damage during peak power events</u>.*" *(Phase 2 DEIS, discussion of No Action Alternative at Sec. 2.1.1, included in the Record at DSD 010246-247, emphasis added).*

54. While thoughtful and caring about their homes, neighborhoods, families, neighbors and environmental stewardship, the vast majority of comments opposing the project came from people with personal motivations like potential view impacts they believe will occur if the project goes forward. While some people complained about the existing powerlines and stray static events that can make your hair stand up on a misty day, most opposition witnesses

would have to acknowledge that the existing powerlines and utility corridor were already in place when they moved into their homes. Their questions and challenges to details in environmental reviews, load studies, demand studies, and the like, appeared jaded and heavily influenced by their desire to stop the project at any cost, to preserve existing conditions. Some expressed their desire to see all lines removed and the corridor used as a greenway.

55. Like other project opponents, CENSE and CSEE representatives voiced concerns but did not offer sufficient, relevant, authoritative, or credible evidence that would rebut the findings and recommendations made in the Staff Report.

56. The "need" studies, analysis of alternatives, pipeline safety reports and other substantive materials provided by the applicant were thoroughly reviewed, challenged, and revised by Staff and independent consultants engaged by the City to review applicant submittals for this project. Independent consultants confirmed that PSE studies and reports were conducted in a manner generally accepted by professionals specializing a particular subject matter, like system reliability, pipeline safety, pole design and the like.

57a. Again, third-party reviews confirmed the substance of the applicant's key submittals at issue in this CUP application. At the close of the hearing, attorneys for the two opposition groups, CENSE and CSEE, asked the Examiner to carefully read the Lauckhart and McCullough materials, included in the record, to see how the applicant has failed to satisfy approval criteria, mostly the requirement to show operational need. Having read and re-read the opposition reports and evidence, and the independent studies prepared by Stantec and USE, one finding and conclusion became crystal clear – the applicant reports, forecasts, and data analyses were in compliance with applicable industry standards. The opponents failed to rebut the independent consultant reviews of PSE's work involved in this application process, all of which concluded that PSE was planning and reviewing data in accord with industry practice and standards.

57b. On the other hand, PSE firmly established that several key aspects of opposition reports were defective and simply not credible, because they failed to follow industry practice. Rebuttal testimony from Mr. Nedrud was powerful and credible. He showed how Mr. McCullough's presentation, which showed far less demand than PSE forecasts, failed to properly account for several considerations required by industry practice and applicable federal electrical system planning mandates (NERC requirements) described by Ms. Koch during her testimony. Mr. Nedrud showed how Mr. McCullough's research analysis presented at the hearing only considered current loads to make load forecasts. This leads to erroneous results, because such analysis fails to include consideration of weather events (at peaks/extremes), projections of economic activity, population projections, building permits,



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and conservation goals. *Testimony of Mr. Nedrud, and his rebuttal slides presented at the hearing, included in the record as Ex. A-17.* Further, Mr. Nedrud demonstrated how Mr. Marsh's illustrations challenging demand data used by PSE were problematic, because the focus was on consumption (use) and not peak demand.

57c. Consumption is the amount of electricity that customers use over the course of a year. "Consumption" is also called "use" or "energy". "Demand" is customer usage at any given moment in time. "Peak Demand" is the maximum amount of electricity that PSE customers will demand at any given time.

57d. The City's consultant addressed the difference of "use versus demand" in its Independent Technical Analysis:

> *"Bellevue's Resource Conservation Manager (RCM) program stats on declining energy use are reflecting a decline in the average use per customer. The DSM programs, solar, etc. are showing success with this decline.* ***But, that is one piece of the story - the energy piece on a per customer basis. The number of customers continues to increase, and the aggregate peak usage (peak demand), is continuing to increase. Growth in peak demand drives the size and amount of infrastructure required and drives the issue of grid reliability****." (USE report, included as Attachment D to the Staff Report, found at DSD 000663-000739, on page 9 of 76; emphasis added).*

57e. In October of 2015, the Federal Energy Regulatory Commission (FERC) dismissed a complex challenge to the Energize Eastside Project raised by CENSE, CSEE, Larry Johnson, and others (identified by FERC as "Complainants"), which was supported by sworn testimony from Mr. Lauckhart, CSEE's principal witness in this matter. The FERC decision includes the following passage, which applies just as well to this Decision: *"Complainants discuss alleged flaws in the load flow studies that Puget Sound conducted for the Energize Eastside Project. However, Complainants do not demonstrate that the studies violated any applicable transmission planning requirements or were otherwise unjust, unreasonable, or unduly discriminatory or preferential. Complainants do not cite anything that would require Puget Sound to use the study inputs and assumptions that Complainants prefer instead of the inputs and assumptions that Puget Sound used." (FERC Order Dismissing Complaint by CENSE, CSEE, et al., issued Oct. 21, 2015, included in the record at DSD 000656, complete Order at DSD 000630-000659).* As in the FERC challenge, in this hearing process Mr. Lauckhart alleged flaws in the load flow reports that PSE relied upon to demonstrate need for its Energize Eastside Project, among other things. He did not rebut the favorable reviews provided by independent consultants engaged by the city regarding PSE's supporting studies. Mr. Lauckhart and other project opponents did not demonstrate that the studies used by PSE violated any applicable transmission planning requirements or were otherwise unjust, unreasonable, or unduly discriminatory or preferential. Opponents do not cite anything that would require PSE to use the study inputs and assumptions that they prefer instead of the inputs and assumptions that PSE used.

58a. Several opposition speakers directed attention to parts of the city's code that they read to say to that electrical facilities should be located where the need exists. In response, City staff argued that city codes do not mandate an entirely new utility corridor if fewer site compatibility impacts occur in a residential area than some other zoning district, and that the South Bellevue Segment proposal is the most feasible, lowest-impact option, emphasizing that the existing powerline route has been in the same place for decades, that poles have been in place in the same neighborhoods for many years, and that no new right-of-way is required as part of this project. The Staff Report, at pages 41-47, explains how the route selected by PSE has fewer site-compatibility impacts than other options.

58b. Even if the City's code could be read to require electrical facilities to only locate in areas that benefit or need the new or expanded electrical facility in question, in this situation, that is precisely what is proposed, because "load-shedding" – i.e. rolling blackouts – is currently part of PSE's corrective action plan (CAP) options in neighborhoods throughout the Eastside, including residential neighborhoods that are located along the route of the South Bellevue Segment. Given these circumstances, there truly is a critical "need" for the project to prevent such problems going forward in the residential areas located along the route.

58c. Pole designs, placement, heights, and wire-connections on poles, were all analyzed to generate conditions that minimize view impacts to the fullest extent reasonable, while still achieving the project objectives, including enhancing the reliability and redundancy in the power-transmission system that serves the City of Bellevue, including neighborhoods and businesses in the area affected by this South Bellevue Segment proposal.

59. The Examiner adopts and incorporates the City of Bellevue's administrative decision approving the associated Critical Area Land Use Permit (CALUP) issued for this project, under File No. 17-120557-LO, which was not appealed, as unchallenged findings, conclusions, and conditions of approval, that all provide support for the requested Conditional Use Permit, including without limitation:

- Findings and Conclusions re: Critical Areas Report Decision Criteria – General Criteria, LUC 20.25H.255.A.4, on page 104 of the Staff Report, which reads as follows:

> The resulting development is compatible with other uses and development in the same land use district.

> *Finding:* The project involves the replacement of an existing transmission line; therefore, no change in land use proposed. The proposed substation is located adjacent to an existing substation and other light industrial uses and non-residential development. PSE's proposal is anticipated by and included in Bellevue's Comprehensive Plan (see Attachment F [Map UT-7] to this Staff Report). The proposal is limited to the existing corridor, and the Project, as modified, is compatible with and responds to the uses and development that has been built up around the transmission line corridor for decades.

- Findings and Conclusions re: Critical Areas Land Use Permit Decision Criteria – item 4 re: LUC 20.30P.140.D, on page 106 of the Staff Report, which reads as follows:

> 4. The proposal will be served by adequate public facilities including street, fire protection, and utilities.
>
> *Finding:* The proposed transmission lines will not impact any existing public facility service level. The Phase 1 Draft EIS and Final EIS concluded that the Energize Eastside Project would not significantly increase the demand for public services, or significantly hinder the delivery of services. Refer to Technical Reviews conducted by the Fire, Utilities, and Transportation in Section V of this Staff Report.

- Findings and Conclusions re: Critical Areas Land Use Permit Decision Criteria – item 6, re: LUC 20.30P.140.F, on page 107 of the Staff Report, which reads as follows:

> 6. The proposal complies with other applicable requirements of this code.
>
> *Finding:* As discussed in Section IV of this Staff Report, PSE's proposal complies with all other applicable requirements of the Land Use Code.

60. Section IV.A of the Staff Report analyzes and explains how the pending proposal is consistent with applicable Land Use Code and Zoning Requirements, specifically PSE's obligation to comply with the Alternative Siting Analysis and design requirements found in LUC 20.20.255.D and 20.20.255.F, which apply to Electrical Utility Facilities. (See Staff Report at page 41). Given that the Critical Areas Land Use Permit was not appealed, any arguments or opposition to the requested Conditional Use Permit that are based on challenges to the Alternative Siting Analysis or design requirements found in the Land Use Code must fail. All findings, conclusions and conditions of approval in the CALUP are now beyond review. Any appeal of this Decision cannot be used to collaterally attack any aspect of the CALUP or determinations made therein. (*See Wenatchee Sportsmen Ass'n v. Chelan County, 141 Wn.2d 169, 182, 4 P.3d 123 (2000), and Habitat Watch v. Skagit County, 155 Wn.2d 397, 410–11, 120 P.3d 56 (2005)).*

61. City staff appropriately relied upon the Final EIS in its review of the requested CUP, and in crafting proposed conditions of approval for the South Bellevue Segment project. The

potential impacts studied in the EIS included a comprehensive set of worst-case scenarios and detailed mitigation measures for the larger project as well as this specific portion of the larger Energize Eastside Project, all of which should serve to adequately avoid, minimize, rectify, reduce, or eliminate adverse impacts associated with the South Bellevue Segment proposal. Several items in the conditions of approval require monitoring and data collection as part of the project, to assure that powerline/pipeline conflicts do not result in adverse impacts. *(See Conditions of Approval, including without limitation No. 17, mandating that PSE must file a mitigation and monitoring report with the City documenting consultations held with Olympic Pipeline to address pipeline safety related issues at least quarterly during construction, and post start-up monitoring to ensure that mitigation measures related to operational issues are followed, at DSD 000144).*

***Olympic Pipeline System.***

62. At the public hearing, multiple local residents expressed their genuine and legitimate concerns with hazards posed by existing electrical lines spanning over the Olympic petroleum pipeline though the City of Bellevue. Similar concerns were already provided in written comments summarized in the Staff Report, including without limitation at DSD 000093.

63. The Olympic Pipeline system is an underground petroleum pipeline system that is co-located with the existing PSE 115 kV transmission line corridor throughout the entire Energize Eastside Project area, except in the central portion of the Renton Segment. The Olympic Pipeline system is a 400-mile interstate pipeline system that runs from Blaine, Washington to Portland, Oregon. The system transports gasoline, diesel, and jet fuel through two pipelines – one 16 inches and one 20 inches in diameter. In the Energize Eastside Project area, the pipelines are generally co-located with PSE's transmission line within all of the segments, although in the Renton Segment it only co-located in the north portion of the segment (although it crosses the corridor in the southern portion of the segment). *(DSD 005451).*

64. The PSE transmission line corridor predates the pipeline by approximately three decades. *(Id.; Testimony of PSE witnesses).*

65. In most of the segments, the pipeline system is along either the east or west side of the PSE right-of-way, crisscrossing the right-of-way from east or west in numerous locations. In parts of the corridor (especially the Newcastle Segment), however, the pipeline system is buried in the center of the right-of-way. BP is the operator of the Olympic Pipeline system, and partial owner of the Olympic Pipe Line Company, with Enbridge, Inc. (Olympic Pipe Line Company, 2017). Typically, the proposed poles would be located at least 13 feet from

the Olympic Pipeline system where it is co-located with the transmission lines to reduce the need for additional arc shielding protection. *(DSD 005451).*

66. Due to the level of public concern expressed during scoping for both Phase 1 and Phase 2 regarding the potential risk of a leak, fire, or explosion that could occur as a result of constructing or operating the transmission lines in the same corridor as the Olympic Pipeline system, the pipeline safety issue is addressed specifically as one of two environmental health issues. Information on pipeline safety, both during construction and operation, is presented in the Final EIS, at Sections 4.9 and 5.9, re: *Environmental Health – Pipeline Safety*. *(DSD 005451).*

67. As the City's Land Use Director, Ms. Stead, noted during her testimony, the Final EIS concludes that the potential for conflicts/risks involving PSE powerlines and the Olympic Pipeline running beneath most all of the corridor in question will be lower or about the same with the project than with no action.

68. The Final EIS provides the following "*Impact Conclusion for PSE's Proposed Alignment",* which expressly includes the South Bellevue Segment addressed in this permit:

> Based on the results of the risk assessment, the probability of a pipeline release and fire occurring and resulting in fatalities remains low under PSE's Proposed Alignment. However, the potential public safety impacts would be significant if this unlikely event were to occur.
>
> Under PSE's Proposed Alignment, including mitigation for corrosion and arc risk incorporated into the design, the probability of a significant pipeline safety incident would likely be the same or lower than the No Action Alternative. Because of the variability of soils, it is possible that the arcing risk could be slightly higher in some locations when compared with the No Action Alternative. In these areas, testing, monitoring, engineering analysis, and implementation of mitigation measures would lower these risks. See Section 4.9.8, *Mitigation Measures* for measures that would lower the risks.
>
> The individual and societal risks described in Section 3.9.5.2 of the Phase 2 Draft EIS would be similar across all segments of PSE's Proposed Alignment. The risk would be proportional to the distance that the transmission lines are co-located with the Olympic Pipeline system. For PSE's Proposed Alignment, the Renton Segment has the lowest number of co-located miles. Table 4.9-1 lists the length of the Olympic Pipeline system (both the 20-inch and 16-inch diameter pipelines) collocated with the transmission lines in each segment.
>
> As described above, the lack of available data for existing fault and arc distance conditions required the risk assessment to use certain assumptions for the No Action Alternative condition that would allow for a worst-case analysis of the proposed 230 kV lines. Using these assumptions likely understates the existing risk (No Action), thereby possibly overstating the actual difference in risk between the No Action Alternative and PSE's Proposed Alignment. The likelihood of a pipeline rupture and fire would remain low, with no substantial change in risk. As a result, the potential impact on environmental health with regard to pipeline safety is not considered

significant. With implementation of the mitigation described in Section 4.9.8 of this Final EIS, conditions related to potential for fault damage due to coating stress and arc distances would likely improve under PSE's Proposed Alignment over the existing operational baseline condition (No Action Alternative) *(DNV GL, 2016 – A Detailed Approach to Assess AC Interference Levels Between the Energize Eastside Transmission Line Project and the Existing Olympic Pipelines, OLP16 & OPL20. Memo to Puget Sound Energy, dated September 9, 2016. Note 15 on page 15 of the Staff Report [DSD 000015] explains that the entire DNV GL 2016 report is included in the Phase 2 Energize Eastside Project EIS materials, and is included in the DSD official files for Permit Nos. 17-120556-LB and 17-120557-LO).* For additional details about the analysis of risks under Alternative 1, see the *Pipeline Safety Technical Report* (EDM Services, 2017).

*(FEIS, Chapter 4.9 Re: "Environmental Health – Pipeline Safety", at DSD 005699. Full discussion and thorough analysis of Pipeline Safety topics provided on pages DSD 005676-005715. Proposed mitigation measures re: pipeline safety issues are addressed on pages DSD 005714-15).*

69. Wolfgang Fieltsch is a qualified expert on issues regarding pipeline safety, particularly when pipelines are located in corridors near powerlines such as the case presented in this matter. During the public hearing, Mr. Fieltsch testified within his area of expertise. His testimony was credible.

70. At the public hearing, the City called Mr. Fieltsch, a recognized expert in the field of pipeline corrosion and safety issues where pipelines are co-located near powerlines, which he testified is very common. Mr. Fieltsch was retained by the City to serve as its independent expert on pipeline safety issues. He verified that he reviewed the DEN GL report (submitted by the applicant) and summarized some of his work performed to address pipeline safety issues discussed in the Environmental Impact Statement. He explained how mitigation measures proposed in the EIS should result in a powerline/pole design that will include "optimal phase arrangement" among other things, to cancel much of the potential AC interference problems that could occur.

71. Mr. Fieltsch's written report illustrates how the environmental review process for this project has resulted in design changes and strict mitigation requirements that make the proposal less likely to cause adverse impacts, particularly with respect to pipeline safety. His professional opinion on the subject served as the basis for additional mitigation measures addressed in the Final EIS, and the specific pipeline safety related conditions of approval proposed in the Staff Report. The Fieltsch Report, identified as the *TECHNICAL REVIEW re: ENERGIZE EASTSIDE AC INTERFERENCE ANALYSIS, dated May 2, 2017, prepared by Wolfgang Fieltsch, P. Eng. Team Lead – CP and AC Mitigation, for Stantec Consulting Services*, which was prepared for the Energize Eastside EIS review team, is included in the Record at DSD 004532-4539, and provides the following detailed "Opinion" and recommendations:

The primary objective of the AC interference study performed by DNV GL was to perform a sensitivity analysis to determine the optimal route and powerline configuration to minimize the AC interference risks on the two collocated pipelines.

An optimal route, phasing, and conductor orientation was selected to minimize the steady-state induced AC voltages on the paralleling pipelines. Shield wires were recommended to minimize the conductive coupling and arcing risks due to a phase -to -ground fault on the powerline structures.

Based on Stantec's experience and industry standards, it is our opinion that the technical approach used to achieve this objective in the subject AC interference study is consistent with industry practice.

The report concluded that the modeling indicated that selection of the recommended optimal route and configuration would result in no AC mitigation requirements on the pipelines. The report further recommends that final mitigation design should be based on field data collected after system energization.

In Stantec's opinion, although the study and modeling performed is sufficient as a sensitivity analysis, it cannot be used to determine the mitigation requirements for the pipelines related to the final design of the powerlines. Furthermore, mitigation based on field testing after energization is also not an acceptable approach, as measurements can only be taken at test stations, which are not necessarily located at locations with highest induced AC voltages and at greatest AC corrosion risk. Additionally, it is not possible to assess safety and integrity risks under powerline fault conditions in the field. DSD 004537

As such, we recommend the following be performed in the detailed design stage of the project prior to energization of the new powerline:

• Perform an AC interference study incorporating the final powerline route, configuration, and operating parameters.
• Obtain and incorporate all of the pipeline parameters required for detailed modeling and study (i.e., locations and details of above-grade pipeline appurtenances/stations, bonds, anodes, mitigation, etc.). This should include a review of the annual test post Cathodic Protection (CP) survey data.
• Fully assess the safety and coating stress risks for phase-to-ground faults at powerline structures along the entire area of collocation. This assessment should include both inductive and resistive coupling.
• Fully assess the safety and AC corrosion risks under steady-state operating conditions on the powerline.
• Reassess the safe separation distance to minimize arcing risk based on NACE SP0177 and considering the findings in CEA 239T817.
• Ensure that the separation distance between the pipelines and the powerline structures exceeds the safe distance required to avoid electrical arcing.
• Design AC mitigation (as required) to ensure that all safety and integrity risks have been fully mitigated along the collocated pipelines.
• Design monitoring systems to monitor the AC corrosion risks along the pipelines.
• Install and commission the AC mitigation and monitoring systems prior to energization of

> the 230 kV powerline.
> • After energization, perform a site survey to ensure that all AC interference risks have been fully mitigated under steady-state operation of the powerline.
>
> Based on the sensitivity analysis performed by DNV GL, it is Stantec's opinion that any remaining AC interference risks to the pipeline identified in the detailed design stage of the project can readily be mitigated via use of standard mitigation strategies. (DSD 004538).

72. The Fieltsch Opinion is largely mirrored in the mitigation measures recommended in the EIS, at DSD 5712-5715, and the proposed pipeline safety related conditions of approval (which include about 23 subparts) addressed in the Staff Report at pages 78-80, 134-137 and 143-146.

73. Pipeline safety arguments against the requested permit were not persuasive, as most all opposition comments based on pipeline coordination and the like are fully addressed in specific conditions of approval that should serve to improve the overall safety and oversight of the Olympic pipeline that runs beneath most portions of the existing powerlines. Opponents did not present any expert testimony to rebut evidence included in the Staff Report, the FEIS, or witness testimony, which established that specific conditions of approval can be included as part of this permit to prevent/avoid/mitigate/minimize potential adverse impacts that could arise due to construction and operation of the powerlines over the Olympic Pipeline.

74. The pipeline risk analyses provided in the record consistently explain that some of the highest risks of pipeline ruptures/emergency incidents occur when people are digging or performing construction work in close proximity to a petroleum pipeline. The Conditions of Approval recommended for the requested permit should serve to enhance and hopefully improve public safety by reducing current risks, as the pipeline corridor will be the subject of strict oversight by city officials and greater public awareness, compared with the complacency or inattention by residents and regulators that often accompanies conditions that have gone unchanged for many years, i.e. where an aging petroleum pipeline runs through neighborhoods beneath high transmission power lines.

***Discussion.***

75. The Staff Report explains that, with the exception of comments from various agencies and tribes, virtually all written comments submitted before its issuance opposed or challenged the pending permit. *(DSD 000087).* At the public hearing, and in written comments submitted as part of the public hearing process, the balance of comments was more balanced. About twenty speakers expressed support for the CUP application, while about thirty people expressed their opposition. In any event, land use decisions may not be based solely upon

community displeasure. Maranatha Mining v. Pierce County, 59 Wn. App. 795, at 804 (Div. II, 1990). In Maranatha, the court overturned denial of a permit, because the local agency disregarded the record before it, basing its decision instead "on community displeasure and not on reasons backed by policies and standards as the law requires." Maranatha, 59 Wn. App. at 805.

76. The record in this hearing process includes a reflection of broad support for reliable and consistent electric service throughout the City of Bellevue.

77. The themes and topics raised in opposition comments from concerned citizens were fully vetted and analyzed by Staff and consultants who aided in preparation of the multi-year effort to generate the Final Environmental Impact Statement. Speculation about alternatives and skepticism about PSE's study data used to demonstrate "need" for the project is healthy, and it led to a thorough analysis of almost every substantive comment or suggestion made by topic throughout the review process. In the end, the City's independent consultant verified "need", and the thorough EIS lays out specific mitigation measures that should apply to the project, leading Staff to recommend approval, subject to lengthy and detailed conditions of approval. Written comments about potential view impacts, especially those in the Somerset neighborhood, were thoroughly analyzed in the Staff Report. Many speakers reiterated their aesthetic/viewshed concerns at the public hearing, even though the project includes design changes and conditions of approval intended to address such issues. *(See Staff Report, at page 119, and Finding 83(B) below).*

78. Several public comments expressed opposition to the project without reservation, and discounted all studies, reports, or proposed conditions to the contrary. Again, community displeasure alone cannot be the basis of a permit denial. Kenart & Assocs. v. Skagit Cy., 37 Wn. App. 295, 303, 680 P.2d 439, *review denied,* 101 Wn.2d 1021 (1984). Multiple studies regarding "need" and alternative site analysis are included in the Record. Substantial evidence in the Record – far more than the preponderance needed – establishes that the requested permit satisfies all applicable approval criteria. Accordingly, the city code mandates that the permit shall be approved, subject to conditions.

79. While opposition testimony, presentations, and materials were thoughtful and well-organized for the most part, none of the individuals testifying at the hearing or submitting written comments opposing the project offered any persuasive expert reports, studies or other compelling environmental analysis that would rebut the expert reports, certifications and/or environmental analyses provided by the applicant, staff, or independent consultants engaged by the City.

80. The findings, recommendations and conclusions provided in the environmental documentation submitted on behalf of the applicant, as well as the City's reviewing consultant reports, are credible and well-reasoned summaries of complicated regulations, conditions, possible impacts and appropriate mitigation measures associated with the South Bellevue Segment proposal. No person or organization presented comparable expert witnesses or evidence with power transmission system planning, engineering, pipeline safety, urban planning, design, or other relevant credentials to support opposing views.

81. The Staff Report includes a number of specific findings and conditions that establish how the pending CUP application satisfies provisions of applicable law and/or can be conditioned to comply with applicable codes and policies. Except as modified in this Decision, all Findings contained in the Staff Report for the pending Conditional Use Permit are incorporated herein by reference as Findings of the undersigned hearing examiner.[3]

82. In sum, city staff review was robust, thorough, and challenging to the applicant – as it should be in a project of this scale and impact on local residents. As shown above, real, substantive changes that will benefit affected parties, the city, and even the applicant, have been made to the project from its initial conceptual notion to the present as a result of public feedback, staff review, and exhaustive studies on various aspects of the project.

***The application satisfies the City's decision criteria for a Conditional Use Permit.***

83. As noted above, the City's decision criteria for the pending conditional use permit is found in LUC 20.30B.140. Unlike the decision criteria specifically applied to electrical facilities in LUC 20.20.255, the general conditional use permit requirements are the same as would be applied to any conditional use permit decision. Applying facts and evidence in the record to the decision criteria for a Conditional Use Permit (found in LUC 20.30B.140.A-E), the Examiner finds and concludes as follows:

**A. The conditional use is consistent with the Comprehensive Plan.** *Staff Report, Attachment G, detailed review of Comprehensive Plan – Policy Analysis, addressing more than 59 Comp. Plan Policies, at DSD 000892-000918; Staff Report, analysis provided on pages 113-119; Application materials at DSD 000600-617; EIS at DSD 005495, 005502-3; Testimony of*

**B. The design is compatible with and responds to the existing or intended character, appearance, quality of development and physical characteristics of the subject property**

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[3] For purposes of brevity, only certain Findings from the Staff Report are highlighted for discussion in this Decision, and others are summarized, but any mention or omission of particular findings or analysis provided in the Staff Report should not be viewed to diminish their full meaning and effect, except as modified herein.

**and immediate vicinity.** *Staff Report, pages 119-120, and pages 133-134, mandating "pole finishes" to reduce aesthetic impacts, implementing recommendations set forth in Pole Finishes Report, Attachment J to Staff Report, at DSD 001465-001510; EIS at DSD 005502-03, 005520, 005525, 005540-5546, 005495, 010303, 010325-26; and application materials at DSD 000617-618. Because so much testimony came from speakers with concerns about potential impacts on views in the Somerset neighborhood, the following excerpt from page 119 of the Staff Report is incorporated as findings supporting this decision as it provides a detailed summary of site-specific changes that have been made in the design to address such concerns, in addition to a thorough consideration of trees, pole-heights, and pipeline safety in the Somerset neighborhood:*

> PSE's proposal is designed to respond to the existing and intended character appearance, quality of development, and physical characteristics of the subject property and the immediate vicinity. Because the Project is sited in an existing corridor shared with another utility (the Olympic Pipeline system), the Project will not introduce a change in land use. It will consolidate the lines onto fewer poles, which, although larger, will not increase visual clutter and could reduce it in some areas. Various pole treatments will be employed to complement the natural environment, and vegetation management will maintain the general appearance of landscaping in a similar manner as the present. Although a number of trees will be removed, the remaining and proposed trees will partially screen views of the taller poles. Likewise, the proposed substation will be screened by a slope and native vegetation. Reinstallation of telecommunications facilities on the same transmission facilities following construction will ensure that there will not be an increase in the number of telecommunications facilities to the maximum extent feasible.
>
> The City's Comprehensive Plan states that electrical utility facilities should be designed, constructed, and maintained to minimize the impact on surrounding neighborhoods (UT-8). The Somerset neighborhood developed around the transmission line corridor, so the increase in height of the current transmission line is not a new use. In the portion of the existing corridor within the Somerset neighborhood where the Project will significantly impact neighborhood character (see Figure 4.2-12 in the Final EIS), the pole design was modified to reduce the necessary height, using dual monopoles instead of single monopoles preferred in other locations within the corridor. These modifications to pole design respond to the existing physical characteristics of the Somerset neighborhood, which has lower building and vegetation heights than other areas of the corridor. The visual impacts in this area, while considered significant, will not cause blight, as defined in the Revised Code of Washington (RCW) 35.81.015, or cause substantial dilapidation or deterioration in this portion of the Somerset neighborhood.
>
> Further modifications to necessary pole heights within the Somerset neighborhood would increase the number of poles in the neighborhood and result in additional impacts to the character and appearance of the immediate vicinity. For example, the City requested that PSE provide additional information regarding pole heights in the Somerset neighborhood as part of the land use process. The analysis provided in response by PSE indicates that pole heights in the Somerset neighborhood could, on average, be reduced by around 16 feet. In order to facilitate this further reduction in pole height, however, the number of poles would more than double (approximately 24 additional poles) and poles would be sited on properties that do not have poles currently (approximately 17 poles sited on new properties). (PSE 9-21-18).



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An increase in the number of poles in the Somerset neighborhood would also impact the physical characteristics of the corridor and the immediate vicinity because the quantity of excavation would more than double due to the increased number of poles. Similarly, additional vegetation impacts, including additional tree removal and fewer replanting options, would occur in the immediate vicinity of the shorter poles. With taller poles, the conductors are installed with more sag (i.e., they curve more), so the conductor attachment poles are farther from the ground, which allows for taller vegetation options. Thus, the increase in pole number required for shorter poles would result in increased excavation, more tree removal to accommodate the additional poles, and fewer screening options for both the existing and new pole locations within the corridor.

Shorter poles (or a significant increase in the number of poles) may also increase the potential for interaction with the co-located Olympic pipeline. While increased EMF levels and potential interaction with the pipeline are unrelated to the visual impacts to the Somerset neighborhood identified in the Final EIS, this information does suggest that the current proposal strikes a better balance.

The Comprehensive Plan lacks policies to protect private residential views. Nevertheless, because building and vegetation heights are lower in the Somerset neighborhood than other areas of the corridor due to private covenants, viewer sensitivity in portions of Somerset is higher than in other areas of the corridor. It is recognized that the contrast between the taller poles proposed by the Project and the current pole heights in Somerset, combined with high viewer sensitivity, could cause some Somerset residents to choose to move. However, the entire residential community surrounding the transmission line has been built next to the existing corridor, and the Project, as modified, is consistent with and responds to the existing or intended character, appearance, quality of development, and physical characteristics the Somerset community. Despite the visual impacts identified in the Final EIS, the Somerset neighborhood will continue to be a healthy, vibrant, and unique community. With the Conditions of Approval specified below for aesthetic impacts and vegetation management, the Project is consistent with LUC 20.30B.140.B.

**C. The conditional use will be served by adequate public facilities including streets, fire protection, and utilities.** *On this topic, there was minimal, if any, material dispute that this criterion has been fully satisfied. Staff Report, pages 121-122, and discussion of relevant technical reviews on the subject that appears on pages 70-73; Application materials at DSD 000618-621; EIS at 005420.*

**D. The conditional use will not be materially detrimental to uses or property in the immediate vicinity of the subject property**. *Staff Report at 121-122; Application materials at DSD 000618-621; EIS at DSD 005502-3, 005525, 005540-5546, 005495.*

**E. The conditional use complies with the applicable requirements of this Code.** *As conditioned, the pending Conditional Use Permit application meets the applicable* *performance standards and requirements included in the City's Land Use Code; Staff Report, page 122, and pages 107-113; Application materials at DSD 000621.*

***The application satisfies the City's additional criteria for Electrical Utility Facilities.***

84. Because the proposal is to construct or expand electrical facilities, the provisions of the City's Land Use Code specifically addressing Electrical Utility Facilities, found in LUC 20.20.255, must be satisfied. Prior to submittal of any Conditional Use Permit application, a detailed Alternative Siting Analysis was required. See LUC 20.20.255.D. Applying the facts and evidence in the record to the additional requirements for new or expanding electrical utility facilities, as detailed in LUC 20.20.255.E.1-6 and .F, the Examiner finds and concludes as follows:

**A. Re: 255.E.1. The proposal is consistent with Puget Sound Energy's System Plan**. *Testimony of PSE Manager of System Planning, Jens Nedrud; Staff Report at pages 107-108; Application materials at DSD 000621, which reads in relevant part as follows: "The need for additional 230 kV capacity in the Eastside region was identified, and has been included in PSE's Electrical Facilities Plan for King County ("Plan"), since 1993. As explained in the Plan, "[t]he 230 kV sources for the 115 kV system in northeast King County are primarily the Sammamish and Talbot Hill substation. The loads on the 230-115 kV transformers in these stations will be high enough to require new sources of transformation." Additionally, the "Lakeside 230 kV Substation project [now referred to as Energize Eastside] will rebuild two existing 115 kV lines to 230 kV between Sammamish and Lakeside [where PSE proposes the construction of the Richards Creek substation], and between Lakeside and Talbot Hill."*

**B. Re: 255.E.2. The design, use, and operation of the electrical utility facility complies with applicable guidelines, rules, regulations or statutes adopted by state law, or any agency or jurisdiction with authority**. *Staff Report at pages 108-109; Application materials at DSD 000621-622; Testimony of Ms. Koch.*

**C. Re: 255.E.3. The applicant demonstrated that an operational need exists that requires the location or expansion at the proposed site**. *Staff Report at pages 109-111, noting that between 2012 and 2015, PSE and the City commissioned three separate studies confirming the need to address Eastside transmission capacity. The Staff Report relies on the analysis in the USE Report verifying operational need, and the entire USE Report, and the other studies commissioned by PSE on the subject of need, are attached to the Staff Report and included in the Record for this matter. See DSD 000663-739, the "USE" Report, commissioned by the City. The review on "need" went further, as an independent electrical system planning and engineering consultant (Stantec) reviewed PSE's needs assessment as* *part of the EIS process and found PSE's assessment "very thorough" and concluded that PSE had followed standard industry practice. See DSD 004521-4531, the Stantec Report. The Staff Report explains that the City's Comprehensive Plan shows a potential need to expand both the transmission line and the Lakeside substation [the "Richards Creek substation"), which are the two parts of the pending CUP application. See Comp. Plan Map UT-7, at DSD 000891, showing general locations and conceptual alignments for PSE's planned facilities in the City of Bellevue. See Finding 84(F), below.*

**D. Re: 255.E.4. The applicant demonstrated that the proposed electrical utility facility improves reliability to the customers served and reliability of the system as a whole, as certified by the applicant's licensed engineer**. *Same as item C, above; Testimony of Mr. Nedrud, a Washington State licensed engineer and PSE's Manager of System Planning; Mr. Nedrud's July 20, 2017 reliability certification letter to Ms. Bedwell, the City's Environmental Planning Manager, referenced at page 111 of the Staff Report, included in the record at DSD 000661-662; Staff Report discussion on page 111; Application materials at pages 000623-626; EIS at DSD 005438, 005413-15, 011102-5, and 011168-70.*

**E. Re: 255.E.5.a. Because the proposal is located on sensitive sites as referenced in Figure UT.5a (now Map UT-7) of the Utility Element of the Comprehensive Plan, the applicant fully complied with the Alternative Siting Analysis requirements of LUC 20.20.255.D.** *Staff Report, pages 41-44 and 111-113; Application materials at DSD 000623 and 626; DSD 011049-747, Ph. 1 Draft EIS, evaluating technological alternatives; DSD 010205-11048, Ph. II Draft EIS, evaluating siting alternatives. See entire Alternative Sighting Analysis included as Attachment "B" to the Staff Report, at DSD 000222-597. See Findings 59 and 60 above, and Finding and Conclusion No. 6 in the CALUP issued for this proposal.*

**F. Re: 255.E.5.b. Where feasible, the preferred site alternative is located within the land use district requiring additional service and residential land use districts are avoided when the proposed new or expanded electrical utility facility serves a nonresidential land use district.** *As explained in the five separate studies performed by four separate parties confirming the need to address Eastside transmission capacity – 1) Electrical Reliability Study by Exponent, 2012 (City of Bellevue); 2) Eastside Needs Assessment Report by Quanta Services, 2013 (PSE); 3) Supplemental Eastside Needs Assessment Report by Quanta Services, 2015 (PSE); 4) Independent Technical Analysis by Utility Systems Efficiencies, Inc. ("USE"), 2015 (City of Bellevue); and 5) Review Memo by Stantec Consulting Services Inc., 2015 (EIS consultant), all of which are provided in the Alternative Siting Analysis – PSE's proposed transmission line upgrade is responsive to projected growth in the Eastside generally and the City of Bellevue specifically. Even if the City's code could be read to require electrical facilities to only locate in areas that benefit or need the* *new or expanded electrical facility in question, in this situation, that is precisely what is proposed, because "load-shedding" – i.e. rolling blackouts – is currently part of PSE's corrective action plan (CAP) options in neighborhoods throughout the Eastside, including residential neighborhoods that are located along the route of the South Bellevue Segment. Given these circumstances, there truly is a critical "need" for the project to prevent such problems going forward in the residential land use districts located along the route.*

**G. Re: 255.E.6. The proposal, as conditioned, will provide mitigation sufficient to eliminate or minimize long-term impacts to properties located near an electrical utility facility.** *Staff Report, at page 113, and Conditions of Approval on pages 124-146. Mitigation measures and conditions include requirements to address impacts related to visual impact, tree and vegetation removal, pipeline safety, historic and cultural resource protection, among other things. See full discussion of mitigation measures, conditions and requirements provided in Sections III, IV, V, VI, VIII, and X of the Staff Report. DSD 000626, 001745-3477,003528-3541 (re: vegetation and trees); DSD 003582-3626 (re: pole color); DSD 003629-63 (re: cultural resources); DSD 003664-72 (re: substation mitigation plan); EIS at DSD 005424-33 (re: impact summary and mitigation options), and DSD 005696 (re: proposed AC interference mitigation).*

**H. Re: 255.F. The proposal, as conditioned, complies with the additional design standards that apply to projects to locate or expand electrical utility facilities.** *Staff Report, pages 44-47, describing how project has been designed or can be conditioned to comply with specific design standards, including without limitation those addressing site landscaping, fencing, setbacks, and height; application materials at DSD 000626-628.*

85. The Conditions of Approval included as part of this Decision are reasonable, appropriate, fully supported by testimony and evidence in the record, and capable of accomplishment.

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## VI. CONCLUSIONS of LAW.

1. As explained above, the record includes credible, unrebutted, and substantial proof that the Conditional Use Permit application satisfies all applicable decision criteria specified in applicable city LUC 20.30B.140, as conditioned herein.

2. Similarly, the record includes credible, unrebutted, and substantial proof that the proposal satisfies the additional criteria for Electrical Utility Facilities, set forth in LUC 20.20.255, as conditioned herein.

3. Based on the record, and all findings set forth above, the applicant established that more than a preponderance of the evidence supports the conclusion that its permit application merits approval, meeting its burden of proof imposed by LUC 20.35.340(A).

4. Any finding or other statement contained in this Decision that is deemed to be a Conclusion of Law is hereby adopted as such and incorporated by reference.

## VII. DECISION.

Based on the record, and for the reasons set forth herein, the requested Conditional Use Permit for the South Bellevue Segment of the Energize Eastside Project should be and is hereby approved, subject to the following conditions of approval, which are incorporated herein by reference.

ISSUED this 25TH Day of June, 2019

Gary N. McLean
Hearing Examiner

Attachments: Conditions of Approval, 20 pages; and
Exhibit List.



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## NOTICE OF RIGHTS
## TO REQUEST CLARIFICATION OR RECONSIDERATION,
## AND TO APPEAL

This Decision has been issued by the Hearing Examiner who has specific authority to address Type I quasi-judicial matters following a public hearing. *See LUC 20.35.100.*

***REQUEST FOR CLARIFICATION OR RECONSIDERATION*** – As provided in Rule 1.25 and 1.26 of the Bellevue Hearing Examiner Rules of Procedure, a party may file a written request for clarification or reconsideration of this Decision within five (5) working days after the date of issuance. Additional requirements and procedures concerning Requests for Clarification or Reconsideration are found in Rule 1.25 and 1.26 of the Hearing Examiner Rules of Procedure.

***RIGHT TO APPEAL – TIME LIMIT*** – Persons and entities identified in Land Use Code (LUC) 20.35.150, may appeal a Process I decision of the Hearing Examiner to the Bellevue City Council by filing a written statement of the Findings of Fact or Conclusions of Law which are being appealed, and paying a fee, if any, as established by ordinance or resolution, no later than 14 calendar days following the date that the decision was mailed. The written statement must be filed together with an appeal notification form, available from the City Clerk. The written statement of appeal, the appeal notification form, and the appeal fee, if any, must be received by the City Clerk no later than **5:00 p.m. 14 calendar days following the date that the decision was mailed.** ***(Because this Decision has been mailed on June 25, 2019, the appeal deadline is July 9, 2019).***

***TRANSCRIPT OF HEARING – PAYMENT OF COST*** – An appeal of the Hearing Examiner's decision requires the preparation of a transcript of the hearing before the Hearing Examiner. Within thirty (30) days of the decision which is appealed from, the appellant shall order from the City Clerk, on a form provided by the Clerk, a full transcript of the hearing before the Hearing Examiner. At the time the order for transcription is placed, the appellant shall post security in the amount of One Hundred Dollars ($100.00) for each hearing hour to be transcribed. If appellant fails to post security, the appeal shall be considered abandoned.

Additional requirements and procedures concerning appeals filed with the Council are found at Resolution 9473 and in the City of Bellevue Land Use Code.

**AFFIDAVIT OF SERVICE**

| | | |
|---|---|---|
| **STATE OF WASHINGTON** | **)** | |
| | **) ss.** | |
| **COUNTY OF KING** | **)** | |

**Karen Hohu, being first duly sworn upon oath, deposes and states:**

**In the Matter of *Energize Eastside CUP Application-South Bellevue Segment*, on the 25th day of June, 2019, I served a copy of:**

## FINDINGS OF FACT, CONCLUSIONS AND DECISION

☒ **BY ELECTRONIC SERVICE – EMAIL by electronically mailing a true and correct copy thereof through the City of Bellevue's electronic mail system to the email address(es) set forth below:**

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☒ **BY U.S. MAIL by placing a true and correct copy thereof enclosed in a sealed envelope with postage thereon fully prepaid, addressed as follows, for collection and mailing at the City of Bellevue in accordance with ordinary business practices:**

## See attached list

**I declare under penalty of perjury under the laws of the State of Washington that the foregoing is true and correct. Executed at Bellevue, Washington on this 25th day of June, 2019.**

Karen Hohu

**Karen Hohu**
**Hearing Examiner Program Coordinator**

**Subscribed and sworn this** 25th **day of June, 2019**

KARIN ROBERTS
Notary Public
State of Washington
My Appointment Expires
Feb 1, 2022

Karin Roberts

**Notary Public in and for the State of Washington, residing at Sammamish, WA**
**My appointment expires: 02/01/2022**

**Application, Petition or Case:** **Energize Eastside CUP Application (South Bellevue Segment) DSD File No.: 17-120556-LB**

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# ATTACHMENT E

## King County Superior Court Appeal Decision

The Honorable Melinda Young
Hearing Dates: Friday, May 22, 2020
Friday, August 14, 2020
With Oral Argument

IN THE SUPERIOR COURT OF THE STATE OF WASHINGTON

IN AND FOR THE COUNTY OF KING

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| COALITION OF EASTSIDE NEIGHBORS FOR SENSIBLE ENERGY, a Washington non-profit corporation,<br><br>Petitioner,<br>v.<br><br>CITY OF BELLEVUE, a Washington municipal corporation, and PUGET SOUND ENERGY, INC., a Washington public utility corporation,<br><br>Respondents. | No. 19-2-33800-8 SEA<br><br>FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER<br><br>(Chapter 36.70C RCW) |

THIS MATTER was heard before the Honorable Melinda Young, the undersigned judge of the above-titled court. The Land Use Petition Act (LUPA) appeal by Petitioner Coalition of Eastside Neighbors for Sensible Energy (CENSE) challenges Respondent City of Bellevue's decision to approve Puget Sound Energy, Inc.'s (PSE) application for a Conditional Use Permit (CUP) for the South Bellevue Segment of the Energize Eastside project. CENSE also challenges the adequacy of the environmental review conducted by the cities of Bellevue, Renton, Newcastle, and Redmond (collectively, “the Partner Cities”) for the entire Energize Eastside project under the State Environmental Policy Act (SEPA).

The City of Bellevue, PSE and CENSE appeared in this matter through their attorneys of record, and this Court heard the arguments presented by counsel at the February 14, 2020 Initial Hearing and during the May 22, 2020 and August 14, 2020 hearings on the merits. The Court has reviewed the following records in connection with this LUPA appeal and SEPA challenge:

1. Petitioner CENSE’s February 6, 2020 Motion on Procedural and Jurisdictional Matters;

2. Respondent City of Bellevue’s February 12, 2020 Response to CENSE’s Procedural and Jurisdictional Motion;

3. Petitioner CENSE’s April 21, 2020 Opening Brief and all attachments thereto;

4. Respondent City of Bellevue’s May 12, 2020 Response to Opening Brief of Petitioner CENSE and all attachments thereto;

5. PSE’s May 12, 2020 Response to CENSE Opening Brief and all attachments thereto;

6. Petitioner CENSE’s May 19, 2020 Reply Brief of Petitioner CENSE and all attachments thereto;

7. The Certified Administrative Record of Proceedings (RCW 36.70C.110);

8. The Excerpts of Record submitted by Petitioner CENSE, Respondent City of Bellevue, and PSE;

9. The March 28, 2019; March 29, 2019; April 3, 2019; and April 8, 2019 Certified Transcripts of Proceedings before the City of Bellevue Hearing Examiner;



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10. The October 16, 2019; November 14, 2019; and December 2, 2019 Certified Transcripts of Proceedings before the City of Bellevue City Council; and

11. All of the argument presented by the parties at the February 14, 2020; May 22, 2020; and August 14, 2020 hearings on this matter.

Based on the Court's review of the foregoing and hearing the argument presented by the parties at the February 14, 2020; May 22, 2020; and August 14, 2020 hearings, the Court now enters the following Findings of Fact, Conclusions of Law, and Order:

## FINDINGS OF FACT

1. PSE's Energize Eastside project is a linear infrastructure project to upgrade sixteen (16) miles of high voltage transmission lines from Renton to Redmond and to construct a new substation in the City of Bellevue (the "Richards Creek substation"). AR 001319.

2. The Energize Eastside project is a single project within the jurisdiction of multiple permitting agencies who will consider various permit applications subject to different land use processes. AR 006823.

3. The purpose of the Energize Eastside project is to meet local electricity peak demand growth and to protect electrical grid reliability in the Eastside of King County, roughly defined as extending from Redmond in the north to Renton in the south, and between Lake Washington and Lake Sammamish. AR 000011-13, 001321, 006812-6815, 011637.

4. The work anticipated as part of the Energize Eastside project is limited to the existing utility corridor, which has existed for almost a century, and PSE's proposed transmission lines and associated infrastructure will generally be in the same location as the existing utility infrastructure. AR 000010-11, 001327, 001340.



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5. Although the Partner Cities and King County each have land use permitting authority over portions of the Energize Eastside project, the City of Bellevue (City) was designated as the lead agency for the Partner Cities' environmental review of the project. AR 000018, 001319, 001387, 006812-6813, 006823.

6. The Partner Cities' environmental review included preparation of a Phase 1 Draft Environmental Impact Statement ("Phase 1 Draft EIS") and Phase 2 Draft EIS, released in January 2016 and May 2017, respectively, and culminated in the issuance of the March 1, 2018 Final EIS. AR 000018-21, 001387, 006793-13385.

7. The environmental analysis presented a comprehensive environmental assessment of the entire Energize Eastside project throughout each jurisdiction, extending from the cities of Renton to Redmond. AR 000018-21, 001387-1398, 006821-6822, 006824-6835, 006891-7182, 007204-7212.

8. The Phase 2 Draft EIS and Final EIS analyzed fourteen (14) transmission line routing alternatives. AR 000018, 06837.

9. The environmental analysis considered potential environmental impacts in the South Bellevue Segment associated with construction of the Richards Creek substation and the transmission line upgrades in south Bellevue. *See* Final EIS (AR 006826, 006860, 006904-6905, 006916, 006923-6928, 006942-6948, 006981-6982, 006986, 007011, 007021-7022, 007033-7034, 007053, 007073, 007111, 007135) & Phase 2 Draft EIS (AR 011683-11686, 011735-11743, 011760-11763, 011769-11770, 011809-11811, 011814-11816, 011818-011823, 011825).



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10. The Final EIS also disclosed and considered PSE's phased construction plan for the Energize Eastside project, and explained the utility and benefit of PSE's phased construction and permitting schedule. AR 006823, 006866, 007557.

11. The Energize Eastside project needs to be built in two construction phases to keep the transmission system on-line to serve customers. AR 006823, 006866. During the construction of the south phase, the Lakeside substation will be served from the north, and after the south phase is complete, the Richards Creek substation will be used to serve the northern phase, located in north Bellevue and Redmond, while this northern phase is permitted and constructed. AR 000021-22, 006823, 006866, 007557.

12. Contrary to CENSE's arguments, the Final EIS never stated that the first phase of construction would be limited to the South Bellevue Segment, or that the first phase of construction from Renton to Bellevue, standing alone, can feasibly attain or approximate PSE's stated objectives for the Energize Eastside project. AR 006823, 006866.

13. Permitting and construction of the South Bellevue Segment will not result in any significant unavoidable adverse environmental impacts in central Bellevue or north Bellevue, and the Final EIS did not identify any significant unavoidable adverse environmental impacts in central or north Bellevue as a result of the entire Energize Eastside project. AR 006826, 007209-7212.

14. Between 2012 and 2015, PSE and the City commissioned three studies that confirmed PSE's conclusion that the Energize Eastside project is needed to meet local electricity peak demand growth and to protect electrical grid reliability. AR 000013, 001323-1324, 001420-1424.



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15. The City also separately commissioned an independent analysis by Utility System Efficiencies, Inc. (USE Study), which evaluated PSE's system and again confirmed the need for the Energize Eastside project. AR 001282, 001978-2053.

16. The independent consulting firm Stantec Consulting Services, Inc. reviewed PSE's analysis of project need (Stantec Report), confirmed that PSE's analysis followed standard industry practice, and confirmed the Energize Eastside project is designed to bring the needed infrastructure to supply the local need. AR 000013, 00016-17, 001864-1873.

17. The Stantec Report explained that PSE must plan for peak demand periods and potentially employ Corrective Action Plans (CAPs) to protect an overloaded system and reduce heating on certain system transformers and lines so that they will not be destroyed. AR 000016-17, 001871-1872.

18. CAPs, load-shedding, and blackouts adversely affect everyone, including residential uses and critical support services like hospitals, nursing homes, fire departments, and police stations. AR 000026, 001872.

19. Consistent with the phased construction plan for the Energize Eastside project identified in the Final EIS, PSE submitted permit applications to the City, Renton, Newcastle, and unincorporated King County for land use approval in connection with the first construction phase of the Energize Eastside project. AR 000010, 001319, 006822, 007557.

20. PSE submitted two land use permit applications to the City for the South Bellevue Segment of the Energize Eastside project simultaneously: (1) the CUP at issue in this lawsuit, and (2) a Critical Areas Land Use Permit (CALUP). AR 001314-1315, 001321-1325.

21. The City's approval of the CALUP has not been challenged by CENSE or any other party and is now final. AR 000006-7, 000027.



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22. PSE's CUP application to the City requested approval to construct the Richards Creek substation and to upgrade 3.3 miles of 115-thousand-volt (kV) transmission lines with 230 kV lines within the existing utility corridor in south Bellevue. AR 000009, 001314, 001319, 006860.

23. PSE's CUP proposal for the South Bellevue Segment of the Energize Eastside project is located in a land use district that currently accommodates the utility corridor and requires the service that PSE's proposal will provide. AR 000022-26, 001328, 001340, 001357, 001539, 001543.

24. The South Bellevue Segment of the Energize Eastside project is being constructed and permitted in exactly the same manner and as part of the same phased construction sequence identified in the Final EIS. AR 000018-22, 001319, 001539, 006823, 006826, 006838, 006842, 006860, 006866, 07557.

25. PSE's CUP application is subject to the Electrical Utility Facilities provisions in the City's Land Use Code (LUC), at LUC 20.20.255, and the CUP decision criteria in LUC 20.30B.140. AR 000005-6, 001416.

26. The Electrical Utility Facilities provisions in LUC 20.20.255 impose additional requirements on PSE's proposal above and beyond standard CUP provisions, including an Alternative Siting Analysis (ASA) and additional decision criteria in LUC 20.20.255.E. AR 001354-1357, 001420-1426.

27. Consistent with the requirements in LUC 20.20.255.D, PSE submitted a comprehensive ASA that described three siting alternatives, the land use districts within which the sites are located, mapped the location of the sites, provided justification for locating the infrastructure upgrades in the existing utility corridor, and depicted the proximity of the sites to



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neighborhood business land use districts, residential land use districts, and transition areas. AR 001355, 001541-1556, 001568-1574.

28. The ASA submitted by PSE provided a location selection hierarchy, as required by LUC 20.20.255.D.2.d., and described the range of technologies PSE considered for its proposal, how the proposal provides reliability to the customers served, how the components relate to system reliability, and how the proposal includes technology best suited to mitigate impacts on surrounding properties. AR 001355-56, 001545-1547, 001553-1562. The ASA explained the community outreach PSE conducted over many years prior to submittal of the CUP application. AR 001356-1357, 001562-001565.

29. The ASA also explained that the Energize Eastside project is needed because cumulative demand on the Eastside is increasing, including in areas along the South Bellevue Segment. AR 001543.

30. Within the City of Bellevue, the CUP application for the South Bellevue Segment is subject to a different land use process (Process I) than a CUP application for the northern construction phase (Process III). AR 00931-938, 01320-1321, 006823.

31. Under the City's Process I land use process, the City's Land Use Director issues a recommendation to the Hearing Examiner, and the Hearing Examiner, after holding a public hearing, issues a decision on the application. LUC 20.35.130 – 20.35.140. The Hearing Examiner's decision may then be appealed to the City Council, and the City Council's quasi-judicial decision on appeal is the City's final decision. *Id.* at 20.35.150.

32. On January 24, 2019, the City's Land Use Director recommended approval, with conditions, of PSE's CUP application. AR 001314, 001354-1357, 001420-1436. In connection



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with the Director's recommendation, the City issued a 151-page Staff Report with fifty-three (53) conditions of approval and ten (10) separate attachments. AR 001314-2825.

33. The Staff Report explained in detail why PSE's proposal satisfied the ASA requirements in LUC 20.20.255.D, the Conditional Use decision criteria in LUC 20.30B.140, and the Electrical Utility Facilities decision criteria in LUC 20.20.255.E. AR 001314-001347 (overview of PSE's South Bellevue Segment proposal and the Energize Eastside project), 001354-001360 (PSE compliance with the ASA requirements in LUC 20.20.255.D), 0001325, 001387-001398 (SEPA analysis), and 001420-001432 (PSE compliance with the Electrical Utility Facilities Decision Criteria in LUC 20.20.255.E and the City's Comprehensive Plan).

34. Prior to the public hearing before the Hearing Examiner, CENSE filed multiple motions, arguing that PSE had violated SEPA by applying for permits for the South Bellevue Segment without simultaneously applying for permits for the northern segment of the Energize Eastside project. CENSE also asked the Hearing Examiner to compel PSE to produce certain energy "consumption data" that CENSE believed was necessary for the public hearing. AR 00841, 001068, 001108.

35. Although the Hearing Examiner denied CENSE's pre-hearing motions, he allowed CENSE to raise the same arguments throughout four (4) days of hearing, and PSE and the City continued to respond to CENSE's arguments throughout the hearing. TR 000605-611, 000654-655, 000682-687. The Hearing Examiner also addressed CENSE's legal arguments at length in his Decision. AR 000020-26, 000032-39.

36. Over the course of the 4 day public hearing, the Hearing Examiner received public testimony from approximately fifty-six (56) individuals. AR 000846, 000007-8, 000022-23.



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37. Local residents, business owners, community leaders, and health care professionals testified in support of PSE's CUP application, citing the need for safe and reliable power as the City and the Eastside continue to grow. AR 000022-23, 0000032-33; TR 000101-108, 000110-113, 000121-124, 000148-157, 000161-164, 000173-174, 000241-245, 000250-252, 000285-288. Conversely, many citizens who live along the existing utility corridor opposed PSE's application, primarily opposing PSE's finding of project "need" and voicing concerns with hazards posed by co-located electrical lines over the existing Olympic petroleum pipeline. AR at 000016, 000023, 000026, 000033; TR 000593-595.

38. Throughout the public hearing, the Hearing Examiner allowed and encouraged CENSE and its members to present their public comments, expert testimony, and legal arguments in opposition to PSE's CUP application and the Energize Eastside project. TR 000090-91, 000130-133, 000146-147, 000296-297, 000621-622, 000644, 000652-653.

39. North Bellevue residents who are members of CENSE and do not reside in south Bellevue also testified at the public hearing in opposition to PSE's CUP application for the South Bellevue Segment. AR 000170-206.

40. By the close of the hearing, CENSE had provided over two (2) hours of presentation, expert testimony, legal argument, and public comment; and the Hearing Examiner admitted and considered a total of thirteen (13) motions, briefs, and written exhibits from CENSE. AR 000841-843, 001312.

41. Contrary to CENSE's argument in its motions and during the public hearing, PSE's evaluation of operational need is based on peak demand and not on the volume of energy consumed over time. AR 000017, 000025, 001864-1873, 13518-13525; TR 000456-459, 000462-463.



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42. If PSE's system cannot meet peak demand, power outages affect everyone, including residential uses along the South Bellevue Segment of the Energize Eastside project and critical support services like hospitals, nursing homes, fire departments, and police stations. AR 000014-18, 000026, 001864-1873.

43. The Hearing Examiner issued his Decision on June 25, 2019. AR 000004-40. The Decision detailed why the technical studies, expert testimony, and argument presented by PSE established that several key aspects of the opposition presented by CENSE were defective and not credible. AR 000023-26. The Decision addressed CENSE's objections to PSE's construction plan and found that the environmental review undertaken by the Partner Cities supported approval of the CUP. AR 000020-21.

44. The Hearing Examiner found that the Staff Report, attachments to the Staff Report, and testimony and evidence submitted by PSE during the public hearing established that PSE satisfied the requirements of LUC 20.20.255.E.3, which requires PSE to demonstrate operational need for its electrical utility proposal. AR 000013-14, 000024-25, 001323-1324, 001420-1424, 001864-1873, 001977-2053; TR 000043-75, 000416-417, 000456, 000483-484, 000562, 000713, 000731.

45. The Hearing Examiner concluded that CENSE, its representatives, and other opponents articulated their concerns but did not offer sufficient, relevant, authoritative, or credible evidence that would rebut the findings and recommendations made in the Staff Report or the substantial evidence presented by PSE throughout the land use process. AR 000024. Ultimately, the Hearing Examiner approved PSE's requested CUP, with conditions. AR 000040, 000042-61.



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46. After the Hearing Examiner issued the Decision, CENSE, three (3) members of CENSE who live in north Bellevue, and another opponent of the Energize Eastside project appealed the Hearing Examiner Decision to the Bellevue City Council. AR 000128-129, 000132.

47. Following an appeal hearing before the Bellevue City Council where CENSE and the other appellants presented argument in opposition to PSE's CUP application, the City's Mayor provided a lengthy explanation of why the Hearing Examiner's Decision was supported by material and substantial evidence in the record. TR 001177-1190. The Mayor explained, on the record, why PSE had satisfied the LUC criteria requiring PSE to demonstrate operational need (TR 001181-1185) and addressed CENSE's objections to PSE's phased construction plan for the Energize Eastside project (TR 001187-1188).

48. On December 2, 2019, the City Council formally and unanimously, with one recusal, adopted the Hearing Examiner's Decision and denied the four appeals through the enactment of Ordinance 6494. AR 000001-3; TR 01202-1203. CENSE then filed the current lawsuit challenging both the City's CUP approval for the South Bellevue Segment and the Partner Cities' environmental review of the Energize Eastside project.

## CONCLUSIONS OF LAW

A. The CUP Challenge

1. Under LUPA, CENSE carries the burden of establishing that the City erred under at least one of following standards of review:

> (a) The body or officer that made the land use decision engaged in unlawful procedure or failed to follow a prescribed process, unless the error was harmless;



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(b) The land use decision is an erroneous interpretation of the law, after allowing for such deference as is due the construction of a law by a local jurisdiction with expertise;

(c) The land use decision is not supported by evidence that is substantial when viewed in light of the whole record before the court; [or]

(d) The land use decision is a clearly erroneous application of the law to the facts…..

RCW 36.70C.130(1)(a), (b), (c) & (d); *Pinecrest Homeowners Ass'n v. Glen A. Cloninger & Assocs.*, 151 Wn.2d 279, 288, 87 P.3d 1176 (2004).

2. In reviewing a LUPA decision, a reviewing court considers only the administrative record and gives "substantial deference to both the legal and factual determinations of a hearing examiner as the local authority with expertise in land use regulations." *Lanzce G. Douglass, Inc. v. City of Spokane Valley*, 154 Wn. App. 408, 415, 225 P.3d 448 (2010) (citing *City of Medina v. T–Mobile USA, Inc.,* 123 Wn. App. 19, 24, 95 P.3d 377 (2004)).

3. Evidence and any inferences are viewed "in a light most favorable to the party that prevailed in the highest forum exercising fact finding authority." *Id.* (citing *City of University Place v. McGuire,* 144 Wn.2d 640, 652, 30 P.3d 453 (2001).

4. Under the substantial evidence standard applicable to RCW 36.70C.130(1)(c), there must be a sufficient quantum of evidence in the record to persuade a reasonable person that the declared premise is true. *Wenatchee Sportsmen Ass'n v. Chelan County*, 141 Wn.2d 169, 176, 4 P.3d 123 (2000). A finding is clearly erroneous under RCW 36.70C.130(1)(d) only when, although there is evidence to support it, the reviewing court is left with the definite and firm conviction that a mistake has been committed. *Id.*



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5. CENSE's has not sustained its burden of establishing that the Hearing Examiner engaged in an unlawful procedure in violation of RCW 36.70C.130(1)(a) or that the City violated the appearance of fairness doctrine, chapter 42.36 RCW.

6. "The [appearance of fairness] doctrine requires that public hearings which are adjudicatory in nature meet two requirements: the hearing itself must be procedurally fair, and it must be conducted by impartial decisionmakers." *Raynes v. City of Leavenworth*, 118 Wn.2d 237, 245-246, 821 P.2d 1204 (1992), citations omitted.

7. The record shows that CENSE and the public fully participated in the public hearing and that the City allowed CENSE, its members, its experts, its attorneys, and the public substantial opportunity to participate in the land use process and the public hearing before the Hearing Examiner.

8. There is substantial evidence in the record showing that the Hearing Examiner acted as a fair and impartial decision maker and lawfully administered the public hearing. AR 000022-23, 0000032-33, 000841-843, 000846, 001312; TR 000090-91, 000101-108, 000110-113, 000121-124, 000130-133, 000146-157, 000161-164, 000173-174, 000241-245, 000250-252, 000285-288, 000296-297, 000621-622, 0000644, 000666.

9. The Hearing Examiner correctly concluded that PSE complied with the Electrical Utility Facility decision criteria in LUC 20.20.255.E and satisfied the ASA requirements in LUC 20.20.255.D.

10. The Hearing Examiner correctly found that "'load-shedding' – i.e. rolling blackouts – is currently part of PSE's corrective action plan (CAP) options in neighborhoods throughout the Eastside, including residential neighborhoods that are located along the route of the South Bellevue Segment." AR 000026.



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11. The Hearing Examiner correctly found that PSE's CUP proposal for the South Bellevue Segment is located in a land use district that currently accommodates the utility corridor and requires the service that PSE's proposal will provide. AR 000022-26, 001328, 001340, 001357, 001539, 001543.

12. CENSE provides no evidence showing that south Bellevue residents are immune to power outages resulting from an electrical utility system that cannot meet peak demand. AR 000026, 001872.

13. CENSE's argument that operational need has changed based on PSE's phased construction plan is not supported by the record because the South Bellevue Segment is being constructed and permitted in exactly the same manner and as part of the same phased construction sequence described and assessed in the Partner Cities' environmental review. AR 000019, 000021-22, 001354-001357, 001417, 001539, 001545-1547, 001553, 001562, 006491-6498, 006503-6507, 006823, 006866.

14. Although CENSE characterizes PSE's CUP application for the South Bellevue Segment as a "truncated, dead-end line," CENSE provided no evidence establishing that PSE has abandoned the larger Energize Eastside project and/or the northern portion of the project, extending from north Bellevue to Redmond.

15. The Staff Report concluded correctly that PSE submitted an ASA that complied with the requirements of LUC 20.20.255.D. AR 000019, 001327-1328, 001354-1357, 001425-001435, 001535-1566.

16. The Hearing Examiner concluded correctly that the ASA "contains sufficient information regarding the methodology employed, the alternative sites analyzed, the



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technologies considered, and the community outreach undertaken to satisfy the requirements of LUC 20.20.255.D." *Id.* at 000019.

17. Given the substantial deference afforded the Hearing Examiner, CENSE failed to sustain its burden to show that the City's approval of the CUP involved any erroneous interpretation of LUC 20.20.255.E or LUC 20.20.255.D.

18. CENSE failed to appeal the City's approval of the CALUP issued by the City, and the Hearing Examiner correctly held that CENSE cannot collaterally attack any aspect of the final CALUP approval or the electrical utility facility siting evaluated and permitted by the CALUP. AR 000027; *Wenatchee Sportsmen*, 141 Wn.2d at 172, 180-182, 4 P.3d 123; *Habitat Watch v. Skagit County*, 155 Wn.2d 397, 410-411, 120 P.3d 56 (2005).

19. Phased construction and permitting for a linear infrastructure project is not an example of piecemeal environmental review prohibited by SEPA or inconsistent with *Merkel v. Port v. Brownsville*, 8 Wn. App. 844, 509 P.2d 390 (1973).

20. SEPA allows phased review in certain circumstances, but SEPA prohibits the practice of conducting environmental review only on current segments of a project and postponing environmental review of later segments until construction begins. *Concerned Taxpayers Opposed to Modified Mid-South Sequim Bypass v. State, Dept. of Transp.*, 90 Wn. App. 225, 231 & fn. 2, 951 P.2d 812 (1998) (citing *Cathcart-Maltby-Clearview Community Council v. Snohomish County,* 96 Wn.2d 201, 210, 634 P.2d 853 (1981)).

21. The SEPA Rules specifically prohibit environmental review that divides a larger system into exempted fragments, avoids discussion of cumulative impacts, or avoids consideration of impacts that are required to be evaluated in a single environmental document. WAC 197-11-060(5)(d)(ii) & (iii). The City's two-phased EIS process properly and fully disclosed and analyzed the potential impacts of the *entire* Project (Redmond, Bellevue, Newcastle, and Renton).



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22. Within the three-volume document, it also assessed the impacts to specific subsections and under a range of alternative routing option—including the South Bellevue Segment. There is no credible claim that the Project's SEPA review was improperly segmented.

23. The comprehensive and exhaustive environmental review conducted by the Partner Cities for the Energize Eastside project did not divide the project into exempted fragments, avoid discussion of cumulative impacts, or avoid consideration of impacts that are required to be evaluated in a single environmental document.

24. *Merkel v. Port v. Brownsville*, 8 Wn. App. 844, 509 P.2d 390 (1973) does not support CENSE's "segmentation" argument or require that PSE submit all land use permit applications for the entire Energize Eastside project simultaneously. No portion of the Energize Eastside project is subject to the Shoreline Management Act (SMA), and the City of Bellevue's local electrical utility regulations, land use processes, and attendant CUP approval for the South Bellevue Segment of the project is not the functional equivalent of the systematic state-wide shoreline management required by the SMA, chapter 9.58 RCW.

25. In this case, the Final EIS does not disclose any significant unavoidable adverse environmental impacts in central Bellevue or north Bellevue as a result of construction of the South Bellevue Segment or from construction of the entire Energize Eastside project. AR 000018-22, 001319, 001539, 006823, 6826, 006838, 006842, 006860, 006866, 7209-7212, 07557.

26. The Partner Cities complied with the procedures established by SEPA, fully considered the potential environmental effects of the entire Energize Eastside project across all jurisdictions, and there is no evidence in the record that construction of the South Bellevue



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Segment will cause or create significant unavoidable adverse environmental impacts to central Bellevue or to north Bellevue.

27. SEPA contemplates circumstances such as the Energize Eastside project where multiple agencies have permitting authority over a single project. *See* WAC 197-11-922 to -948; and WAC 197-11-055(5). In such a situation, the lead agency prepares the EIS for the proposed project, and other agencies with jurisdiction over the project use the EIS prepared by the lead agency to inform their permitting decisions. WAC 197-11-050(2)(b); WAC 197-11-600(3)(c).

28. The north and south segments of the Energize Eastside project have been combined for environmental review in compliance with SEPA, but SEPA does not require that the north and south segments of the project must be combined by PSE for land use permitting purposes.

29. PSE's CUP for the South Bellevue Segment is not within the East Bellevue Community Council's (EBCC) jurisdiction, and the EBCC does not have any permitting authority over land use decisions outside of its jurisdiction. RCW 35.14.040.

49. Under the City's LUC, the CUP application for the South Bellevue Segment is subject to a different land use process than a CUP application for the northern construction phase, and the record shows that the only CUP application before the City at the time of approval was for the South Bellevue Segment of the Energize Eastside project. AR 001314-1315, 001321-1325; TR 001188.

B. <u>The SEPA Challenge</u>



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1. SEPA requires agencies to integrate environmental concerns into their decision-making processes and study and explain the environmental consequences before pursuing actions. *Stempel v. Dep't of Water Res.,* 82 Wn.2d 109, 117-118, 508 P.2d 166, 171 (1973).

2. An EIS is the most detailed form of environmental review required under SEPA and is prepared when an agency determines that it is probable that a project would have significant environmental impacts. AR 001387; WAC 197-11-400.

3. Under SEPA, the Court's review of EIS adequacy is *de novo*, but the Court gives "substantial weight" to the Environmental Coordinator's determination that the EIS is adequate. *Glasser v. City of Seattle, Office of Hearing Exam'r*, 139 Wn. App. 728, 739-740, 162 P.3d 1134 (2007) (citing RCW 43.21C.090; *Klickitat County Citizens Against Imported Waste v. Klickitat County,* 122 Wn.2d 619, 633, 860 P.2d 390, 866 P.2d 1256 (1993) (citing R. Settle, *The Washington State Environmental Policy Act: A Legal and Policy Analysis* § 14(a)(i) (4th ed.1993)).

4. The Court's *de novo* review gives deference to agency discretion required by SEPA, at RCW 43.21C.090, and the "rule of reason." *Id*.; *Cheney v. Mountlake Terrace*, 87 Wn.2d 338, 344-45, 552 P.2d 184 (1976).

5. Under the "rule of reason," the EIS must present decision makers, in this case the City of Bellevue, with a "'reasonably thorough discussion of the significant aspects of the probable environmental consequences'" of the agency's potential land use decision. *Glasser*, 139 Wn. App. at 740 (citing *Klickitat Cnty.,* 122 Wn.2d at 633, 860 P.2d 390 (quoting *Cheney,* 87 Wn.2d at 344–45, 552 P.2d 184)); *Residents Opposed to Kittitas Turbines v. State Energy Facility Site Evaluation Council,* 165 Wn.2d 275, 311, 197 P.3d 1153 (2008) (citation omitted).



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6. Thus, the determination by the City's Environmental Coordinator that the Final EIS was adequate "shall be accorded substantial weight" under SEPA, and this judicial deference, combined with the "rule of reason," is the standard of review for adjudication of CENSE's challenge to EIS adequacy. *Id.*; RCW 43.21C.090.

7. SEPA requires that an agency consider alternatives to a proposed action. RCW 43.21C.030(c)(iii). Although the purpose of the EIS is to facilitate the decision-making process, it need not list every remote, speculative, or possible effect or alternative. *Klickitat Cnty.*, 122 Wn.2d at 641, 860 P.2d 390. Instead, EIS alternatives must "include actions that could feasibly attain or approximate a proposal's objectives, but at a lower environmental cost or decreased level of environmental degradation." WAC 197–11–440(5)(b); AR 006814.

8. Under SEPA, supplemental environmental review is not required when probable significant adverse environmental impacts are covered by the range of alternatives and impacts analyzed in the existing environmental documents. WAC 197-11-600(3)(b)(ii).

9. CENSE fails to provide any evidence showing that the South Bellevue Segment alone can feasibly attain or approximate PSE's stated objectives for the Energize Eastside project as required by WAC 197-11-440(5)(b).

10. CENSE fails to provide any evidence that construction of the South Bellevue Segment as a "standalone" project would meet local electricity peak demand growth and protect electrical grid reliability in the Eastside of King County, from Redmond in the north to Renton in the south, or provide necessary redundancy to ensure electrical power production remains on-line when equipment in the north or the south is not working. AR 001321, 006815, 011637.

11. The environmental record confirms that the Partner Cities' environmental review complied with SEPA as the Final EIS provided full analysis of potential environmental



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impacts in the South Bellevue Segment and across all jurisdictions from Renton to Redmond. AR 000018, 001325, 001387, 006818-006822, 006824-6835, 06838-6839, 006891-7182, 011642, 011645, 011659-011700, 012469-12470, 012531-012532, 012563-12569, 012583-12584, 012586-12587, 012592-12593, 012597-12600.

12. The Partner Cities' environmental review complied with SEPA because it included a "'reasonably thorough discussion of the significant aspects of the probable environmental consequences'" of the Energize Eastside project within the South Bellevue Segment and across all jurisdictions with permitting authority. *Glasser*, 139 Wn. App. at 740 (citing *Klickitat Cnty.,* 122 Wn.2d at 633, 860 P.2d 390 (quoting *Cheney,* 87 Wn.2d at 344–45, 552 P.2d 184)); *Residents Opposed to Kittitas Turbines,* 165 Wn.2d at 311, 197 P.3d 1153 (citation omitted).

**ORDER**

Now, therefore, it is hereby ORDERED that the City of Bellevue's decision approving PSE's CUP application, with conditions, is AFFIRMED, and Petitioner CENSE's LUPA appeal is DENIED. Likewise, Petitioner CENSE's challenge to the adequacy of the environmental review undertaken by the Partner Cities for the Energize Eastside project is DENIED.

Over the course of the underlying land use process and when issuing its decision on this matter, the City did not engage in an unlawful procedure; the City's approval of PSE's CUP application was not an erroneous interpretation of the law; the City decision was supported by substantial evidence in the record before this Court; and the City's decision was not a clearly erroneous application of the law to the facts present in the record. RCW 36.70C.130(1)(a), (b), (c) & (d). The City did not err when it approved PSE's CUP application for the South Bellevue Segment of the Energize Eastside project or when it certified that the Final EIS was adequate.



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For each of the foregoing reasons, Petitioner CENSE's Land Use Petition, brought under chapter 36.70C RCW, and SEPA challenge, brought under chapter 43.21C RCW, are DENIED in full.

DATED this 21st day of September, 2020.

THE HONORABLE Melinda Young
King County Superior Court Judge



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# King County Superior Court
## Judicial Electronic Signature Page

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| Case Number: | 19-2-33800-8 |
| Case Title: | COALITION OF EASTSIDE NEIGHBORS FOR SENSIBLE ENERGY VS CITY OF BELLEVUE |
| Document Title: | ORDER |

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| Date: | 9/21/2020 9:00:00 AM |

Judge/Commissioner: Melinda Young

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# ATTACHMENT F

# Energize Eastside Summer 2018 Update

PSE PUGET SOUND ENERGY

Puget Sound Energy
P.O. Box 97034
Bellevue, WA 98009-9734
PSE.com

June 8, 2018

Brad Miyake
City of Bellevue
City Manager's Office
450 110th Avenue NE
Bellevue, WA 98004

Dear City Manager Miyake,

As summer approaches, we would like to brief you on PSE's plans related to electric reliability on the Eastside. Our forecasts have long indicated that peak customer demand could exceed capacity as early as the winter of 2017 or the summer of 2018, hence the Energize Eastside project. In fact, our peak demand increased faster than modeled and our actual 2017 summer peak demand exceeded our load forecast for summer 2018 – one year earlier than expected.

Because the 2017 actual summer peak usage exceeded our planning forecast, we have prepared for a similar scenario in 2018 by having corrective action plans in place that include intentional load shedding. Such actions could have an impact to customers and the City. Under certain scenarios, we will utilize corrective action plans in anticipation of this summer's peak load to protect the integrity of the grid and ultimately the reliability of service to our customers.

The likelihood of having to use load shedding is low, but we believe it is important for the impacted cities in our service area to be aware of the potential. We have reached out to your Emergency Manager, Curry Mayer, to schedule a briefing and seek input from the City.

While we are actively involved in the permitting process to upgrade the Eastside transmission system to eliminate these risks in the future, those upgrades will not be in service this summer. Until those upgrades are in place, PSE will continue to monitor the possible need for corrective action plans.

Sincerely,

Dan Koch

Dan Koch
Director, Electric Operations
Puget Sound Energy

# Alternative Siting Analysis

PUGET SOUND ENERGY

energizeEASTSIDE

# Alternative Siting Analysis

## North/Central Bellevue Segments

## LUC 20.20.225.D

## March 2021

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energizeEASTSIDE

# Table of Contents

# Attachments

**Attachment A – Figures**

**Attachment B – Phase 2 DEIS Impact Table**

**Attachment C – Supporting Studies**

- C-1: Electrical Reliability Study (Exponent 2012)
- C-2: Eastside Needs Assessment Report (Quanta Services 2013)
- C-3: Supplemental Eastside Needs Assessment Report (Quanta Services 2015)
- C-4: Independent Technical Analysis (Utility Systems Efficiencies, Inc. 2015)
- C-5: Review Memo (Stantec Consulting Services, Inc. 2015)
- C-6: Eastside System Energy Storage Alternatives Screening Study (Strategen 2015)
- C-7: Eastside System Energy Storage Alternatives Assessment, Report Update (Strategen 2018)
- C-8: Assessment of Proposed Energize Eastside Project (MaxETA Energy and Synapse Energy Economics 2020)

**Attachment D – Community Advisory Group Report**

**Attachment E – Coalition of Eastside Neighbors for Sensible Energy v. City of Bellevue and Puget Sound Energy, Inc.**

# 1.0 Introduction

## 1.1 Project Summary

Puget Sound Energy, Inc. (PSE) proposes the construction of a new substation in the City of Bellevue (City), known as the “Richards Creek substation” and the upgrade of 16 miles of two existing 115 kV transmission lines with 230 kV lines (collectively the “Energize Eastside Project” or the “Project”). The new substation and upgraded lines are needed to address electrical system deficiencies identified during federally required planning studies. Combined with aggressive conservation, the Project significantly improves electric reliability for Eastside communities, including the City, and will supply the additional electrical capacity needed for current and anticipated growth.

The existing system is not robust enough to maintain reliable service if the entire facility is taken out of service at one time. Therefore, the Project will be constructed in two phases. This is the best approach to allow PSE to keep the existing 115 kV facilities partially in service during construction, which will allow PSE to maintain reliable service to all customers during construction. Both phases of the project are needed to complete the identified solution. The first phase includes construction of the Richards Creek substation and upgrading 3.3 miles of existing 115 kV lines with 230 kV lines between the Lakeside and Talbot Hill substations (the “South Bellevue Segment”). See LUP 17-120556-LB.

The second phase (the “North Bellevue Segment”) is the primary focus of this application and includes replacing approximately 5.2 miles of existing 115 kV lines with new transmission lines that can operate up to 230 kV lines (herein referred to as 230 kV lines) between the Redmond/Bellevue city boundary and the new Richards Creek Substation. This requires replacing existing wood H-frame poles with steel monopoles. After deliberate review and extensive stakeholder input, PSE proposes to undertake this work in the existing transmission line corridor rather than siting a new corridor through Eastside communities[1]. Within the existing utility corridor, the proposed pole locations for the rebuilt lines will generally be in the same locations as the existing poles. Selective tree removal will also be required within the managed corridor to meet federal vegetation management requirements and PSE standards. Use of the existing corridor (which has housed transmission lines since the 1920s and 30s) minimizes environmental impacts and impacts to adjacent uses to the fullest extent feasible.

This Alternative Siting Analysis summarizes the years of study, including dozens of technical studies and two-phases of review under the State Environmental Policy Act (SEPA), required to reach a decision on how to best meet growing demand and ensure PSE’s compliance with federal performance standards.

## 1.2 Alternative Siting Analysis Purpose and Objectives (LUC 20.20.255.D)

PSE is proposing the Project—the construction of a new substation and upgrading of 115 kV transmission lines to 230 kV lines in an existing transmission line corridor. In the Bellevue Comprehensive Plan, PSE’s proposed route is on a “sensitive site.” See Map UT-7. For new or expanded utility facilities on sensitive sites, an Alternative Siting Analysis is required per LUC 20.20.255.D in conjunction with the Conditional Use Permit (CUP) process.

[1] The existing transmission lines were last upgraded in the 1960s and are in PSE’s Sammamish – Lakeside – Talbot Hill transmission line corridor, which was established in the late 1920s and early 1930s.

Under LUC 20.20.255.D, an Alternative Siting Analysis must: 1) identify, describe and map three alternative site options; 2) analyze whether each alternative site is feasible; 3) describe the technologies considered and how the proposed facilities will improve system reliability; and 4) describe community outreach related to the new or expanded facilities. Where proposed sites are located within a Neighborhood Business or Residential Land Use District, the applicant must also 1) describe whether the proposed location is a consequence of demands from customers within the district and 2) describe whether operational need requires locating the proposed facility in the district. Using the location selection hierarchy, the applicant must then identify the preferred site alternative. Finally, where the preferred site is in a Residential Land Use District, the applicant must demonstrate that the siting causes fewer site compatibility impacts than a nonresidential siting.

## 2.0 Alternatives Analysis

Adding a new substation and upgrading the 115 kV transmission lines with 230 kV transmission lines, combined with continued aggressive conservation measures, constitutes the Project[2]. As confirmed by the City's independent consultants, the Project will improve reliability for Eastside communities and supply needed electrical capacity for growth and development on the Eastside.

Siting of electrical transmission infrastructure through urbanized areas presents unique challenges. Finding the best way to route a transmission line is complex, as dozens of elements of both the natural and built environments need to be considered. This is especially true here as the proposed Project traverses the City from north to south.

Within the City, the Project will be constructed in two phases: a north and south phase, with the northern phase of the transmission line traversing approximately 5.2 miles of the City. Construction of the entire project is necessary to address the identified system need. As a linear project, it necessarily travels through many land use districts. To limit the need to construct new facilities (and the associated environmental impacts), when looking at the entirety of the Project, all transmission line route alternatives start at PSE's Sammamish substation in Redmond (at the north end) and end at the Talbot Hill substation in Renton (at the south end). PSE considered various routing options for the entire line, including three route options in the North/Central Bellevue Segments. The North Bellevue and Central Bellevue Segments were assessed separately throughout the EIS but are both addressed as part of this "North Bellevue Phase" submittal.

### 2.1 Routing Analysis Methodology (LUC 20.20.255.D.1)

*LUC 20.20.255D.1. Alternative Sites Analyzed. Prior to submittal of the application for Conditional Use Permit required pursuant to subsection C of this section, the applicant shall*

2 Notably, the City's Final EIS concluded that "Under the No Action Alternative, PSE would continue to manage its system in largely the same manner as at present, with some exceptions. Specifically, PSE indicates it would be necessary to operate with additional Corrective Action Plans (CAPs) including load shedding plans as described in Section 1.3 [of the Final EIS]. These additional plans are not necessary at present but will become necessary as the electrical load continues to grow. Operation of the existing system includes maintenance programs to reduce the likelihood of equipment failure (including pole replacement), and stockpiling additional equipment so that in the event of a failure, repairs could be made as quickly as possible. Implementation of the No Action Alternative would not meet PSE's objectives for the proposed project, which are to maintain a reliable electrical system and to address a deficiency in transmission capacity on the Eastside. Implementation of the No Action Alternative would increase the risk to the Eastside of power outages or system damage during peak power events." Final EIS at 2-4.

*identify not less than three alternative site options to meet the system needs for the proposed new or expanding electrical utility facility. At least one of the alternative sites identified by the applicant shall be located in the land use district to be primarily served by the proposed electrical utility facility.*

PSE determined that the best approach to route selection would be to use a modern tool that employed a graphical information system (GIS)-based Linear Routing Tool (LRT) to conduct a broad evaluation of possible transmission line routes.

PSE contracted Tetra Tech, a consulting and engineering firm who has developed an LRT, to conduct evaluations. Details of the LRT assessment can be found in the Eastside 230 kV Project Constraint and Opportunity Study for Linear Site Selection (December 2013) (Attachment C, Study C-2). The LRT is a tool developed by Tetra Tech based on commercially available geospatial technology and Tetra Tech's linear routing experience. It is a collaborative process that combines powerful analytical software with project experience, system planning, engineering, land use and local knowledge considerations. The LRT's innovative geospatial tool identifies the most suitable route alternatives based on modeled environmental and infrastructure factors and constraints.

PSE and Tetra Tech began this process by identifying an approximately 255 square mile study area (Attachment A, Figure 1) that encompasses the Sammamish substation in the north and Talbot Hill substation in the south. The study area was bounded on the west by the eastern shore of Lake Washington and extending far enough east to include the BPA corridor near Soaring Eagle Regional Park (located north east of the City of Sammamish). Any new transmission line route had to connect to one of the new potential 230 kV to 115 kV transformation sites (substation) within this area in order to solve the problem. For the study, three possible substation sites were identified.

The LRT combined GIS data layers and created an output file called the suitability grid, which represents a summation of all the constraints and opportunities for every point (grid cell) across the entire study area. The LRT processed and combined the data layers to model preferred corridors across the suitability grid, while still connecting the corridors to one of the transformation site (i.e., substation) options within the study area. The LRT analyzed more than 200 route and substation alternatives. From these, the preferred corridors identified by the LRT were used to develop route alternatives.

All alternatives analyzed are in the land use district to be primarily served by the North Bellevue Phase, as construction of the project will improve reliability throughout north Bellevue and, once constructed, will eliminate the need for the use of Corrective Action Plans that include load shedding on the Eastside.

## 2.2 Alternative Sites Analyzed (LUC 20.20.255.D.1-2)

*LUC 20.20.255D.1. Alternative Sites Analyzed. Prior to submittal of the application for Conditional Use Permit required pursuant to subsection C of this section, the applicant shall identify not less than three alternative site options to meet the system needs for the proposed new or expanding electrical utility facility. At least one of the alternative sites identified by the applicant shall be located in the land use district to be primarily served by the proposed electrical utility facility.*

LUC 20.20.255D.2b. Map the location of the sites identified in subsection D.1 of this section and depict the proximity of the sites to Neighborhood Business Land Use Districts, Residential Land Use Districts, and Transition Areas.

As set forth in detail below, this Alternative Siting Analysis addresses the requirements of LUC 20.20.255.D. First, using nomenclature developed during the 2014 community advisory group process and the Phase 2 Draft Environmental Impact Statement (DEIS), PSE discusses three siting alternatives considered for the North Bellevue Phase:

1) Willow 1 route (Attachment A, Figure 2, entirely within the existing corridor for the Bellevue North and Bellevue Central Segments)
2) East Bellevue Community Council (EBCC) Bypass Route 1 (Attachment A, Figure 3, Bellevue Central Segment)
3) EBCC Bypass Route 2 (Attachment A, Figure 4, Bellevue Central Segment)

The Willow 1 and EBCC Bypass Routes 1 and 2 are all feasible; however, based on the information obtained through the EIS process and extensive public outreach, PSE will proceed with the Willow 1 route to limit environmental impacts and the siting of an entirely new corridor which would result in greater, new impacts to adjacent uses. In addition, pipeline safety experts concluded that the Willow 1 route gives PSE the greatest assurance that the Project will operate safely in the same corridor as the pipelines operated by the Olympic Pipeline Company (OPL).

## 2.3 Alternative Site Descriptions

*LUC 20.20.255D.2.a. Describe the sites identified in subsection D.1 of this section and the land use districts within which the sites are located.*

*[...]*

*LUC 20.20.255D.2.c. Describe which of the sites analyzed are considered practical or feasible alternatives by the applicant, and which of the sites analyzed are not considered practical or feasible, together with supporting information that justifies the conclusions reached. For sites located within a Neighborhood Business Land Use District, Residential Land Use District, and/or Transition Area (including the Bel-Red Office/Residential Transition (BR-ORT), the applicant shall:*

*i. Describe whether the electrical utility facility location is a consequence of needs or demands from customers located within the district area; and*

*ii. Describe whether the operational needs of the applicant require location of the electrical utility facility in the district or area.*

The Project serves all of the potentially impacted land uses which require electricity (essentially, this encompasses most if not all land uses). The Project will provide an upgraded, reliable transmission system serving the Eastside including adjacent uses. The Project is needed because cumulatively, demand on the Eastside is increasing. The transmission line component of the project must run between the Sammamish and Talbot Hill substations. It must also connect with the proposed Richards Creek substation in South Bellevue. In addition, operationally, the transmission line must transverse through the City of Bellevue from the north to the south, making it impossible to completely avoid areas of residential zoning. The existing corridor (Willow 1) provides the shortest distance through the city and therefore, crosses the least amount of residential zoning.

As required under LUC 20.20.255.D.1 and LUC 20.20.255.D.2.c.i-.ii, all siting alternatives are located in land use districts served by the Project. The growing demand for power in both Bellevue and the Eastside is a primary driver of the need for the Project.

This conclusion was confirmed by the City's independent experts. Utility System Efficiencies, Inc. (USE) was engaged by the City in December, 2014 to conduct an independent technical analysis of the purpose, need, and timing of the Project. In April 2015, USE published a report summarizing its findings. *See* Independent Technical Analysis of Energize Eastside for the City of Bellevue, WA (April 28, 2015) ("USE Report") (Attachment C, Study C-4). The USE Report answered the following questions:

**Is the EE Project Needed to Address the Reliability of the Electric Grid on the Eastside? Yes.**
Although the new 2014 forecast resulted in an 11 MW decrease in the Eastside area's 2017/18 winter forecast, the reduced loading still resulted in several overloaded transmission elements in winter 2017/2018, which drive the project need.

Although the corrective action plan (CAP) required in the 2017/18 winter to avoid facility overload doesn't require dropping load (turning off customers' power), by winter 2019/20 approximately 63,200 customers are at risk of losing power.

The USE Report went on to confirm PSE's conclusion that, applying federal electrical system planning requirements, transformers serving uses adjacent to the North Bellevue Phase will experience overloads (i.e., reduced reliability) in foreseeable planning scenarios. USE Report at 52 (containing tables summarizing PSE's forecasting results that show overloads at the Talbot and Lakeside substations).

In addition to the USE Report, in 2012, Bellevue retained Exponent to perform an electrical system reliability assessment. Exponents report stated "As a minimum, the following capacity additions have been identified as being needed within the next 5 to 10-year time frame:

- Upgrade of existing 115 kV lines to 230 kV
- Addition of transformer banks to support expected growth in various areas of the City (Downtown, Bel-Red, and Somerset/Eastgate)
- Addition of new 115 kV lines to reinforce the overall electric system."

*See* City of Bellevue Electrical Reliability Study, Phase 2 Report at 140 (Attachment C, Study C-C-1). All studies assessing whether the project is needed for PSE to comply with federal reliability criteria since this report have also concluded that the project, including the North Phase, is needed to improve reliability on the Eastside. Most recently, this includes the 2020 Synapse report drafted under the direction of the City of Newcastle (Attachment C, Study C-8), which concluded that "PSE has demonstrated that the proposed transmission upgrades are needed to safeguard the operational reliability of the electric system as a whole. To maintain system security, power systems are operated so that overloads do not occur either in real-time or under any statistically likely contingency. Not securing the bulk electric system to operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies could affect the electric supply reliability in Newcastle. This peer review verified that under specific contingencies (N-1-1 and N-2) the as-is bulk electric system serving Newcastle is already susceptible and operationally reliant in the implementation of Corrective Action Plans (CAPs)." See Attachment C, Study C-8. Although focused on impacts to Newcastle, the report confirms that the existing system does not comply with transmission planning criteria under current summer load scenarios and accordingly is susceptible to outages.[3] Following construction, uses adjacent to the proposed transmission line will benefit from improved reliability now, and into the future.

As described above, numerous route alternatives were developed and evaluated in the public review processes, detailed in Section 4.0 of this document. Three of the options for the North Bellevue Phase are described below and shown in Attachment A (LUC 20.20.255.D.1). These include the one existing transmission line corridor and two bypass routes. The one existing corridor includes PSE's Sammamish-Lakeside-Talbot Hill 115 kV corridor. The two bypass routes were developed based on public comments during scoping for the Phase 2 DEIS and bypasses the boundaries of the EBCC.

### 2.3.1 Willow 1, Existing PSE 115 kV Transmission Line Corridor for North Bellevue and Central Bellevue Segments

"Willow 1" was one of the original two routes recommended by the community advisory group in 2014. The route utilizes the existing Sammamish-Lakeside-Talbot Hills 115 kV corridor (Attachment A, Figure 2). The corridor was established in the late 1920s and early 1930s. In the 1960s, the line was upgraded from 55 kV to 115 kV, which included replacement of original poles with the existing H-frame poles. As noted in Section 2 of this document, PSE identified in the early 1990s that the lines within the same corridor would need to be upgraded to the next higher transmission voltage (230 kV). This 230 kV upgrade has been included in Bellevue Comprehensive Plans since the adoption of the Growth Management Act in 1990.

The North Bellevue Phase is located within 9 different land use districts, which include R-1, R-1.8, R-2.5, R-3.5, R-5, BR-GC, BR-CR, BR-ORT, and LI (LUC 20.20.255.D.2.a Consistent with the City's Phase 2 DEIS and Final EIS, PSE considers this route to be feasible (LUC 20.20.255.D.2.c).

As described in the City's Phase 2 DEIS (page 3.1-7), specific to the Bellevue North Segment:

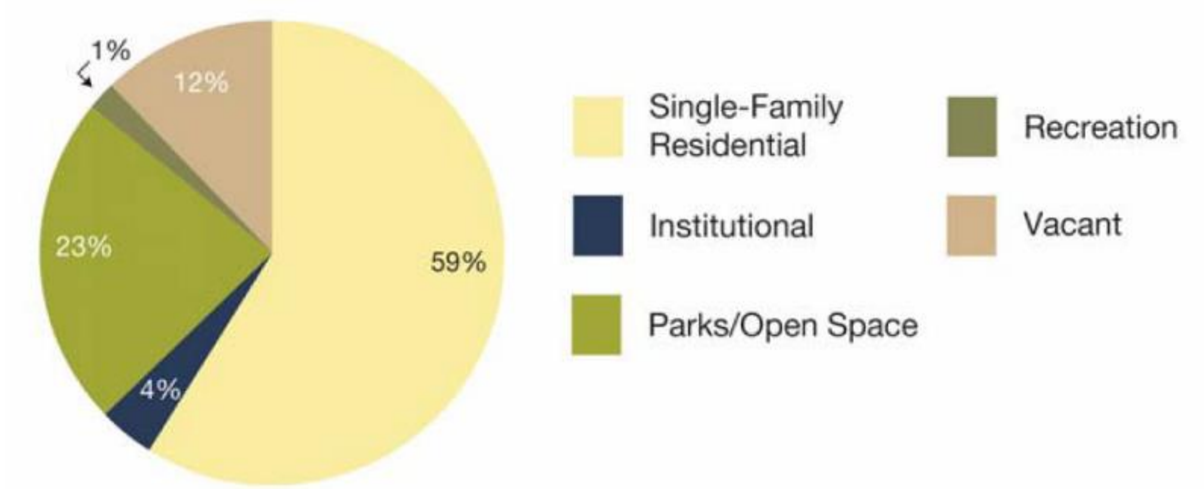
Existing land uses are mostly single-family residential homes. Approximately 118 parcels are adjacent to the existing corridor. Unique land uses include Westminster Chapel and Viewpoint Park. This segment goes through the residential neighborhoods of Bridle Trails and Bel-Red. Bridle Trails is predominantly a single-family residential area, with large lots and mature evergreen trees. The portion of the Bellevue North Segment that goes through Bel-Red is just south of State Route (SR) 520 and characterized by a large commercial property.

The existing corridor is located in four different zoning districts in the City of Bellevue, including single-family residential and commercial districts. The Bridle Trails Subarea Plan land use designations within the segment study area include Single-Family Residential. A small portion of

[3] In upholding the City's recommendation for approval on PSE's applications for the South Bellevue Segment, the King County Superior Court held that "The Hearing Examiner correctly found that "'load-shedding' – i.e. rolling blackouts – is currently part of PSE's corrective action plan (CAP) options in neighborhoods throughout the Eastside, including residential neighborhoods that are located along the route of the South Bellevue Segment." Attachment E, at 14.

the segment goes through the Bel-Red Subarea Plan boundaries and has a future land use designation as General Commercial. Therefore, future land use in the study area is expected to mostly stay the same.

There are 102 single-family and no multi-family residences within this segment. Approximately 59% of the Willow 1 route would impact Single-Family uses (Graph 1) (Phase 2 DEIS at 3.1-7). All of these residences currently have two 115 kV transmission lines as an adjacent use. The use of an existing corridor does not impose a new transmission line on new areas, does not require the acquisition of new easements, and is specifically identified on Bellevue's Comprehensive Plan UT-7 map as being expanded to 230 kV.




*Graph 1: Bellevue North Segment Existing Land Uses*

As described in the City's Phase 2 DEIS (page 3.1-8), specific to the Bellevue Central Segment (Existing Corridor Option):

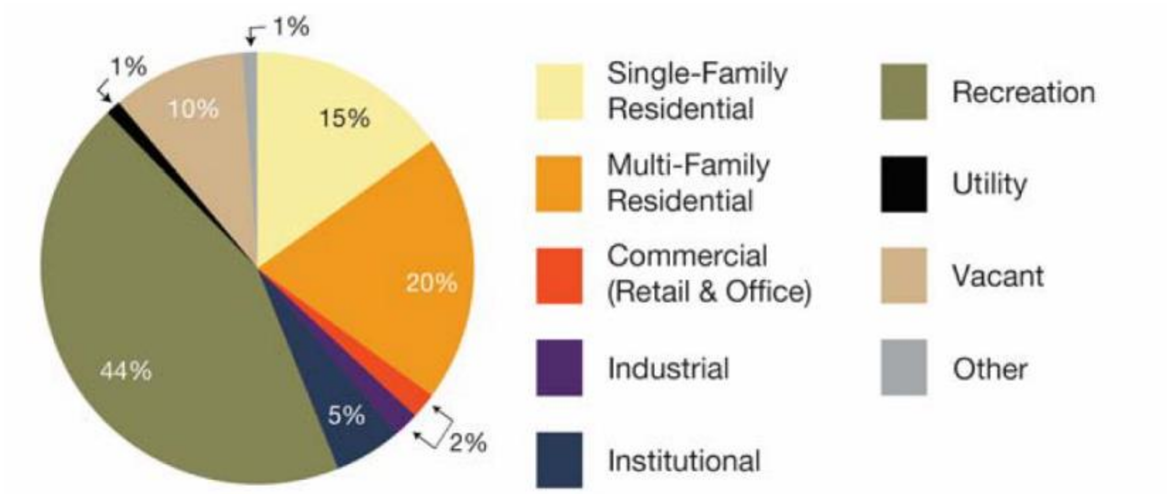
Existing land uses include mostly recreation. Approximately 135 parcels are immediately adjacent to the existing corridor. Unique land uses include Glendale Country Club and Skyridge Park.

This route follows the existing corridor, which starts in the Bel-Red neighborhood just south of SR 520, and is characterized by large manufacturing and commercial spaces. The Bellevue Central Segment runs along the Wilburton (covered by the Wilburton/NE 8th Street Subarea Plan) and Crossroads neighborhood boundaries and the Woodridge and Lake Hills neighborhoods. The border between Wilburton and Crossroads neighborhoods is characterized by a mix of single-family and a multi-family development, with the exception of the Glendale Country Club, which is immediately adjacent to the option. The border of Woodridge and Lake Hills is mostly single-family housing and open spaces, and is covered by the Richards Valley Subarea Plan, the Eastgate Subarea Plan, and the SE Bellevue Subarea Plan. Several parks (including Kelsey Creek Park) are along this option.

The existing corridor is in 13 different zoning districts in the City of Bellevue, including single-family residential, multi-family residential, commercial, industrial, and mixed-use districts.

The Bellevue Comprehensive Plan land use designations for this option include a mix of Single-Family and Multi-Family designations along the existing corridor. This indicates that the neighborhoods along this option will continue to have residential land uses into the foreseeable future. The policies specific to the Wilburton/Crossroads and Woodridge/Lake Hills neighborhoods indicate the intent to preserve the current residential character without limiting the potential for growth.

There are 92 single-family and 1,318 multi-family residences within this portion of the study area. Approximately 15% of the Willow 1 route would impact Single-Family uses (Graph 2) (Phase 2 DEIS at 3.1-8). All of these residences currently have two 115 kV transmission lines as an adjacent use. The use of an existing corridor does not impose a new transmission line on new areas, does not require the acquisition of new easements, and is specifically identified on Bellevue's Comprehensive Plan UT-7 map as being expanded to 230 kV.




*Graph 2: Willow 1 Existing Land Uses*

PSE has selected the Willow 1 route as its preferred alternative. All of the proposed routes, including Willow 1, traverse residential land use districts. By constructing the proposed transmission line facilities in the existing 115 kV transmission line corridor, site compatibility impacts are limited by this alternative (LUC 20.20.255.2.d). By using the existing corridor, PSE minimizes tree removal and management within the corridor (see Attachment B), as compared to establishing a new corridor and can better assess and limit potential interactions with a co-located petroleum and natural gas pipeline (*AC Interference Analysis – 230 KV Transmission Line Collocation with Olympic Pipelines OPL16 & OPL20*; DNV-GL 2016). It also avoids the creation of new impacts to adjacent uses, including residential uses. As properties adjacent to the transmission line corridor already have utility facilities in their viewsheds and neighborhoods, Willow 1 significantly limits new impacts.

### 2.3.2 Bellevue Central Segment, Bypass Option 1

PSE submitted the Bellevue Central Segment, Bypass Option routes as part of the public comment period for Phase 2 Scoping of the EIS process. This submittal ensured that the Bypass Option 1 (and Bypass Option 2, described below in Section 2.3.3), along with PSE's preferred route, were studied in the Phase 2 EIS.

Both Bypass Options 1 and 2 use a combination of the existing corridor and new corridors. The bypass routes wind through the Spring District, Bel-Red Corridor, Wilburton neighborhood, and along Lake Hills Connector before rejoining the existing corridor (Attachment A, Figure 3).

Where the existing transmission corridor crosses NE 20th Street/Northup Way, the new route would run west on NE 20th Street/Northup Way, and turn south along 132nd Avenue NE. The route would then run southwest along NE Bel-Red Road, and then south along NE 1st Street/Lake Hills Connector, where it would meet up with the existing corridor (Attachment A, Figure 3).

The Bypass Option 1 route crosses through the following land use districts: BR-GC, BR-RC-1, BR-RC-2, BR-CR, BR-ORT, BR-OR, O, PO, GC, CB, R-20, R-10, R-7.5, R-4, and R-3.5 (LUC 20.20.255.D.2.a). In sum, Bypass Option 1 would be located in a total of 15 different zoning districts in the City of Bellevue, including a combination of commercial, office, multi-family residential, and single-family residential districts (LUC 20.20.255.D.2.a).

As described in the City's Phase 2 DEIS (pages 3.1-9 to 3.1-10):

Existing land uses include mostly commercial, industrial, and vacant lands. Approximately 199 parcels are immediately adjacent to the corridor (existing and new). Unique land uses include large blocks of commercial and manufacturing along Northup Way, 132nd Ave NE, the International School and Bel-Red Road, Bannerwood Park, and Skyridge Park.

Bypass Option 1 goes through the neighborhoods of Bel-Red, Wilburton, Woodridge, and Lake Hills. In Bel-Red, the Bypass Option 1 corridor is characterized by large industrial and commercial spaces. In Wilburton (covered by the Wilburton/NE 8th Street Subarea Plan), Bypass Option 1 follows major street corridors that are lined with office parks and commercial spaces. In Woodridge, Bypass Option 1 follows the Lake Hills Connector road, which is lined with vacant or open space areas (classified as vacant lands by King County Assessor parcel information), as well as the existing corridor, which is lined by single-family residences. The Lakeside substation is in an area characterized by industrial utilities. This option also traverses areas covered by the Richards Valley Subarea Plan, the Eastgate Subarea Plan, and the SE Bellevue Subarea Plan. Several parks (including Kelsey Creek Park), government buildings, and a school (International School) lie along Bypass Option 1.

Within this portion of the study area, the future land use is anticipated to be mixed-use and commercial for the northern portion of the option and transitioning into multi-family and single-family residential along the Lake Hills Connector.

This option is also covered by several subarea plans. The Bel-Red Subarea Plan designates commercial development as a future land use; the Wilburton Subarea Plan designates commercial and multi-family for future development; the Woodridge and Lake Hills Subarea Plans would continue to develop with single-family residential.

Bellevue intends for the Bel-Red Subarea to focus on nodal development, which means that the planned Sound Transit's East Link light rail stations (anticipated to open in 2023) would be nodes around which development would be focused. The nodes would feature higher density buildings, with taller buildings toward the center of the nodes allowed with a variance process in exchange for various public amenities. Additionally, the Bel-Red Subarea Plan establishes policies to generate new jobs and new housing units; restore streams and ecological functions;

construct new amenities such as parks, trails, and bike paths; and promote economic development.

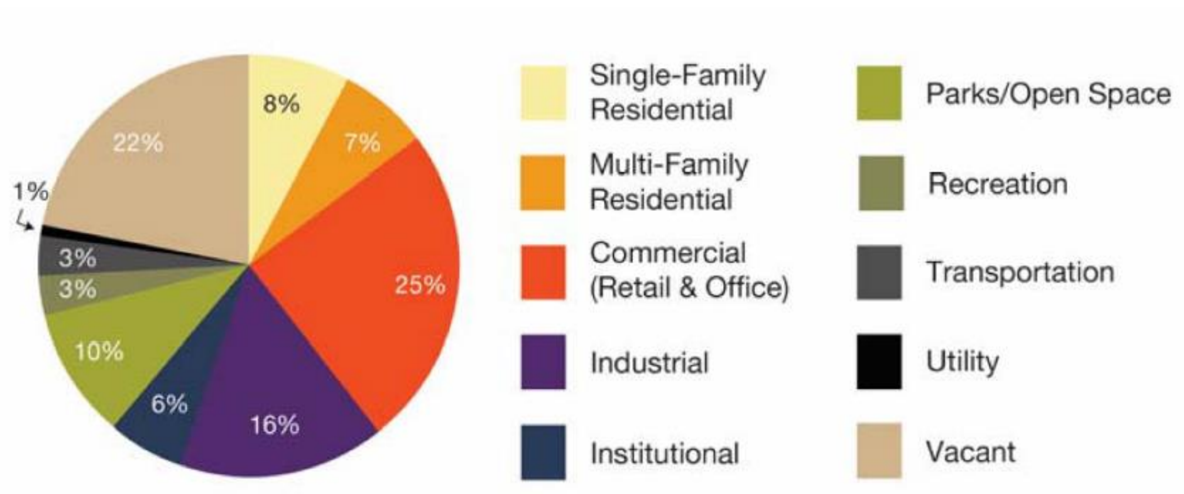
The Wilburton-Grand Connection planning initiative is an ongoing two-part project to improve non-motorized connectivity, as well as a re-visioning of the Wilburton Commercial Area.

1. The Grand Connection will improve pedestrian and cyclist connectivity from Meydenbauer Bay to the Eastside Rail Corridor, including a crossing over I-405 that will reconnect Downtown Bellevue and the Wilburton Commercial Area. Ultimately it will interface with the Eastside Rail Corridor, providing a comprehensive north-south and east-west non-motorized network.
2. The Wilburton Commercial Area planning initiative will identify land use, urban design, transportation, and environmental opportunities, including design guidelines addressing changes to floor area ratio, height, permitted uses, and design character.

The Richards Valley Subarea Plan plans for future development that would not compromise the existing natural features of dense vegetation and wooded vistas. It includes policies for utilizing common corridors (places where utility infrastructure already exists) for new utilities and for placing them alongside transportation rights-of-way.

The policies of each of these subarea plans support development that would accommodate continued residential and commercial growth in the foreseeable future.

There are 54 single-family and 292 multi-family residences within this option. Approximately 8% of the Bypass Option 1 route would impact Single-Family uses, and 7% would impact Multi-Family uses (Graphic 3) (Phase 2 DEIS at 3.1-9). The project would not impact the existing land use pattern of commercial uses to the north and west, and open space and single-family residential to the south. In the portion of the option using the existing corridor, new easements would not be required on adjoining properties. The transmission lines would also use a new corridor, which would require new easements. New easements are not anticipated to affect adjacent land uses since they would be negotiated with the property owner and would not interfere with the current use of adjacent properties.




*Graphic 3: Bypass Option 1 Existing Land Uses*

Consistent with the City's Phase 2 DEIS, PSE considers this route to be feasible (LUC 20.20.255.D.2.c), but significantly more impactful than PSE's preferred alternative. PSE ultimately eliminated this route from consideration, however, because the Bellevue Central Segment, Bypass Option 1 route could result in significant adverse visual impacts because the transmission line would be in a new corridor, resulting in a high level of contrast with high viewer sensitivity (Phase 2 DEIS at 1-15). Also, acquisition of easements in publicly owned recreation sites is not consistent with the City of Bellevue recreation plans and policies, which would result in significant unavoidable adverse impacts (Phase 2 DEIS at 1-23). Additionally, the Bypass Option 1 route was removed from consideration because the Willow 1 route requires the fewest number of trees to be removed in order to comply with NERC standards.

### 2.3.3 Bellevue Central Segment, Bypass Option 2

The Bellevue Central Segment, Bypass Option 2 routes wind through the Spring District, Bel-Red Corridor, Wilburton neighborhood, and along Lake Hills Connector before rejoining the existing corridor.

Where the existing transmission corridor crosses NE 20th Street/Northup Way, the new route would run west on NE 20th Street/Northup Way, and turn south along 132nd Avenue NE. The route would then run southwest along NE Bel-Red Road, and then south along NE 1st Street/Lake Hills Connector, where it would turn south on Richards Road, then east on SE 26th Street where it would connect to the Lakeside Substation (Attachment A, Figure 4).

The Bypass Option 2 route crosses through the following land use districts: BR-GC, BR-RC-1, BR-RC-2, BR-CR, BR-ORT, BR-OR, O, PO, GC, CB, R-20, R-10, R-7.5, R-4, R-3.5, and LI (LUC 20.20.255.D.2.a). In sum, Bypass Option 2 would be in 16 different zoning districts in the City of Bellevue, including a combination of commercial, light industrial, office, multi-family residential, and single-family residential districts (LUC 20.20.255.D.2.a).

As described in the City's Phase 2 DEIS (pages 3.1-11 to 3.1-12):

Similar to Bypass Option 1, existing land uses include mostly vacant, commercial, and industrial lands. Approximately 169 parcels are immediately adjacent to the corridor (existing and new). Unique land uses include large blocks of commercial and manufacturing along 132nd Ave NE and Bel-Red Road, Bannerwood Park, Skyridge Park, and Bellevue Foursquare Church.

Bypass Option 2 goes through the neighborhoods of Bel-Red, Wilburton, and Woodridge. Bel-Red is characterized by large industrial and commercial spaces. Wilburton (covered by the Wilburton/NE 8th Street Subarea Plan), is characterized by major roads lined with industrial parks and commercial spaces. In Woodridge, single-family homes and open space characterize the land along the corridor, including Richards Road, which is predominantly single-family residences. The Lakeside substation is in an area characterized by industrial utilities. This option also traverses areas covered by the Richards Valley Subarea Plan, the Eastgate Subarea Plan, and the SE Bellevue Subarea Plan. Several parks (including Kelsey Creek Park), government buildings, and schools (International School and the Asian Pacific Language School) are along Bypass Option 2.

Within this portion of the study area, the future land use is anticipated to be mixed-use and commercial for the northern portion of the option and transitioning into multi-family and single-family residential along the Lake Hills Connector. The main difference between Bypass Option 1 and Bypass Option 2 is that this option travels down Richards Road and then follows SE 26th

Street to connect with the existing corridor. The future land use on Richards Road is anticipated to be multi-family residential, with industrial development planned along the south side of SE 26th Street.

This option is also covered by several subarea plans. The Bel-Red Subarea Plan designates commercial development as a future land use; the Wilburton Subarea Plan designates commercial and multi-family for future development; the Woodridge and Lake Hills Subarea Plans would continue to develop with single-family residential.

Bellevue intends for the Bel-Red Subarea to focus on nodal development, which means that the planned Sound Transit's East Link light rail stations (anticipated to open in 2023) would be nodes around which development would be focused. The nodes would feature higher density buildings, with taller buildings toward the center of the nodes allowed with a variance process in exchange for various public amenities. Additionally, the Bel-Red Subarea Plan establishes policies to generate new jobs and new housing units; restore streams and ecological functions; construct new amenities such as parks, trails, and bike paths; and promote economic development.
The Wilburton-Grand Connection planning initiative is an ongoing two-part project to improve non-motorized connectivity, as well as a re-visioning of the Wilburton Commercial Area.

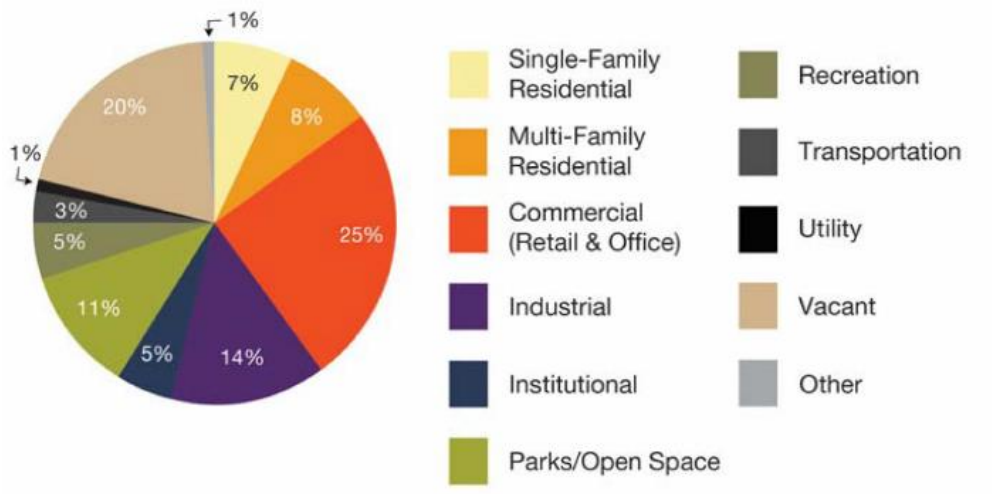
1. The Grand Connection will improve pedestrian and cyclist connectivity from Meydenbauer Bay to the Eastside Rail Corridor, including a crossing over I-405 that will reconnect Downtown Bellevue and the Wilburton Commercial Area. Ultimately it will interface with the Eastside Rail Corridor, providing a comprehensive north-south and east-west non-motorized network.

2. The Wilburton Commercial Area planning initiative will identify land use, urban design, transportation, and environmental opportunities, including design guidelines addressing changes to floor area ratio, height, permitted uses, and design character.

The Richards Valley Subarea Plan plans for future development that would not compromise the existing natural features of dense vegetation and wooded vistas. It includes policies for utilizing common corridors (places where utility infrastructure already exists) for new utilities and for placing them alongside transportation rights-of-way.

The policies of each of these subarea plans support development that would accommodate continued residential and commercial growth in the foreseeable future.

There are 26 single-family and 530 multi-family residences within this option. Approximately 7% of the Bypass Option 2 route would impact Single-Family uses, and 8% would impact Multi-Family uses (Graphic 4) (Phase 2 DEIS at 3.1-11). The project would not impact the existing land use pattern of commercial uses to the north and west, or single-family and multifamily residential along Richards Road. In the portion of the option using the existing corridor, new easements would not be required on adjoining properties. The transmission lines would use a new corridor, which would require new easements. New easements are not anticipated to affect adjacent land uses since they would be negotiated with the property owner and would not interfere with the current use of the properties.




*Graphic 4: Bypass Option 2 Existing Land Uses*

Consistent with the City's Phase 2 DEIS, PSE considers this route to be feasible (LUC 20.20.255.D.2.c), but significantly more impactful than PSE's preferred alternative. PSE ultimately eliminated this route from consideration, however, because the Bellevue Central Segment, Bypass Option 2 route could result in significant adverse visual impacts because the transmission line would be in a new corridor, resulting in a high level of contrast with high viewer sensitivity (Phase 2 DEIS at 1-15). Also, acquisition of easements in publicly owned recreation sites is not consistent with the City of Bellevue recreation plans and policies, which would result in significant unavoidable adverse impacts (Phase 2 DEIS at 1-23). Additionally, the Bypass Option 2 route was removed from consideration because the Willow 1 route requires the fewest number of trees to be removed in order to comply with NERC standards.

## 2.4 Selected Site and Route

*LUC 20.20.522D.2.d. Identify a preferred site from the alternative locations considered for the proposed new or expanding electrical utility facility. The following location selection hierarchy shall be considered during identification of the preferred site alternative: (i) nonresidential land use districts not providing transition, (ii) nonresidential Transition Areas (including the Bel-Red Office/Residential Transition (BR-ORT), and (iii) residential areas. The applicant may identify a preferred site alternative in a Residential Land Use District or Transition Area (including the Bel-Red Office/Residential Transition (BR-ORT) upon demonstration that the location has fewer site compatibility impacts than a nonresidential land use district location.*

After years of study and extensive community dialogue, PSE selected the Willow 1 option, which is located in the existing transmission line corridor option, as the best location to site the transmission line upgrade. Because PSE's project requires reconstruction of miles of transmission lines through the City, all routes evaluated by PSE traverse residential uses. As such, PSE cannot completely avoid residential uses by selecting a site reflective of the City's selection hierarchy (LUC 20.20.255.D.2.d). The Willow 1 route, however, minimizes compatibility impacts by using an existing utility corridor that has been in operation since the 1920s and 1930s. By doing so, it does not require acquisition of additional easements, it removes the fewest number of trees, and it prioritizes safety by having the lowest potential AC interaction with the two petroleum pipelines that share the corridor. Additionally, any adjacent residential use already incorporates transmission line uses in these neighborhoods and homeowners bought their homes with full knowledge of the adjacent high voltage transmission line corridor.

Willow 1 is more consistent with the City's selection hierarchy which seeks to limit impacts to residences. When considering the location selection hierarchy (LUC 20.20.225.2.d.), there is no possible way to route a transmission line, between the Redmond/Bellevue city border and Richards Creek substation, entirely within nonresidential land use districts not providing transition or non-residential Transition Areas. This is a result of city zoning that does not provide any congruent nonresidential north-south corridors. The Willow 1 route was originally established in the late 1920s and early 1930s when little to no development in the area had occurred. The residential areas that exist today have developed around the transmission line corridor. Additionally, the proposed upgrade of the existing 115 kV lines to 230 kV has been incorporated in the City's comprehensive plan since the early 1990s; therefore, using the Willow 1 route is compliant with the Comprehensive Plan.

In sum, as Willow 1 upgrades an existing transmission line and follows the existing route, this alternative creates the fewest new impacts (including compatibility impacts) as compared to the Bypass 1 and 2 routes (LUC 20.20.255.D.2.d). These are the key factors that make Willow 1 the preferred alternative for the Project.

### 2.4.1 Other Rejected Transmission Line Options

The 2015 Solutions Study and 2014 Solutions Report concluded that the preferred solution to solve the Eastside's transmission deficiencies was aggressive conservation combined with construction of a new 230/115 kV transformer and the development of 230 kV transmission lines to connect existing facilities. Transmission line alternatives evaluated, but rejected, by PSE included the use of the Seattle City Light 230 kV corridor, underwater transmission lines (Phase 1 DEIS), the undergrounding of transmission lines, as well as numerous overhead alternatives. These are discussed below.

#### 2.4.1.1 Seattle City Light 230 kV Corridor

Seattle City Light (SCL) operates a dual 230 kV transmission line through the Project area. The use of these transmission lines/corridor was evaluated in the Phase 1 DEIS. The SCL corridor traverses approximately 7.3 miles within the city of Bellevue, with about 4 miles in the north phase.

PSE explored the idea of using the SCL lines as an option; however, the SCL facility is not under PSE ownership, and SCL stated that it needs these lines to serve its customers (Gentile et al., 2014). For the foregoing reasons (lack of sufficient capacity, need for new transmission line facilities that will provide sufficient capacity for less than 10 years, and lack of permission from SCL), PSE does not consider this alternative to be feasible (LUC 20.20.255.D.2.c).

#### 2.4.1.2 Lake Washington Submarine Cable Alternative

The option of using a submerged or underwater transmission line in Lake Washington was also included in the Phase 1 DEIS. Additional detail about constructing a submarine cable in Lake Washington is included in the Eastside 230 kV Project Lake Washington Submarine Cable Alternative Feasibility Report (Power Engineers, 2015). A submerged line would be prohibited by shoreline regulations in the Beaux Arts Village and Hunts Point communities, because new utility corridors are prohibited in the aquatic environments of these communities.

As described in the Phase 1 DEIS, development of new corridors is expected to have higher environmental impacts than use of existing corridors, including permanent displacement of existing uses, vegetation removal, visual impacts, and construction duration. As such, this alternative was not seen as a reasonable alternative to using the existing corridor as proposed by PSE. For these reasons, an underwater line in Lake Washington was not carried forward as a viable alternative.

#### 2.4.1.3 Underground Alternative

The option of placing the new 230 kV transmission lines entirely underground was evaluated in the Phase 1 DEIS. Underground transmission lines involve several technical and economic challenges that would necessitate acquiring a new or expanded right-of-way, including greater restrictions on surface vegetation and uses than are present in PSE's existing 115 kV right-of-way. Factors contributing to the need for additional right-of-way include the need for heat dissipation from each conductor, and the need for separation from the OPL pipelines, which is collocated in much of PSE's existing 115 kV corridor, in order to prevent corrosion of the pipeline. For heat dissipation, underground transmission lines must be placed approximately 12 to 15 feet apart and 3 feet below the surface (Power Engineers, 2014), which means there can be no trees or large shrubs planted over them. The potential for the electrical line to cause unacceptable corrosion of the pipeline is greater if the electrical line is underground than for overhead lines because soils are more conductive than air. Large access vaults are also required every quarter mile and must remain unobstructed by surface structures.

While PSE has an easement for their overhead lines, placing a transmission line underground would require permission from both the Olympic Pipe Line Company and each property owner along the route. Gaining such permission would likely require extensive legal action that would delay the project and thus not meet the project objectives regarding timing. A study of potential undergrounding of the transmission lines prepared for PSE by Power Engineers (2014) states that installation adjacent to the pipeline is technically viable, but that the Olympic Pipe Line Company has stated to PSE that they will not consent to other underground facilities being installed longitudinally in their easements. PSE would therefore have to place its transmission lines outside the Olympic Pipeline easement which is, in some places, nearly as wide as the PSE corridor. Even in places where the pipeline easement is substantially narrower than PSE's corridor, PSE generally does not have enough easement area to provide the necessary separation without the pipeline being relocated. As such, an underground line would require a new corridor to avoid colocation with the Olympic Pipeline (Power Engineers, 2014). This would need to be in a street or on other public or private property that PSE would have to obtain rights to use.

The construction costs for an overhead transmission line are about $3 million to $4 million per mile; versus $20 million to $28 million per mile to construct the line underground (PSE, 2016). When a new line is constructed overhead, project costs are distributed evenly between PSE's 1.1 million customers and paid for over time. If a transmission line were to be constructed underground, PSE can't justify asking customers across its entire service territory to pay the significant cost increases. As a result, per state-approved tariff rules, the requesting party, often the local jurisdiction, must ultimately decide whether to make this investment. The requesting party is then responsible for paying the difference between overhead and underground costs. Bellevue has not requested that PSE underground the project, nor proposed a method of payment for the cost delta.

Given the high cost of acquiring and developing an entirely new underground corridor, and the likely delays it would entail, this option was not considered reasonable as an alternative for the entire corridor, although it is considered as an option for mitigation in limited areas, should one or more jurisdictions determine that it was necessary to avoid significant impacts. Impacts generally associated with the undergrounding of the transmission lines are addressed in the Phase 1 DEIS (in the analysis of Option C).

## 3.0 Technologies Considered and Reliability Need (LUC 20.20.255.D.3)

*LUC 20.20.255D.3.a: Describe the range of technologies considered for the proposed electrical utility facility.*

PSE studied a range of potential solutions to resolve the Eastside transmission deficiencies; these included additional conservation, additional generation, demand response (DR), distributed generation (DG), energy storage, expansion of existing transmission substations, transmission line upgrades, and new transmission lines. PSE's analysis of alternative technologies is documented in detail in PSE's Solutions Report (2014), Pre-Screening Study (Feb. 2014), Underground Feasibility Study (2014), Supplemental Eastside Solutions Study Report (2015) ("Solutions Study") (Attachment C, Study C-3), the Lake Washington Submarine Cable Alternative Feasibility Study (June 2015), and Eastside System Energy Storage Alternatives Screening Study (*Strategen*, 2015 and 2018) (Attachment C, Studies C-6 and C-7). All of these studies can be accessed at https://energizeeastside.com/documents. Non-wire technology solutions are also evaluated in detail in the Phase 1 DEIS (available at http://www.energizeeastsideeis.org/).

The following section summarizes PSE's analysis with respect to each alternative technology.

### 3.1 Increasing Conservation

PSE retained Energy and Environmental Economics, Inc. (E3) to conduct a Non-wires Alternatives Screening Study in 2014. E3 included energy efficiency, demand response and distributed generation measures in its evaluation of cost-effective non-wires potential in the Eastside area. The study concluded that the cost-effective non-wires potential for the Eastside is not large enough to provide sufficient load reduction to address the need. Recent studies conducted as part of PSE's integrated resource plan process continue to evaluate the cost-effective non-wire potential. Including all of the available cost-effective non-wire potential identified in the 2021 IRP study is still not sufficient to address or defer the Eastside transmission upgrade needs.

### 3.2 Construction of New Generation Facilities

PSE studied both conventional generation and distributed generation (DG) in its 2015 Solutions Study. To be effective, this alternative would require at least 300 MW of generation located in the Eastside. Locating conventional generation of this size on the Eastside has major siting and environmental challenges, as a facility with necessary capacity would require a site of approximately 12 to 15 acres and would have significant supporting infrastructure, noise, emissions, and permitting challenges. For DG to meaningfully impact the identified needs, DG must be installed in the right locations, available when needed and be of significant magnitude. Locating 300 MW or more of distributed renewable generation within the Eastside area by the winter of 2017/2018 or summer of 2018 was not practical and highly impactful to the environment and surrounding communities. Additionally, the Cities' Phase 1 DEIS determined that this alternative did 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); Phase 2 DEIS at 2-56).

## 3.3 Energy Storage and Battery Alternatives

PSE contracted with Strategen to perform an Eastside System Energy Storage Alternatives Screening Study, which concluded that an energy storage system with power and energy storage ratings comparable to PSE's identified need has not yet been installed anywhere in the world. In addition, Strategen determined that the existing Eastside transmission system does not have sufficient capacity to charge energy storage systems to a level sufficient to meet PSE's operating standards.

Chemical (battery) storage was determined to be potentially the most appropriate and commercially-viable technology for application within the Eastside. Chemical storage technology is rapidly advancing, but the only system of comparable size to what PSE requires is a 100 MW/400 MWh lithium-ion ESS recently procured by Southern California Edison ("SCE"), which is not expected to be operational until 2021. The largest deployed and commissioned chemical storage project (by power rating) in the United States at the time of report drafting was SDG&E's Expedited Energy Storage Project in Escondido, CA, a 37.5 MW/150 MWh lithium ion battery SCE's Tehachapi Wind Energy Storage ESS, an 8 MW/32 MWh lithium ion battery. Confidential interviews with various vendors indicate that the technology and capability exists for batteries to be deployed for this application and at this magnitude exists. However, since no similarly-sized system has ever actually been built or commissioned, it is difficult to estimate the time necessary for development, procurement, construction and deployment. Procurement of battery cells in particular may result in long lead times, especially for the two larger systems contemplated would constitute a significant portion of the global market for batteries.

Based upon the results of the study, Strategen concluded that the existing Eastside transmission system does not have sufficient capacity to charge a large chemical battery to a level sufficient to meet PSE's operating standards. Specifically, 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. In other words, an energy storage system is not capable of meeting the Project's need, nor does an example of this scale of energy storage exist anywhere in the world.

## 3.4 The Energize Eastside Project Ensures a Long-Term Solution to Near-Term Reliability Deficits

*LUC 20.20.255.D.3.b. Describe how the proposed electricity utility facility provides reliability to customers served.*

The Project is needed to meet local demand growth in the eastside of King County, including Bellevue, Redmond, Kirkland, Renton, Newcastle and Issaquah. It is PSE's responsibility to plan and operate the electrical system while complying with federal standards and guidelines.

Electricity is currently delivered to the Eastside area through[4] two 230 kV/115 kV bulk electric substations – the Sammamish substation in Redmond and the Talbot Hill substation in Renton – and distributed to neighborhood distribution substations using 115 kV transmission lines. No 230 - 115 kV transformer upgrades have been made and the primary 115 kV lines connecting the Sammamish and Talbot Hill substations (the backbones of the Eastside electrical system) have not been upgraded since the 1960s. Since then, the Eastside population has grown eight-fold and this growth is expected to continue. The Puget Sound Regional Council estimates that the Eastside population will likely grow by another third and employment will grow by more than three-quarters over the next 25 years.

The Eastside's rapid growth is also documented in the City's Phase 1 and Phase 2 DEIS':

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). 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 (Phase 1 DEIS at 2-13).

As required by federal regulations, PSE performs annual electric transmission planning studies to determine if there are potential system performance violations (transformer and line overloads) under various operational and forecasted electrical use scenarios. These exercises are generally referred to as reliability assessments.

The need for additional 230 kV to 115 kV transmission transformer capacity and 230 kV support in the Eastside was identified in the 1993 reliability assessment, and has been included in PSE's Electrical Facilities Plan for King County ("Plan") since that time.[5] It was first determined during PSE's 2009 annual reliability assessment, that if one of the Talbot Hill Substation transformers failed, it would significantly impair reliability on the Eastside. Replacement of a failed 230 kV transformer can take weeks, or even months, to complete depending on the level of failure and other site-specific parameters. Since 2009, other reliability deficits have been identified. These include concerns over the projected future loading on the Talbot Hill Substation and increasing use of Corrective Action Plans (CAPs) to manage outage risks to customers in this portion of the PSE system.

In total, since 2009, eight separate studies[6] (Attachment C) performed by four separate parties have confirmed the need to address Eastside transmission capacity:

- Electrical Reliability Study by Exponent, 2012 (City of Bellevue)
- Eastside Needs Assessment Report by Quanta Services, 2013 (PSE)
- Supplemental Eastside Needs Assessment Report by Quanta Services, 2015 (PSE)

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[4] For the purpose of this project, the Eastside is defined as the area between Renton and Redmond, bounded by Lake Washington to the west and Lake Sammamish to the east.

[5] As explained in the Plan, "*[t]he 230 kV sources for the 115 kV system in northeast King County are primarily the Sammamish and Talbot Hill substation. The loads on the 230-115 kV transformers in these stations will be high enough to require new sources of transformation*." Additionally, the "*Lakeside 230 kV Substation project [now the Energize Eastside Project] will rebuild two existing 115 kV lines to 230 kV between Sammamish and Lakeside [where PSE proposes the construction of the Richards Creek substation], and between Lakeside and Talbot Hill*."

[6] These studies are relevant to the City's review under LUC 20.20.255.E.4 and LUC 20.20.255.D.3.b & c.

- Independent Technical Analysis by Utility Systems Efficiencies, Inc., 2015 (City of Bellevue)
- Review Memo by Stantec Consulting Services Inc., 2015 (EIS consultant) [7].
- Eastside System Energy Storage Alternatives Screening Study by Strategen, 2015 (PSE)
- Eastside System Energy Storage Alternatives Assessment, Report Update by Strategen 2018 (PSE)
- Assessment of Proposed Energize Eastside Project, 2020 MaxETA Energy and Synapse Energy Economics)[8]

The studies performed by PSE in 2013 and 2015 confirmed that the Eastside's existing grid will not meet federal reliability requirements by the winter of 2017/2018 and the summer of 2018 without the addition of 230 kV to 115 kV transformer capacity in the Eastside area. The City of Newcastle commissioned a study on project need that was released in 2020 that looked at the latest data provided by PSE and concluded that the project is needed (Attachment C, Study C-8). Additionally, PSE performs annual planning studies that continue to confirm the need for Energize Eastside.

## 3.5 Electrical Utility Facility Components

*LUC 20.20.255.D.3c. Describe components of the proposed electrical utility facility that relate to system reliability.*

PSE's proposal is to install and operate a new 230 kV to 115 kV electrical transformer in the center of the Eastside load area. The ideal location for the new transformer is in close proximity to PSE's existing Lakeside 115 kV substation, which provides the connection to the existing 115 kV electrical system that serves the surrounding neighborhood distribution substations. The new 230 kV to 115 kV transformer is the principal component that will allow the Eastside electrical system to reliably operate and meet Federal Planning standards. By installing a new 230-115 kV transformer at the new Richards Creek substation, electrical load can be taken off of the 230-115 kV transformers at the Sammamish (Redmond) and Talbot Hill (Renton) substations. To operate the new transformer it must be connected to the both the Sammamish and Talbot Hill substations by approximately 16 miles of new high-capacity electric transmission lines (230 kV). Electrical power would come into the Richards Creek substation and the voltage lowered, or "stepped down" (transformed), from 230 kV to 115 kV. The 115 kV power would then be sent to the adjacent Lakeside substation for distribution to local customers on the existing 115 kV transmission network. In sum, and as confirmed by independent experts, all of the proposed Project components will benefit all Bellevue customers by improving reliability of the entire electrical system on the Eastside.

## 3.6 Technology Best Suited to Mitigate Impacts to Surrounding Properties

*LUC 20.20.255.D.3d. Describe how the proposed facility includes technology best suited to mitigate impacts on surrounding properties.*

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[7] The City's consultant's evaluation concluded as follows: "*...PSE['s] needs assessment was overall very thorough and applied methods considered to be the industry standard for planning of this nature. Based on the information that the needs assessment contains, I concur with the conclusion that there is a transmission capacity deficiency in PSE's system on the Eastside that requires attention in the near future.*" (DeClerck, Review Memo by Stantec Consulting Services Inc., July 31, 2015).

[8] Technical review prepared for the City of Newcastle

As proposed, the Project uses the existing transmission line corridor that was originally established in the late 1920s and early 1930s. By building within the existing corridor, new environmental impacts are avoided, including vegetation impacts as trees in the corridor are already managed for collocation with transmission lines. As part of the Project, PSE has also aggressively sought to mitigate impacts by reducing pole height and moving pole locations where feasible and requested by a stakeholder. Post-construction and consistent with the City's code, PSE will fully mitigate all vegetation impacts by replanting both on and off-site. PSE has also prepared pole finish reports for each jurisdiction/segment to limit contrast with the skyline or adjacent uses.

## 4.0 Community Outreach Conducted

*LUC 20.20.255.D.4: Upon submittal of the Conditional Use Permit application required pursuant to subsection C of this section, the applicant shall provide a description of all methods of community outreach or involvement conducted by the applicant prior to selecting a preferred site for the proposed electrical utility facility.*

The Project was designed specifically to address system reliability deficits identified in multiple PSE and independent review studies. Overall, the Eastside's electrical grid will become less reliable in the near-term during times of peak demand without an upgrade in transmission facilities from 115 kV to 230 kV. The North/Central Bellevue Segment (230 kV transmission line upgrade) are designed to implement this change and improve reliability.

### 4.1 PSE has Fully Engaged the Public in Evaluating Energize Eastside Project Alternatives

Since launching the Project in December 2013 and consistent with LUC 20.20.255.D.4, PSE has engaged the Eastside community in a robust public involvement process. This process has included mailings, public meetings and direct outreach efforts to ensure that stakeholders are informed about the project and have had plentiful and diverse opportunities to participate. PSE's public involvement process, especially with regards to routing, goes well beyond environmental review and permitting requirements, including a year- long route selection process with a Community Advisory Group (CAG).

To date, public outreach, and involvement has included:

- 22 CAG-related meetings, including 6 public open houses, 2 question and answer sessions, and 2 online open houses at key project milestones
- 650+ briefings with individuals, neighborhoods, cities and other stakeholder groups
- More than 3,000 comments and questions received
- 40+ email updates to more than 1,500 subscribers
- 10 project newsletters to 55,000+ households
- Ongoing outreach to 500+ property owners, including door-to-door and individual meetings
- Participation in 16 EIS-related public meetings

In addition, PSE's Energize Eastside website (https://pse.com/energizeeastside) provides project updates and functions as a repository for project materials, including maps, technical studies, the CAG Final Report, fact sheets, newsletters, meeting summaries and other materials. An overview of the public engagement process is provided in the following sections.

#### 4.1.1 Phase 1: Public Route Discussion (2014)

To analyze and narrow the potential route alternatives to a reasonable number to study in detail and remove routes with considerable constraints, PSE engaged the CAG in 2014 to consider community values when evaluating the route options. The advisory group was comprised of representatives from various interests within the study area, including potentially affected neighborhood organizations, cities, schools, social service organizations, major commercial users, economic development groups, and other interests. The advisory group spent a year learning about the Eastside's electrical system, participating in meetings and workshops and evaluating 18 route options identified by PSE using a Linear Routing Tool (see Section 2.2 for discussion). The advisory group looked at the factors used to develop different route options, narrowed the route options based on values and constraints, and prepared route option recommendations for further consideration.

In addition to the CAG, PSE involved the community through public meetings, neighborhood meetings, briefings and comments, which provided Eastside residents opportunities to share their community values and ask initial questions about the project. The details about the advisory group process can be found in the Community Advisory Group Final Report (2015) (Attachment D).

#### 4.1.2 Phase 2: Fieldwork and Environmental Review (2015 – 2018)

In 2015, PSE began collecting field information necessary for design and environmental review. PSE kept stakeholders informed about these fieldwork activities to ensure residents knew when crews were expected to perform surveys near their homes and businesses.

In 2015, the City began its review under the SEPA (discussed in greater detail below). The City of Bellevue lead the EIS process in cooperation with Newcastle, Kirkland, Redmond and Renton.

PSE has provided supplemental EIS notifications about major milestones and comment periods to keep stakeholders informed and to support community engagement in addition to those provided by the City of Bellevue and other jurisdictions. PSE has also participated in eight scoping meetings and eight draft EIS hearings over the two-phased EIS process where input on EIS alternative solutions and route options was solicited from the public.

#### 4.1.3 Phase 3: Property-Owner Consultations (2016 – Today)

As project design progressed, PSE began reaching out to individual property owners to share information and answer questions. In spring 2016, the project team visited neighborhoods along the existing corridor and Factoria area to talk with residents and business owners about the project. This door-to-door outreach was conducted to help inform customers about the project status and to address questions and concerns from property and business owners.

In September 2016, PSE began meeting with property owners and tenants along the existing corridor to discuss property-specific design and tree replacement plans. The current design for that specific property was shared, including pole locations and how PSE planned to access those locations during construction. These conversations helped refine the project design and better understand customer interests and concerns.

In May 2017, PSE began meeting with property owners to begin developing property-specific landscaping and tree replacement plans with property owners. PSE has reached out to affected property owners about these efforts. However, the COVID-19 restrictions have made in-person meetings difficult.

Input received through the CAG process, neighborhood and stakeholder briefings, the EIS process, one-on-one property owner meetings, and the nearly 3,000 comments and questions received to date has helped to shape the Project and PSE's decision making.

## 4.2 State Environmental Policy Act Review

The City rigorously evaluated the Project, including the North Bellevue Phase, under SEPA. In conjunction with the cities of Redmond, Kirkland, Renton, and Newcastle, the City published a Phase 1 and Phase 2 DEIS and a Final EIS. These documents can be found online at http://www.energizeeastsideeis.org/.

The Phase 1 DEIS contained a programmatic review of project alternatives including analysis of the feasibility of an overhead transmission line (such as the one currently proposed), use of the Seattle City Light transmission system, the construction of underwater transmission lines, and an integrated resource approach (i.e., employing non-transmission line technologies such as additional aggressive conservation and demand response technologies, new distributed generation facilities, and/or energy storage systems) (See Phase 1 DEIS, Ch. 2). A thorough analysis of all project alternatives relative to defined project objectives (e.g., meeting demand growth and being environmentally acceptable to impacted cities), resulted in a narrowing of reasonable alternatives to an overhead transmission solution.

The Phase 2 DEIS contains the City's focused review of overhead transmission line route alternatives and impacts. It contains a detailed analysis of six route segments and seven route options within those segments. The Phase 2 DEIS analyzes three different routing options in the Central Bellevue Segments. Attachment B compares environmental impacts of each of the three Central Bellevue Segment alternatives. Ultimately, PSE chose to move forward with a plan to build its proposed system upgrades in the existing transmission line corridor. This route is the least impactful (particularly because it minimizes *new* environmental impacts) and prioritizes safety by limiting the potential for interactions with Olympic's petroleum pipelines.

The Final EIS was issued on March 1, 2018 and built upon the previous Phase 1 DEIS and Phase 2 DEIS, released in January 2016 and May 2017, respectively. The Final EIS assessed PSE's project-level Proposed Alignment, as described in Section 1.5 and Chapter 2. Based on the results of the Phase 2 DEIS analysis, PSE has refined the proposed route of the transmission lines and associated project components, as evaluated in greater detail in the Final EIS.

Project opponents appealed, but were unsuccessful in challenging the adequacy of the project EIS through the King County Superior Court after which they abandoned their appeal. *See* Coalition of Eastside Neighbors for Sensible Energy v. City of Bellevue and Puget Sound Energy, Inc. (Attachment E).

## 5.0 Conclusion

The City of Bellevue has previously assessed the project during its review of the South Bellevue Segment. That assessment included an ASA that was submitted with those applications. The City critically reviewed this document and determined that it complied with ASA criteria. Additionally, a decision, upheld on appeal by the King County Superior Court, held that "the ASA contains sufficient information regarding the methodology employed, the alternative sites analyzed, the technologies considered, and the community outreach undertaken to satisfy the requirements of LUC 20.20.255.D." See Attachment E at pp. 8-9; 15-16.

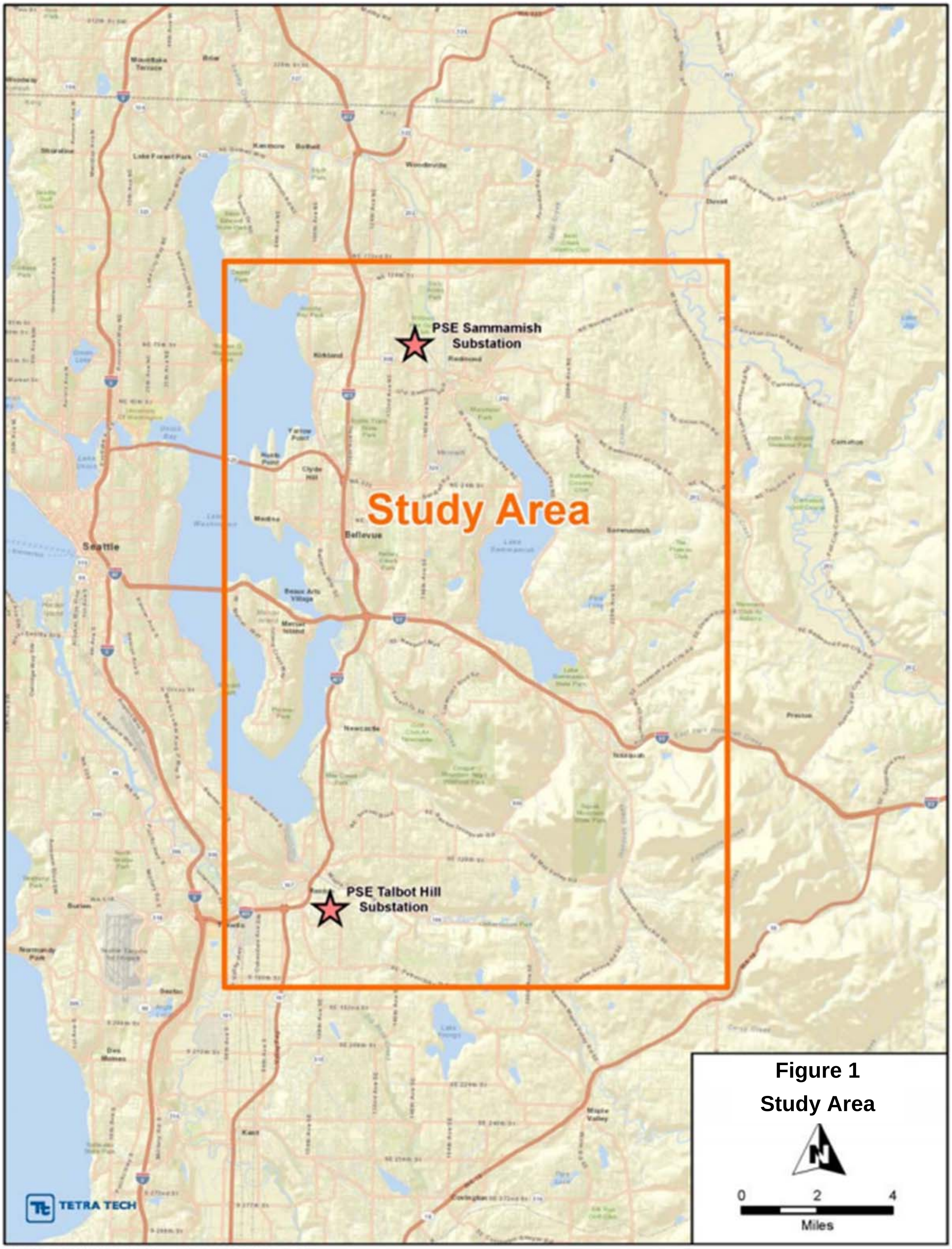
This North Bellevue Phase ASA follows the same methodologies and contains analogous information as the South Bellevue Segment ASA. Following extensive study over a number of years, PSE has and continues to conclude that its existing system does not comply with federal reliability planning criteria and that under current summer demand conditions on the Eastside, North Bellevue customers are at risk of outages. PSE evaluated a full range of wire and non-wire alternatives, but PSE ultimately determined that installing a new 230 kV to 115 kV transformer and upgrading the existing 115 kV lines to 230 kV lines between 230 kV substations in Redmond and Renton is the least impactful and best solution to meet the identified need.

The new 230 kV – 115 kV transformer will be placed at the new Richards Creek substation and the 230 kV transmission lines will be within the Willow 1 (existing) transmission line corridor - the site for the Project. To summarize, the new lines will bring 230 kV power from the Sammamish substation in Redmond and the Talbot Hill substation in Renton to the Richards Creek substation in Bellevue. This will take electrical load off of the existing 230-115 kV transformers at those substations. For the Project to meet the intended objective, a 230 kV power is required from both the north and the south source and must connect to the new transformer at the Richards Creek substation.

The Willow 1 route has been selected and uses an existing transmission line corridor that has been in operation since late 1920s and early 1930s. By using this corridor, additional easements or properties are not required. Even though the existing vegetation within the corridor is managed, which includes trimming and periodic removal, conversion of the existing transmission lines from 115 kV to 230 kV requires removal of taller growing tree species in order to meet federal vegetation management standards (NERC FAC-003). By using the existing corridor, the fewest number of trees will need to be removed. The use of the Willow 1 route combined with optimized transmission line design and 230/230 kV operation, allows for the lowest potential AC interaction with the two petroleum pipelines that share the corridor. These are the key factors that make the Willow 1 transmission line route the preferred alternative for the Project.

# ATTACHMENT A

## Figures

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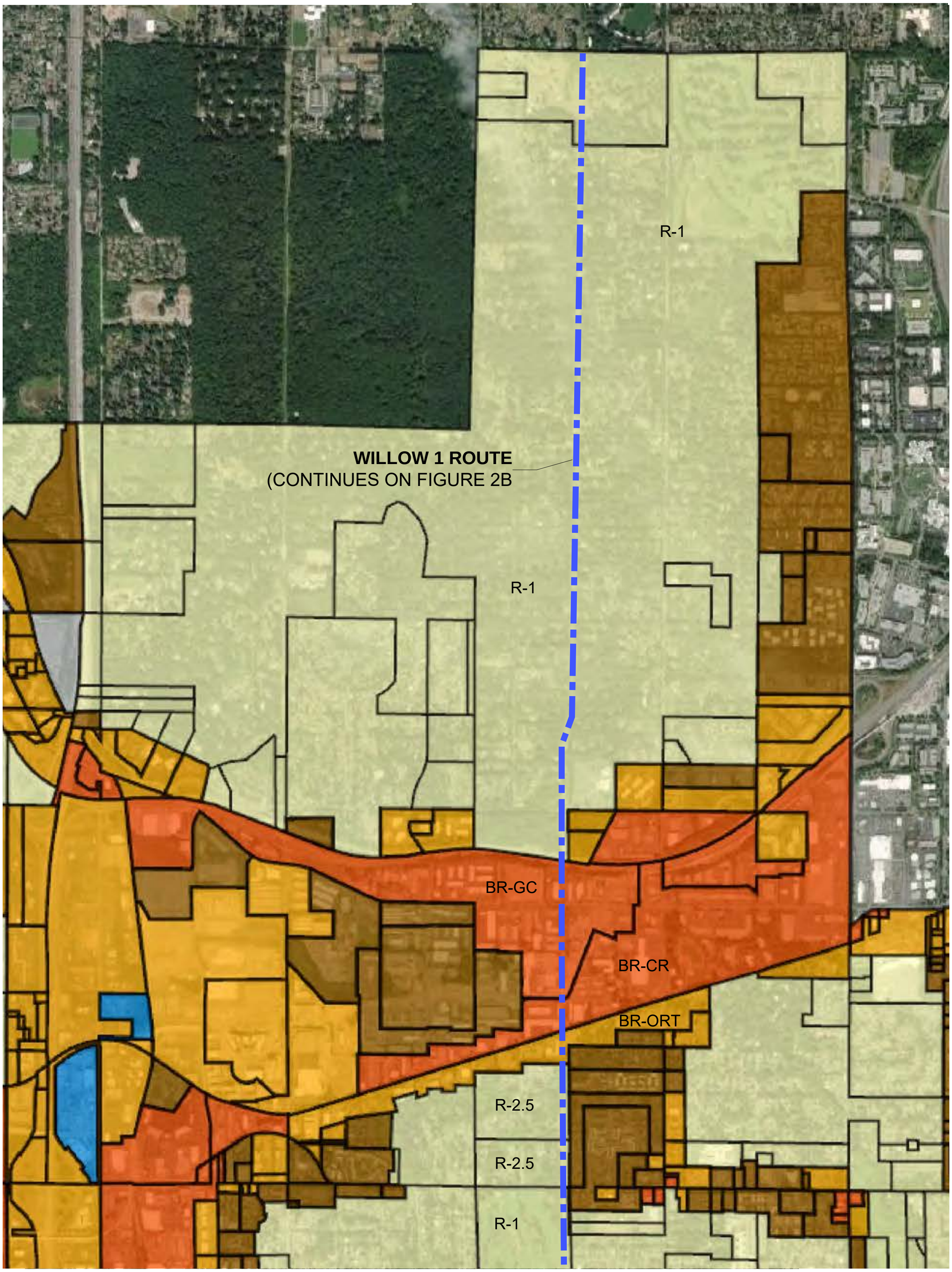
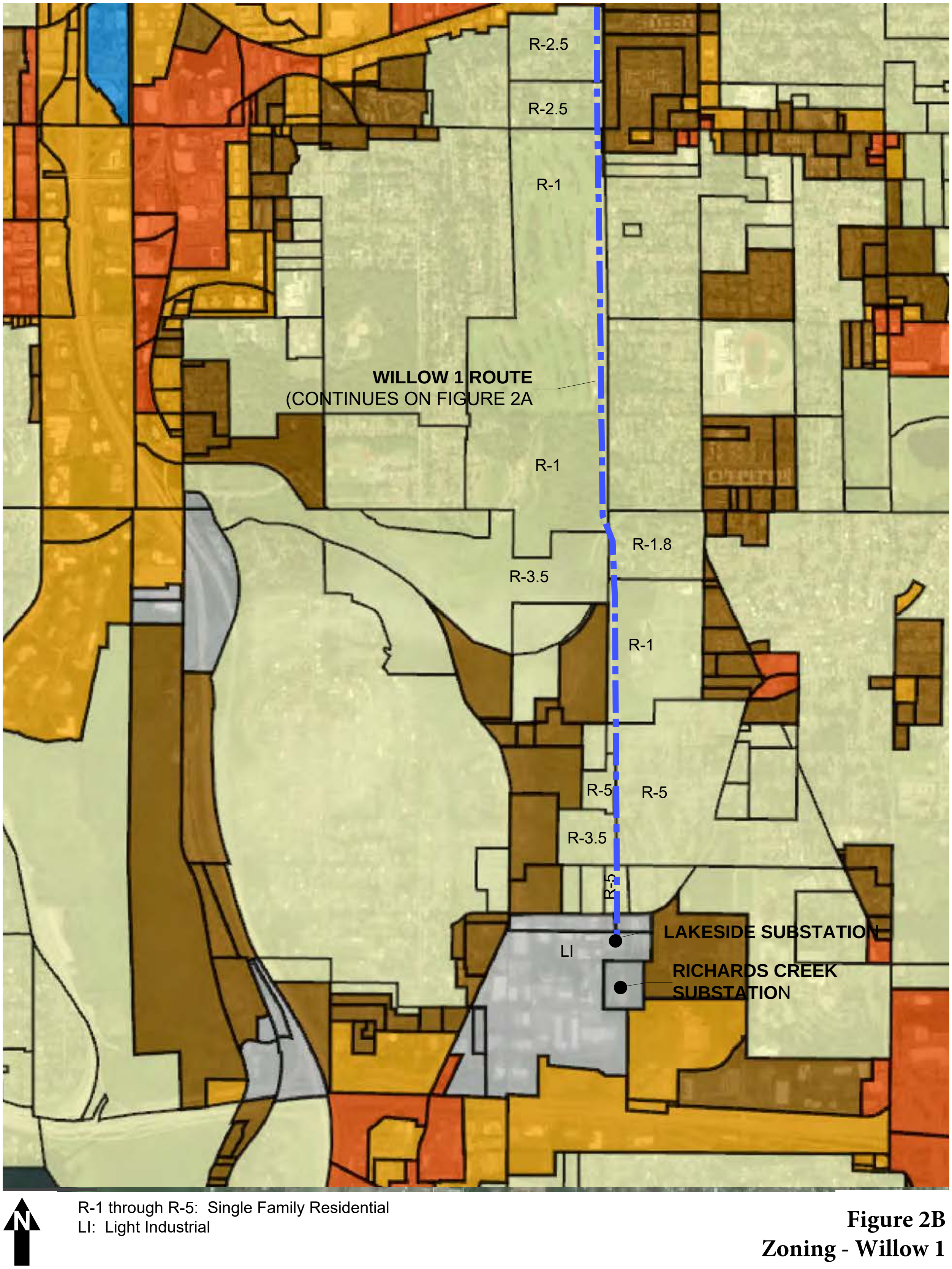


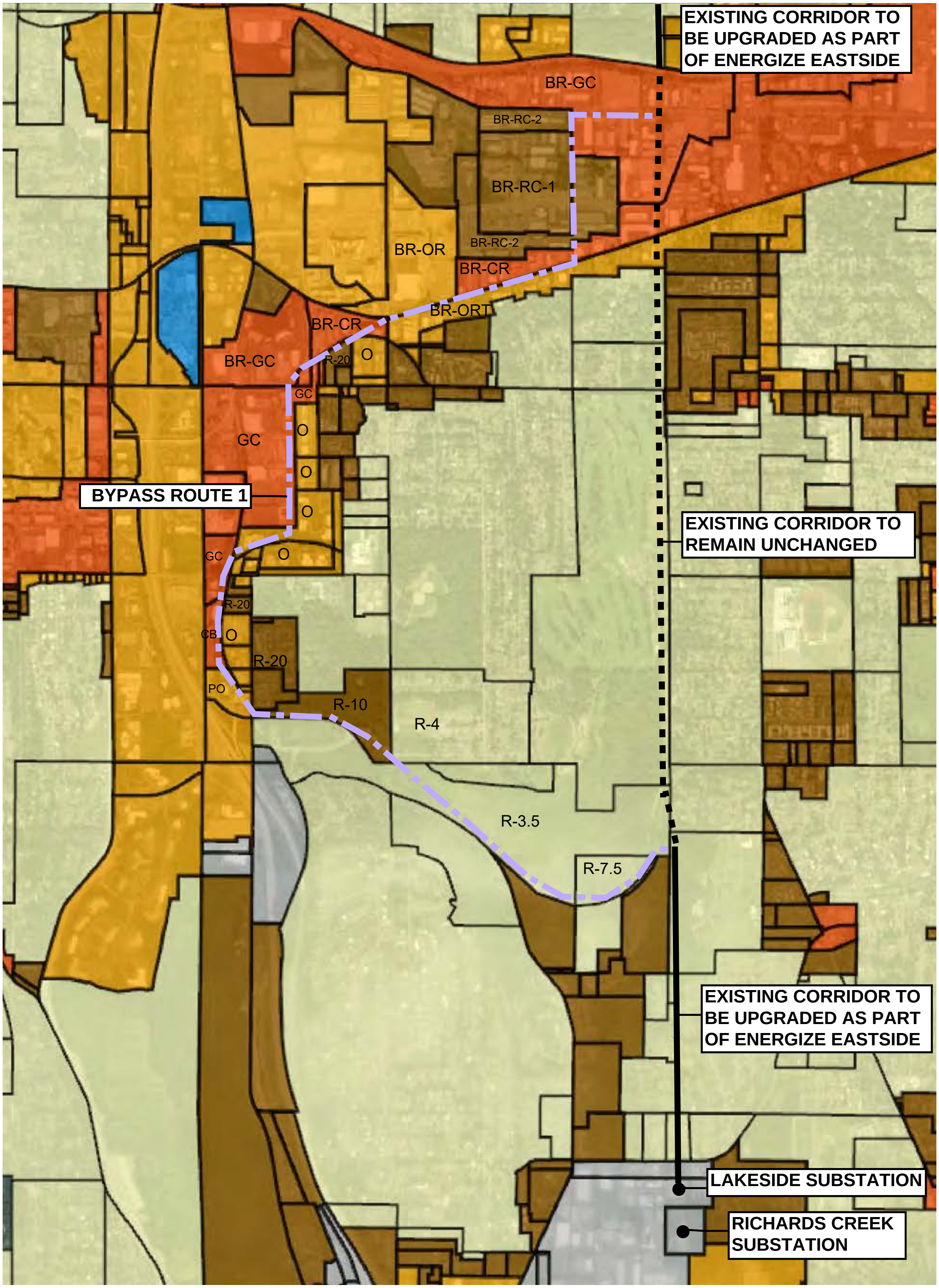

R-1 and R-2.5: Single Family Residential
BR-GC: Bel-Red General Commercial
BR-CR: Bel-Red Commercial/Residential
BR-ORT: Bel-Red Office/Residential Transition

**Figure 2A**
**Zoning - Willow 1**



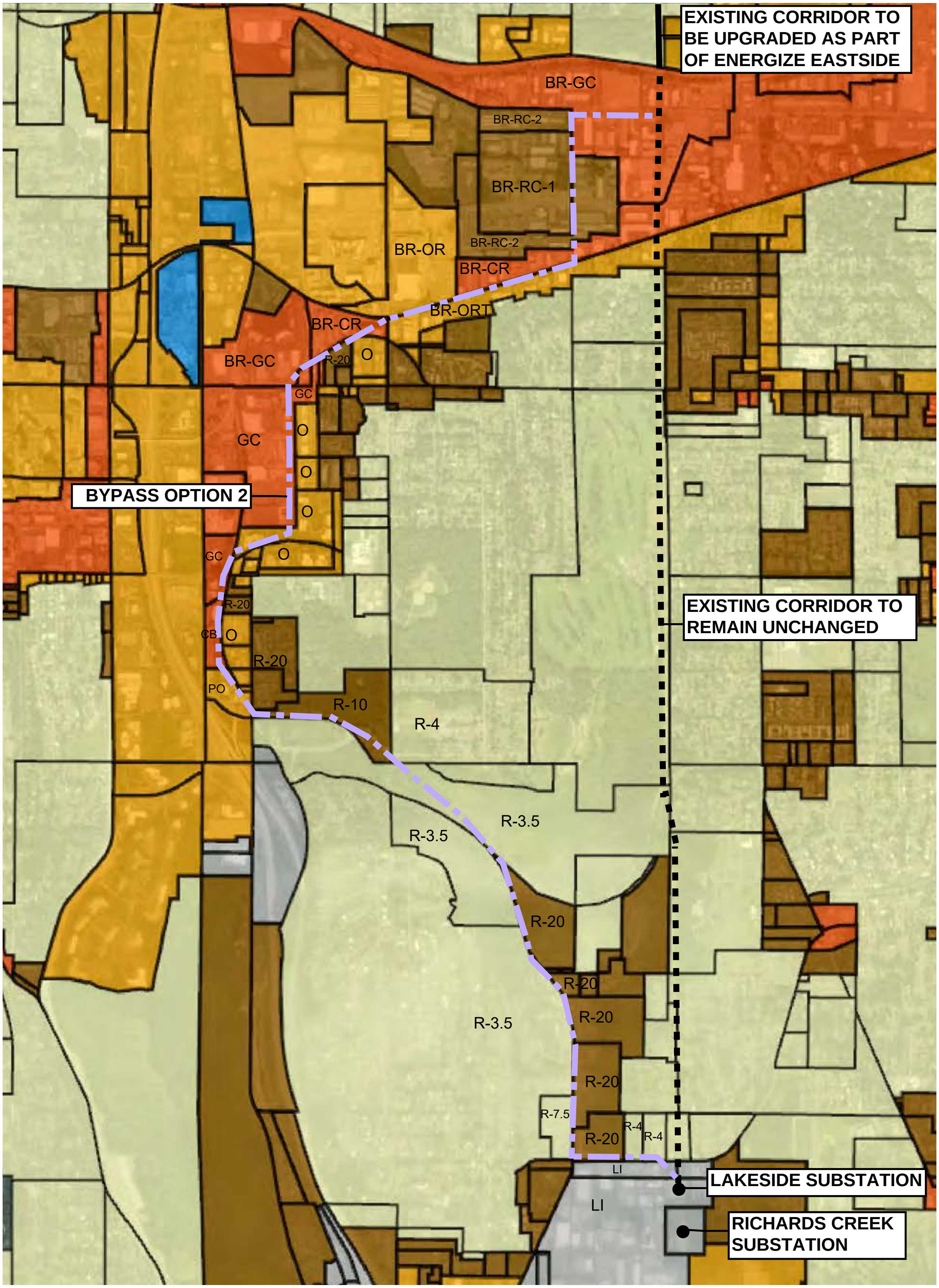

R-1 through R-5: Single Family Residential
LI: Light Industrial

**Figure 2B**
**Zoning - Willow 1**




BR-GC, BR-CR, GC, and CB: Commercial
BR-OR, BR-ORT, O, and PO: Office
R-3.5, R-4, and R-7.5: Single Family Residential
BR-RC-1, BR-RC-2, R-10 and R-20: Multi Family Residential

**Figure 3**
**Zoning - Bellevue Central Segment, Bypass Option 1**




BR-GC, BR-CR, GC, and CB: Commercial
BR-OR, BR-ORT, O, and PO: Office
R-3.5, R-4, and R-7.5: Single Family Residential
BR-RC-1, BR-RC-2, R-10 and R-20: Multi Family Residential
LI: Light Industrial

**Figure 4**
**Zoning - Bellevue Central Segment, Bypass Option 2**

## ATTACHMENT B

## Phase 2 DEIS Impact Table

# Impacts During Operation

## BELLEVUE CENTRAL OPTIONS

| POTENTIAL IMPACT | EXISTING CORRIDOR *PSE's Preferred Alignment* | BYPASS OPTION 1 | BYPASS OPTION 2 |
|---|---|---|---|
| **LAND USE** | | | |
| Potential inconsistencies with plans and policies | Consistent | Inconsistent | Inconsistent |
| New easements needed for new corridor | No New Easements | New Easements Needed | New Easements Needed |
| Shoreline of the state | Not a Shoreline | Shoreline | Shoreline |
| **SCENIC VIEWS & AESTHETIC ENVIRONMENT** | | | |
| Impacts to visual quality | Low Potential | High Potential | High Potential |
| Impacts to scenic views | Low Potential | Moderate Potential | Moderate Potential |
| Viewer sensitivity | Low | High | High |
| **WATER** | | | |
| Stream and buffer impacts | No Impacts | 15 New Stream Crossings | 17 New Stream Crossings |
| Wetland and buffer impacts | Fewer Poles in Wetlands (Benefit) | New Wetland/Buffer Impacts (in 5 Category-1 Wetlands) | New Wetland/Buffer Impacts (in 6 Category-1 Wetlands) |
| Shoreline management impacts | No Impacts | New Poles in Kelsey Creek Shoreline Jurisdiction | New Poles in Kelsey Creek Shoreline Jurisdiction |
| **PLANTS AND ANIMALS** | | | |
| Total trees removed | 620 Trees | 1,790 Trees | 1,240 Trees |
| Significant trees removed | 250 Trees | 1,230 Trees | 930 Trees |
| Trees removed in critical areas | 140 Trees | 244 Trees | 177 Trees |
| **GHG (METRIC TONS OF CO2e/YEAR)** | | | |
| GHGs from sequestration loss | 8.5 Mt | 53 Mt | 39 Mt |
| Fugitive loss of SF6 from new gas-insulated substation equipment | 75 Mt | 75 Mt | 75 Mt |
| Total GHG losses | 121 Mt | 165 Mt | 151 Mt |
| **RECREATION** | | | |
| Trees removed at recreation sites | 45 Trees | 430 Trees | 310 Trees |
| New easements at recreation sites | No New Easements | New Easements Needed | New Easements Needed |
| **HISTORIC & CULTURAL RESOURCES** | | | |
| Sensitivity for unrecorded resources | Very Low Potential | Very Low Potential (except at Kelsey Creek) | Very Low Potential (except at Kelsey Creek) |
| New easements needed (i.e., potential for unevaluated resources) | No New Easements | New Easements Needed | New Easements Needed |
| **ECONOMICS** | | | |
| Loss of ecosystem services through tree removal (e.g., carbon storage, stormwater runoff, etc.) | 620 Trees | 1,790 Trees | 1,240 Trees |
| **EMF (MILLIGUASS OR MG)** | | | |
| Calculated magnetic field levels (maximum) | 36 Mg | 22 Mg | 22 Mg |
| Calculated magnetic field levels (edge of right-of-way) | 26 Mg | 19 Mg | 19 Mg |
| **PIPELINE** | | | |
| Risk to pipeline safety | No Substantial Change in Risk | No Substantial Change in Risk | No Substantial Change in Risk |
| Miles of co-location | **2.9 Miles** (20" pipeline)<br>**2.9 Miles** (16" pipeline) | **0.91 Miles** (20" pipeline)<br>**0.91 Miles** (16" pipeline) | **0.60 Miles** (20" pipeline)<br>**0.60 Miles** (16" pipeline) |

- No or Negligible Adverse Impact (in some cases, beneficial)
- Potential Impact but Not Considered Significant (or can be mitigated)
- Potentially Significant Impact

# ATTACHMENT C

## Supporting Studies

C-1 Electrical Reliability Study (Exponent 2012)

C-2 Eastside Needs Assessment Report (Quanta Services 2013)

C-3 Supplemental Eastside Needs Assessment Report (Quanta Services 2015)

C-4 Independent Technical Analysis (Utility Systems Efficiencies, Inc. 2015)

C-5 Review Memo (Stantec Consulting Services, Inc. 2015)

C-6 Eastside System Energy Storage Alternatives Screening Study (Strategen 2015)

C-7 Eastside System Energy Storage Alternatives Assessment, Report Update (Strategen 2018)

C-8 Assessment of Proposed Energize Eastside Project (MaxETA Energy and Synapse Energy Economics 2020)

Exponent®

# City of Bellevue
# Electrical Reliability Study
# Phase 2 Report

# City of Bellevue
# Electrical Reliability Study
# Phase 2 Report

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# Contents

# List of Figures

# List of Tables

# Acronyms and Abbreviations

| | |
|---|---|
| AMI | advanced metering infrastructure |
| AMR | automatic meter readers |
| BPA | Bonneville Power Administration |
| CCIF | Critical Consumer Issues Forum |
| CIS | Customer Information System |
| CLX | ConsumerLinX |
| CPUC | California Public Utilities Commission |
| DMS | Distribution Management System |
| DNP | distributed network protocol |
| DOE | U.S. Department of Energy |
| ECC | Emergency Coordination Center |
| EISA | Energy Independence and Security Act |
| EMS | Energy Management System |
| EOC | Emergency Operations Center |
| EPRI | Electric Power Research Institute |
| FERC | Federal Energy Regulatory Commission |
| GIS | geographic information system |
| IEEE | Institute of Electrical and Electronic Engineers |
| IOU | investor owned utility |
| IP | Internet protocol |
| IRP | Integrated Resource Plan |
| KEMA | KEMA Consulting Company |
| kV | kilovolt; one kV equals 1000 V |
| kW | kilowatt |
| kWh | kilowatt-hours |
| LBNL | Lawrence Berkeley National Laboratory |
| MDMS | Meter Data Management System |
| MVA | megavolt-ampere |
| MW | megawatt (1 MW equals one million watts) |
| NERC | North American Electric Reliability Corporation |
| NIMS | National Incident Management System |
| NIST | National Institute of Standards and Technology |
| NOS | network open seasons |
| $^{o}$C | degree Celsius |
| OMS | Outage Management System |
| PG&E | Pacific Gas & Electric Company |
| PSE | Puget Sound Energy |
| R&D | research and development |
| RCW | Revised Code of Washington |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SAP | Systems Analysis and Program Development System |
| SCADA | Supervisory Control and Data Acquisition |

| | |
|---|---|
| SF6 | sulfur hexafluoride |
| T&D | transmission and distribution |
| V | volts; a unit for voltage (electric potential) |
| VAC | volts alternating current |
| WAC | Washington Administrative Code |
| WECC | Western Electricity Coordinating Council |
| WUTC | Washington Utilities and Transportation Commission |

# Acknowledgements

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Neal Parker, Incident Forensics and Root Cause
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Jennifer Tada, Planning

# Executive Summary

## Study Results

The City of Bellevue (the City) retained Exponent to perform an electric system reliability assessment to assist the City in meeting its goals to be an informed stakeholder and to work with Puget Sound Energy (PSE) to ensure a reliable electric power supply for the City. The study was performed to answer the following questions from the Electric Reliability Study Plan[1]:

1. *"How does PSE's existing system serving Bellevue perform relative to the Washington Utilities and Transportation Commission (WUTC) expectations, industry standards, and peers relative to reliability?"*

   There are over 90 circuits in Bellevue and while the performance on individual circuits can vary, the overall system in Bellevue is reliable.

   Electric system reliability is measured by the availability of the system to deliver electric power to a customer's meter in accordance with voltage and frequency requirements specified by the WUTC.[2] Reliability is therefore a measure of the probability that electric power is delivered in accordance with those requirements. Electric system reliability is typically measured based on the frequency (System Average Interruption Frequency Index [SAIFI]) and duration (System Average Interruption Duration Index [SAIDI]) of outages relative to the number of customers.

   WUTC has established reliability goals for its regulated utilities (service quality indices). Prior to 2010, the measures included SAIFI (frequency of outages per customer) and SAIDI (duration of outages per customer) goals for PSE of 1.3 and 136 minutes, respectively, excluding major storm events. While PSE has not always met the SAIDI goals system-wide, Bellevue's reliability has met the SAIFI and SAIDI goals over the past 5 years. In 2010, the reliability in Bellevue measured 0.44 and 66 minutes, respectively for SAIFI and SAIDI. In 2010, the measure for SAIDI was changed to include a 5-year average including major storm events and PSE met that goal system-wide. They will report this measure for Bellevue's circuits in 2011.

   PSE participates in an industry reliability survey through the Institute of Electrical and Electronics Engineers. PSE's overall system reliability performance is typically in the 1st or 2nd quartile on SAIFI (frequency of outages) and 2nd or 3rd quartile in SAIDI (duration of outages) (with the 1st quartile being best performance). PSE's 2010 performance for SAIFI and SAIDI was 0.86 and

1 Reference 10.

2 Washington Administrative Code (WAC)480-100.

129 minutes, respectively, and as shown above, Bellevue had significantly better reliability performance.

2. *“What changes relative to facilities, equipment, planning, and emergency operations will improve electric system reliability, communication, and outage response in Bellevue?”*

   While there has been improvement in the reliability of the Bellevue system over the past several years, the following enhancements are required to ensure continued improvement in reliability for the City:

   - Hardening of the Bellevue system to ensure appropriate redundancy to all substations and circuits.
   - Continued focus on underground cable replacement and remediation as well as replacement of older switches and transformers placed in underground vaults.
   - Review of specific circuits within the City that experience lower reliability to identify improvement actions.
   - Accelerate investments in distribution automation (including a Distribution Management System [e.g., Supervisory Control and Data Acquisition]) to improve reliability and to enable future technologies.
   - Develop strategies to provide greater opportunities for undergrounding lines experiencing lower reliability due to tree and storm impacts.
   - Improvements in the information technology infrastructure for outage management and customer interface to specifically improve communication and outreach to customers during outages on the system.

3. *“Will the City have adequate and reliable power supply to meet future City growth needs?”*

   Based on current plans, the City will have an adequate and reliable power supply to meet the medium-term (5–10 years) and long-term (10–20 years and beyond) growth requirements. The current plan includes:

   - Capacity additions, including upgrade of the 115 kV lines running north-south through Bellevue.
   - Addition of transformer banks to support growth in the Downtown, Bel-Red, and Eastgate/Somerset areas.
   - Upgrade of 115 kV lines to support additional transformer banks.
   - Support of PSE plans to significantly reduce the peak electric power demand through the use of more efficient electric lighting and equipment.

4. *"What opportunities are available to the City to work with PSE, regulators (WUTC,* Federal Energy Regulatory Commission*), and other stakeholders to ensure the needs and expectations of Bellevue's residents and businesses are met relative to the reliability of the power supply?"*

   Bellevue's role as an informed stakeholder requires that the City take an active role in becoming informed on matters affecting the reliability and planning for the electric system in Bellevue. This role includes direct communication with PSE as well as other stakeholders regarding electric service. Specific opportunities for the City to engage as an active stakeholder include:

   - WUTC: The City has a role in informing lawmakers and commissioners regarding matters that affect reliability. The City also has the opportunity to comment or participate in matters directly affecting PSE and its interaction with WUTC. It may be possible for Bellevue to support measures for investment brought forward by PSE that support its overall City goals for electric system reliability and service.
   - PSE: The City has many opportunities to proactively interact with PSE on issues related to system reliability, long-term planning, near-term major project planning, Smart Grid initiatives, and emergency planning.

5. *"How can the City measure and monitor whether improvement in reliability is being achieved?"*

   This reliability assessment includes recommendations for the City to consider moving forward. Proposed reliability improvement metrics have also been included to assist the City in measuring and monitoring the implementation and effectiveness of these recommendations.

This reliability study provides the analyses and recommendations to support the City in meeting its goals to be an informed and active stakeholder and to ensure that the City has an adequate and reliable electric system now and into the future.

## Recommendations Summary

The outcome of this reliability assessment is a set of recommendations that will support the City's efforts to meet its stated goals. The recommendations are summarized below:

1. **Conduct Joint City/PSE Reliability Workshops—**The City should conduct an annual reliability workshop with PSE to perform a review of the following topics that relate to reliability in Bellevue:

   - Specific Circuit Reliability: The City should request reliability metrics (SAIDI and SAIFI) on a circuit basis. This will provide the City with information regarding the performance of circuits throughout the City and provide a basis for the City to work with PSE to identify appropriate means to improve performance.

- The City should trend circuit performance over time to identify the effectiveness of completed reliability projects (review number of outages and causes to trend improvement). This assessment provides the City with a means of reviewing the overall Downtown performance and performance for specific neighborhoods that have experienced frequent outages (such as neighborhoods with overhead circuits).

- Equipment Reliability Projects: The City should request a list of the current PSE projects identified for Bellevue (both funded projects in the capital plan and those waiting future funding) to understand the potential reliability improvement efforts for Bellevue.

- Maintenance and Inspection Program Results: PSE should identify to the City any new items likely to significantly affect the electric system reliability from its review of maintenance and inspection programs during the prior year.

- System Redundancy Projects: The City should review the design improvements that are being added to the Bellevue system.

- Automation Installation: The City should review with PSE the automation improvements that are being added in the Bellevue system. The City can monitor the overall upgrades to the system and the degree of system automation.

2. **Joint City/PSE Planning Workshops—**It is recommended that the City engage PSE in an annual planning workshop around future projects. The Comprehensive Plan includes an electric system plan that can serve as the basis for the annual workshop. The workshop should focus on the following items:

   - Current growth projections and electric power use in Bellevue

   - Review and update of current plan

   - Actions for capacity projects required to initiate siting and permitting activities within the next 2 years.

   An outcome of the workshop should be an updated plan for inclusion in the Comprehensive Plan (if required) and an action plan to move designated projects forward into siting analysis and/or planning.

3. **Integrated Resource Planning (IRP)—**The City should remain active in the IRP process and should begin to understand potential long-term impacts of this strategy.

4. **Vegetation Management—**The visual review of overhead circuits indicates that there are many substations and lines located in heavily wooded areas. The only way to significantly improve reliability is to perform more comprehensive tree

trimming. The City should review its vegetation policies, specifically in the areas of substations, to look at alternative vegetation approaches.

5. **Community Communications—**City personnel involved in emergency response should meet with PSE to understand the capabilities of the new outage management system (when completed) to assist in communications with the Bellevue community.

6. **Emergency Response Capability—**The City and PSE should consider the development of a more formal process (procedure) related to response and support activities during an outage. The outcome should be an agreement (or procedure) for communication and coordination during large-scale events affecting Bellevue.

7. **Energy Efficiency Improvements—**The City should lead the energy efficiency effort to assist PSE in reaching its long-term electric energy usage goals to help ensure adequate electric power supply during peak power periods for the City. Electric energy savings programs require active outreach to the customers and citizens to support various efficiency initiatives. The PSE long-term plan has a large reliance on reducing the electric energy demand by installing lower power consuming appliances and lighting systems. The City will have a major role to play in terms of City policy and regulations that support efforts that are alternatives to building additional power plants to supply peak power during high demand periods. The City will also have a major role in community outreach.

8. **Undergrounding of Distribution Lines—**The City should investigate opportunities for additional undergrounding of distribution lines through coordination of multiple utility projects and evaluation of local improvement districts. The City's Comprehensive Plan requires undergrounding of new distribution lines and strategies should be developed to increase opportunities to convert overhead lines to underground circuits.

9. **City Interface with WUTC—**Bellevue's involvement with WUTC should be one of informing lawmakers and commissioners regarding matters that affect reliability. This involvement should include:

   - Assigning a designated individual to electric system matters. This individual should remain informed of electric system activities related to WUTC.

   - Developing "white papers" for submittal to WUTC to inform the Commission of issues affecting electric reliability in the City. This provides a means to provide feedback to WUTC without direct response to hearings.

   - Commenting on or participating in matters directly affecting PSE and their interaction with the WUTC.

There are several additional recommendations that can be incorporated into the recommendations listed above. These include:

10. **Smart Grid Strategies—**PSE has identified a series of Smart Grid technology projects that are being considered over the next 2 years. These projects include a range of programs from the base infrastructure required to enable the Smart Grid to specific customer-related efforts. The City should review the overall PSE plan and determine its level of support for the various customer initiatives. The City needs to define a Smart Grid approach that it would like to see implemented in Bellevue, specifically addressing the level of support for customer interface applications, such as customer energy management, demand response, home automation, etc. The City should work with PSE to develop a Bellevue deployment plan consistent with PSE obligations. (Include with Recommendation #1)

11. **Long-Range Planning—**The City and PSE should synchronize their growth projections for the City by frequent information exchange on expected projects, expected timing of projects, and coordination of actions required by PSE and the City to address these projects. This exchange is meant to assist longer-term planning and should occur well in advance of any specific permitting or development activities. (Include with Recommendation #2)

12. **Multi-Utility Planning—**The City should engage with its utility partners to identify new projects (both large and small) to maximize efficiency for projects in the rights-of-way. The City can take advantage of projects that require trenching to place conduit for potential future use of undergrounding. The existence of conduit may allow for more economic alternatives for undergrounding in the future. (Include with Recommendation #1)

Detailed descriptions of these recommendations are included in this report.

## Conclusions

This assessment of the electric system serving the City has shown that electric system reliability is improving and that the programs and projects shown in PSE's planning documents should continue to improve system reliability. However, successful execution of plans, programs, and projects is required to ensure that there is an adequate and reliable electric power system serving the City.

The recommendations offered for consideration by the City are intended to provide a basis for the City to become an informed and active stakeholder relative to decisions and actions required to support continued and improved electric system reliability.

# 1 Introduction

## 1.1 Background

The City of Bellevue (the City) retained Exponent to perform an electric system reliability assessment to assist the City in meeting its goal to be an informed stakeholder to ensure a reliable electric power supply for the City. The scope of the study is to answer the following questions from the Electric Reliability Study Plan[3]:

1. **Current System Assessment:** Define good industry practices for electric service providers in areas such as system planning, operations, maintenance, and new technologies to compare against the current state of the electric system in the City of Bellevue; and identify areas of improvement to increase reliability, system modernization, innovation, and capacity. This task will answer questions such as:

    a. "How does Puget Sound Energy's (PSE's) existing system serving Bellevue perform relative to the Washington Utilities and Transportation Commission's (WUTC's) expectations, industry standards, and peers relative to reliability?"

    b. "What changes relative to facilities, equipment, planning, and emergency operations will improve electric system reliability, communication, and outage response in Bellevue?"

2. **Future System Study:** Assess PSE's long-term electric system plan to serve the City of Bellevue to identify opportunities to increase system reliability, system modernization, innovation, and capacity. This task will address the question of "will the City have an adequate and reliable power supply to meet future City growth needs?"

3. **Role of the City:** Define the role of the City relative to its interaction with PSE, the electric system owner, and associated regulatory agencies, such as WUTC, the Federal Energy Regulatory Commission (FERC), and the Western Electricity Coordinating Council (WECC) to ensure a highly reliable electric system for the City of Bellevue and to increase confidence in electric system reliability. This task will address the concern of "what opportunities are available to the City to work with PSE, regulators (WUTC, FERC), and other stakeholders to ensure Bellevue residents' and businesses' needs and expectations are met relative to the reliability of the power supply?"

[3] Reference 10.

4. **Measurement and Monitoring:** Define the criteria for the City to measure and monitor the performance of the electric power system serving its residents and businesses to ensure continuous reliability and planning improvement. This task addresses the issue of "how can the City measure and monitor whether improvement in reliability is being achieved?"

This study was performed in two phases. During the first phase, Phase 1, Exponent prepared an Electric Reliability Study Plan[4] that outlined the scope of work for Phase 2 of the electric reliability study. The Phase 1 effort defined the scope of the reliability study to answer the questions above and to achieve the City's objectives defined below:

- Enhance the City's role as an informed stakeholder
- Ensure that an adequate and highly reliable electric system is built, operated, and maintained
- Ensure that the electric system keeps pace with future load growth
- Enhance the relationship between the City and PSE
- Ensure fair and reasonable rates
- Improve PSE transparency of operation.[5]

The Phase 1 scope was based on an initial review of the PSE electric system in Bellevue and feedback received from the Bellevue stakeholders.

## 1.2 Scope of Work

The planning horizon for this study covers the time period between 2010 and 2030 (the projected time frame for build-out of the Downtown). The reliability study was performed in four tasks:

1. **Current System Study:** The current system study reviewed current electric system performance including:
   - Review of PSE reliability metrics and how they compare to industry performance
   - Assessment of PSE outage data to identify current issues (equipment and event causes) affecting reliability in the City
   - Assessment of system and equipment design relative to distribution, transmission, and generation assets and their impact on reliability

[4] Reference 10.

[5] Reference 1.

- Assessment of PSE work processes for the key activities affecting reliability including maintenance, capital project prioritization, and outage management
- Identification of industry practice and benchmarks related to the above areas of review.

2. **Future System Study:** The future system study reviewed the activities related to growth and reliability affecting the City including:
   - Short-term issues related to current capital investments, planning, Smart Grid deployment, outage management, and other operating systems
   - Medium-term issues related to growth and reliability of the generation, transmission, and distribution assets
   - Long-term issues related to growth and reliability including build-out of the City for its generation, transmission, and distribution assets.
3. **Role of the City:** The role of the City is defined relative to:
   - Its interactions with its stakeholders and industry participants, including WUTC, PSE, and other stakeholders
   - Transparency of electric system operations in the City.
4. **Measurement and Monitoring:** This task provides the plan to measure and monitor the implementation of the recommendations provided in the previous tasks.

Table 1 shows how the four tasks in the reliability study address the City's objectives. Exponent's scope did not include a review of the rate structure for the objective related to "ensure fair and reasonable rates."

The study was prepared from the perspective of the City and its role as a key stakeholder in working with PSE to ensure reliable electric supply for Bellevue residents and businesses. Therefore, the assessment is primarily focused on reviewing and evaluating the current and future status of the distribution system in Bellevue. However, some aspects of reliability require an assessment of the overall capability to deliver power to Bellevue. Where appropriate, therefore, assessments of the transmission and generation systems were performed to determine their impact on reliability in Bellevue.

The results of the study are provided in the Sections 2 through 5. The following appendices are presented at the end of the main text:

- Appendix A—*References*
- Appendix B—*Electric Reliability Basics*

- Appendix C—*Outage and Equipment Codes*
- Appendix D—*List of Documents Reviewed*
- Appendix E—*Circuit Reliability Analysis*
- Appendix F—*Reliability Projects in Bellevue*
- Appendix G—*Phase 1 vs. Phase 2 Roadmap*
- Appendix H—*Response to Questions*

**Table 1. Reliability Study vs. Bellevue Goals**

| | Task | | | |
|---|---|---|---|---|
| City Objective | Task 1: Current System Assessment | Task 2: Future System Assessment | Task 3: Role of the City | Task 4: Measurement and Monitoring |
| Enhance City's role as informed stakeholder | X | X | X | X |
| Ensure that a highly-reliable electric system is built, operated, and maintained | X | X | | |
| Ensure that the electric system keeps pace with future load growth | X | X | | |
| Enhance the relationship between the City and PSE | X | X | X | X |
| Ensure fair and reasonable rates | | | X | |
| Improve PSE transparency of operation | X | X | X | X |

## 1.3 Reliability Vision for Bellevue

Bellevue's goal is to have a highly reliable electric system that maintains good service to its current community and attracts new businesses and members to the community in the future.

A reliable system today for Bellevue could include the following elements:

- A redundant system in the Downtown area and other densely populated areas that is capable of surviving two independent fault events without an outage (N-2 contingency).
- A redundant system in the neighborhoods of the City that is capable of sustaining an outage with one circuit out of service (N-1-1 contingency) with back-up ties to other feeders.
- A robust system that can minimize damage from storms and external events.
- Equipment replacement, inspection, and maintenance programs that utilize current technology to enable a robust system that minimizes equipment failures.

- Extensive use of distribution automation and distribution management to provide visibility into the state of the system and to allow for fast recovery when an outage occurs.
- Installation of a communications backbone that enables the use of new technologies, including Smart Grid technologies, in the future.
- Effective outage and emergency management programs that provide timely and frequent communication to customers.

This vision of reliability is the basis for providing recommendations that the City can use to become an active participant in ensuring reliable service to the City. To achieve this level of reliability requires capital investments that could increase the cost of power delivered to Bellevue. In addition, many of the investments must be made by PSE across its entire service area. Therefore, this vision must be tempered and balanced to avoid increasing the cost of power to Bellevue and PSE's customers. Consequently, the investments have to be made over time. This vision of reliability is the basis for providing recommendations that the City can use to become an informed stakeholder.

The current Bellevue system contains many elements of this vision and has plans to move in this direction. This report will indicate where the City stands relative to this definition of reliability and what activities the City can undertake to work with PSE to obtain this vision.

In its Comprehensive Plan, the City outline goals for planning, permitting, undergrounding of new lines, multiple uses of sites, and joint utility operations that are consistent with its vision of a reliable system.

The future system must accommodate two major needs: capacity additions and cost-effective investments in new technology. The system must:

- Maintain its redundant nature even as capacity expansion occurs.
- Make use of distribution automation and communication infrastructure that will enable various new technologies and allow PSE to operate more efficiently, and to facilitate distributed generation, demand management, and customer Energy Management Systems (EMSs).
- Increase visibility into the electric system for all customers, which should increase the customer satisfaction level.
- Contain electric efficiency that will minimize utility needs for peaking capacities if this is a cost effective use of resources.
- Accommodate significant power supply from renewable generation sources to meet regulatory demands.

This report focuses its recommendations on areas for the City to engage with PSE in order to ensure reliable service.

# 2 Current System Study

## 2.1 Study

### 2.1.1 Study Scope

The current system study was performed to assess the current electric system reliability in Bellevue. The study addresses the following questions:

- "How does PSE's existing system serving Bellevue perform relative to WUTC expectations, industry standards, and peers relative to reliability?"
- "What changes relative to facilities, equipment, planning, and emergency operations will improve electric system reliability, communication, and outage response in Bellevue?"

### 2.1.2 Reliability Definition

Power system reliability encompasses the time an electric system is available to deliver electric power to a customer's meter in accordance with voltage and frequency requirements specified by PSE's agreement with WUTC.[6] Reliability is therefore a measure of the probability that electric power is delivered in accordance with requirements. Reliability measures include frequency of interruptions, time between interruptions, duration of restoration, and number of end-users affected. Momentary power system disturbances with a duration from a fraction of a cycle to several cycles are not included in this review because the electrical equipment should be designed to ride through many such disturbances.[7]

Today, reliability is typically measured based on the frequency and duration of outages relative to the number of customers. There are several measures for reporting and measuring electric reliability, such as the Institute of Electrical and Electronics Engineers (IEEE) Standard definitions[8] or similar approaches to report reliability. These measures include SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index). See Appendix B for further information about how these numbers are calculated.

For the current system assessment, a highly reliable system is one that has redundancy in the power system design; equipment that is designed, operated, and maintained to minimize the probability of failure; sufficient automation to identify faults and their locations and to support

6 See WAC Sections 480-100-368 and 480-100-373.

7 See http://www.itic.org/clientuploads/Oct2000Curve.pdf for detailed information about momentary voltage interruptions, sags, and swells. The performance limits defined in this document are applicable to information technology equipment.

8 Reference 11.

minimizing outage recovery time; and provisions for effective communication between all stakeholders.

### 2.1.3 Study Approach

The current system assessment was performed in the following steps:

- Assessment of past and current reliability performance as measured by industry standard reliability metrics to determine current PSE performance and evaluation of outage data to determine major causes of outages in Bellevue to identify potential actions to improve reliability. This evaluation included a review of overall Bellevue performance and a review of representative circuits in the City, and is intended to identify current issues affecting reliability in Bellevue.
- Review of system and equipment design to determine system strengths and weaknesses to support reliability in the City and to identify potential improvement actions.
- Review of work processes that support system reliability to identify areas of improvement. These work processes include maintenance, capital project prioritization, vegetation management, and outage management.

The overall result of the current system study provided a set of observations and findings that led to identified actions for reliability improvement and to recommendations that the City can take to ensure a reliable system. This section is focused on the status of the current system and provides the basis for near-term observations and recommendations, which will be presented for each of the subtasks below. A longer-term assessment of the system in the City for future growth needs is discussed in Section 3.

## 2.2 PSE's Past and Present Reliability and Outage Performance

### 2.2.1 Study Approach

Electric service is provided to Bellevue by PSE, a regulated utility under the auspices of the WUTC. PSE provides electric service in Washington State to approximately 1.2 million electric customers and Bellevue represents roughly 10% of PSE's customer base. PSE provides annual reliability reports to WUTC and also provides Bellevue with an annual reliability report specifically for the City. Therefore, the available data facilitates a comparison between PSE's overall system performance as well as Bellevue-specific performance data. Thus, this section provides a review of PSE's overall system reliability based on reported reliability metrics (the SAIDI and SAIFI outage statistical data) and an analysis of specific outage causes in the City to determine issues affecting reliability.

## 2.2.2 Analysis

### 2.2.2.1 Reported Reliability Performance

The overall reliability performance in the PSE territory as well as the performance in Bellevue is shown in Figure 1 below:

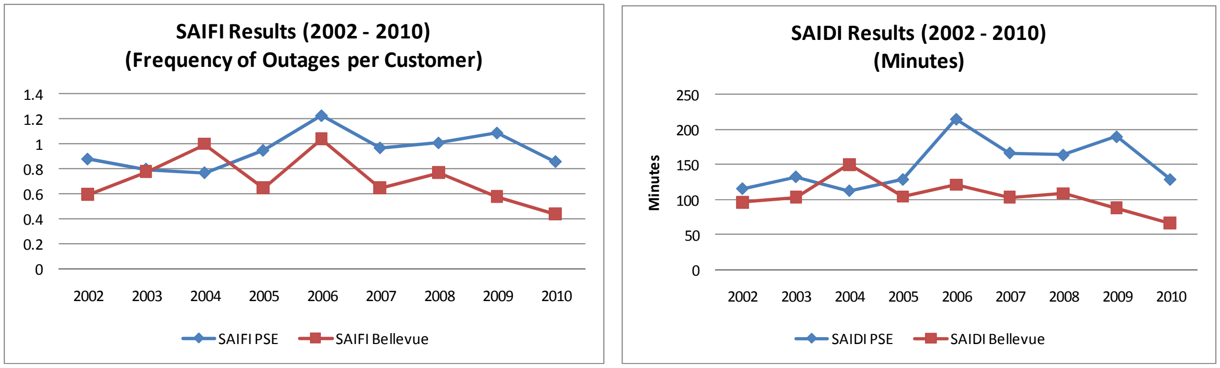


Figure 1. PSE System and Bellevue SAIFI and SAIDI Results[9]

The focus of the assessment has been on performance over the past 5 years after the major storm in 2006. At the request of the Stakeholder Committee, data has been included in the graphs covering the last 9 years but no detailed analysis has been performed on the failure causes and trends for more than the past 5 years since the massive restoration efforts after the 2006 storm should have changed the average equipment population age, making trend analysis difficult to interpret.

The reliability metrics reported include only non-major (storm) outages, where a major outage is defined as an outage that affects greater than 5% of the customers. Based on this definition, the overall reliability within PSE's territory shows improvement over that past 5 years.

The performance in Bellevue is better than that of PSE's total service area, which has also shown improvement during this 5-year period. These results for Bellevue compared with the rest of the PSE territory are expected since Bellevue represents one of the densest parts of PSE's service territory. Typically, these urban areas have the most built-in system redundancy, which makes it possible for the electric power system to lose one or more components without causing service interruptions to most if not all of the connected power users. Therefore, they may experience fewer outages and shorter recovery times. Additionally, faster recovery is due to the proximity of the urban areas to service centers where material and personnel are available for the restoration efforts.

There are several benchmarks that can be used to assess overall PSE performance, including the following:

- WUTC has established goals for its regulated utilities (service quality indices) and several of these goals relate to electric system reliability. Prior

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9 References 2 and 5–8.

to 2010, the measures included SAIFI and SAIDI goals for PSE of 1.3 and 136 minutes, respectively. PSE has achieved the SAIFI goals over the past 5 years, but has not achieved the SAIDI goals, except in 2010. In 2010, the WUTC measures changed to a SAIDI based on a 5-year average including all customer outage minutes. The current goals are 1.3 and 320 minutes, respectively. PSE achieved both goals in 2010.

- With respect to the performance in Bellevue, the reliability measures are well below PSE's system-wide averages for the time period 2006–2010 and have experienced significant improvement during the time period. Some reasons for the improved performance over the past 5 years are presented later in this section.

While these measures represent overall performance at a high level, they do not highlight specific issues. The key is to understand the bases behind these reliability statistics. The discussion that follows provides an analysis of the past 5 years of outage events in Bellevue to determine the main causes of outages and to evaluate the actions that may mitigate these events.

### 2.2.3 Analysis of the Outage Statistics

The outage assessment was conducted by performing an analysis of available outage data to identify the main causes of outages in the City to provide a basis for developing recommendations for improvement. The outages experienced by Bellevue are defined in the annual PSE Reliability Reports[10] prepared for the City. The reliability information included in the annual reports includes a listing of each outage as follows:

- Circuit identification
- Identified cause
- Equipment type affected
- Non-storm or storm event.

#### 2.2.3.1 Outage Data Information Content

The reliability and outage information for Bellevue shows the overall annual outage trends and outage causes for the entire City. The outage data shown in the following graphs includes both non-major storm events and major storm events. The non-major storm events show the outage performance for all power users in the City but the major storm events only show the system performance during events that affect a large number of customers (> 5% of the power users). Storm events tend to drive outages produced by equipment failure related to effects of water, ice, and snow damage, and more significantly by wind-driven impacts that produce failures from tree damage. The environment in the City is vulnerable to wind-driven storm damage on its overhead system. Outage data are also included for the 2006 storm.

[10] References 2 and 5–8.

### 2.2.3.2 Overall Bellevue Outage Trends

The annual outage trends for the past 5 years are provided in Figure 2.[11]

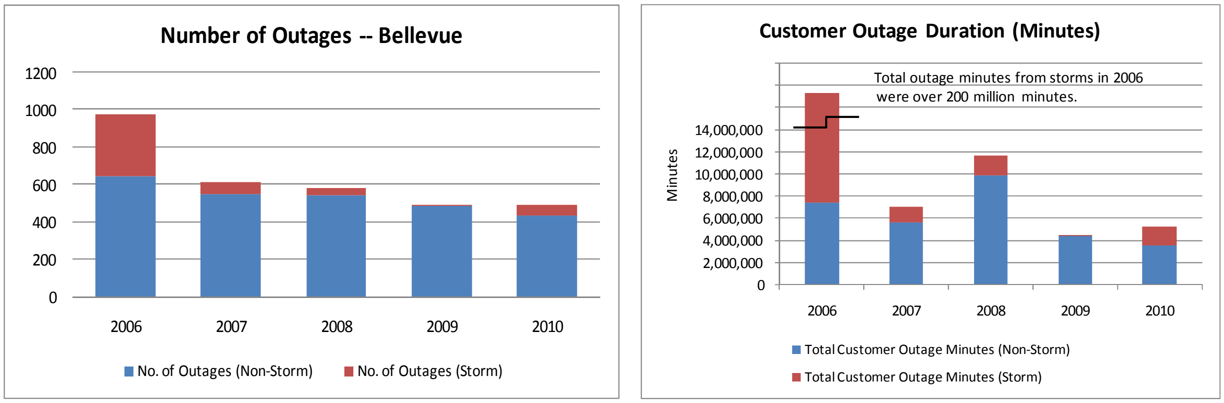


Figure 2. Outage Data in Bellevue–Number of Outages and Total Customer Duration[12]

The overall trends show an improvement in number of outages and in outage duration. A few observations on the non-major storm outages:

- During 2008, there were several major circuit outages that required significant time to restore. These few events contributed a large amount to the outage durations. These events are included in the data above, but are highlighted due to their significant contribution to the outage duration.
  - SOM-16: There was a major circuit outage that resulted from a failed underground transformer that caused over 1.4 million outage minutes.
  - COL-26: There was a major circuit outage caused by an underground cable failure that resulted in an outage of over 600,000 minutes.
  - There were five other events that produced outages of greater than 300,000 customer minutes.

Despite the performance in 2008, the overall trend (of non-major event outages) shows a pattern of improvement in the City.

While there has been no event comparable to the 2006 storm, major storms have contributed to the outage durations in 3 of the past 4 years. As stated previously, these major storm outages are being measured and reported in the reported reliability data moving forward.

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[11] The first figure shows the number of outage events and the second figure shows the duration (in minutes) of customer outages. This convention will be used throughout this section.

[12] References 2, 5–8, and 30.

### 2.2.3.3 Overhead vs. Underground Performance Data

Segregation of the outage information into overhead (OH) and underground (UG) systems is also of interest since the perception is that underground systems are more reliable than overhead systems. This is illustrated in Figure 3 below, which shows the impacts of outages associated with underground and overhead system. [Note: This information is based on non-major events only. However, it can be generally assumed that major storm outages will add to the overhead outages and durations.] There are roughly an even number of overhead and underground outages; however, there is a significant difference in outage duration with underground outages producing more outage minutes.

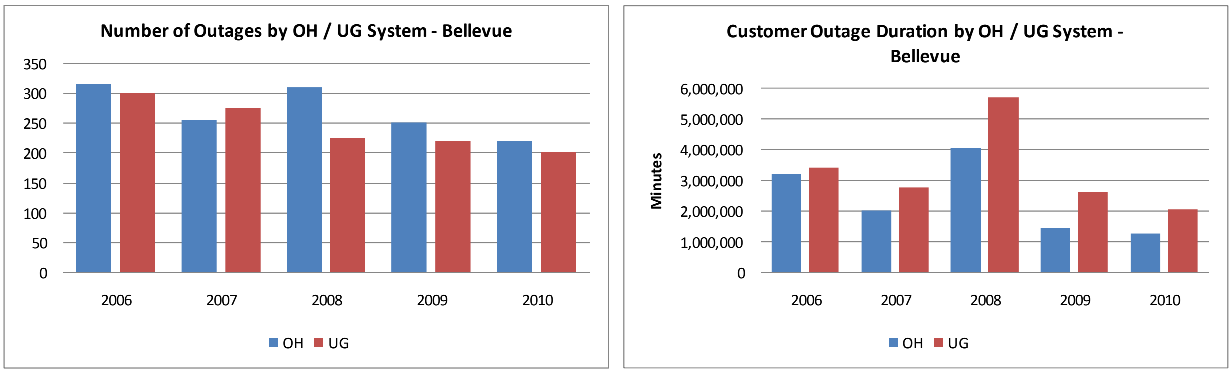


Figure 3. Outage Data in Bellevue by OH/UG Systems for Number of and Total Customer Duration[13]

### 2.2.3.4 Information by Type of Outage

Figure 4 provides a look at outages by cause over the past 5 years, based on number of outages and overall duration of outages. [Note: This information is based on non-major events only. However, it can be generally assumed that major storm outages will add to and increase the impact of tree-related events.]

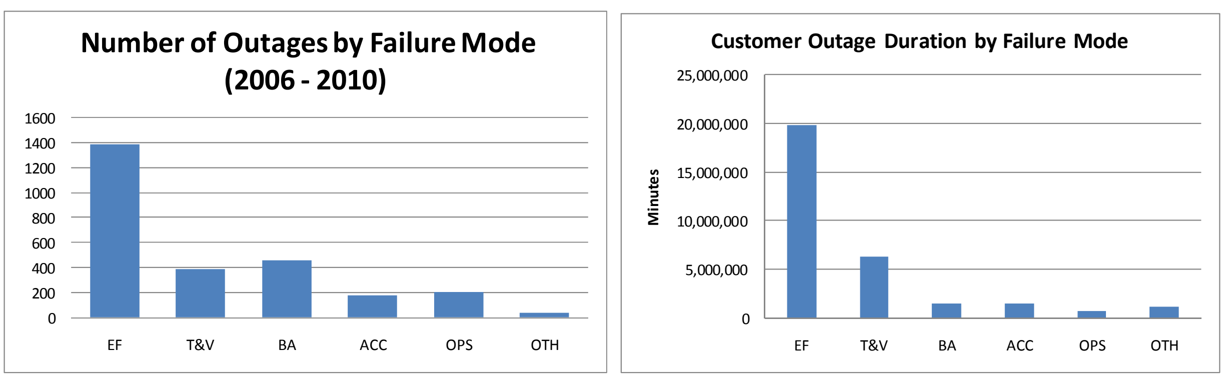


Figure 4. Outage Data in Bellevue by Failure Type for Number of Outages and Total Customer Duration[14]

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13 References 2 and 5–8.

14 References 2 and 5–8.

The PSE reports utilize approximately 16 outage type codes. However, for purposes of this assessment, the outage codes have been enveloped into six major categories:

- Equipment failure (EF)
- Trees and vegetation (T&V),
- Bird and animal (BA)
- External accidents (ACC)
- Operations (OPS)
- Other (OTH).

The other category includes items such as installation and manufacturer issues. A list of the all the outage types is provided in Appendix C.

This higher-level view of outage types indicates that there are three primary contributors to outage events in Bellevue. Equipment failure produces the greatest number of outage events and has the greatest impact on duration, followed by tree-related and wildlife-related events. A more detailed look at the three main categories of outages provides additional insight.

### 2.2.3.5 Equipment Failure Outage Events

Equipment failures are identified as the most significant cause of outages in the City. Figure 5 provides the annual outage trends for equipment failure-related events.

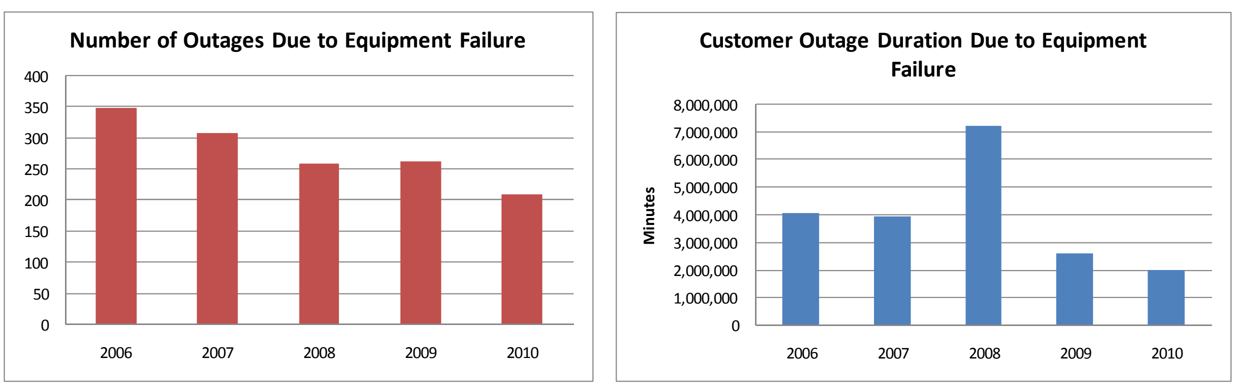



Figure 5. Outage Data in Bellevue Due to Equipment Failure for Number of Outages and Total Customer Duration[15]

The number of equipment failure-related outages has trended downward over the past 5 years, showing an overall improvement in number of outage events of approximately 40%. The reduction in total outage duration minutes due to these events has been reduced by 50%, from

15 References 2 and 5–8.

2006 to 2010. The duration of outages in 2008 shows a significant large spike upward. This spike does not correlate to the continued reduction in number of outage events. The causes of this spike were several significant circuit events that affected a large number of customers for a significant time period. This shows that the outage duration depends on where in the system a piece of equipment fails.

#### 2.2.3.6 Overhead vs. Underground Equipment Failures

Equipment failure-related outages can be based on overhead (OH) and underground (UG) events. Figure 6 shows the breakdown in outage events resulting from this differentiation.

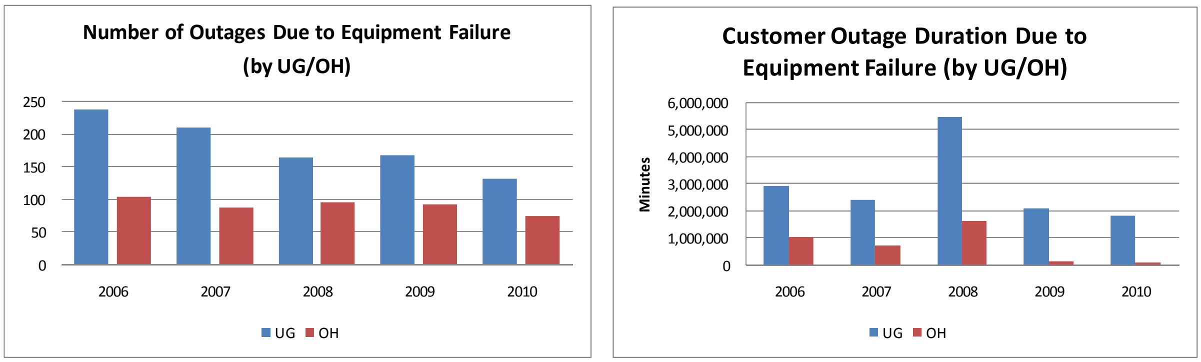



Figure 6. Outage Equipment Failure by UG/OH for Number of Outages and Total Customer Duration

The equipment failure trends for outages show that underground events are the more common in terms of number events, as well as duration. However, there has been a significant reduction in the number and duration of underground events except for 2008, which was described previously. The reduction in the number of overhead events has been slower but the duration of these events has been reduced. A further review of the equipment-failure outages is shown based on the type of equipment attributed to the event. Figure 7 shows a breakdown over the 5-year period of outage by equipment type for overhead-related events and Figure 8 shows a breakdown for underground events.

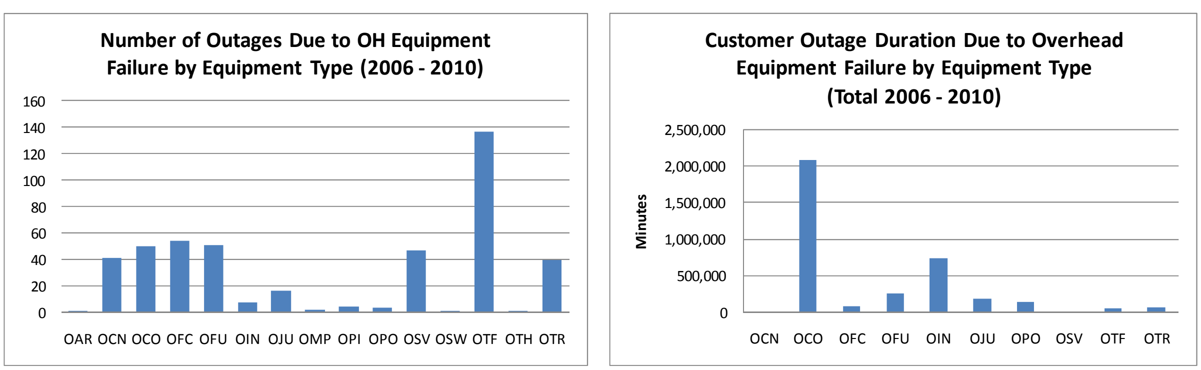
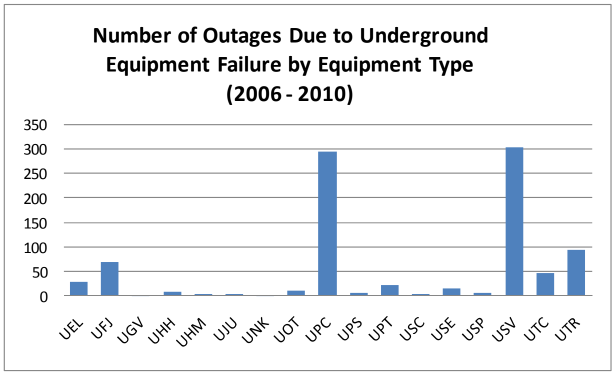



Figure 7. Underground Outages (2006–2010) in Bellevue Due to Equipment Failure by Equipment Type for Number of Outages and Total Customer Duration[16]

[16] References 2 and 5–8.



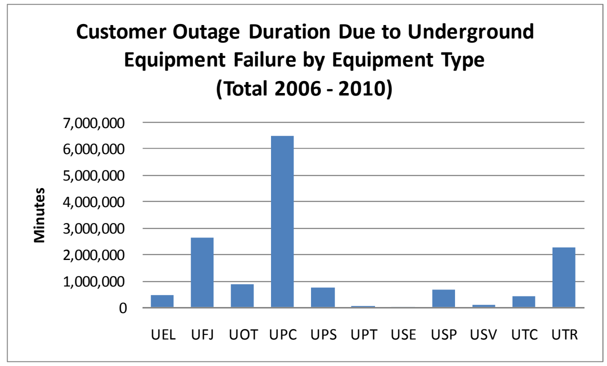




Figure 8. Underground Outages (2006–2010) in Bellevue Due to Equipment Failure by Equipment Type for Number of Outages and Total Customer Duration[17]

The major causes of overhead equipment failures are:

- Overhead transformer fuses (OTF)
- Overhead cut-outs (OFC)
- Overhead line fuses (OFU)
- Overhead conductors (OCO)
- Overhead services (OSV)
- Overhead connectors (OCN)
- Overhead transformers (OTR).

These equipment types account for approximately 90% of all overhead equipment failures with a majority of the failures associated with fuse operations (OTF and OFU). From a duration perspective, the overhead conductor (OCO) and overhead insulator (OIN) pieces of equipment account for the majority of the duration.

The number of events related to multiple types of equipment failures is mostly driven by distribution line equipment being designated as “run-to-failure.” The majority of events are related to line equipment. Specific items (excluding conductors) are easily identified, replaced or repaired, and restored. Therefore, when an outage occurs, it is quickly handled by service personnel. Conductor failures, however, require more time to locate where the fault occurred and may also require more work to repair or replace. Therefore, conductor failures drive outage duration in Bellevue.

[17] References 2 and 5–8.

There are limited outages in Bellevue caused by substation equipment failures, where it is technically feasible to perform diagnostic tests on the equipment, which often can be used to prevent failures.

The major causes of underground equipment failures are:

- Underground services (USV)
- Underground primary cable (UPC).

These equipment types account for approximately 66% of all underground equipment failures. From a duration perspective, the underground primary cable (UPC), underground J-box (UFJ), and underground submersible transformer (UTR) equipment account for about 75% of the duration.

Underground cables in Bellevue were some of the first cables installed in PSE's system. The underground cables can be either directly buried cables or cables installed in conduits. The directly buried types of cables are more prone to being affected by environmental factors including damage from soil excavation and corrosion. Underground cable degrades over time due to stresses related to the applied voltage as well as the heating produced by the load currents. Since an outage produced on the underground system is difficult to locate and requires time to access and repair, these events are significant contributors to outage durations.

#### 2.2.3.7 Tree and Vegetation Related Outage Events

Tree and vegetation related failures are identified as a significant cause of outages in the City. From a practical perspective, tree-related events are the primary contributor to these types of outages. Figure 9 provides the annual outage trends for tree failure-related events.

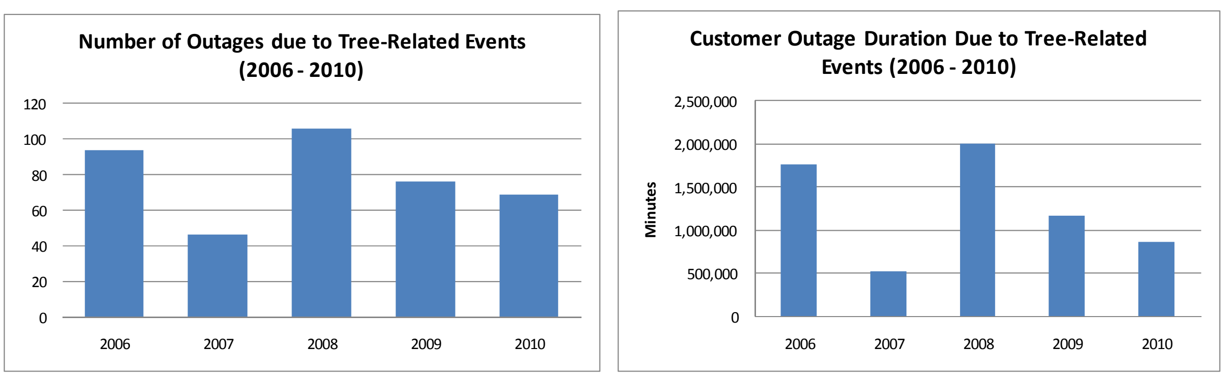



Figure 9. Outage Data in Bellevue Due to Tree-Related Events for Number of Outages and Total Customer Duration[18]

[18] References 2 and 5–8.

The number of tree-related outages appears to have trended downward slightly over the past 5-years. The outage duration appears to be well correlated with the outage frequency data. While these data are based on non-major events, major storms drive significant tree-related events. As shown previously in Figure 2, the impact of storms related events will drive the number and duration of these tree-related events higher.

Tree-related outages were caused by the following affected equipment as shown in Figure 10.

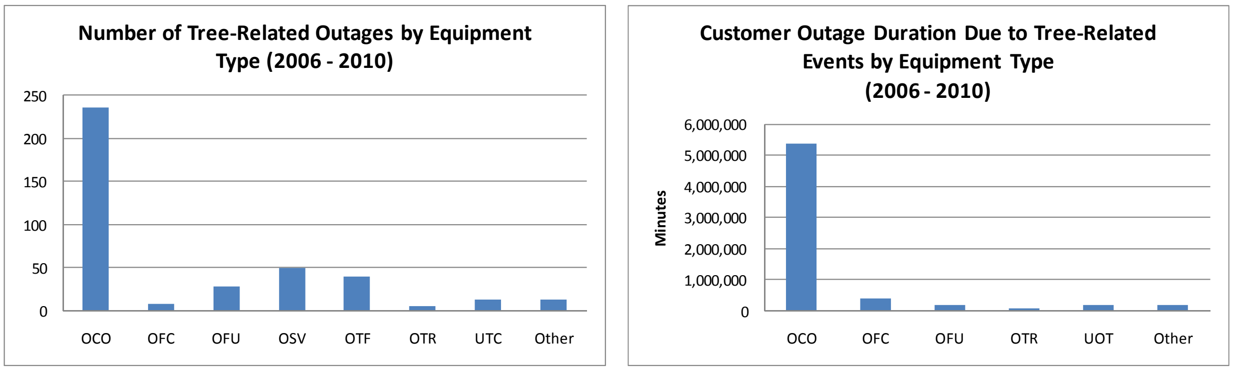



Figure 10. Tree-Related Outages by Equipment Type for Number of Outages and Total Customer Duration[19]

The major pieces of equipment impacted by tree-related events are:

- Overhead conductors (OCO)
- Overhead services (OSV).

The impact of falling branches or branches coming in contact with lines is the primary cause of faults on the overhead lines. Overhead conductors are the most significant contributor to both number of events and duration because there are many miles of overhead lines and not nearly as many miles of service drops. A visual inspection of circuits in Bellevue shows that there are large trees (both on and off the right of way) that can contact overhead distribution lines and produce faults (and therefore outages).

The reliability measures are based on reviewing sustained outages. For areas affected by tree-related sustained outages, these areas would also be expected to be impacted during major events (such as storms). Therefore, some areas may not show the full reliability picture based on the current data, which excludes storm events.

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[19] References 2 and 5–8.

### 2.2.3.8 Bird and Animal Outage Events

Bird- and animal-related failures are identified as a significant cause of outages in the City. These types of outage events are closely related to tree-related outage events. Figure 11 provides the annual outage trends for equipment failure-related events.

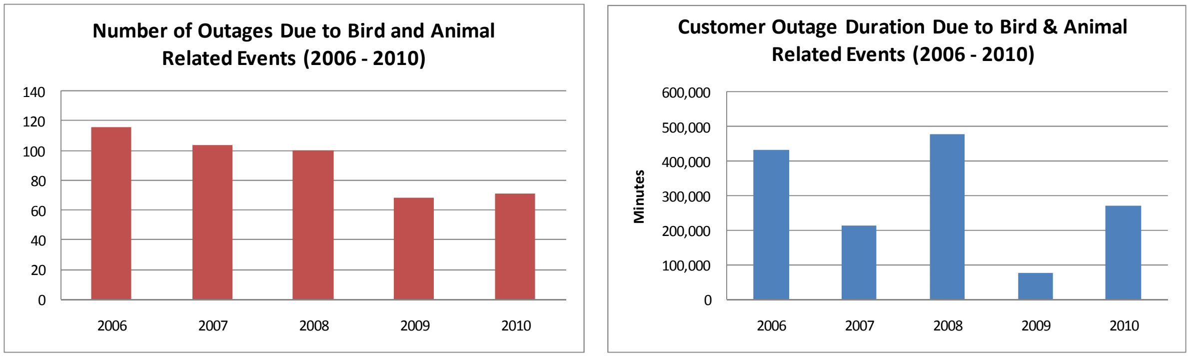


Figure 11. Outage Data in Bellevue Due to Bird- and Animal-Related Events for Number of Outages and Total Customer Duration[20]

The number of bird- and animal-related outages has trended downward over the past 5 years. However, there is no corresponding pattern for duration of events. Bird- and animal-related outages were caused by the following affected equipment as shown in Figure 12.

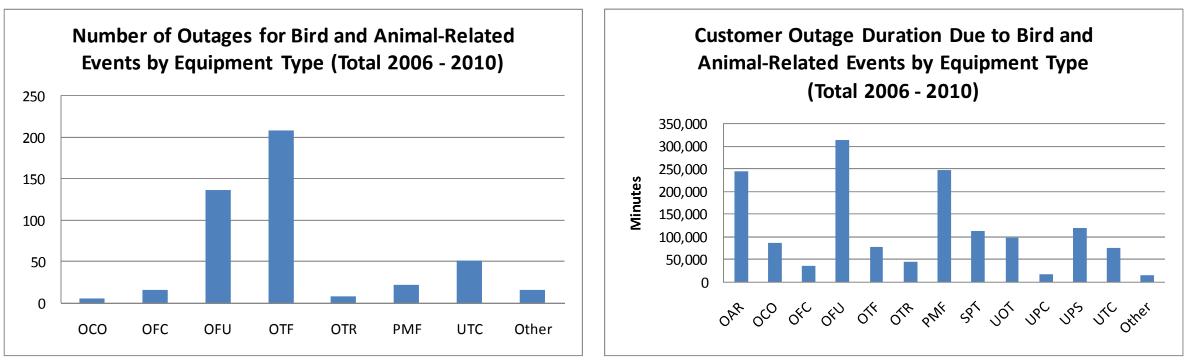


Figure 12. Bird- and Animal-Related Outages by Equipment Type for Number of Outages and Total Customer Duration[21]

The major pieces of equipment impacted by bird and animal-related events are primarily related to overhead equipment such as fuses (OFU) and pole transformers (OTF). These pieces of equipment account for the majority of occurrences. However, animal-related events can occur on non-overhead equipment, such as pad-mounted switch fuses (PMF) and underground fuses (UTF). While these events are low in number, they are significant in duration.

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20 References 2 and 5–8.

21 References 2 and 5–8.

For the overhead equipment causes (fuses and transformers), each outage tends to affect a small number of customers. There has been a slight decline in the number of outages per year related to the overhead equipment. The overhead components are relatively easy to identify and repair so that these events are restored quickly. There were a few large outages associated with surge arrestors and pad-mounted switch fuses. These outages affected a large number of customers, and therefore, contributed significantly to the duration statistic despite the small number of events.

### 2.2.4 Outage Analysis of Representative Circuits within the City

The previous section provided a review of outage causes and related equipment involved in the outages from an overall City perspective. As shown, there has been a general reduction in the overall number of outages and the duration of outages in Bellevue. However, a review of circuits in representative neighborhoods provides additional insight into the reliability of the electric system in Bellevue. Appendix E includes a copy of Figure 32, which provides a map of substation locations in Bellevue.

The selection of circuits for review was based on looking at a set of circuits that were representative of Bellevue—both Downtown and in the neighborhoods. The selection of circuits was based on the following methodology:

- The outage data were compiled by circuit for the overall equivalent SAIDI (duration) and the overall number of events for each circuit in Bellevue for the cumulative 5-year period from 2006 to 2010.
- The circuits were listed from highest to lowest SAIDI to ensure that Bellevue circuits experiencing outages were selected.
- The circuits were then reviewed to select circuits that represented different geographic areas of Bellevue.
- The circuits in specific areas were reviewed for number of customers to ensure that appropriate customer representation was considered.

The listing of Bellevue circuits is provided in Appendix E. Based on this review, the following circuits were selected for further review, including visual inspections:

- Downtown circuits
- Outside Downtown areas (SBE-26 and CLY-23)
- South Bellevue area (SOM-13)
- North Bellevue area (NRU-23 and BTR-22)
- East Bellevue area (LHL-23).

The review of these representative circuits included a visual inspection of the substation and the circuit to assess the equipment layout, condition, and surrounding environment. While the underground circuits were not available for review, the associated substations, surrounding areas, and overall circuit layouts were reviewed. The objective of the representative circuit review was to provide more specific input to the prior outage analysis.

### 2.2.4.1 Downtown Assessment

The Downtown area of Bellevue receives electrical service primarily from the following substations and circuits:

- Center (CEN-11, -12, -14 and -22)
- North Bellevue (NOB-13, -21 and -22)
- Lochleven (all)
- Clyde Hill (CLY-22, -25 and -26).

The Downtown is served mostly by underground circuits and equipment. However, there has been a recent program to replace the underground equipment with aboveground pad-mounted equipment (transformers and switches). The reliability performance of these circuits is shown in Figure 13.

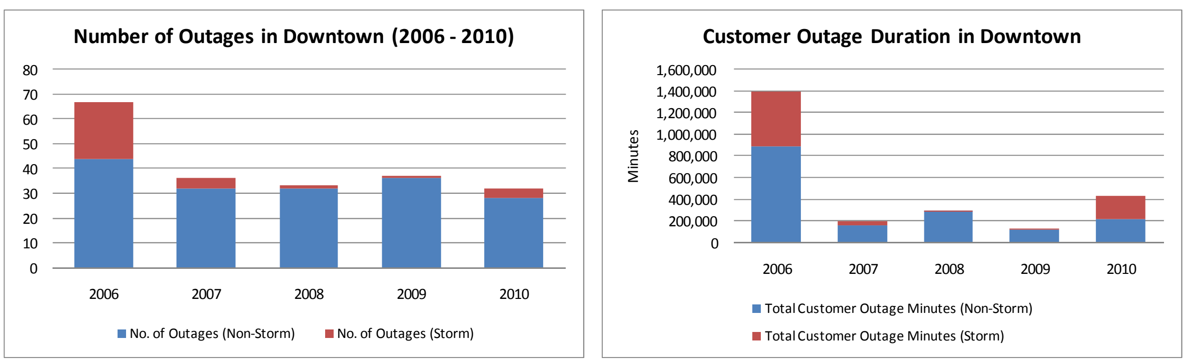


Figure 13. Outage Data in Downtown for Number of Outages and Total Customer Duration[22]

The overall trends show reduction in number of outages and in outage duration. However, in 2010 there was a significant contribution to outage duration caused by major storms that resulted in a circuit outage. Additional information is provided by reviewing the outage cause by type in Figure 14.

22 References 2, 5–8, and 30.

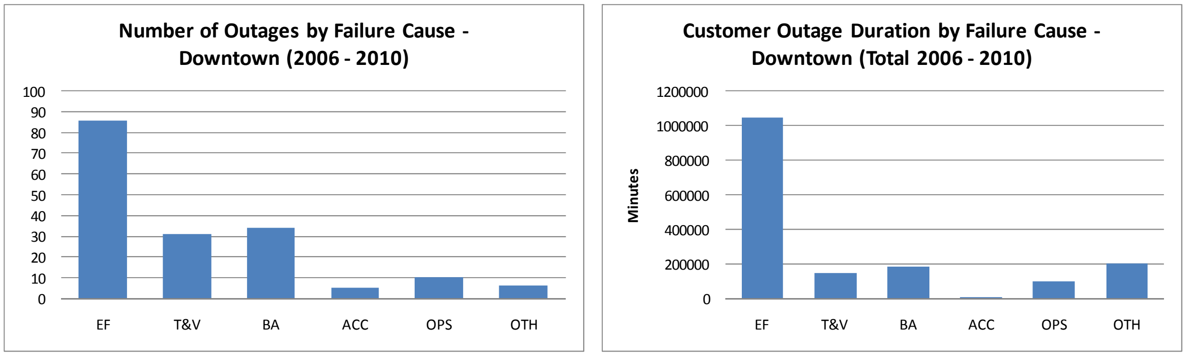


Figure 14. Outages by Failure Cause in Downtown for Number of Outages and Total Customer Duration (2006 – 2010)[23]

Similar to the previous overall analysis, the PSE reports utilize approximately 16 outage type codes. However, for purposes of this assessment, the outage codes have been sorted into six major categories as follows:

- Equipment failure (EF)
- Trees and vegetation (T&V)
- Bird and animal (BA)
- External accidents (ACC)
- Operations (OPS)
- Other (OTH).

The other category includes items such as installation and manufacturer issues. A list of all the outage types is provided in Appendix C.

This view of outage types indicates that the primary contributor to outage events in downtown Bellevue is equipment failure. There were four “other” outage events in 2006 that resulted in approximately 200,000 outage minutes. Tree-related and bird- and animal-related outages still occur in this area, but with most of the system underground, eliminating equipment problems should be the major focus.

Figure 15 provides a view of outages by equipment type.

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23 References 2 and 5–8.

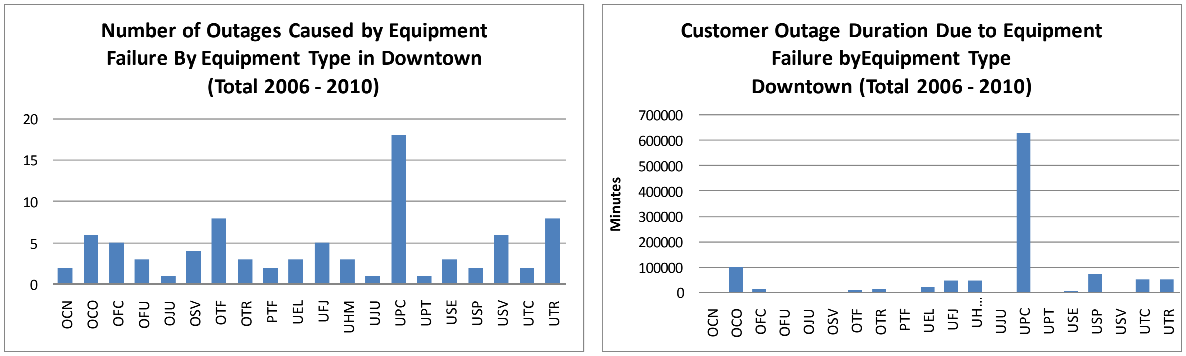


Figure 15. Outages Due to Equipment Failure by Equipment Type in Downtown for Number of Outages and Total Customer Duration (Total 2006–2010)[24]

Based on the review of the outages by equipment type, there are multiple causes of outages, but underground cable failures are the dominant cause of outage duration. Over the past 5 years, PSE has made a significant effort to replace and remediate the underground cables in Bellevue and to increase the ability of the underground system in the Downtown area to deal with contingency situations.

#### 2.2.4.2 South Bellevue (SBE-26) Assessment

This South Bellevue circuit was selected for review as this circuit serves an area south of the Downtown area and has a relatively large number of customers. As is shown in Figure 16, this area has also experienced a high number of outages over the past 5-year period.

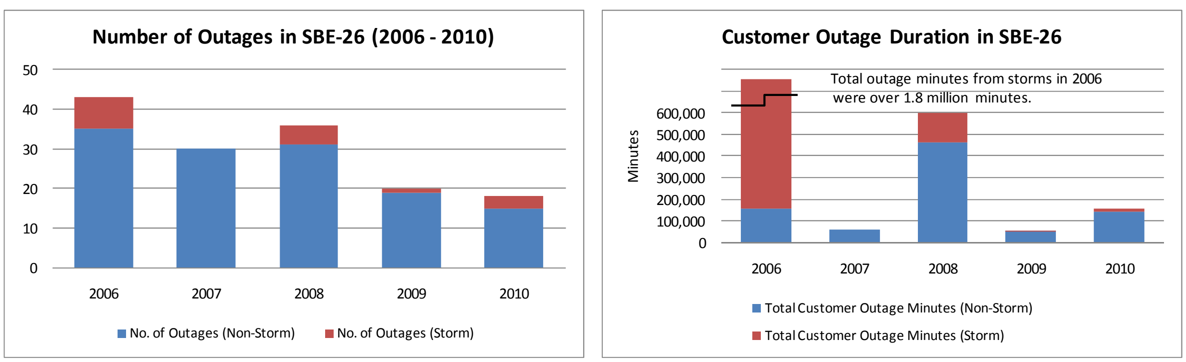


Figure 16. Outage Data in SBE-26 for Number of Outages and Total Customer Duration[25]

The outage history for this area shows a decreasing number of outages, but the overall duration of the outages varies quite a lot. In 2008, this circuit experienced two large events (one due to an animal-related event at the substation and another one related to an overhead conductor equipment failure) that produced circuit outages which contributed about two-thirds of the

24 References 2 and 5–8.

25 References 2, 5–8, and 30.

outage duration minutes. The outages by failure cause are shown in Figure 17. A review of the outage data shows three major causes of failure, which are:

- Equipment failure
- Tree-related
- Bird- and animal-related events.

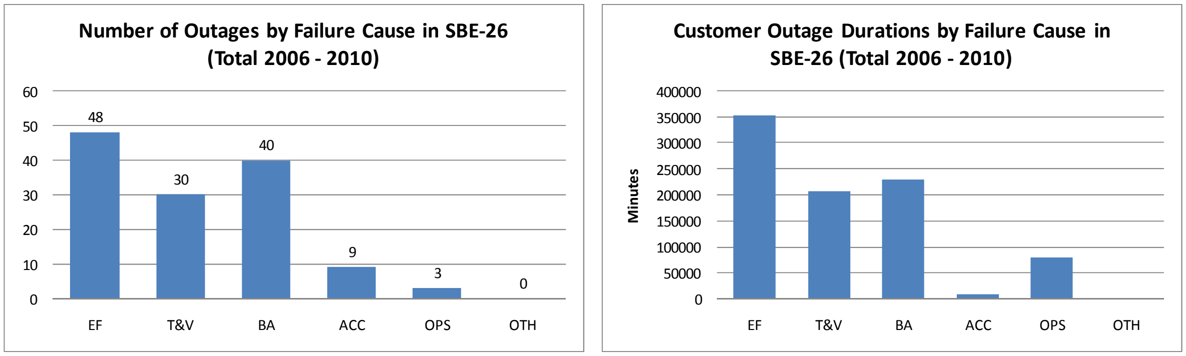


Figure 17. Outages by Failure Cause in SBE-26 for Number of Outages and Total Customer Duration (Total 2006–2010)[26]

Figure 18 shows a view of the substation which shows its location surrounded by tall trees. This circuit is mostly an overhead distribution circuit.[27]

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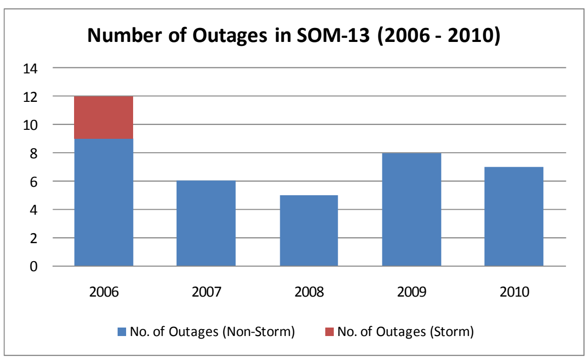
[26] References 2 and 5–8.

[27] This station would benefit greatly from replacement of the tall trees by shorter varieties that still could provide a visual screen for the substation.


Figure 18. South Bellevue Substation

#### 2.2.4.3 Somerset (SOM-13) Assessment

This Somerset circuit was selected for review as it serves an area in the south end of Bellevue and has a relatively large number of customers. This area has also experienced an increase in outage duration over the past 2 years. The outage trends are shown in Figure 19.[28] The outage causes on this circuit are almost entirely equipment failure-related for both number of outages and duration.



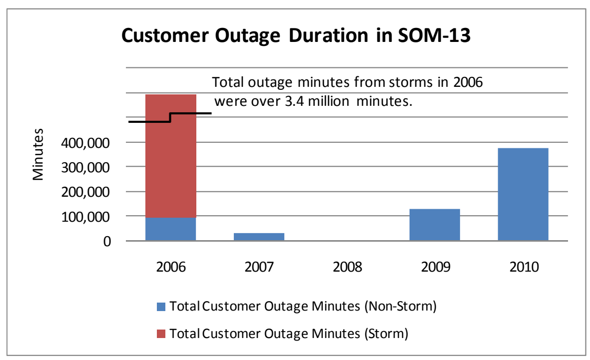




Figure 19. Outage Data in SOM-13 for Number of Outages and Total Customer Duration[29]

This circuit is mostly underground and is currently a radial circuit which is only fed from one substation. In 2010, this area experienced a major circuit outage due to failed cable elbows and

28 It should be noted that there was a large outage on SOM-16 circuit in 2008 that was produced by a failure in an underground submersible transformer. This event caused a SOM-16 circuit outage that took significant time to restore.

29 References 2, 5–8, and 30.

junction box. In 2009, failed feeder cables resulted in a major circuit outage. While there are relatively few events on this circuit, the restoration time is significant because there is no alternate power infeeds to the area that can be used to work around the faults. Current plans involve continued cable remediation and the installation of a feeder circuit tie to provide for an additional source of power. These actions are intended to reduce the causes of the outages and to reduce restoration time.

#### 2.2.4.4 Northrup (NRU-23) Assessment

This Northrup circuit was selected for review as this circuit serves an area in the north end of Bellevue and is in a heavily wooded area. This circuit has experienced a significant number and duration of outages in the past. This circuit has both underground and overhead portions of the distribution circuit and has a moderate number of customers. Figure 20 shows the outage trends including a major event in 2008 caused by the failure of an underground cable splice, which accounted for an outage duration of about 350,000 minutes. If this event is excluded, the outage duration trends are relatively constant.

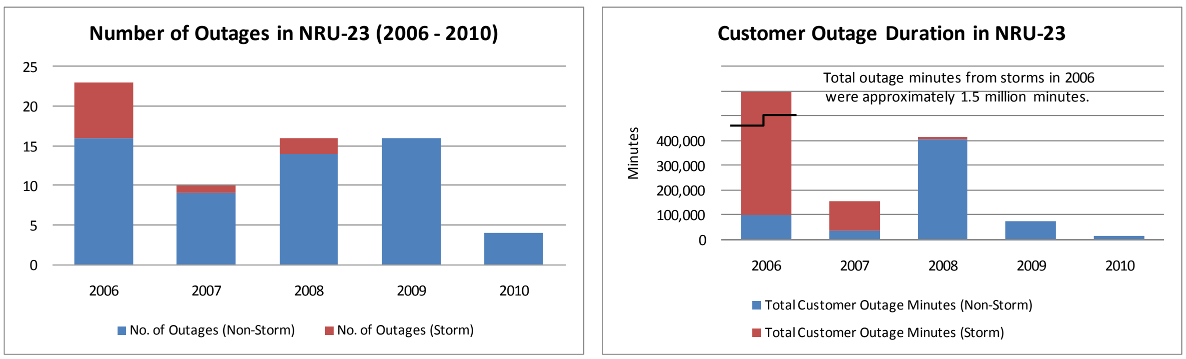



Figure 20. Outage Data in NRU-23 for Number of Outages and Total Customer Duration[30]

An examination of the outages by type is shown in Figure 21. Outages in this area are produced by a combination of equipment failure, tree-related, and bird- and animal-related events. Figure 22 shows the environment around this circuit. The photographs show that the substation and lines are very close to tall trees. The elimination of tree-related impacts is not possible, since falling branches can easily contact the wires.[31] Recent additions of tree wire to attempt to reduce the impact of branches contacting the wires may help reduce outages due to this cause. There is also a major project on this circuit to underground the feeder along NE 24$^{th}$ Street to increase overall performance of the circuit.

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[30] References 2, 5–8, and 30.

[31] This is another substation that would benefit greatly from replacement of the tall trees by shorter varieties that still could provide a visual screen for the substation.

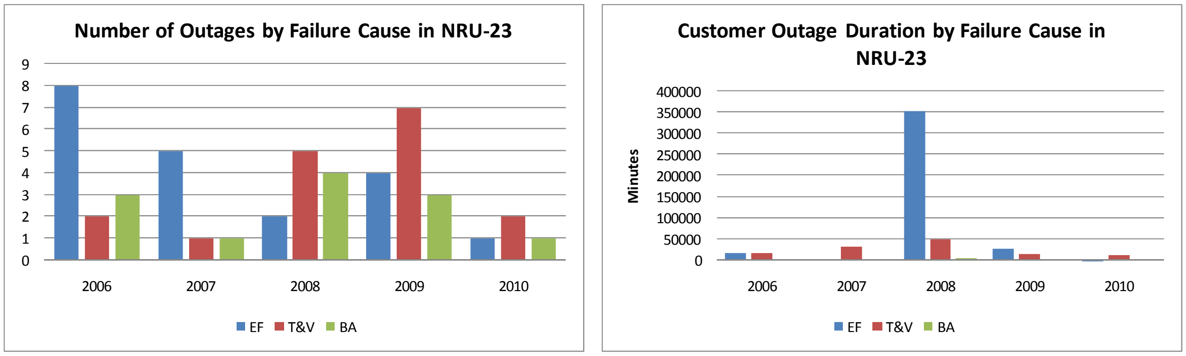


Figure 21. Outages by Failure Cause in NRU-23 for Number of Outages and Total Customer Duration (Total 2006–2010)[32]

Figure 22. Northrup Substation

#### 2.2.4.5 Bridle Trails (BTR-22) Assessment

This Bridle Trails circuit was selected for review as this circuit serves an area in the north end of Bellevue and is in a heavily wooded area. This area was also identified as an area heavily impacted in the 2006 storm event. This circuit has both underground and overhead portions of the distribution circuit and has a moderate number of customers (similar to NRU-23). The outage trends are shown in Figure 23.

This circuit experienced two significant outages in 2008 (one caused by a tree in the overhead conductors and one caused by failure of a switch and feeder cables). These two outages accounted for about two-thirds of the outage duration during 2008. In 2006, there was a tree-related outage that also accounted for over 50% of the outage duration. Storm-related events also produced significant outage duration in 2010.

[32] References 2 and 5–8.

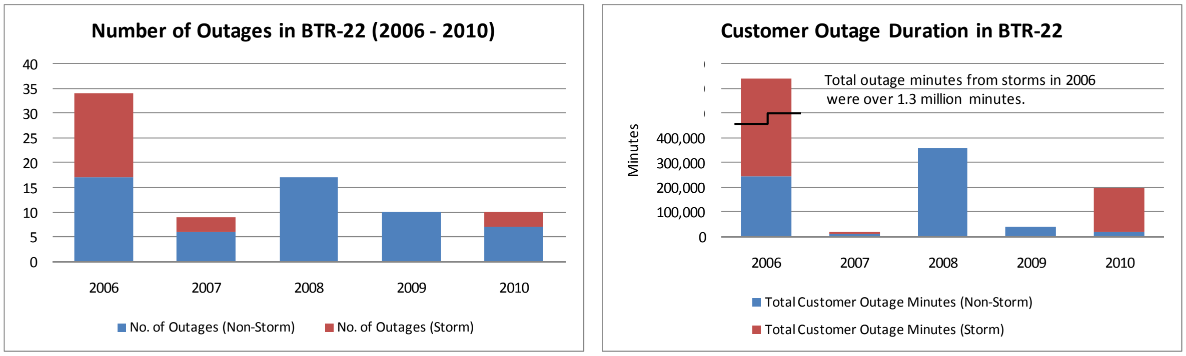


Figure 23. Outage Data in BTR-22 for Number of Outages and Total Customer Duration[33]

Similar to the Northrup circuit, outages in this area are produced by a combination of equipment failure, tree-related, and bird- and animal-related events as indicated in Figure 24. Since this circuit is predominantly overhead and in a heavily wooded environment, elimination of these events is not possible unless the feeder is put underground. However, recent additions of tree wire have been made in an attempt to reduce the impact of branches contacting the wires, which should help reduce outages due to this cause.

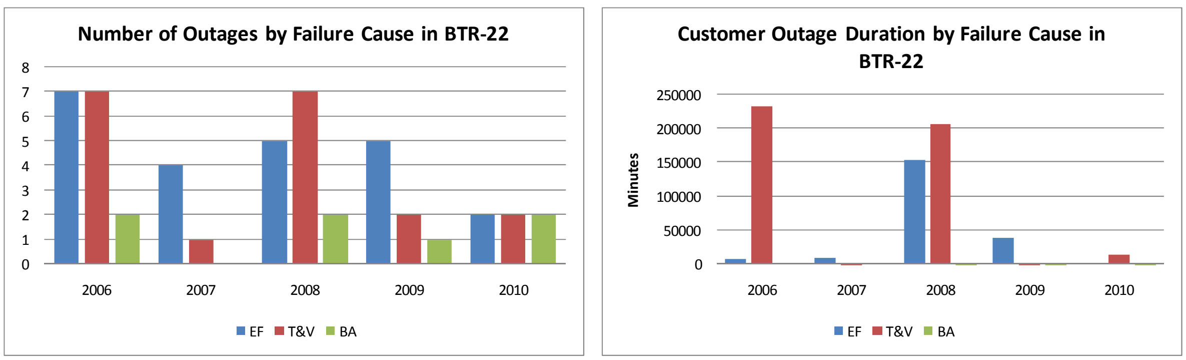


Figure 24. Outages by Failure Cause in NRU-23 for Number of Outages and Total Customer Duration (Total 2006–2010)[34]

#### 2.2.4.6 Lake Hills (LHL-23) Assessment

This Lake Hills circuit was selected for review as this circuit serves an area on the east side of Bellevue with a slightly different environment than that of the north circuits. This circuit has both underground and overhead portions of the distribution circuit and has a large number of customers. The outage trends are shown in Figure 25.

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33 References 2, 5–8, and 30.

34 References 2 and 5–8.

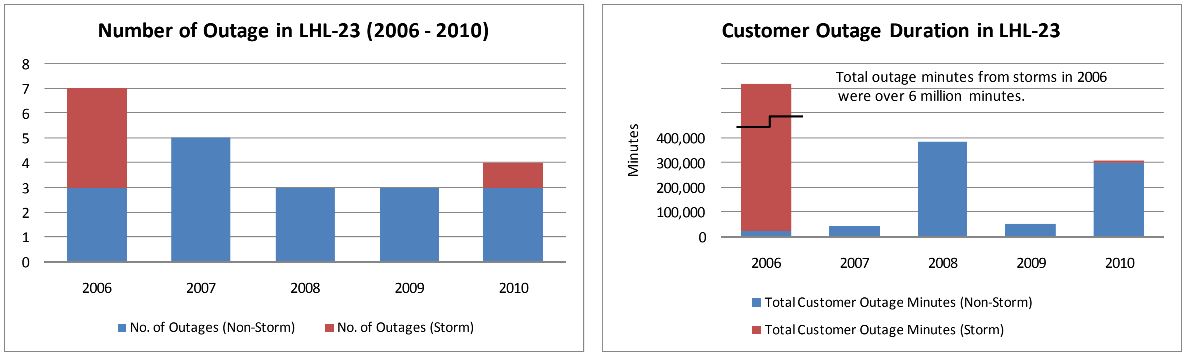


Figure 25. Outage Data in LHL-23 for Number of Outages and Total Customer Duration[35]

This circuit experiences a low number of outages, but shows long outage durations. During 2010, an underground cable failure produced a lengthy outage. The outage was prolonged due to difficulty in locating the failure and restoring the system. This circuit is also a radial circuit that currently is only fed from the Lake Hills substation. Therefore, an alternate power source is not available on this circuit which contributes to the longer duration outages. A similar event occurred in 2008, which resulted in an extended outage. For this circuit, almost all events and durations are attributed to equipment failure (primarily underground cable). There is an ongoing program to monitor and remediate cable in this area to reduce the causes and durations of outages.

#### 2.2.4.7 Clyde Hill (CLY-23) Assessment

This Clyde Hill circuit was selected for review as this circuit serves an area just north of the Downtown and there has seen an increasing level of outage duration. This circuit is primarily an overhead distribution circuit and has a moderate number of customers. The outage trends are shown in Figure 26. Significant outages occurred in 2008, 2009, and 2010 that were tree-related (suspected to be tree branches falling onto the overhead line). There was one outage each year that accounted for the majority of the duration of the outages.

Figure 27 shows a breakdown of outage cause by type. Similar to other equipment in wooded areas, the elimination of these tree-related outages is difficult (Figure 28). There are potential recloser projects identified to sectionalize the line which will improve the ability to quickly restore power to many customers connected to the line after tree branch contact with the line.

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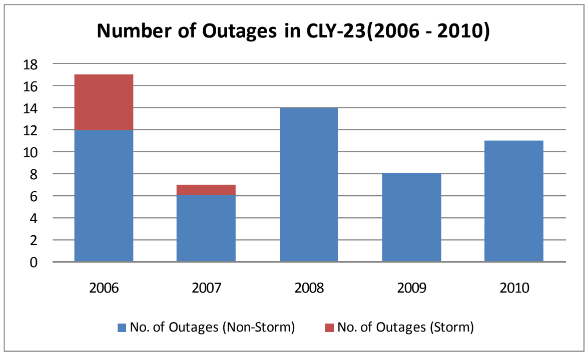
[3535] References 2, 5–8, and 30.



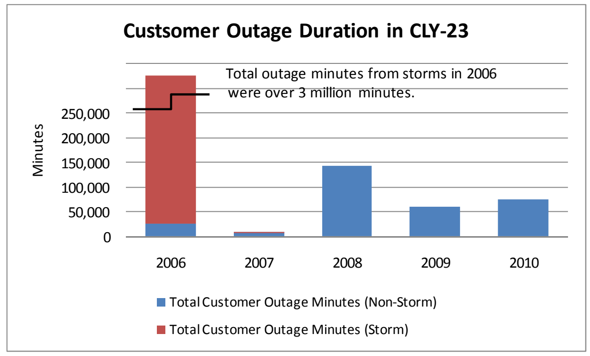
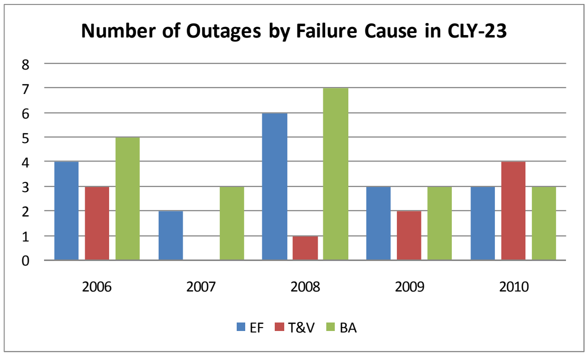




Figure 26. Outage Data in CLY-23 for Number of Outages and Total Customer Duration[36]



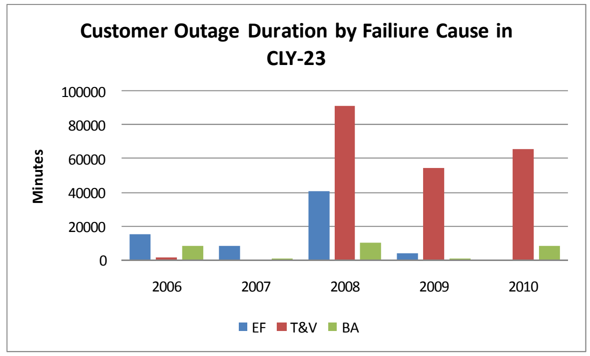




Figure 27. Outage by Failure Cause in CLY-23 for Number of Outages and Total Customer Duration[37]

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[36] References 2, 5–8, and 30.

[37] References 2 and 5–8.


Figure 28. Clyde Hill Substation

### 2.2.5 Summary of the Outage Review

The results of the outage assessment are summarized below with a list of findings and observations, a discussion of potential improvement actions, and a list of recommendations.

#### 2.2.5.1 Findings and Observations

Key observations from a review of the outage data show:

- The overall reliability within PSE's service territory and the City has improved over the past 5 years. Both frequency of outages and duration of outages have shown steady decreases over this period of time. However, performance is not uniform over all circuits and circuits remain in the City that have not shown the same improvement in reliability as the City overall. The inclusion of major-storm outages in the reported reliability metrics (beginning in 2010) provides added input into identifying circuits in need of improvement.

- There are few outages due to substation and transmission line failures. Utilities typically manage electric system assets by focusing maintenance and replacement programs on the assets that have the biggest impact on reliability—transmission lines and substations. Therefore, outages due to transmission line and substation problems are minimized. There is a very small number of outages attributed to equipment failures at substations within the City and on the PSE system.

- Distribution-level assets affect a much lower number of customers per circuit and the equipment is relatively inexpensive and easy to replace. Distribution assets are typically run-to-failure and are replaced when they fail. From an equipment perspective, the major contributors to outages in Bellevue over the past 5 years are underground cable failures and overhead equipment failures (conductors, fuses).

- The number and duration of overhead events related to tree and vegetation effects have decreased slightly over time. However, the potential for overhead line failures in heavily wooded areas remains and cannot be eliminated completely given the height of the trees and often close proximity to the substations and overhead wire rights-of-way. The effects of storms increase the potential for outages due to tree-related events in these wooded areas.

- PSE has performed specific reliability projects for the circuits reviewed previously including:

  - BTR-22: Overhead feeder along 140th Avenue NE was replaced with tree wire in 2007.

  - CLY-23: Underground feeder cables were proactively replaced in 2010. A follow-on companion tree wire project is planned for 2011–2012.

  - LHL-25: A pad-mounted switch together with distribution rebuild provided redundancy.

  - NRU-23: Current projects along NE 24th Street (underground feeder) and 134th Avenue NE.

  - SOM-13: Two cable replacement projects; a system project adding switches to separate distribution sources along Forest Drive; SOM-13 to EGT-12 feeder tie.

A list of reliability projects performed in the City over the past 5 years is provided in Appendix F. This list is based on discussions with PSE around projects that have been identified as projects aimed at improving reliability in Bellevue. These projects were developed to respond to specific events on the circuits based on PSE's review of the circuit performance. These projects directly relate to repair and replacement of equipment, network system enhancements, and automation upgrades. Since these projects address specific problems on the circuits, the selection of these projects should improve overall reliability on the selected circuits. Targeted selection of circuits for improved reliability is an approach taken by utilities to improve overall performance.

The findings above consider issues that affect overall system reliability. When improving reliability, utilities focus on reducing the causes of outages as well as reducing the response time. Potential actions that address the issues identified above are presented below.

### 2.2.6 Industry Issues and PSE's Corrective Actions

There are several items that dominate PSE's overall reliability performance. These are typical issues facing the electric utilities across the country. Potential improvement actions are discussed below.

#### 2.2.6.1 Underground Cable and Equipment Failures

The utility industry has experienced failures of underground cables due to age of cables and type of construction. Since underground outages tend to be longer outages, prevention of these cable failures or underground equipment failures has a significant impact on both frequency and duration of outages.

Utilities have addressed underground cable failures in the past through repair and remediation of cables. However, recent practice has been to develop proactive cable programs that include:

- Prioritization of cables from a failure perspective
- Continued remediation of cables
- Proactive replacement of cables.

These cable replacement programs consider cable type, manufacturer, age, and failure history. These programs involve identification of the cables most susceptible to failure and proactive replacement (intended to replace cables prior to failure). Additionally, where appropriate, remediation of cable through silicon injection to extend the life of cables is prescribed.

Utilities are placing cables in conduit to allow for better access and to reduce the time to repair cable failures in the future. Distribution automation is also available to improve identification of cable failure locations. Cable failures have been difficult to locate since there is no visible means to identify the location of the fault. The use of fault recorders and installation of Supervisory Control and Data Acquisition (SCADA) systems on switches provide a more effective means of identifying fault locations. Utilities are also installing Distribution Management Systems (DMSs) to improve overall visibility into the distribution system and operability of the equipment.

Underground transformers and switches that are placed in vaults are susceptible to failure due to equipment aging and environmental impacts (water and corrosion). The replacement and repair of this equipment is difficult due to limited access into the vaults. Utilities experiencing a large number of failures of these equipment types have developed proactive replacement programs to replace older equipment models.

#### 2.2.6.2 PSE's Corrective Action Initiatives

From the perspective of the City, Bellevue was one of the first areas of the PSE system to use underground cable and equipment, and the age of the cables and design approach (direct bury) has resulted in a large number of equipment failures due to aging. PSE has implemented a system-wide (including Bellevue) underground cable program to reduce the potential for cable failures. The PSE program includes all the elements of cable replacement and remediation. Additionally, PSE is utilizing conduits for the cables to further extend the life of new cable.

PSE has implemented a strategy to replace older less reliable underground switches and when possible, is replacing these with aboveground equipment. The aboveground equipment provides greater accessibility to speed up outage recovery.

The development of an active cable replacement and remediation program as well as replacement of aging and problem equipment is an appropriate action to improve system reliability by reducing the number of equipment failures. Additionally, the use of more modern technology is expected to result in a system with longer asset life.

#### 2.2.6.3 Overhead Conductor and Equipment Failures

Overhead equipment is also susceptible to aging-related failures. However, overhead systems are also subject to the effects of tree-related faults due to storms and wind, bird- and animal-related events, and damage due to vehicle accidents. Given the environment in Bellevue, the effects of storms and weather have an impact on system reliability. Most utilities address overhead equipment performance through vegetation management, wildlife management, and pole and line inspection programs to limit the potential for faults on the overhead distribution system. Also, overhead equipment is typically low cost, not easy to test *in situ*, but easy to repair, so the common practice is to run these pieces of equipment to failure at which time they are replaced.

#### 2.2.6.4 Conversion of Overhead Line to Underground Circuits

Another means to address overhead susceptibility to weather and tree-related events is undergrounding. Underground systems, while susceptible to other outage causes, are not as vulnerable to wind and weather events, but are also susceptible to damage through soil excavation and potentially earth quake damages. Many utilities now install underground distribution systems for new installations. Through the Comprehensive Plan (Policy UT-39), the City already requires undergrounding of new distribution lines. Replacing overhead lines with underground cables is a different issue since the cost for such a conversion is at present not covered. Conversions of overhead systems to underground are not common in the industry. Since the cost of underground systems is significantly higher than overhead systems, the common practice requires the party benefitting from the underground conversion to pay the difference in cost between overhead maintenance and replacement and the cost of undergrounding. The Edison Electric Institute[38] performed a study to investigate the conversion of overhead lines to underground systems. While the report does not specifically address conditions in Washington, it does provide a comparison of the costs of overhead and underground construction. A summary of this information is provided in Table 2 below. This information specifically applies to distribution systems.

[38] Reference 12.

**Table 2. Cost of Overhead vs. Underground Construction (Cost per mile)[39]**

| Location | New Construction Overhead (Average) | New Construction Underground (Average) | Conversion from OH to UG (Average) |
|---|---|---|---|
| Rural | $135,000 approx | $410,000 approx. | $395,000 approx. |
| Suburban | $200,000 approx. | $570,000 approx. | $725,000 approx. |
| Urban | $200,000 approx. | $560,000 approx. | $830,000 approx. |

The state of Washington does have provisions relative to conversions. Revised Code of Washington (RCW) 35.96[40] specifies requirements that allow cities or towns to create local improvement districts and to levy and collect special assessments against real property benefitting from the conversion of overhead facilities to underground facilities. PSE also has a tariff that provides a basis for performing work for others (Electric Tariff G 73 and 74 for conversion to underground for non-government and government entities, respectively).

There is very limited precedence for allowing regulated utilities to place underground conversions into the rate base. California has Rule 20 which allows cities, on a limited basis, to identify areas for undergrounding under very specific safety criteria. Rule 20 projects require pre-approval from the California Public Utilities Commission. However, at the completion of the conversion, the cost is added to the utilities' rate base. Duke Energy Carolinas is also considering a pilot program to work with municipalities to place qualifying areas underground with some cost sharing between the utility and municipality.

#### 2.2.6.5 Vegetation Management

The implementation of effective vegetation management, wildlife management, and pole inspection programs provide industry-accepted means of preventing overhead line failures. The selected use of "tree wire" also is an appropriate method to reduce faults on overhead conductors that produce outages from tree-related causes. Undergrounding of lines minimizes storm and weather impacts and the City already requires new installations to be constructed underground. All of the above represent positive solutions to the prevention of outages.

PSE has vegetation management, wildlife management, and pole and line inspection programs comparable to others in the industry. These programs are described in more detail later in Section 2.4. PSE has also utilized tree wire to reinforce the overhead lines in certain areas with success. The tree wire is a covered conductor and reduces the potential for faults due to tree contact. Tree wire is heavier and provides some support against larger branch contact. However, tree wire has both positive and negative attributes. While the covered conductor helps to reduce faults, the covered conductor also increases the potential for a downed line to

39 Reference 12, Figure 6.3 (new construction) and Figure 6.4 (conversions)

40 Reference 25.

remain energized creating potential safety hazards. However, this safety issue also exists to some extent for bare wire.

#### 2.2.6.6 Distribution System Automation

The use of automation, including the use of SCADA systems, for remote control of breakers and switches provides the means to reduce the outage duration due to overhead but also underground outages. The installation of reclosers to automatically re-energize a line after a fault provides an effective method of reducing outage duration (especially due to “quick” tree interactions with the conductors). While these do not eliminate faults, they allow the system to respond automatically if the fault clears due to some momentary contact between the line and a tree. PSE is implementing the use of such reclosers and distribution system automation to improve its overall outage response. There are other design features available for reduction of the duration of outages that are described later in Section 2.3.

A key factor in improving reliability, therefore, needs to be focused on reduced outage recovery times and outage management in addition to the activities above. Outage management activities are discussed in Section 2.4.6.

### 2.2.7 Comparison between PSE and Other Utilities

PSE participates in an industry reliability survey through IEEE. PSE’s overall system reliability performance is typically in the 1st or 2nd quartile on frequency of outages and 2nd or 3rd quartile in duration of outages (with the 1st quartile being best performance). The overall reliability performance in the City is significantly better than that of the overall system. This was to be expected as Bellevue represents one of the densest areas of the PSE service territory. Typically these urban areas have more built-in system redundancy and therefore, should experience fewer outages and shorter recovery times. Additionally, faster recovery is enhanced by the proximity of the urban areas to service centers for restoration.

WUTC also reports reliability indices for its three regulated electric utilities based on the IEEE criteria for SAIFI and SAIDI. As shown in Figure 29, PSE’s performance is comparable with the other regulated utilities in the State.

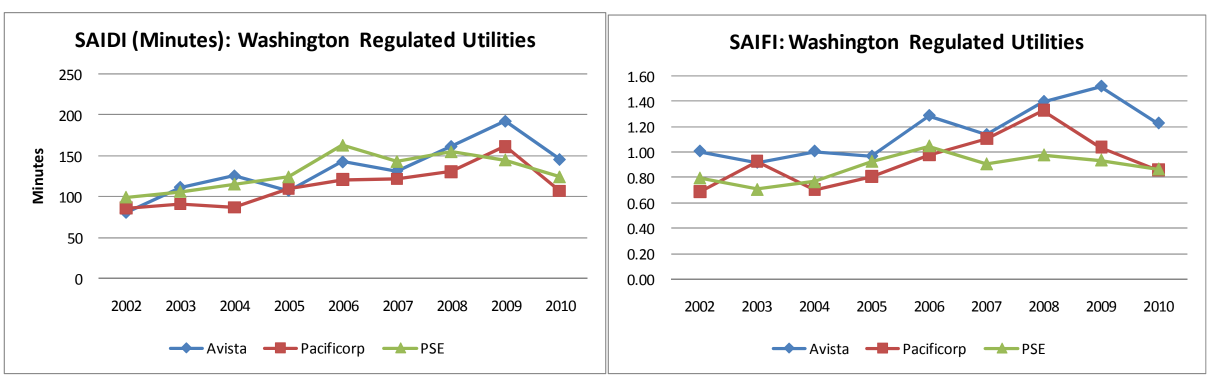


Figure 29. Washington Regulated Utilities SAIFI and SAIDI Results

Additionally, Seattle City Light (not regulated by the WUTC) reports in its 2010 annual assessment that it achieved its SAIFI goal of less than one. Therefore, on an overall basis, PSE is comparable to other utilities within the state, and the City overall has significantly better performance.

Lawrence Berkeley National Laboratory (LBNL) performed an assessment of the electric power system based on 2006 data. The industry reliability indices reported in 2006 based on the LBNL study (Reference 3, Table 2) indicate an average SAIDI of 244 minutes per customer and an average SAIFI of 1.49. The values in the western U.S. (Pacific Region as defined in Reference 3, Table 2) are considerably higher at 296 minutes and 1.99, respectively for SAIDI and SAIFI. The Pacific Region is defined as the states of Washington, Oregon, California, Alaska, and Hawaii; and includes information from the only 12 regulated utilities that provided information. From an overall perspective, the performance in the PSE area appears better than the industry in 2006.

A further review of the LBNL report indicates that most utilities report information using greater than 5 minutes as the basis for a sustained outage. Less than a quarter of the utilities reporting use greater than 1 minute for sustained outages. It should be noted that PSE utilizes the 1-minute rule for reporting its reliability indices. For the subset of utilities reporting using the 1-minute rule, the average SAIDI and SAIFI are 143 and 1.4, respectively. The PSE performance during this time period shows that PSE has a higher SAIDI value, but a lower SAIFI value. The LBNL also addresses reliability with major event information included. PSE had not reported this information prior to 2010, but this information has been requested by WUTC and, beginning in 2010, is a part of the annual reporting requirements[41]. The requested metric is a 5-year rolling average so, for now, this metric is not a good basis for comparison.

Another aspect of comparison with other utilities is customer satisfaction. JD Powers conducts surveys of electric utilities that measures overall customer satisfaction. The survey measures utility performance around six key factors: power quality and reliability, price, billing and payment, corporate citizenship, communications, and customer service. The survey indicates that a key to achieving customer satisfaction is the management of customer expectations as they relate to outages and restoration of service. If utilities manage expectations around outages, this effort may have a positive influence on customer satisfaction. In the latest survey by J.D. Power and Associates,[42] PSE ranked in the top half of large utilities in the Western Region Large Segment. The PSE scores placed them above the average and also in range with other utilities in the Northwest. In the 2010 survey,[43] PSE scored just below the midpoint of Western Region Large Segment utilities. This information provides another benchmark for performance against peers, but a key finding is that communication around outages is a major factor in overall customer satisfaction. As indicated in the review with stakeholders and the City, the communication around outage status was identified as an important element and a key area for improvement.

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[41] Reference 4.

[42] Reference 31.

[43] Reference 32.

### 2.2.8 Recommendations

Based on the outage assessment and the current status of PSE's programs to respond to these events, the following recommendations are made to improve the City's ability to be a more proactive participant in improving reliability:

- There are several programs underway to address prevention of outages and to reduce duration of outages. The City can and should proactively monitor the progress and extent of those programs focused on improving the reliability of the City's power distribution system. This will require the City to add staff with power system know-how.
- The City should investigate opportunities for additional undergrounding of distribution lines through coordination of multiple-utility projects and evaluation of funding for conversion of overhead lines to underground cable circuits by forming local improvement districts.
- PSE has ongoing reliability initiatives and performs system-wide and targeted projects to improve system reliability. The City should track the reliability impacts experienced in the various neighborhoods. Since, in the future, PSE will be reporting additional reliability information including storm outages, the City can utilize this information to determine the effectiveness of the various reliability programs and projects, and to work with PSE in identifying circuits requiring attention. A fast track implementation of system improvements is an option for the City to explore with PSE, although accelerated investments might have a negative impact on the power rates.
- The visual review of overhead circuits indicates that there are many substations and lines located in heavily wooded areas and the only way to significantly improve reliability is to perform more comprehensive tree trimming. The City should review its vegetation policies, specifically in the substation areas, to look at alternate vegetation approaches where the risks for large-scale disturbances related to vegetation issues is high.

The remainder of the section provides a discussion of the overall system design and work processes relative to the potential for reliability risk.

## 2.3 Review of PSE's System Design

### 2.3.1 Scope

System design has a major impact on electric reliability from the standpoint of limiting outages and reducing the restoration period in response to events. This section provides an assessment of the current PSE system relative to the overall design and layout of the Bellevue distribution system. The review of PSE's system design is intended to identify potential opportunities or vulnerabilities in the overall electric power system relative to reliability within Bellevue.

### 2.3.2 Approach

The assessment was performed solely through a review of publicly available WUTC documents, publically available PSE and other documents, and limited discussions with PSE's staff. In addition, a walk-through of PSE's substations and control centers was a part of the review in order to obtain an understanding of PSE's design practices. PSE proprietary and confidential documents were not made available for the review. The information reviewed for this assessment is listed below and was discussed with PSE personnel during meetings on these topics:

- Distribution System Design, Loadings, and Operations
- Transmission System Design, Loadings, and Operations
- Capital Project Planning and Prioritization
- Projects and Reliability Initiatives in Bellevue
- Substation and Line Maintenance and Problem Investigations
- PSE Electric Substation Work Practice Standards
- PSE Electric Relay Work Practice Standards.

The WUTC information included in Washington Administrative Code (WAC) 480-100 series was also reviewed as part of this assessment.

### 2.3.3 State of Washington Requirements

#### 2.3.3.1 Relevant State Codes

WUTC provides oversight of electric utilities through regulations codified in WAC Chapter 480-100. As noted in WAC 480-100-001, the purpose of these regulations is "to administer and enforce chapter 80.28 of Revised Code of Washington (RCW) by establishing rules of general applicability and requirements for consumer protection, financial records and reporting, electric metering, and electric safety and standards". The principal statutes that define WUTC's authority and responsibility with respect to electric utilities are found in RCW Title 80. WUTC regulates electric non-public power utilities, such as PSE[44]. These laws provide the basis for the operations of the electric utilities and how they must conduct business. A more detailed discussion of the regulations and their impact on system reliability is provided in Section 4.2.1.

A brief summary relative to the regulatory impacts on reliability are:

- Requirements for maintaining fair rates subject to rate case hearings: These requirements have an impact on the utility's capital expenditures and projects selected each year.

44 WUTC does not have jurisdiction over the Public Utility Districts (PUD) or Municipal Utilities.

- Requirements for power quality that define voltage range provided to the customers: This item requires both the utility and end-users (major industrial or power users) to manage their assets to minimize voltage fluctuations on the system.
- Requirements for submitting annual reliability reports: Regulated utilities are required to submit reports on electric system reliability and on actions taken to improve reliability. This requirement also has a major impact on the selection of capital projects and maintenance each year.
- Requirements for interacting with jurisdictions relative to access to rights-of-way in order to maintain a safe and reliable system.
- Guidance on renewable, energy efficiency, and environmental concerns: The State provides requirements and incentives to utilities to promote reductions in power use and the use of environmentally friendly power sources.

#### 2.3.3.2 PSE's Regulatory Environment

Based on this review it was concluded that the state of Washington has codes and requirements similar to other states. However, the code requirements are less detailed than, for example, those of the state of California, which has issued detailed regulations in regard to design, operation, and maintenance of the electric power system.[45] California's key code sections are:

- General Order 95—Rules for Overhead Electric Line Construction
- General Order 128—Rules for Construction of Underground Electric Supply and Communication Systems
- General Order 165— Inspection Cycles for Electric Distribution Facilities.

That is, the state of California has issued detailed rules for design, construction, and maintenance of facilities. No similar rules have been found among WUTC's rules. Thus, it appears as if PSE can design and operate its power system with a higher degree of freedom. However, it still has to meet prevailing standards such as the National Electric Safety Code.[46]

According to information provided by PSE, expenditures and investment costs to be included in the rate base are not reviewed and approved in advance by WUTC but are reviewed after the expenditures and investments have been made. That is, PSE carries the entire risk for investment decisions that it makes until the investments have been made and are presented to WUTC for inclusion in the rate base. If WUTC does not find the investments or expenditures to be prudent it might not allow for these costs to be included in the rate base. In some other states, such investments may have to be preapproved by the regulators prior to initiating the project or starting construction.

[45] See http://docs.cpuc.ca.gov/gos/index.html for information about the California codes.

[46] IEEE Standard C2-2012 National Electric Safety code: ISBN: 9780738165882 (Latest Issue).

## 2.3.4 Review of PSE's Power Supply

Electric reliability depends on a stable power supply. Relative to the City, the power supply starts with generation and transmission assets feeding the distribution assets in Bellevue. Since the power flows to whatever loads are connected, it is not possible to evaluate the power generation portion specifically related to Bellevue. The Bellevue-specific aspect of the power supply relates to having transmission lines that are capable of supplying the generated power to the City. This section provides a brief synopsis of the current power supply situation for Bellevue.

### 2.3.4.1 Risk Analysis—Present Generation Capacity

Generation capacity has been sufficient to support the overall PSE electric demand at present, including Bellevue. However, issues have arisen about the ability of wind energy to be delivered through the transmission system in the Northwest from wind power plants in eastern Washington, Idaho, and Oregon.[47] This has not caused power supply problems for Bellevue but indicates that the location of PSE's power supply sources is important and that bottlenecks exists outside of PSE's service territory that can impact how much power PSE will be able to transfer over transmission lines that are not owned by PSE. The risk to Bellevue related to insufficient generation available to PSE cannot be quantified because data are lacking to enable such an analysis. A detailed discussion of generation issues is provided in Section 3 with the review of the Integrated Resource Plan (IRP).

## 2.3.5 Risk Analysis—Bulk Power Transmission System for Bellevue

### 2.3.5.1 Scope

PSE operation depends on power wheeling over relatively few transmission lines. This task entailed reviewing the contingencies under which PSE might lose all or a significant amount of the power it needs to keep its customers supplied with electric power in order to assess any potential risks to reliability.

### 2.3.5.2 Present Transmission System Design

The City receives its electric supply via a 115 kV looped subtransmission system that is connected to primary substations at Sammamish (to the north) and Talbot Hill (to the south). These two stations, in turn, are connected to the high-voltage transmission grid that serves the northwestern states, and receive energy from a mixture of fossil fuel and renewable sources, often located many miles away from Bellevue. The 115 kV lines roughly encircle the City and feed several distribution substations, which step the voltage down to 12.5 kV, a voltage which can more readily be routed through the neighborhoods of the City. It is important to note that most (although not yet all) of these distribution substations are fed from the 115 kV system using two different lines, a method which provides redundancy should one line experience a

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[47] See http://www.nytimes.com/2011/11/05/business/energy-environment/as-wind-energy-use-grows-utilities-seek-to-stabilize-power-grid.html for a discussion of wind power issues in the Pacific Northwest.

fault or if maintenance on a line is required. On the 12.5 kV system, the service transformers, whether located on poles, underground, or as ground-level “pad-mounted” units, further reduce the voltage to the familiar ones we all use, such as 120, 240, or 480 VAC, and also provide 3-phase service to commercial and industrial customers.

Figure 30 provides a map of the existing 115 kV system for the City and the surrounding area. The map also shows an existing, double circuit (two 3-phase circuits on one pole) 230 kV line that is owned by Seattle City Light which is not available for power transmission into the City, although the line affects the power flows on other lines owned by other entities in the region. PSE has two 230 to 115 kV, 325 MVA transformers and three 115 kV lines feeding power north up to the City from its Talbot Hill substation. The two lines from Talbot Hill to Lakeside carry about 157 MW each under N-0 conditions (normal winter peak load with all circuits in operation).[48] The map also shows five 115 kV circuits feeding power from the north into the City. These terminate in the Sammamish substation, where there are also two 230/115 kV, 325 MVA transformers installed to feed power into the 115 kV lines.

The Talbot Hill and Sammamish substations receive power from 230 kV lines connected to the Bonneville Power Administration’s (BPA) Maple Valley substation (which is shown in Figure 31) and from its Monroe substation to the northeast of Sammamish. The Maple Valley substation is located a short distance to the east of Talbot Hill. Figure 31 also shows the 230 kV line that comes from BPA’s Monroe substation to PSE’s Novelty Hill substation (not shown on the BPA map) and from there a transmission line extends west where it is terminated in PSE’s Sammamish substation, which has a total of three 230 kV line terminations. One of these is leased from BPA by PSE. This line loops south from Sammamish via Klahanie to BPA’s Maple Valley Substation. This lease expires in 2018 at which time the lease has to be renegotiated or the line reverts to BPA’s control. The third line connects PSE to the Seattle City Light substation at Bothell.

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48 Reference 33 (Section 28, Reliability/Availability of Systems). N is the number of elements in the system and the minus zero designation means that no element is missing or out of service.

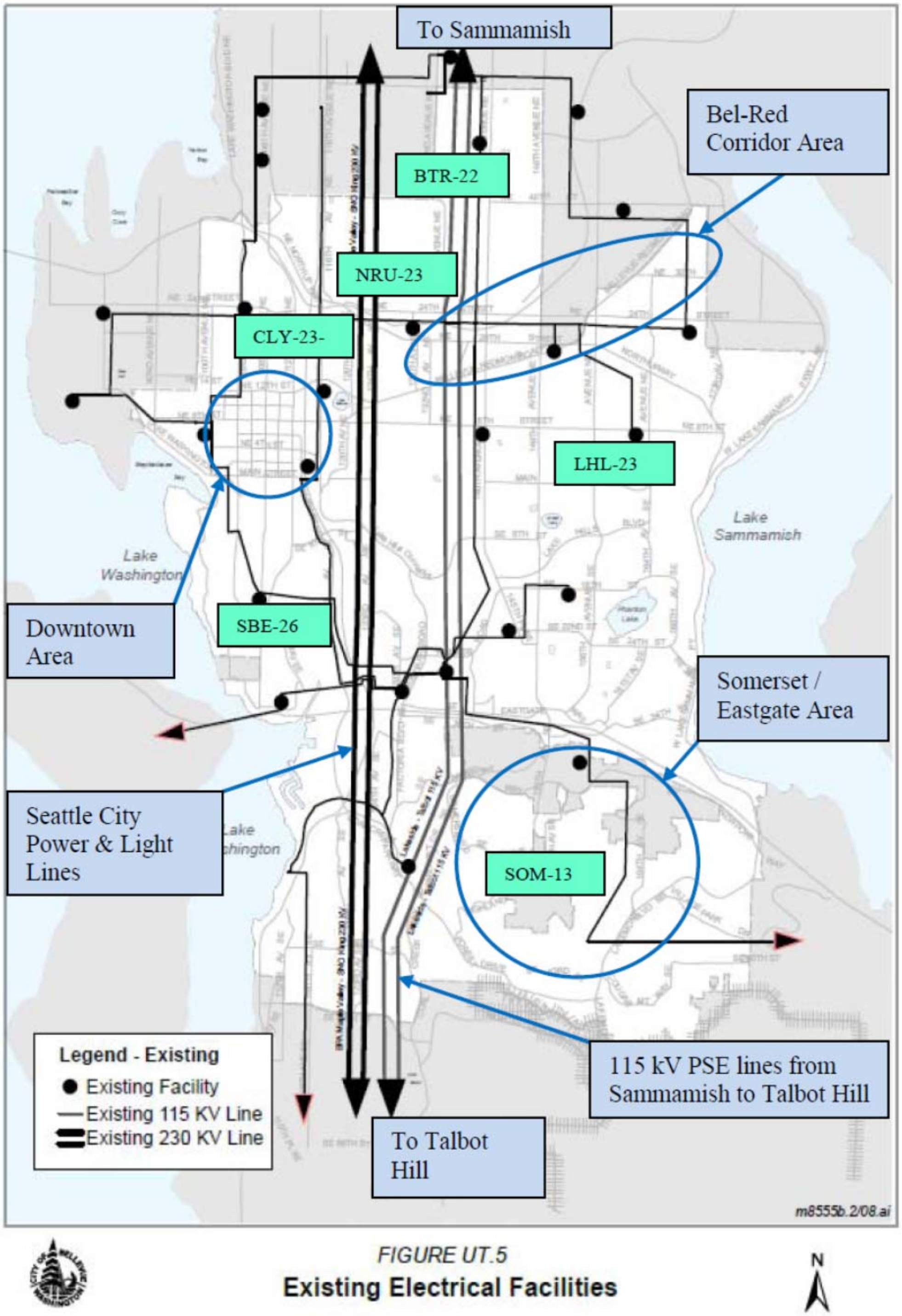


Figure 30. Existing Transmission Facilities around the City of Bellevue

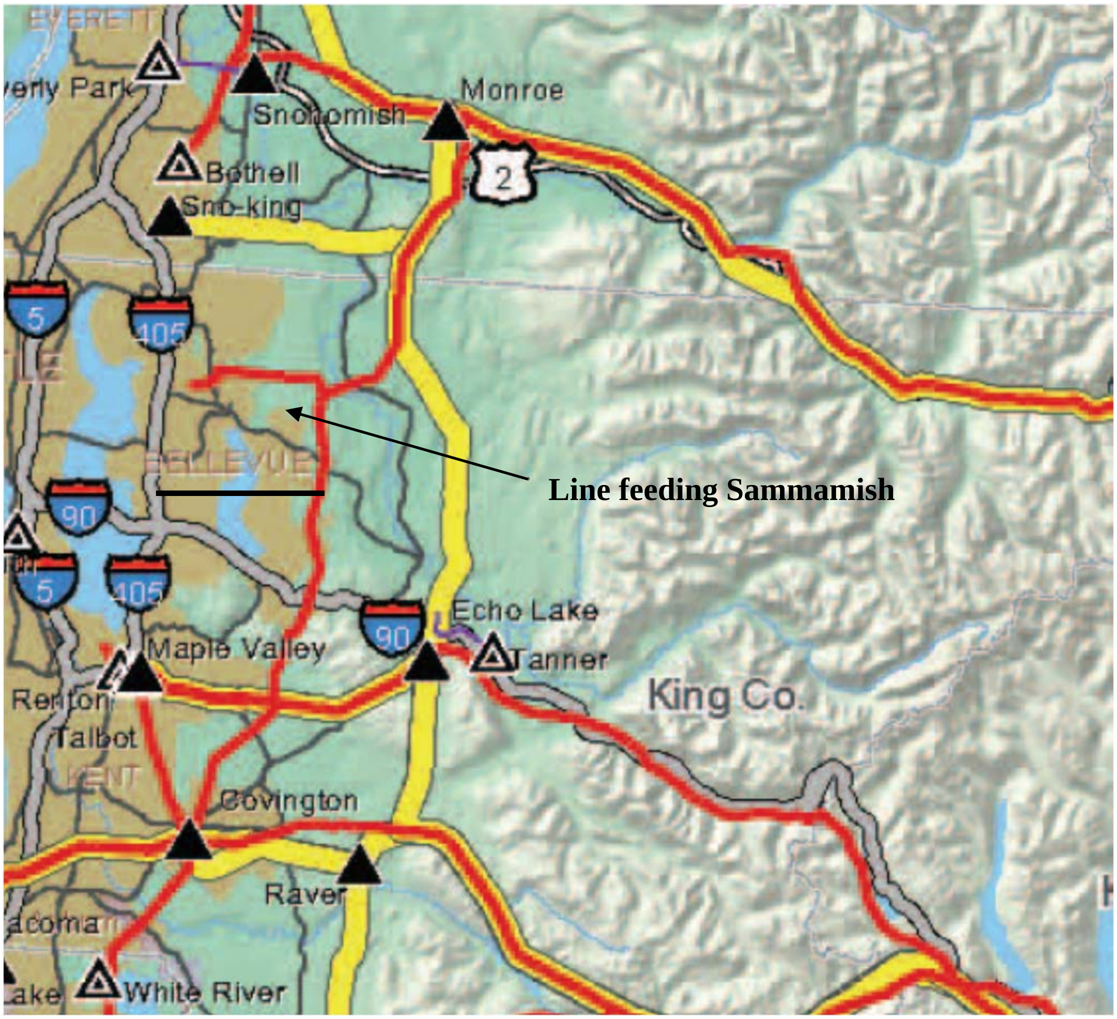


Figure 31. BPA's 500 kV (Yellow) and 230/345 kV (red) lines East and South of Bellevue

#### 2.3.5.3 Bulk Power (230 kV) Transmission System Assessment

BPA's Maple Valley substation is a strong source supplied via 500 kV lines, whereas the Sammamish substation receives its power via longer 230 kV circuits from the Monroe, Bothell, or Maple Valley substations. (PSE also owns a 230 kV line going from Sammamish to the Bothell substation, which is owned by Seattle City Light.)

A loss of the 230 kV line to Monroe or the one to Maple Valley (N-1 contingency) is a serious stress to the City's power supply but should not cause any outages in the City.[49] There will be a future need for better voltage support to the Sammamish substation in order to support growth in the City and the surrounding areas.[50] Conversion of one of the 115 kV lines between Talbot

49 Loss of the 230 kV lines from BPA was one of the reasons (but not the only one) for the widespread power outage in 2006. (Based on interview with PSE personnel; see also Reference 34)

50 Interview with PSE planners.

Hill and Sammamish to 230 kV and installation of a 230/115 kV, 325 MVA transformer in the Lakeside substation will also be needed to support the region's expected future growth.

### 2.3.6 115 kV Transmission System Review

#### 2.3.6.1 Scope

PSE's 115 kV system is considered a subtransmission system with transmission service being provided by BPA. This review consisted of assessing PSE's 115 kV transmission system, since disturbances on the 115 kV system would be most likely to cause power system disturbances in Bellevue.

#### 2.3.6.2 System Load Scenarios and Planning Assumptions

PSE is a winter peaking utility. Therefore, transmission system outages have a larger impact in the winter than a similar outage during the summer period, since the summer peak load is only about 65% of winter peak.

PSE has not experienced any load growth since 2008. The planned growth has therefore been shifted foreword by a couple of years. The present planning criteria is for 0.5% annual growth for the immediate future and a growth rate of about 1% per year for the next 10 years.

PSE builds its transmission infrastructure to minimize outages and avoid overloads on the 115 kV transmission system on an N-1 basis (N-1 is the first contingency). This is defined as a Category B event by the North American Electric Reliability Corporation (NERC). NERC defines a Category C event as an N-2 contingency case (two simultaneous events). An example of this is a breaker failure (the first event) that would lead to clearing all circuits connected to a substation bus (the second event). For this contingency, according to the NERC rules, PSE is allowed to drop non-consequential load.

PSE also tries to minimize many so called N-1-1 events. That is, with one outage in the system, planned or unplanned, it tries to be in position to handle a second, unplanned outage. However, this is not possible for some portions of the 115 kV transmission system where a portion of the City is fed via a single 115 kV line. A loss of this line might cause power disruptions to a portion of the power users in the City. For example, as is shown in Figure 32, the loss of the single, radial line to Lake Hills would cause a loss of power to those connected to the substation, unless power can be provided via a looped 12.5 kV distribution circuit that can be fed from another 115 kV substation.

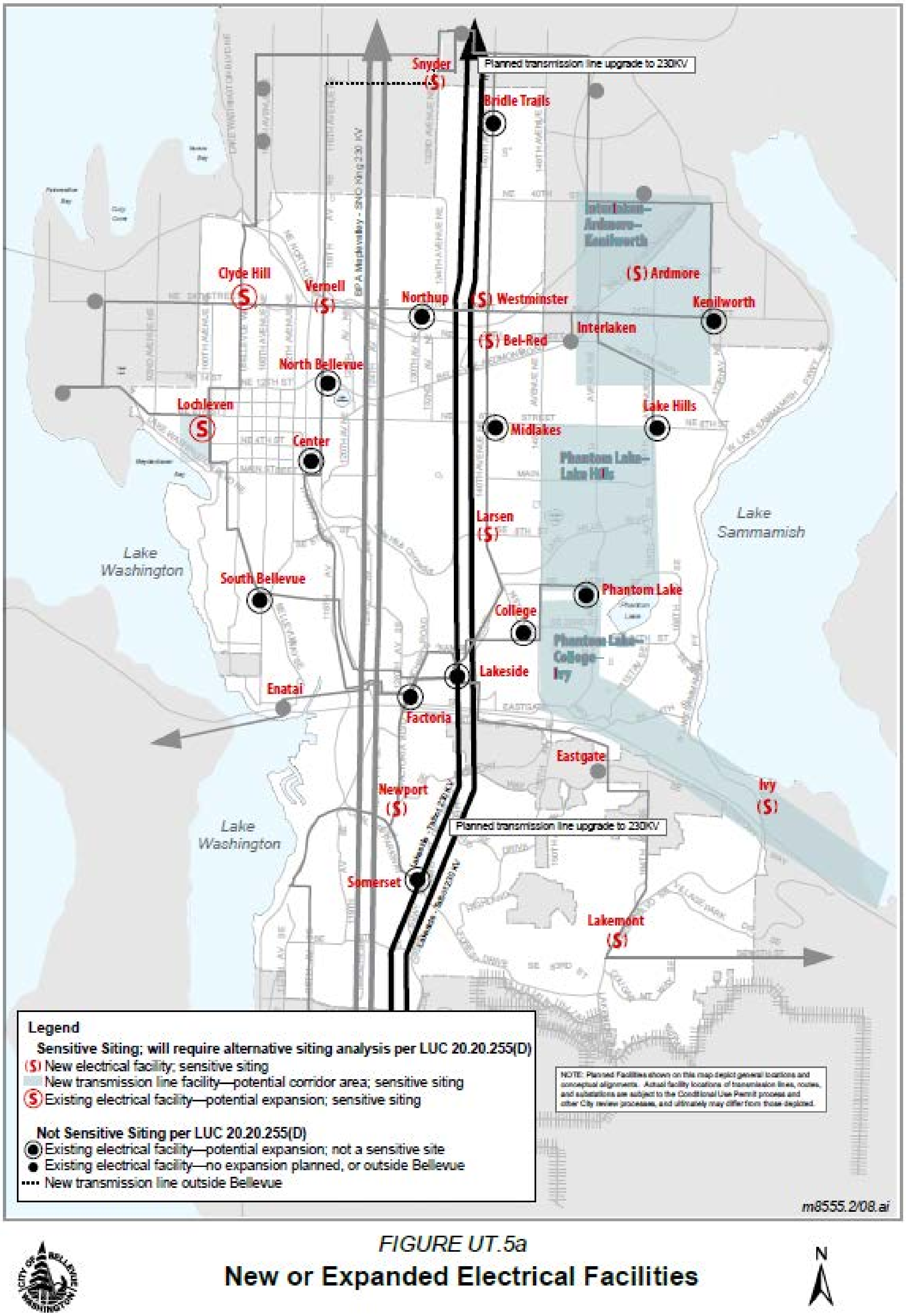


Figure 32. PSE's Expansion Plan for Bellevue

A line between Lake Hills and Phantom Lake, which is in the process of being designed, is needed to supply these two substations from two directions. This should meet the N-1 criteria but might not meet the N-1-1 condition since an outage on this circuit would still affect the customers connected to the line if the line is lost when a section of the line is out of service. This is also true for the Downtown area that is fed via a line from South Bellevue to Sammamish. This circuit will also survive an N-1 but not an N-1-1 scenario.[51] To survive this without a loss of power to the customers, three circuits have to be feeding each substation or each 12.5 kV distribution circuit has to be connected to two substations fed from different 115 kV lines.

According to PSE's planners, the worst case outage is the loss of a transformer in Talbot Hill, in which case the second transformer could be overloaded. For this case, the load on this transformer has to be reduced and shifted over to Sammamish.

#### 2.3.6.3 115 kV Transmission System Analysis

PSE has upgraded the 115 kV transmission line conductors to be capable of operating up to 100°C (212°F). This allows the lines to be loaded higher under contingency situations to avoid having to drop loads. (The 230 kV line between Bothell and Sammamish has been upgraded to 200°C, which requires special "hardware" capable of operating at such high temperatures.)

Contingencies that might cause outages are:

- Lakeside to Sammamish with Kenilworth line open: Under these conditions, a loss of the transmission line from Sammamish or Lakeside could cause customer outages.
- Work on Lakeside to South Bellevue would drop load in Bellevue if any second fault would occur. A new line to Clyde Hill from Sammamish would be needed to avoid such outages.

Other similar examples of contingencies that would result in outages exist in and around the City. To avoid outages, the 115 kV system needs to be reinforced.

#### 2.3.6.4 Comparison to Other Utilities

PSE's planning assumption to operate under N-1-1 scenarios for its 115 kV system is consistent with good planning for power distribution systems at feeding distribution substations. However, PSE is not able to meet these criteria for some areas of its service territory because of not having 115 kV circuits to provide the additional power infeeds to some substations. This primarily affects residential neighborhoods. It would not be unusual to find the same situation in many other utilities.

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[51] PSE has stated that it avoids planned outages on the circuit during the fall and winter seasons to minimize the risk of a power outage that would affect the downtown.

#### 2.3.6.5 Recommendations

To achieve high reliability of the power supplied via the 115 kV power transmission lines, it is recommended that the system be reinforced to handle all N-1 contingencies by adding 115 KV transmission lines to the substations feeding the Downtown area.

For the substations which at present are fed from a single 115 kV line, it is recommended that these substations are reinforced from a second 115 kV line to be able to ride through an N-1 contingency.

### 2.3.7 Distribution System

#### 2.3.7.1 Scope

PSE is using a combination of 12.5 kV underground cables and overhead lines for the distribution of power to users via transformers that step down the voltage to a level that can be directly used by most power users. The objective of this task is to review the design assumptions for the power distribution system from reliability perspectives.

#### 2.3.7.2 Distribution System Review

PSE utilizes a network of 12.5 kV conductors to route electric power around the City and to deliver power to its customers. The 12.5 kV power is delivered from electrical substations situated at various locations within and adjacent to Bellevue's city limits (see Figure 30). Each of these substations is fed from at least one 115 kV line, as previously discussed, and one or more transformers within each substation steps the voltage down to 12.5 kV for distribution within the City. Two different methods are used for distributing this power:

1. Overhead bare or covered conductors on utility poles
2. Underground cables directly buried in the earth or fed through conduits.

Some amount of redundancy is built into the PSE distribution system in Bellevue. For example, all of the distribution substations contain an auxiliary 12.5 kV bus that is available for use in the event that the main 12.5 kV bus becomes unavailable. In addition, transformer and feeder loading guidelines, as well as a network of distribution switches at various locations, allow for backup feeds to portions of the City affected by outages. Although this switching system is mostly manual at this time, requiring action by onsite personnel, PSE has implemented a program to replace older switches with newer-technology devices that will allow for more remote switching in high density load areas, allowing for faster power restoration after outages.

Nearly the entire distribution system in the City is capable of N-1 (single contingency) operation, meaning that power can be restored during the loss of one distribution line via switches in the system to provide alternate feeds to loads while system repairs are made. However, the Downtown area of the City presents its own challenges due to the density of PSE customers in this area. Figure 33 provides a geographic representation of the four distribution substations that feed the Downtown. The Clyde Hill, North Bellevue, Lochleven, and Center substations together supply essentially all of the electric power to this area. To increase the reliability of this crucial part of the City, PSE has installed a "reliability ring" that provides a redundant standby feed to Downtown loads, which can be used in case of faults on the primary circuit feeding the load. The ready availability of the ring allows for faster restoration of power in the event of an unplanned outage, along with the ability to provide alternate feeds during times of system maintenance or construction.

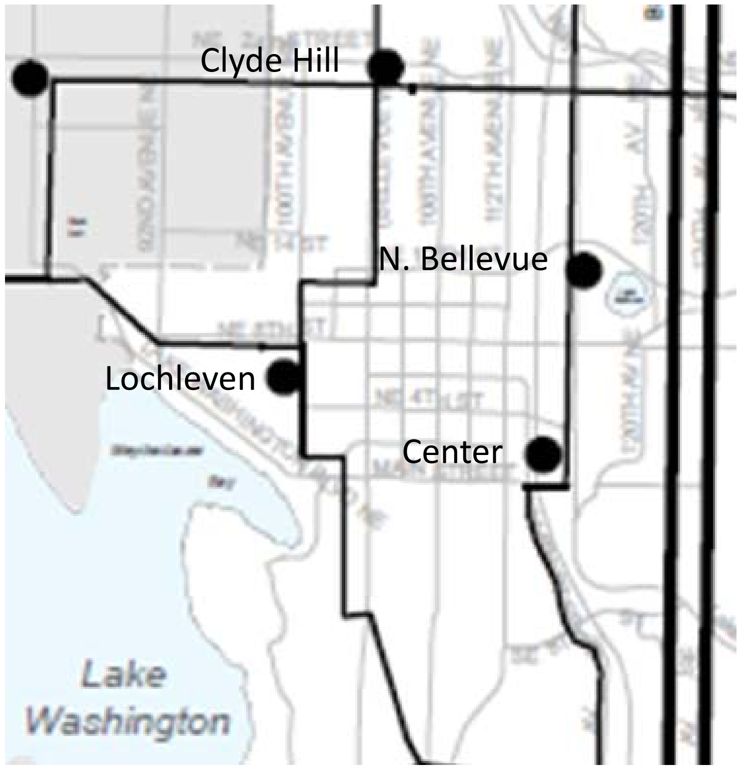


Figure 33. Downtown Substation Support

#### 2.3.7.3 Distribution System Analysis

Overhead and underground distribution methods have distinct advantages and disadvantages. For example, installing overhead bare conductors on utility poles can be considerably less expensive than underground systems. However, overhead power distribution is not feasible for locations with the density of the City's Downtown area, which therefore is fed via underground cables. On one hand, overhead installations are generally subject to more frequent electrical faults and damage, especially from falling trees and tree limbs during storms and periods of gusty wind, from automobile accidents, and from animal contact. On the other hand, while underground conductors do not normally endure these problems (although occasional animal contact does happen), when underground electrical faults occur, the outage duration is often longer. One reason for this is that the fault locations are not readily observable so identification of an underground system fault is time consuming, and access to the fault location is typically difficult because of safety and physical access issues. Consequently, repair times are generally greater for underground cable systems than for overhead systems. This impacts the outage duration statistics.

While in general, underground systems should have fewer faults per circuit mile than overhead transmission circuits, they are often subjected to flooding of the vaults and workmanship issues related to joints or splices that can affect the reliability of the circuits. That is, underground systems are not as robust and forgiving as overhead circuits are. These issues are reflected in the actual failure statistics as discussed in Section 2.2.3.3.

#### 2.3.7.4 Comparison to Other Utilities

Some older utilities use a low voltage network that typically operates at voltages that can be directly used by the power users. This means voltage levels at 480 V or 120/208 V. The load flows in these types of systems are not easily monitored and faults frequently lead to underground vault explosions since faults in cables of such a system will often burn free. In younger, modern cities, the power distribution is typically handled as it is done in Bellevue using 15 kV or higher class distribution cable systems, often with redundant feeder cables to supply the loads. In modern high rise buildings, 5 to 15 kV class substations are sometimes placed on many of the floors up through the building. Since PSE began to install underground cables a long time ago for the Downtown area, it does not have the redundant feeder cables often used for critical loads in newer cities. PSE has therefore installed a number of unloaded reliability circuits, which can be switched to feed power to customers affected by a cable outage. Thus, PSE’s system design compares well with other cities with which Exponent is familiar.

#### 2.3.7.5 Recommendations

- The City needs to decide how to approach conversion of overhead distribution lines, used primarily in the residential areas, to underground systems, which requires special funding mechanisms.
- PSE needs to continue to reinforce the distribution system to meet the N-1 criteria for the entire City.

### 2.3.8 PSE’s Substation Designs

#### 2.3.8.1 Transmission Substations

PSE has built, owns, and operates transmission substations operating with voltages up to 230 kV for its bulk power supply. These incorporate large power transformers, which are used to reduce the voltage for distribution of power at 115 kV. Most of the substations used for power infeeds to load areas contain transformers rated 25 MW that are used to reduce the voltage from 115 kV to 12.5 kV for power distribution using cables and overhead distribution lines. The power is then stepped down to voltage levels that can be used by PSE’s customers by means of underground vault transformers, pad mount transformers placed aboveground, or pole top transformers placed on the distribution power poles close to residences.

The Sammamish North King substation is one of two bulk power substations feeding power into Bellevue. As is shown in Figure 34, bulk oil circuit breakers are used for switching of the 230 kV lines and buses. However, as can be seen in Figure 35, a sulfur hexafluoride (SF6) circuit breaker is used in one 230 kV breaker position. According to PSE, oil breakers are replaced by SF6 circuit breakers when the oil breakers are no longer maintainable or repairable if they fail. This can be expected to reduce the maintenance costs since oil breakers require frequent maintenance whereas SF6 breakers are almost maintenance free.[52] Figure 36 and Figure 37 show the same mixture of oil and SF6 breakers in the 115 kV switchyard at Sammamish as in the Lakeside switchyard.


IMG_1893 resized.jpg

Figure 34. 230 kV Switchyard with Bulk Oil Breakers at Sammamish Substation

52 Oil breakers generate an arc under oil when they interrupt currents. This degrades the oil. Also, the breakers are exposed to ambient air and will therefore absorb moisture, which also degrades the oil. Frequent oil testing is therefore necessary. If the oil quality is below minimum standards, it needs to be reprocessed or replaced. SF6 breakers are installed in a completely sealed tank and require only a minimum amount of testing and monitoring. Both types of breakers require inspection and possibly replacement of internal components after interrupting high level, long duration, short circuit currents.


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Figure 35. SF6 Circuit Breaker at Sammamish Substation

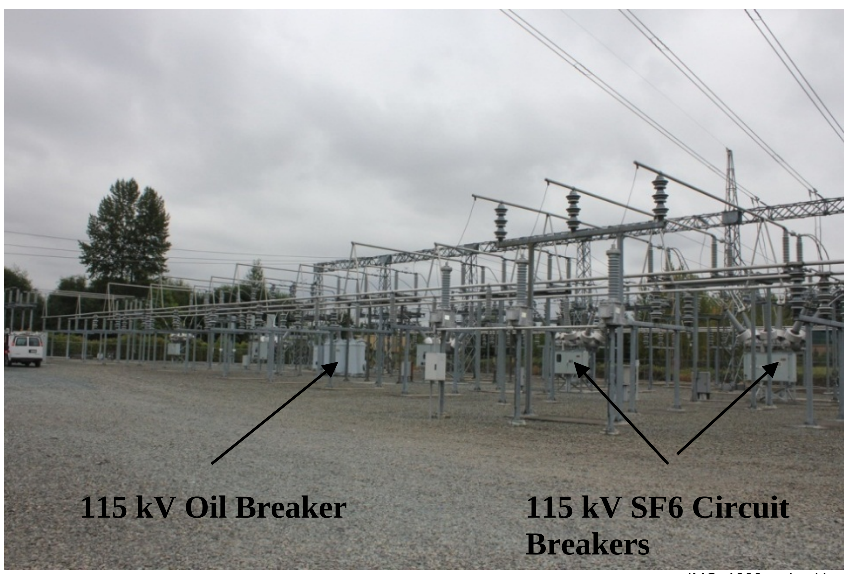


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Figure 36. 115 kV switchyard with a mixture of bulk oil and SF6 circuit breakers at Lakeside Substation

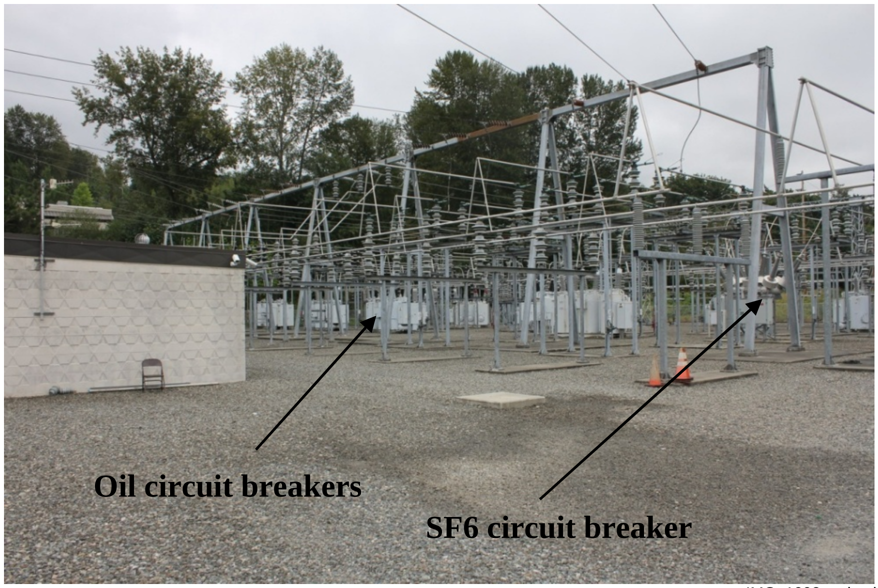


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Figure 37. Lakeside 115 kV switchyard

Figure 38 shows a new 325 MVA transformer that was installed a short time ago to replace a transformer that failed. The installed transformer was a spare that had been procured by PSE in case of a failure of a transformer of this type. Since PSE has established 325 MVA as the rated power for bulk 230/115 kV transformers, PSE is able to have one spare high power transformer to be used in case of any bulk power transformer failure. This enabled PSE to restore the Sammamish substation to normal operation in a short time after removing the failed transformer. It could have taken from 10 to 18 months to obtain a replacement transformer, during which time the station would have had to operate at reduced capacity. PSE demonstrated in this case that it pursues a prudent strategy of spare parts inventory. Figure 39 shows that the new transformer is equipped with an on-line gas-in-oil monitoring device, which should enable early detection of many incipient transformer failures, which should reduce the cost of future transformer repairs.

The Sammamish substation appears to be relatively well designed to survive at least moderate earthquake forces. The transformers are welded to the foundation and if the breakers are also welded or secured to their foundations, they should remain in place during an earthquake. The station for the most part uses equipment placed directly on ground level foundations, which reduces the risk of amplification of earthquake forces. One potentially weak point might be the attachment of the flexible connections shown in Figure 40, since some experience from other earthquakes has demonstrated that flexible conductors attached to the overhead structure by means of suspension insulators have failed and fallen down to the ground. However, in case of a severe earthquake, the power supply is not likely to remain after the event. But such damage would be easy to repair and if the equipment is not seriously damaged, it should be relatively easy to restore the power and to put the system back in operation.[53] An assessment of the dynamic forces on the suspension insulators caused by earthquake forces would possibly reduce the risk of damage to the substation and would be a prudent use of resources.

[53] Experience has shown that the transformer breakers will be tripped because of sudden pressure or Buchholtz relay operations from the transformer protections. However, if the transformers are not damaged by the earthquake forces, restoring power is a simple operation.

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Figure 38. New 325 MVA Transformer at Sammamish Substation


IMG_1898 resized.jpg

Figure 39. Transformer equipped with a modern on-line gas-in-oil monitor at Sammamish Substation


Figure 40. Suspension insulator string that might be vulnerable in case of a major earthquake

Figure 41 shows a section of the protective relaying system racks in the Sammamish substation. It shows that PSE has installed newer, microprocessor-based, digital protective relaying equipment in the station. These types of relays record the data sample sets associated with power system disturbances, including information about output commands to open (trip) circuit breakers or to initiate other functions needed to isolate a fault on a line or in a piece of equipment. These types of relays also typically estimate the location of a fault, which enables the power system operators to dispatch crews to a location close to where the fault most likely occurred. After the event, the recorded information can also be used to assess if the protective relaying functions were executed properly, if the circuit breakers operated as they should have operated, and if the circuit breakers potentially suffered from high fault current duty requiring inspection of the breaker contacts. The information provided by digital protective relays has many uses that enable the utilities to assign resources more efficiently and to maintain equipment on a “just in time” basis, which should reduce the operating costs for the utility that uses such equipment. Figure 42 shows that digital protective relays are also installed in older switching and substations as a retrofit or upgrade of the protective relaying systems. Figure 43 shows the human interface panel connected to the SCADA remote unit in the substation. This piece of equipment enables the operators to control the equipment in the substation locally. All of this is evidence that PSE is pursuing a strategy of gradual upgrading of its aging infrastructure.

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Figure 41. Digital protective relaying installed in the Sammamish substation

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Figure 42. Digital relay retrofit in the Lakeside switching station

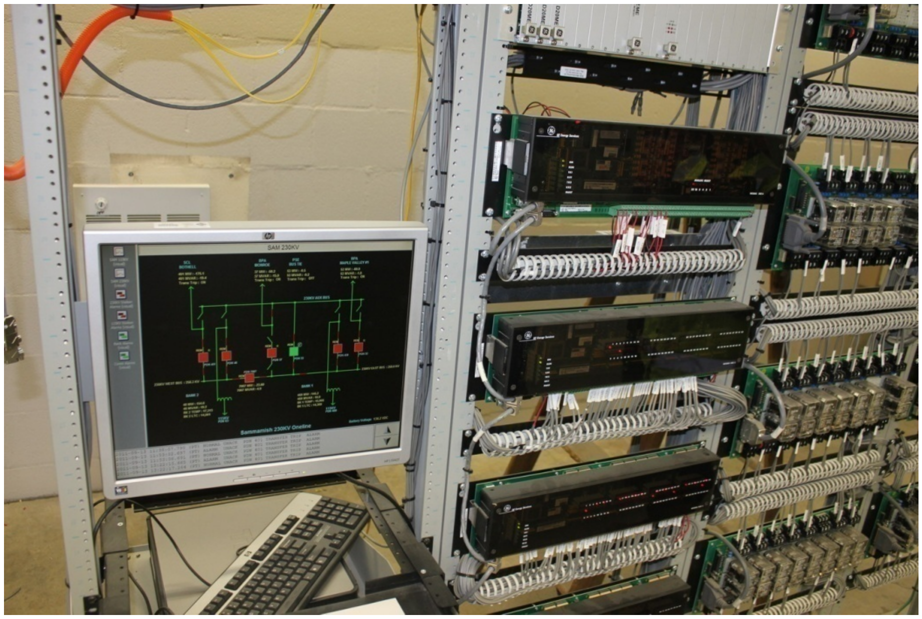

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Figure 43. SCADA system and control panel for the Sammamish substation

Figure 44 shows the high voltage, 115 kV side of the Factoria substation. In this substation, new, gas-insulated substation equipment has been installed for the 115 kV side switching equipment, which is saving space but also to some degree, reduces the probability of a falling tree branch causing a short circuit that leads to loss of power feeding the loads that are supposed to be fed from this substation. This substation also has metal clad switchgear installed for a portion of the 12.5 kV distribution system. This also reduces the probability for tree branch-induced faults to the 12.5 kV distribution circuits inside the substation. As can be seen in Figure 45, the open air distribution switchgear racks includes a number of animal guards primarily intended to prevent squirrels form climbing up into the switchgear and causing outages. Such guards or shields should help improve the reliability of the power system even though other wildlife induced outages are still probable. However, as shown in Figure 46, outages are probably more common along distribution lines than in transmission substations. [54]

[54] The birds survived at least this time.


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Figure 44. Factoria Substation


IMG_1922 resized.jpg

Figure 45. 15 kV Open Air & Metal Clad Switchgear in Factoria Substation

IMG_0891 cropped.jpg

Figure 46. Turkey Buzzards Perched on Top of a 15 kV Distribution Pole and Transformer

### 2.3.8.2 Distribution Substations

A typical distribution substation contains one or two 25 MVA power transformers, and to help ensure long transformer life, PSE has established operating guidelines that dictate the maximum power loading of these transformers under both winter and summer conditions. The guidelines are based on existing IEEE standards and available information from other utilities and substation transformer manufacturers, and are used as both a power loading maximum and asset management tool to allow system planners to effectively manage the equipment and plan for system upgrades. These maximum loadings take into account the ambient temperature, which affects the amount of power the transformers can safely handle without an expected reduction in lifespan. The maximum loading values must account for the configuration of the system at a given time. Thus, for N-0 (normal) operating conditions, a continuous power flow maximum is specified, while for an N-1 condition (where a distribution transformer must supply some portion of another transformer's normal load), a larger, short-term power rating is allowed. PSE's proper adherence to maximum transformer loading criteria is essential to asset management and also to overall system reliability.

In a similar way, maximum power loading values for individual 12.5 kV distribution feeder circuits are specified. A typical feeder circuit on PSE's Bellevue system consists of a looped feed such that a circuit breaker from one substation normally feeds certain loads, but those loads can receive an alternate (normally open) feed from another circuit breaker in the event of a loss of the normal feed. This capability increases the overall reliability of the distribution system, and is made possible through the use of manual switches on the distribution system located throughout the City. In the event that such an N-1 condition exists (such as a faulted distribution line), an individual feeder circuit could be called upon to deliver more than its usual power, since it must temporarily feed its own normal loads plus some portion of loads normally fed from another source. PSE feeder loading guidelines require no more than 83% loading of feeders in the N-0 condition but do allow for temporary 100% feeder loading during N-1 conditions.

Roughly half of PSE's distribution conductors within Bellevue are installed underground. Due to the inherent difficulties associated with locating underground faults and subsequent repairs, PSE has enacted several proactive projects to help reduce the number of unplanned outages caused by underground cable and equipment. For example, older, failure-prone underground oil-filled switches are being replaced with more robust S&C Vista SF6 switches, especially in the busy Downtown area. PSE is addressing its aging population of underground cables (some installed as early as 1965). Some of the older underground cable installations use unjacketed, concentric neutral high molecular weight polyethylene directly-buried cable, which has experienced a high failure rate. PSE replaces these cables when they are found to be in poor condition.

In locations where underground cable replacement is particularly costly, a program that uses injection of silicon into the cables has been implemented as a preventive, cable life-extension measure. Since PSE recognizes the potential vulnerability to having cables from multiple circuits in the same underground vaults, ongoing projects are underway to relocate underground cables such that underground vaults contain cables from no more than two circuits. Underground installations often make use of self-contained underground service transformers, which have a high risk of failure as they age. PSE replaces these transformers when they are found to be in poor condition (or when associated bayonet fuses blow or fail) with aboveground pad-mounted transformers, where possible, or direct underground replacement with stainless-steel tank enclosed transformers.

Overhead conductors also present special challenges. Due to the large number of tall trees in Bellevue, the overhead distribution system is subject to electrical faults from falling tree limbs and occasionally entire trees. PSE's vegetation management program normally addresses these issues, but in some areas vegetation management restrictions prevent more comprehensive removal of limbs that threaten the lines. Whereas these types of faults are normally short duration events, PSE has installed covered conductors (tree wire) in areas where vegetation management restrictions prevent more comprehensive removal of limbs that threaten the lines.[55] Animal contact with high-voltage lines is also an ongoing concern, similar to the situation within substations, where buswork and other live parts are frequented by squirrels, birds, and other animals. To reduce the incidents of animal contact with live overhead conductors, animal guards have been added where the original equipment design has been deemed ineffective (see Figure 45 and Figure 47) and newer equipment, such as transformers, comes equipped with animal guards.

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55 The insulation of these tree wire conductors do, however, reduce the probability that fuses will operate in case such a wire falls down on the ground. Tree wires reduce the number of faults resulting from contacts between a tree branch and a line. However, a broken tree wire on the ground represents an electrocution hazard but at the same time it must be recognized that all wires on the ground can be an electrocution hazard.


Figure 47. Use of an animal guard (arrow) to prevent inadvertent contact at the top of an overhead service transformer

While the transmission system uses SCADA systems for monitoring and control for its daily operations, nearly all of the PSE distribution system in Bellevue uses SCADA for monitoring only, this is mostly within the distribution substations. From both a reliability and outage restoration perspective, SCADA can be used to more quickly isolate distribution system problems and to remotely switch portions of the system that are affected, allowing power to be restored to customers more quickly.

PSE projects are addressing this enhanced functionality on two fronts. First, a pilot project is being planned that will enable several field distribution switches in the Downtown area to communicate load data to the SCADA system, while providing the capability of remote SCADA operation of those switches for system sectionalizing. Once the remote equipment modifications are made, another phase of the project will introduce automatic switching logic at select locations, such that switching and restoration decisions can be made faster. The current plan is to do this type of upgrade on several switches a year for the next few years.

### 2.3.9 System Design Summary

The results of the system design assessment are summarized below with a list of findings and observations, a discussion of potential actions, and a list of recommendations.

#### 2.3.9.1 Findings and Observations

Key findings and observations are:

- Reliability is impacted by the design of the distribution system within the City. The design of the system to provide redundancy through multiple sources (substations) to each circuit provides for faster recovery times from outages through the ability to switch power from one source to another. There remains a need within the City to improve the overall redundancy in the City, such as:
  - Completing and maintaining the reliability ring in the Downtown area to provide additional backup sources of power
  - Providing additional substation feeds to radial circuits outside of the Downtown (e.g., Phantom Lake and Lake Hills)
  - Provide switches and ties to distribution circuits to provide additional feeds to isolated circuits.
- Distribution automation is not yet utilized throughout the system. Installation of switches with SCADA, reclosers on overhead lines, and fully automated substations provides an opportunity to improve overall system reliability through better control and response to events on the system.
- Upgraded equipment is being installed at transmission substations. These equipment items represent more current technology, provide for hardening of the substations through reduced maintenance, and they are less susceptible to external events.

Potential actions to improve system reliability through system design are discussed below.

#### 2.3.9.2 Industry Practice

Most distribution systems are radial systems with a main feeder coming from a substation. Lateral branches or taps come off the main feeder to supply power to customers. For conditions requiring additional reliability, looped radial systems are used which allow for redundancy by providing the ability to switch power sources in the event of an outage to provide faster recovery. The switching is typically performed by onsite manual operation of the switches. The looped system provides higher reliability than radial systems resulting in limited long-duration outages.

Major industry developments for reliability from a distribution design perspective are:

- As described above, the use of looped radial or network systems to improve system redundancy. This design configuration provides a means for faster restoration when an outage occurs because backup feeds are available to supply power after switching (manual or automatic).
- The use of SCADA to allow for remotely-controlled (or automatic) switches and reclosers to provide faster response to faults and to reduce the duration of outages.
- Redistribution of circuit loads to allow for effective use of multiple transformer banks and to allow for effective switching during a circuit outage. This again provides a means to restore power to a circuit in the event of an outage.
- When replacing failed or aging equipment, the use of current technology provides a means to reduce equipment failure and reduce maintenance costs. Currently technology deployments include:
  - Gas-insulated substations are more compact and require less space for installation, result in reduced maintenance, and are less susceptible to external events.
  - SF6 breakers (to replace oil-filled circuit breakers) reduce environmental impacts of potential oil spills, are more compact, and require less maintenance.
  - Microprocessor-based protection relays provide better communication and data capture to evaluate events on the system and to respond to regulatory requirements.
  - Metal clad switchgear for distribution stations
  - On-line monitoring of substation equipment to improve maintenance and find problems before they occur.

  The key benefits of these new equipment features are to minimize equipment failure.

The majority of the current Bellevue system is served by a looped radial system to allow for multiple sources of power. However, much of the system is served by manual switches. PSE has:

- Ongoing projects to fully loop the Bellevue system and is increasing the use of switches and feeder ties to provide for the ability to supply power to circuits from alternate sources.
- Ongoing projects to increase the installation of reclosers to minimize recovery from faults.

- Longer-range plans to improve overall automation of the system (both DMS and SCADA within the system).

Exponent concurs with the actions being conducted by PSE. These actions are consistent with maintaining and improving reliability of the Bellevue system. These actions are intended to provide additional redundancy in the Bellevue system and the equipment upgrades are accepted industry practice to improving reliability.

#### 2.3.9.3 Recommendations

Based on the system design assessment, the following recommendations are made to improve the City's ability to be a more proactive participant in improving reliability:

- Similar to recommendations from the outage review, the City should meet with PSE on an annual basis to understand what projects are being identified and scheduled each year with the specific goal of improved reliability including system design improvements.
- PSE should continue with its implementation of current programs designed to improve overall system reliability in the City, including:
  - Continuation of system hardening projects.
  - Installation and implementation of distribution automation.

The remainder of the section provides a discussion of the work processes relative to the potential for reliability risk.

## 2.4 Review of PSE Work Practices

### 2.4.1 Scope

The outage assessment and review of the PSE system design provide input into issues that may impact system reliability. This section provides a review of the work processes that utilities use to address system expansion, aging, and reliability issues. These work processes include design practices, maintenance, capital work prioritization, vegetation management, and outage management.

### 2.4.2 Study Approach

PSE made personnel and information accessible to describe these various programs and to allow assessment of these programs relative to reliability in Bellevue. The review of the work processes was performed to allow for assessment of these work practices as they impact system reliability.

### 2.4.3 Maintenance Practices Review

Distribution maintenance processes are evolving in the industry. The typical maintenance practice for distribution assets was to run-to-failure since there is a large amount of equipment and it is relatively inexpensive and easy to replace. Additionally, there was limited automation on distribution systems so that there was limited opportunity to do on-line or remote monitoring. As the industry has evolved, maintenance practices have advanced relative to distribution assets.

PSE has implemented a maintenance program that includes the following attributes:

- Annual review of the maintenance plans based on equipment types
- Scheduling and work management of maintenance tasks in the Systems Analysis and Program Development (SAP) system
- Procedures available for all equipment on company intranet
- Ongoing review of maintenance and standards by intercompany team.

The maintenance program is reviewed annually as part of the annual budget process to define or confirm maintenance and inspection plans. A team of engineering, planning, and maintenance personnel perform ongoing reviews of the program and make recommendations for changes to work standards and maintenance requirements. A description of the maintenance process is provided based on a discussion with PSE personnel and a review of the substation maintenance standards.

#### 2.4.3.1 Maintenance Plans

Equipment and outage trends are reviewed and provide the basis of the annual plans. Based on current performance or other issues raised during the review, PSE prepares the maintenance plan. From a practical perspective, the annual plan consists of standing maintenance and inspection tasks which are modified based on equipment performance. The maintenance plan is divided into two specific areas:

- Substation equipment (which consists of all equipment inside the substation fence plus batteries)
- Distribution line equipment.

Currently, there are no Bellevue-specific maintenance programs relative to equipment items. The current maintenance programs apply system-wide. These programs are discussed below

There are approximately 400 substations in the PSE system. PSE personnel maintain and inspect the substations. Maintenance crews and inspectors are assigned to various areas within the PSE system and are responsible for performing the defined maintenance tasks. From a substation perspective, the following maintenance programs are defined:

- Monthly substation walk-through of distribution substations by inspectors. The inspectors collect substation equipment readings and review the general condition of the substation. These inspectors are capable of switching operations if necessary.

- Transformer maintenance and inspection performed by substation crews:

  - 6-month oil dissolved gas analysis

  - 3-year oil physical test

  - 6-month maintenance of load tap changers

  - 12-month overall transformer maintenance.

  There is a program to provide on-line monitoring of all of the transmission transformers, but there are no current plans for the distribution substations.

- Circuit breaker maintenance and inspection performed by substation crews:

  - Although oil-filled circuit breakers are being replaced, frequent tests of the oil quality are still needed and are performed

  - Mechanism tests on circuit breakers at defined intervals.

- Substation infrared scans are performed every 2 years to identify any potential problem areas.

- Prioritized program for replacement of banks based on age profile of the assets. There are very few outages each year associated with substation equipment failures. However, the prioritized program is replacing about five transformers per year. This program is aimed at the banks that were installed in the 1970s time frame. The purpose of this program is to proactively replace banks prior to failure.

Based on the substation outage performance, the maintenance program for substations is assisting PSE in maintaining system reliability. Substation outages have the potential to impact a large number of customers but PSE's program has been effective in minimizing substation impacts on system reliability.

PSE implements a maintenance strategy for distribution line equipment that includes inspection of some assets and run-to-failure for other assets. The distribution maintenance programs include the following:

- Pole inspections (test and treat) are performed on a 15-year cycle (distribution) and consist of visual inspection and other tests as required by PSE standards

- A pilot program is being evaluated for performing partial discharge testing of underground cable to determine if this methodology will be effective in identifying potential cable problems
- Equipment items, such as switches, regulators, reclosers, and line transformers are identified as run-to-failure components.

The distribution line maintenance is also supplemented by general infrared inspections that are intended to identify problems and eliminate potential future failures. However, this general inspection is utilized on an as-needed basis.

#### 2.4.3.2 Comparison between PSE and Other Utilities

The overall maintenance strategies employed by PSE are consistent with industry practices for transmission and in most respects also for distribution equipment. PSE employs corrective maintenance (run-to-failure); time-based maintenance and replacement for some assets (poles, banks, breakers); and predictive (condition-based monitoring) for more critical elements, such as transformers. However, some utilities have developed methods for replacing distribution transformers, such as those placed at the top of power poles based on the total energy consumed by the connected loads. The assumption is that the total energy supplied through a specific transformer is an indication of the peak load carried by the transformer, which is an indicator of the operating temperature of the transformer. Since transformers operating hot are likely to fail early, transformers carrying heavy loads are moved out and replaced by a higher capacity transformer. Such practices could avoid some transformer failures and improve the reliability of the system.

#### 2.4.3.3 Maintenance Work Management

PSE utilizes the SAP system for scheduling and work management. All maintenance tasks are entered in the SAP system and assigned due dates. The work management process for maintenance is performed in the following steps:

- The SAP system provides a monthly list of work orders by the 15$^{th}$ day of the month prior to the required task.
- These orders are assigned to crews by the maintenance supervisors, who then plan for performing the task.
- The crew completes the defined maintenance tasks within the defined month.
- The completed work order is reviewed by the maintenance supervisor and by substation operations coordinator, who closes the order.
- The maintenance documentation is then sent for engineering review and submitted to records storage.
- There is a biweekly work coordination meeting to identify any changes to the work plan. Operations requirements, clearances, and unplanned maintenance

may require modifications to the schedule, this meeting is intended to address changes. PSE also utilizes standing work orders for routine tasks.

The maintenance and inspection crews are originally scheduled for about 60% planned work, which allows time for responding to corrective maintenance and other tasks.

#### 2.4.3.4 Comparison between PSE and Other Utilities

The industry uses maintenance programs that include defined maintenance tasks for equipment items that consist of a range of maintenance tasks from run-to-failure and corrective maintenance to preventive maintenance (time-based tasks) to preventive maintenance (condition-monitored). These tasks are then incorporated into a computerized maintenance management system that provides for timely scheduling and close-out of tasks. The overall maintenance program is reviewed on a regular basis to allow improvements and changes to the maintenance program.

The use of SAP or similar programs is an industry standard for maintenance management. Many large utilities use this type of program to identify, schedule, and track maintenance tasks.

#### 2.4.3.5 Maintenance Process Analysis

The maintenance program supports the overall reliability of the electric system. Utilities that are leaders in maintenance practice incorporate an approach that defines the maintenance strategy for equipment types, reviews equipment performance to modify the strategy, and implements an effective work management program. PSE appears to perform its maintenance program well. No obvious areas for improvements have been identified except to explore the use of total metered energy to indicate timely replacement of distribution transformers.

PSE has a well-defined strategy for substation assets and based on the outage review and the overall system design, there are limited outages in Bellevue from substation events. Therefore, the PSE strategy relative to substations is effective in supporting substation reliability.

The distribution line outages are mostly related to underground cables and overhead conductors. There is currently limited ability to perform maintenance on lines. Periodic inspection (through use of infrared or other technique) may be beneficial in identifying potential failures before they occur; however, this has limited use due to the large number of distribution assets and difficulties associated with interpretation of infrared diagnostic data.

### 2.4.4 Capital Project Prioritization

#### 2.4.4.1 Scope

Capital investments made by utilities most likely lead to increased rates charged for the electric power but can also be beneficial in improving the reliability of the power system. Utilities define capital projects in response to various business drivers, such as new capacity or expansions, asset replacement, reliability initiatives, regulatory requirements, and compliance needs. Industry-leading capital project prioritization programs provide a standard and consistent set of decision parameters to define and prioritize projects within an organization. The list of prioritized projects is then matched with budget and resource constraints.

#### 2.4.4.2 Study Approach

PSE made personnel and information accessible to describe these various capital improvement projects and the process used to select projects for implementation. The review of the work processes was performed to allow for assessment of these work practices as they impact system reliability.

#### 2.4.4.3 Prioritization Process

PSE utilizes the following criteria in determining infrastructure assessment as stated in their IRP:

- Load growth
- Reliability
- Regulatory compliance
- Aging infrastructure
- External commitment
- Integration of resources.

PSE has a capital project tool (IDOT) that is used for all proposed projects. Projects are typically proposed by the transmission and distribution (T&D) planners for the electric system, but all PSE capital projects are entered into the IDOT system. The requirement for entry into IDOT is that a proposed project has a scope of work, proposed budget, and evaluation against a standard set of criteria. The projects are entered into IDOT and receive an IDOT priority number. This process places the project in a prioritized list against all other projects. If the project makes the cut relative to budget and resources, then the project is appropriately scheduled. If a project does not make the cut, the project remains on the list and gets updated for the next review period. PSE typically performs the capital project assessment with the annual budget cycle, but projects are reviewed on a monthly basis.

#### 2.4.4.4 Capital Project Review

PSE planners are assigned specific areas in the PSE system. The planners are responsible for reviewing the performance of the distribution circuits and recommending projects for consideration in the capital project prioritization process. Given the slow growth over the past few years, there is limited need for capacity additions and reliability programs have gained higher priority. PSE has established the following programs that contribute to improved system reliability across the PSE system:

- **Reliability Initiative:** This program addresses the addition of reclosers into the system to provide for automatic re-energizing of lines when a fault on the line occurs. The recloser will automatically reclose into the fault and if the line holds, the fault is gone. Reclosers might make several attempts to clear the line. This reduces the restoration time since crews are not required to manually re-energize the line.

- **Bellevue Reliability Program:** This program exists to reinforce the Downtown area of Bellevue. Since this area is one of the densest areas of the PSE system, this reliability program exists to enhance the redundancy and reliability of the Downtown system.

- **Underground Cable Remediation Program:** This program is a system-wide program to address older cable. The program consists of remediation (silicon injection) to extend the life of the cable and cable replacement (cable older than 30 years). There has been an ongoing effort to replace underground cable in Bellevue to address reliability concerns.

- **Aging Asset Replacement:** This program is aimed at proactively replacing aging equipment assets, and in Bellevue is primarily aimed at replacing older switches.

- **Overhead Conductor Tree Wire:** This program is aimed at areas that have significant numbers of overhead line outages due to tree-related events. The use of tree wire is intended to reduce the potential for faults (and outages) from tree branch contact with overhead wires. The tree wire is a covered conductor so that it does not create a fault upon contact with a branch. The tree wire is also stronger so that it can resist some tree branch impacts.

- **Distribution Automation:** The use of automation in distribution systems is increasing and companies are investing in distribution automation to improve reliability. PSE is undertaking a program to install distribution substation automation to improve distribution system visibility and to allow for a basic level of control by the operators.

In addition to these system-wide programs, PSE also reviews circuits of concern and proposes specific projects to address these issues. Over the past 5 years, PSE has performed or is in the process of performing about 80 capital improvement projects in Bellevue. These projects include 20 projects related to reliability outside the Downtown area and 20 projects in the Downtown area. These projects were specifically designated as reliability projects and include projects such as tree wire installations, feeder and switch replacement, feeder ties, and reinforcement of the Downtown circuits. These projects are intended to address issues identified on circuits in Bellevue and to provide for improved reliability.

#### 2.4.4.5 Comparison between PSE and Other Utilities

Prioritization and selection of capital projects are normally evaluated in the industry against a defined set of criteria consistent with the utility's goals. These criteria apply to all projects and are used to guide decision-making around budgeting and scheduling of projects. Management of the capital program also requires ongoing evaluation of new project requests against the standard criteria and decisions to adjust the portfolio of projects, as required.

PSE has employed a consistent approach to project prioritization. This system is used for all company capital projects, gets a significant management review, and represents a good industry practice.

#### 2.4.4.6 Capital Project Process Analysis

The capital projects identified in Bellevue have very specific impacts on system reliability. While many of the projects are related to aging asset replacement, these projects (over the past 5 years) are specifically identified as addressing reliability in Bellevue. These projects are part of the system-wide upgrades, as well as circuit-specific improvements. As identified in the outage analysis and system review, there are several concerns being addressed by the capital projects:

- Underground cable failures (cable replacement and remediation)
- Tree-related outages (tree wire)
- System reinforcement (completion of the Downtown reliability loop and feeder ties to improve performance on radial lines)
- System restoration (SCADA, reclosers).

Many utilities are now focusing on initiatives related to underground cable remediation and distribution automation. As reliability improvement is being required, utility initiatives related to reliability are receiving favorable rate case reviews and dispositions.

### 2.4.5 Vegetation Management

#### 2.4.5.1 Scope

Vegetation management is a major issue relative to the reliability of Bellevue's overhead system.

#### 2.4.5.2 Approach

PSE made personnel and information accessible for the review of the vegetation management process. In addition, some areas in the City were inspected on foot.

#### 2.4.5.3 Vegetation Management Review

The environment in the City with its tall and dense trees is a valued treasure to the City and its citizens. However, this environment places a stress on the overhead system assets. The interaction of tree limbs and branches with electric wires creates faults which may develop into outages.

From a reliability perspective, the impacts of tree and weather events on the overhead system require attention. Selected use of tree wire to preclude faults and the ability to utilize reclosers and automation to limit outage durations will provide some increased overhead reliability.

PSE utilizes a 4-year cycle to trim trees. It also implements programs to identify at-risk trees and provide alternatives when trees need to be removed. The City, however, has restrictive rules regarding tree maintenance as defined in the Franchise Agreement, which sets the limits for what PSE can do.

#### 2.4.5.4 Vegetation Management Analysis

There is a natural conflict between the desire to have large and beautiful trees in the neighborhoods and to have reliable electric power delivery. It is really a choice between one or the other, since the goals are incompatible. The rules for vegetation management are under the control of the City and therefore, any changes will have to begin by changing the City's ordinance related to vegetation control.

Undergrounding of the distribution circuits is an option if a formula for how to obtain financing for such an investment can be found. However, even underground systems, as can be seen from the reliability statistics presented above, do not remove all of the reliability problems but it would reduce those outages caused by trees or tree limbs. The requirements for underground conversions were discussed earlier in Section 2.2.6.4.

### 2.4.6 PSE's Operations Centers

#### 2.4.6.1 Scope

PSE is currently installing and implementing a major change to its system information technology. The current projects include an integrated system to upgrade the systems for geographic information management, customer management, outage management, and distribution management. This effort is a major, multi-year initiative to upgrade and modernize their utility information architecture and systems. The upgrade of the information technology systems is a major step to improving reliability now and in the future.

This review covered a review of the existing systems used for operation and control of the system as well as a look at the plans and states of the development of the new systems used for power generation dispatching systems, power delivery systems for T&D of electric power, as well as dispatching people to perform operations in the field and repairs of equipment. The review also included systems available for management of major events that can be classified as emergencies.

#### 2.4.6.2 Approach

PSE made personnel and information accessible for the review of its operations centers. This included the Emergency Operations Centers (EOCs), storm centers, dispatch center, and load center. A visit arranged to review the center facilities and operations was also included. This review also included a review of the KEMA Consulting Company (KEMA) report prepared after the 2006 storm event.

#### 2.4.6.3 Emergency Operations Center Review

If a major storm is forecasted or other emergencies arise, PSE will staff one of its EOC.[56] The EOC is opened up for operation if there are reasons to believe that an approaching storm could be expected to cause widespread outages. It is also staffed if an event such as an earthquake or other non-predictable event were to occur and cause major power system damages. The main EOC is located in the same building as PSE's main power system control center.

The EOC is equipped with computer and communication systems that will give the PSE managers, charged with management of the emergency, the visibility of the situation needed to direct PSE's resources required for handling the event. It has links to outside agencies and news media with which PSE has to interact. This includes links (mostly telephone links) to county and city EOCs. The staffing in PSE's EOC includes the following:

- PSE managers for:
  - Crew dispatching
  - Resource allocation
- Communication people from PSE
- News media
- PSE's control center.

The centers are also staffed for training purposes to ensure that the people required to be at the centers know how to perform their assigned duties. The staffing is rotated among PSE's management personnel such that there will always be trained people available to staff the centers at any time (day or night) of the week.

The EOC is being upgraded with systems connected to the control center. A display providing minute-to-minute information about the electric power transmission system has been added.

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[56] PSE has one EOC and one backup EOC in case the main EOC becomes unavailable or is inaccessible.

#### 2.4.6.4 Storm Center Review

PSE dispatches crews to assess the damages and for repair of damaged systems or components from so called storm centers. These centers are basically paper-driven with large map boards for tracking failure reports and crew assignments. Although this seems to be an "old fashioned" approach, it is inherently a rugged system that can operate almost without any complex support systems for as long as telephone and radios are operational. At the center that was visited, a large amount of spare parts and materials needed for repair of lines and cables was also available.[57] That is, the storm center design seems appropriate for the situations facing PSE.

#### 2.4.6.5 Outage and Distribution System Management Review

PSE utilizes software tools to help track outages, customer feedback, and maintenance tasks. Customer relations management software known as ConsumerLinX (CLX) is used to log customer-reported outages and other feedback, similar to a conventional customer contact center, but with the added advantage of a networked system. Use of the tool allows many individuals within the PSE organization to be aware of the latest reported outages and for the correct response to be undertaken (send evaluation personnel, alert maintenance crews, etc.). Calls are still received by a reception person who then enters the information manually into CLX, which can then be queried by appropriate individuals as needed. Additionally, PSE uses another software tool called SAP to track maintenance tasks, parts inventory, and repair status. Generally speaking, CLX is used for customer-originated information and SAP is used for PSE-originated information. Only limited communication and data sharing is possible between the two systems. Furthermore, support for the CLX has become expensive, making the system difficult to maintain.

Today, the outage management system relies on communication from the customer regarding an outage and an onsite review (or call backs) by PSE personnel to confirm that power is restored. There is limited ability to use the automated meters installed throughout Bellevue to identify the location of outages and to ensure restoration. However, a review of the CLX system shows a quasi-real time system that has the ability to provide timely information to customers. All customer contacts are recorded and included in the CLX database. PSE office and field personnel also have the ability to update the CLX tool so that status of outages can be obtained. Therefore, even though PSE can obtain status of outages, the outward communication of status is limited. The current system does not provide for web access updates for outage events so the only means of tracking outage status is through calls into the utility. The inability to access updated status information has been raised as an issue during the stakeholder review.

In the event of a major outage, this system may get overwhelmed with the volume of information. The ability to provide timely status updates and communication with customers is very difficult.

[57] Concentrated storage of unsecured spare parts would not be recommended in areas that could be impacted by severe earthquakes. Although this is possible in the northwest, the most likely severe event would be a repeat of the 2006 storm, in which case the spare parts depot would probably not be seriously impacted.

PSE is planning a series of upgrades that will address not only the shortcomings of the legacy CLX, but add new and important functionality as well. The new systems will benefit both the electric and gas portions of PSE's business. These upgrades are driven by the following objectives, as stated by PSE:

- Through improved ability to track customer data and maintain and utilize electric/natural gas infrastructure data, PSE will be able to more efficiently perform system maintenance
- PSE will be able to restore customer power in a more timely manner by targeting where the electric outage is within the network
- The new systems will allow PSE to proactively provide more detailed communications to our customers during power outages
- Improve PSE's ability to deliver better customer service by providing more accurate information.

#### 2.4.6.6 Outage Management System Upgrade Review

The KEMA report concerning the 2006 storm event contained recommendations for an improved Outage Management System (OMS). As a result of this, PSE selected General Electric's (GE) Smallworld™ platform for its new OMS for both gas and electric systems.[58] PSE has also purchased a new EMS.

A geographic information system (GIS) will be connected to the new EMS. It will be used both for the gas and for the backbone electric systems to support OMS. However, it has been found necessary to do 100% field audits to establish circuit-by-circuit connectivity to get details such as phasing information correct. This is a time-consuming, but necessary process. The rollout of the GIS portion is expected to begin early 2012. The system is expected to be fully completed by 2017, but portions of the system are being rolled out as soon as they are ready. However, as discussed below, there are limits on how much power restoration can be improved by means of better information technology systems.

##### 2.4.6.6.1 Outage Management Process

###### *2.4.6.6.1.1 Tree Fault Sequence of Events*

If a tree branch or a tree falls and causes an overhead distribution line fault, the fault might trigger fault detection systems that will open (remove power from) the circuit, followed a short time later by automatically reapplying power to the circuit. A momentary tree branch contact or an animal that might have caused the fault might no longer make contact with the line or might have caused fuses to melt as a result of an overcurrent caused by the fault, in which case the power will be restored automatically to some part of or the entire affected circuit.

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[58] Reference 13.

If the first attempt to restore power is unsuccessful, additional attempts will typically be made with a longer time between the time the circuit was opened and the power is reapplied. If none of the automatic power restoration attempts are successful, the process will stop and the circuit will remain open. Such faults can be detected by reports from the automatic meter readers (AMR) installed in PSE’s system reporting a loss of power or by someone calling into PSE reporting the outage.

###### *2.4.6.6.1.2 Present Fault Identification and Repair Processes*

At present PSE is primarily relying on phone calls to obtain outage information even though all of the meters connected to the affected circuit should have reported the outage. The AMR system information will only give information about the loss of power when it first happened but the callers might provide additional information about where the fault is located and the nature of the fault. However, if additional tree branches or trees fall on other parts of the line, such information will only be received from callers, who provide additional information. Especially, during a storm-related event, multiple tree-related damages to the overhead lines have to be considered.

In case of a permanent outage, there is no alternative for PSE but to send a qualified person out to inspect the damage or damages. This person will be able to determine the nature of the damage and provide information to the repair crews needed to identify what resources will be needed for the repair. The person sent to inspect the damage can also operate switches to isolate the faulted area and restore power to the parts of the circuit that are undamaged. However, the area served by the damaged part of the distribution circuit will be without power until the repair has been completed.

###### *2.4.6.6.1.3 New Information Technology Aspects*

Installation of additional control systems, automation and information gathering equipment, in the power system will reduce the time between the occurrence of the fault and the restoration of power to unaffected circuits. The added information provided by these systems will enable the fault location to be more precisely identified by means of fault location features installed in the monitoring equipment. Manually executed commends to operate switches from a remotely located operating center can be used to isolate the fault region and to restore power to the unfaulted regions. The rest of the process, including the inspection of the damages and the dispatching of repair crews as described above, must still take place.

###### *2.4.6.6.1.4 Severe Storm Events*

A severe storm, even such as the one experienced in 2006, poses several additional problems that have to be addressed. The first of these being that the amount of reported damages is reaching a level where resources are not available for the initial inspections that are needed to identify what needs to be repaired. The second is that if the power is lost to the 115 kV substations, there will be no information coming from the monitoring systems since these systems depend on recording voltage and current excursions from normal values to identify faults. In this situation, PSE would have to send out inspectors to identify where faults have occurred and where repair is needed. Automatic restoration of power or even manually initiated power restoration sometime after the initial power restoration attempts described above, would be hazardous to people and could not be attempted until the circuits had been inspected since the risk of electrocuting people close to downed conductors would be too great if such faults were not first eliminated.

During severe storm events, such as the one that affected Bellevue in 2006, PSE will be facing additional logistics problems. There is a limited number of qualified inspectors to make the damage assessments, and a limited number of repair crews readily available to perform the work. In addition, there will probably be a lack of spare parts, including a limited supply of the conductor material needed for the repair. While PSE has access to repair crews from outside the area and also access to spare parts and material from utilities located in other areas, the time to get crews and materials in place and working to restore power in Bellevue, would be significant.

###### *2.4.6.6.1.5 Downed Conductor Hazards*

Downed conductors represent a real hazard to people because such faults might not melt fuses to isolate the fault or might not open circuit breakers to remove power from the affected circuit under all conditions. There is no technology available to detect such faults with 100% certainty so a conductor in contact with ground always has to be considered as live; that is energized, until proven otherwise. Therefore, there is a limit to how much the outage duration can be reduced by installing additional monitoring systems and automation. Manual inspections are still needed to keep people safe.

#### 2.4.6.7 Distribution Management System Upgrade Review

PSE has planned an upgrade of the distribution systems to incorporate automation for improved system visibility and control. These automation upgrades include the addition of equipment that allows for SCADA to both monitor system status and to provide for automatic or operator-initiated control. The installation of DMS to enable enhanced distribution automation is also being performed by many utilities.

Release of the EMS Version #1 system will take place in October 2012. This will be an enhanced system version, but it will not yet have the DMS installed. GE just purchased the company that will furnish the DMS portion, so it is not yet fully integrated into the Smallworld platform. This will be completed by mid-2013.

The SCADA system portion will be implemented first beginning in 2012. All call centers will have a read-only view of all known outages. The EMS system will have programs installed that will enable the system operators to perform a load analysis for the outage area.[59] The operators will then be able to decide on how to switch loads to restore as much of the system experiencing outage as possible without overloading any of the circuits. This will speed up the power restoration work. When this is coupled with remotely operating switches, the time for power restoration will be even shorter.

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[59] System operator is the title used by PSE for distribution system operators. Load office is used for the PSE's transmission system segment.

The roll out of the system is scheduled to begin in July 2012, covering the Skagit area and then proceed clockwise until all of PSE's service territory is covered. A part of the system will be website links to outage maps for the affected cities[60]. There will also be automated updates of outages fed to the Customer information System (CIS).

These developments represent a significant investment by PSE in a modern DMS. Once the system is fully built, it should result in a significant improvement of PSE's abilities to handle major outages.

PSE has had an AMR system installed for many years. These are early versions of "smart meters," since they can and will report if a metering point has lost power. However, in the case of a major outage, the AMR system chokes because there are too many lost power reports flooding the system. Therefore, PSE still relies on customer calls for information about outages.

It is sufficient for PSE to know if a transformer has lost power, since that defines the outage area. This is known as soon as one customer has called in and reported an outage. Once distribution SCADA modules are installed along the distribution lines, this information will be immediately available to the system operators.

The new information platform will have an improved CIS to replace the CLX application. To perform this task, SAP's Customer Relations & Billing system will be installed. The new system will integrate all PSE-customer contacts, thus consolidating inquiries, billing, requests for service, and outage notification into one place. The system will eventually provide the latest outage information to the public via an online portal, enhancing customer awareness regarding the status of restoration from power outages.

#### 2.4.6.8 Load Center Operation Review

PSE has a separate computer and communication system for management of its generators or power purchases and high voltage transmission system. This system has separate work stations for the following functions:

- Power dispatching
- Transmission system control
- Outage scheduling
- Load forecasting
- Contingency analysis.

The operator responsible for having sufficient power to serve all of the loads deals with the operation of the power plants under PSE's control, as well as obtaining the purchased power from other power producers.[61] A part of this system is a function that calculates a so-called

[60] These will only be useful if access to the Internet is available.

[61] At the time of the visit to the load center, the purchased power was up to 800 MW.

Area Control Error, which is used to balance the generation to match PSE's load on a minute by minute (or shorter time base) basis.[62]

The high voltage transmission system dispatcher monitors the state of the transmission lines, breakers, and transformers. If a line fault occurs such that the line is lost, it is the role of the dispatcher to manage any line overloads arising as a result of the failure and to restore the lost line back to service, if at all possible. The transmission line dispatcher also manages all requests for line outages or work clearances associated with the high voltage transmission system.

Outage scheduling requests require special studies for those segments of the system that must be de-energized to enable people to perform maintenance or other tasks. These studies take the expected loads, as well as other outages in place or requested, etc., into account to make sure that the outage can be handled safely, even if other unforeseen events were to occur during the outage. These are time-consuming tasks performed by specialists and are typically performed one or more days ahead of the time for the outage. There is a special workstation for such activities.

Load forecasting is also a special function. Historical loads, modified by the predicted weather for the studied time period (typically at least a day ahead), are used to forecast the future loads for each hour of the day. This becomes the basis for scheduling of both power generation and procurement to support the predicted load.

Contingency analysis is also performed in the load center. This function requires information about the system states in the generation and transmission systems operated by other utilities in the region, since abnormal system conditions in neighboring systems could impair the operating safety of PSE's system.[63] The contingency analysis process steps through the loss of any single component in the power system to determine if the system is still able to deliver power to all of the connected customers. Often, the process also includes the loss of any second component when one component is out of service. (This is the N-1-1 contingency where N is the number of connected elements.) In this case, the objective is to minimize the number of customers affected by the two outages. Since not all of the system states are known, the systems for this contingency analysis also utilize sophisticated statistical processing techniques to estimate the conditions of the unknown states.[64] This program is called a state estimator. It is a very important part of the contingency analysis because it can identify if the information about the system contains errors and where those errors most likely exist. A special workstation is often used for this analysis. Such a workstation is used in PSE's existing system.

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[62] If load and generation is not balanced, the electric clocks driven from the AC system will not keep accurate time, if the load is less than the generation, the power system frequency is above 60 Hz (cycles per second) and if the load is higher than the generation, the frequency is less than 60 Hz. BPA performs the function to keep the frequency constant and the time accurate from midnight to midnight.

[63] In 1994, an unknown scheduled line outage in BPA's system caused a collapse of the entire west coast power system when a new disturbance of the system arose.

[64] A state is a general way of referring to a mathematical element in an equation. For example, a line's connection status is a state element. (If the line is out of service, the state takes on a different value than if the line is connected.)

PSE is in the process of acquiring a new EMS system. Although the existing system is functionally quite adequate, the hardware needs to be upgraded. This new system will perform essentially the same functions as are being performed in the existing system, but with different hardware and new program packages. It will also be built to interface with the new communication systems being installed, or planned to be installed, in the near future by PSE.

#### 2.4.6.9 Comparison between PSE and Other Utilities

Current utility trends are to increase the use of automation within their distribution systems. The automation includes both information technology systems as well as equipment to enable the visibility and control of their distribution systems. The systems include DMS, OMS, and customer management systems. These systems improve response to outages through the faster availability of data to identify location of faults, automatically switch power sources, and provide timely information to staff and customers.

From an outage management perspective, most utilities are moving away from manual systems to computerized systems that allow for more rapid update of information and communication with customers. Industry experience from major storms identifies the need for integration of the GIS, customer interface system, and OMS to manage and communicate information during outages. The integrated systems provide for more visibility on identifying outage extent and restoration, updating status, and communicating results. These computerized systems provide for multiple locations to share and view outage status.

The use of DMS is currently being included in utility plans. Current industry data indicate that approximately 20% of utilities have active DMS. However, because these systems are also required for enabling future applications of Smart Grid technologies (e.g., management of distributed generation on the system, effective use of Smart meter technology to allow for improved customer interface and improved system operations), many utilities are embarking on installation of DMS to increase system visibility and system control.

PSE is implementing an integrated OMS to improve outage reporting and status information. Many utilities provide outage status through their utility web-sites under the assumption that their customers have access to the web even during outage events, which might not be correct.[65] This functionality is based on the use of computerized systems that increase visibility into system status and that allows for on-line reporting by field staff. This information is updated in real-time and communicated quickly to customers.

### 2.4.7 Recommendations

Based on the work process assessment, additional recommendations include:

- Similar to previous recommendations, there are many programs underway at PSE to improve system reliability. It is recommended that the City meet with PSE on

[65] AM radio should be considered in addition to other communication means during major disturbances because most people would have access to AM broadcasts by means of a car radio.

an annual basis to understand what projects are being identified and scheduled each year with the specific goal of improved reliability. There are several programs underway to address prevention of outages and to reduce duration of outages. The City can monitor progress and the extent of those programs focused on improved reliability.

- PSE should continue with its implementation of current programs designed to improve overall system reliability in the City, including:
  - Upgrade of its information technology infrastructure, including implementation of the OMS and DMS.
  - Installation of distribution automation.
  - Consider a replacement program of distribution transformers based on estimated peak loads as a surrogate for operating temperature. This could reduce the number of transformer failures, oil spills, and also improve the reliability of the distribution system.
- PSE is deploying a new OMS system over the next year that should provide improvement in overall outage communications. After deployment, it may be appropriate for selected City personnel involved in emergency response to understand the capabilities to assist in communicating to the Bellevue community.

## 2.5 Current System Assessment Recommendations

**Recommendation Current 1:** Reliability Progress

**Finding:** PSE has several programs underway to reduce the number and duration of outages, including:

- Hardening of the Downtown system
- Underground cable life extension and cable replacement
- Equipment replacement (older switches and transformers)
- Review of City circuit performance to address underperforming circuits
- Installation of reclosers
- Installation of SCADA
- Major information technology upgrade, including outage management and distribution management.

**Recommendation Current 1:** The City can and should proactively monitor progress and the extent of those programs focused on improved reliability of the City's power distribution system. This will require that the City add staff with power system expertise.

**Recommendation Current 2:** Reliability Progress

**Finding:** PSE has ongoing reliability initiatives and performs system-wide and targeted projects to improve system reliability.

**Recommendation Current 2a:** The City should track the reliability impacts experienced in the various neighborhoods. Since, in the future, PSE will be reporting additional reliability information including storm outages, the City can utilize this information to determine the effectiveness of the various reliability programs and projects, and to work with PSE in identifying circuits requiring attention. A fast track implementation of system improvements is an option for the City to explore with PSE, although accelerated investments might have a negative impact on the power rates.

The tracking of reliability performance is a trending metric that indicates how the system performs over time. Reliability can be tracked with and without storm information to determine how effective various projects and programs affect reliability. For example, if equipment changes are made, such as replacement of underground cable, then expectations are that equipment failures on these circuits should be reduced and the City can track this performance based on information provided in PSE's annual reliability reports to the City. The number of outages reported on these circuits would then be a measure to be used for the evaluation. If feeder ties are added or SCADA and other distribution automation solutions are put into place, then these projects or improvements should show an overall impact in total customer outage durations. Again, the City can assess these based on the information provided in PSE's annual reliability report to Bellevue. This type of assessment will provide the basis for the City to work with PSE on overall reliability improvement.

**Recommendation Current 2b:** It is recommended that the City meet with PSE on an annual basis to understand what projects are being identified and scheduled each year with the specific goal of improved reliability. There are several programs underway to address prevention of outages and to reduce duration of outages. The City can monitor progress and extent of these programs focused on improved reliability

**Recommendation Current 3:** Undergrounding Opportunities

**Finding:** Opportunities exist to advance undergrounding of lines by inter-utility cooperation.

**Recommendation Current 3:** The City should investigate opportunities for additional undergrounding of distribution lines through coordination of multiple-utility projects and evaluation of funding for conversion of overhead lines to underground cable circuits by forming local improvement districts. Further, the City needs to decide how to approach conversion of overhead distribution lines, used primarily in the residential areas, to underground systems, which requires special funding mechanisms.

**Recommendation Current 4:** Vegetation Management

**Finding:** The visual review of overhead circuits indicates that there are many substations and lines located in heavily wooded areas and the only way to significantly improve reliability is to perform more comprehensive tree trimming.

**Recommendation Current 4:** The City should review its vegetation policies specifically in the areas of substations to look at alternate vegetation approaches specifically where the risks for large scale disturbances related to vegetation issues is high.

**Recommendation Current 5:** Outage Management System

**Finding:** PSE is deploying a new OMS system over the next year which should provide improvement in overall outage communications.

**Recommendation Current 5:** After deployment, it may be appropriate for selected City personnel involved in emergency response to learn the capabilities to assist in communicating to the Bellevue community.

**Recommendation Current 6:** Recommendations for PSE

**Finding:** Several key components of high system reliability are within PSE's control.

**Recommendation Current 6a:** To achieve high reliability of the power supplied via the 115 kV power transmission lines, it is recommended that the system be reinforced to handle all N-1 contingencies by adding 115 KV transmission lines to the substations feeding the Downtown area.

**Recommendation Current 6b:** For the substations which at present are fed from a single 115 kV line, it is recommended that these substations be reinforced from a second 115 kV line to be able to ride through an N-1 contingency.

**Recommendation Current 6c:** PSE needs to continue to reinforce the distribution system to meet the N-1 criteria for the entire City.

**Recommendation Current 6d:** PSE should continue with its implementation of current programs designed to improve overall system reliability in the City, including:

- Continuation of system hardening projects.
- Installation and implementation of distribution automation.

- Upgrade of its information technology infrastructure, including implementation of the OMS and DMS.
- Consideration of a replacement program for distribution transformers based on estimated peak loads as a surrogate for operating temperature. This could reduce the number of transformer failures, oil spills, and also improve the reliability of the distribution system.

# 3 Future System Study

## 3.1 Study Scope

An assessment was performed to review the effects of growth on the PSE electric system within the Bellevue area. The assessment of the short-term capability of the system was addressed in the review performed in Section 2, which presented current PSE actions and plans to address reliability issues. This section addresses the future growth scenarios by looking at expected growth over the next 10 years plus the requirements for full build-out of the City. The study addresses the question "will the City have adequate and reliable power supply to meet future City growth needs?" Exponent's review covered the following:

- The City's Comprehensive Plan, which contains critical assumptions regarding load growth projections within the City
- PSE's long-term energy supply and transmission contracts
- Transmission line projects planned by PSE to enhance the capacity of the system that feeds the City
- Available power supply resources including PSE's own generation assets
- Demand-side assumptions including energy conservation and Smart Grid integration
- PSE's plan to incorporate a DMS and increased use of remote sectionalizing via SCADA
- Planned PSE reliability projects, such as the replacement and/or mitigation of underground feeder cables and equipment.

Based on this information, it is Exponent's opinion that the City should have an adequate and reliable power supply to meet the medium-term (5–10 years) and probably also to meet long-term (10–20 years and beyond) growth requirements.

## 3.2 Growth Scenario (Medium Term)

### 3.2.1 Study Approach

The medium-term growth scenario review was performed to assess the requirements for growth in each of the major systems affecting power delivery—generation, transmission, and distribution. The growth scenarios impacting the City are presented in this section along with a discussion of opportunities for use of Smart Grid technologies.

### 3.2.2 Generation

There are several questions that need to be answered when assessing the likelihood that the City will have an adequate electric power supply at competitive prices for the next 10 or 20 years. Some of the key questions are:

- Are the load forecasts for PSE reasonably accurate?
- Does PSE consider new demands or changes in the usage of electricity in its forecasts?
- Will PSE be able to acquire generation resources to serve all of its customers?
- What reinforcements will be made to PSE's 115 kV power transmission system that are needed to support the anticipated growth in the City?

PSE's planning process entails a comprehensive review of a multitude of factors that can impact PSE's ability to supply electric energy to its customers. All of this is documented in an IRP that is prepared on a biennial basis. This plan, which contains forecasts for PSE's electric as well as gas business, covers a 20-year time horizon.

The IRP document describes in detail all key issues with which PSE must deal. The IRP process covers, among others things, the macroeconomic climate, the political environment within which PSE operates, possible future new legislation of importance to PSE, past use of electricity, and potential savings that can be implemented cost effectively by PSE. Advanced statistical methods are used to develop various scenarios for the electric power and energy needs for PSE as an entity. The resulting forecast of the average annual electric energy needs is shown in
Figure 48. (The estimated number of megawatt hours can be obtained by multiplying the numbers in the graph by 8,760 hours per year.)

Chapter 3 of the 2011 IRP discusses the planning environment that PSE has considered. PSE states that in the near term, it recognizes that there are substantial uncertainties. PSE's planners recognize that the economy is foremost among the factors that can have a significant impact on the need for electricity in PSE's service area. Slow growth will benefit PSE and its customers because the likely result is a surplus of available electric energy. The effect of a continued slow growth is assumed to be a shift of the demand curve into the future before the economic growth will resume. Any change in the growth scenario will therefore be captured in the 2013 IRP, which is a reasonable approach. The IRP, however, does not provide specific information on growth in Bellevue. Therefore, this review covers all of PSE's service territory. Some aspects of the plan are discussed below.

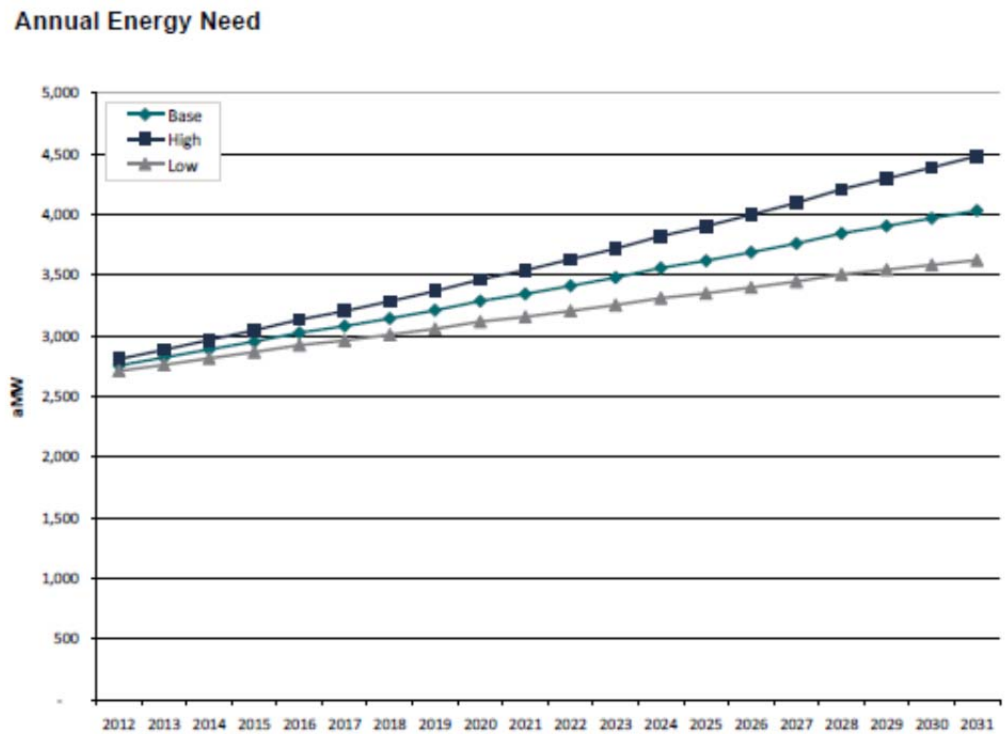


Figure 48. Annual Energy Need[66]

#### 3.2.2.1 Demand Side Resource Assumptions

A significant portion of PSE's future peak power demand forecast is assumed to be reduced by encouraging its customers to install equipment and devices with reduced electric power consumption. Since the assumed reduction of the electric power demand is substantial, this aspect of the plan has been reviewed in some detail.

PSE is assuming that the electric power demand can be reduced by as much as an annual average of 645 MW in 20 years, as shown in Figure 49 (from the 2011 IRP), which summarizes the expected power reduction by business sector. It is expected that the residential and commercial sectors will each comprise approximately 50% of the demand reduction. The 645 MW value is estimated to equate to an 18% reduction of the retail sales by 2031 and a reduction of PSE's load growth by 50%.[67] It is assumed that 85% of this potential is achievable over time but the timing of the savings is uncertain. The plan for the near term assumes that energy conservation programs that cost up to $150 per MWh will be put in place. However, as will be shown below, while the saving in electric energy use might be realizable, some of the electric energy savings are likely to be offset by increases in consumption of natural gas.

66 Reference 9, Chapter 5, Figure 5.2.

67 Reference 9, Appendix K, page 2.

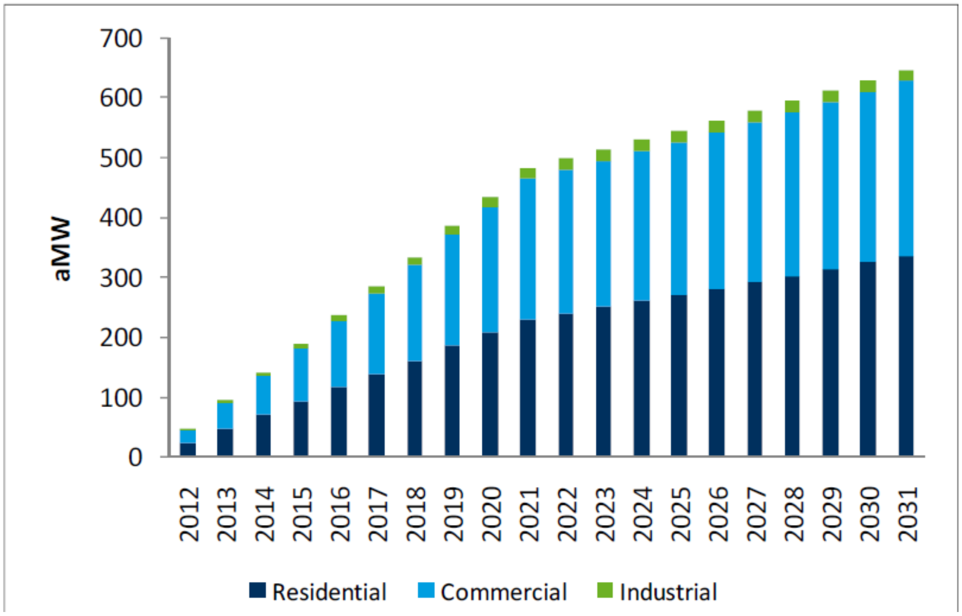


Figure 49. Electric Energy Efficiency Acquisition Schedule by Sector[68]

Figure 50 shows PSE's forecasted annual energy savings from use of more efficient lighting technologies within the time period from 2010 through 2031. An annual average energy savings of about 200 MW is estimated for year 2031.

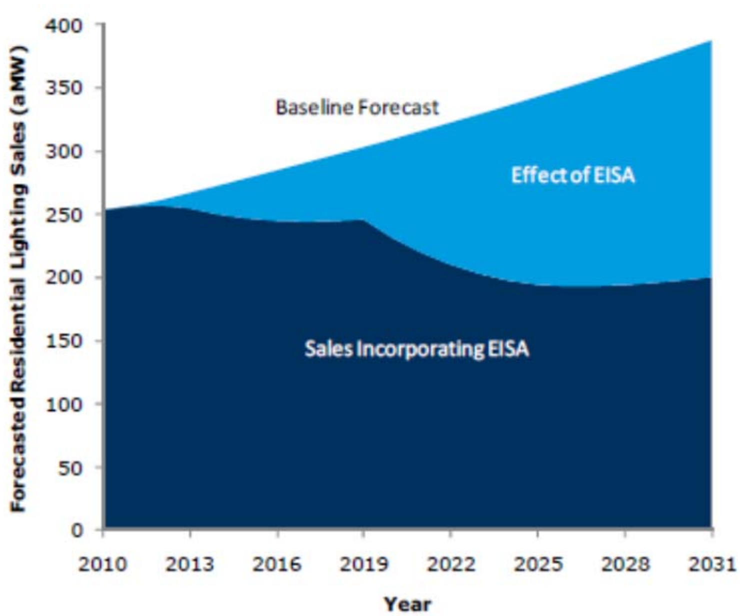


Figure 50. Residential Lighting Forecasts before and after Energy Independence and Security Act Adjustment[69]

68 Reference 9, Appendix K1, Figure 7

69 Reference 9, Appendix K1, Figure 3

Table 3 shows an analysis of the annual cost of owning different types of light bulbs and the energy consumed by each type. As can be seen in the table, most of the energy consumed by the incandescent light bulb is converted to heat. If heating is required for the space in which the energy is dissipated, then the energy from the light bulb is not wasted but useful for space heating. However, if the energy is dissipated in a space that requires air conditioning (cooling), then it will lead to even more energy consumed by the air conditioning unit so this is truly wasted energy.

**Table 3. Comparison of Lighting Technologies**[70]

| | Incandescent Light | Compact Fluorescent Light | Light Emitting Diode |
|---|---|---|---|
| Power rating | 60 watts | 13–14 watts | 12–13 watts |
| Lifespan/3 hours per day | 333 days | 7–9 years | 22 years |
| Price per bulb | 25–50 cents* | $1.99–$4.99 | $30–$40 |
| Annual energy use | 66 kWh | 14–15 kWh** | 13–14 kWh** |
| Annual approximate heating contribution | 62 kWh | 4.4 kWh | 4 kWh |
| Net light energy | 4 kWh | 9 kWh | 10 kWh |
| Cost of Money @ 5%*** | $0.03 | $0.10–$0.25 | $1.50–$2.00 |

**Note:** * - add 10% to the price of the light bulb to get the equivalent life time cost for 365 days.
** - assuming that 30% of the power generates heat.
*** - PSE's internal capital recovery rate is above 8%.

In the Pacific Northwest, air conditioning of residences is not likely to be used many hours a year during times when a light bulb is switched on so the cost of extra air conditioning can probably be ignored. Also, if the opportunity cost is counted by assigning a reasonable interest factor to the purchase price of the light bulb, it can be seen that the cost of owning a more efficient light bulb is so high that the consumer can almost afford to replace incandescent light bulbs every year and still nearly break even.[71] That is, there is no real incentive for consumers to buy more energy efficient light bulbs.

Note that this analysis does not take into account the cost of energy used to make the more efficient light bulb. However, it can be assumed that a significant portion of the price of the more energy efficient light bulbs represents the cost of energy used to produce it. Thus, when considering the societal savings in having more energy efficient lighting, the savings are probably exaggerated. Also, there is no guarantee that the newer light bulbs last as many years as is often stated.

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70 Reference 14.

71 An interest rate of 5% is high at this time, but it is historically much lower than the average return on investments in the stock market.

The purpose of this simple analysis is to illustrate that the energy savings from using more energy efficient light bulbs will lead to more demand for natural gas, if natural gas is the energy source used for space heating, but it should reduce the peak demand for electric power used for lighting. Thus, it might reduce or postpone the need for construction of more electric power plants if the consumers are prevented from replacing the newer light bulbs with the old, cheap incandescent type bulbs. Similar reasoning would apply to other electric energy efficiency improvements where electric energy is merely replaced by thermal energy from other sources.[72]

#### 3.2.2.2 Impact of New Technologies

The forecasting methodology used by PSE consists largely of extrapolations based on past load growth. However, the potential impact of electric vehicle usage has been analyzed and found to be low. The estimate is that about 50 MW will be added to the peak power demand by 2031 as a result of the increased use of plug-in electric vehicles.[73] Also, an increased use of distributed generation has been evaluated but found to not represent a significant portion of the electric mix in the near future. Technology breakthroughs could change this assumption.

An emerging technology is cloud computing, which has not been assessed. Because it is very early in the product mix that is available to consumers and businesses, it is difficult to forecast the potential impact of this offering. However, if it becomes widely accepted, it might lead to a significant expansion of computer server farms, which could put a high demand on the electric power system in locations where electric energy is inexpensive. At this time it is too early to predict if it is going to be successful and how it will be implemented. It is likely that this will have to be addressed in the 2013 IRP. Similarly, the impact of potentially new consumer electronics equipment, increased introduction of so-called smart appliances that can be controlled remotely, and other consumer electric and electronic equipment is not known and will therefore have to be left to future planners to assess.

#### 3.2.2.3 Availability of Power Supply

Figure 51 shows the power that is available to PSE between 2012 and 2031. Also, on this chart is shown the forecasted peak power demand for PSE's entire service area. This graph shows the gap between the available power and the forecasted power needs. The peak power demand is assumed to be needed for 1 hour per day. The probability for reaching this peak load is assumed to be once over a 2-year period. The gap between the available generation and the estimated load has been adjusted as follows:

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[72] High efficiency equipment and products almost always cost more than the less efficient equipment would because more material and often higher cost materials are used to achieve the higher efficiency. High efficiency products often weigh more or incorporate more expensive lightweight materials such as aluminum or carbon fibers to obtain weight reductions. This requires more energy to make the products and equipment so a portion of the higher purchase price represents energy consumed prior to putting the equipment into use. The time for the payback in the form of energy savings to offset the increased energy to make the equipment can be long.

[73] Reference 9, Chapter 4, page 4-15.

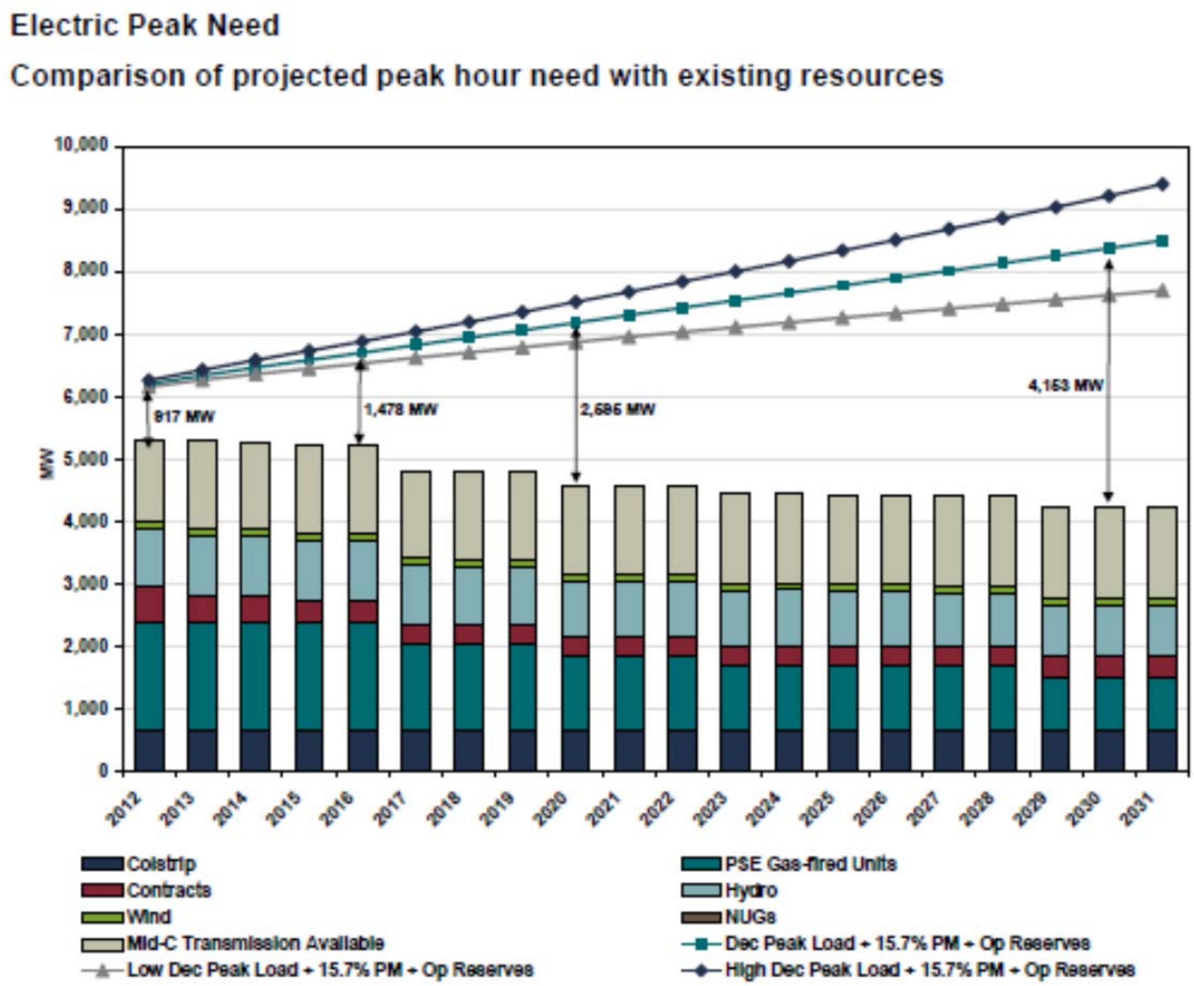


Figure 51. Electric Peak Need: Comparison of Project Peak Hour Need with Existing Resources[74]

- WECC requires a 15.7% margin between available generation and the forecasted peak power load. This is required to be in a position to survive a 5% loss of load probability.[75] In this graph the load forecast has been increased by 15.7% to account for the possible loss of generation instead of reducing the available generation by this amount.
- Since wind power is not a firm power source, the available wind power used in this forecast is only 7–8% of the wind power capacity.[76]

74 Reference 9, Chapter 5, Figure 5.1

75 This means that PSE should be in a position to survive the loss of any single generator or any single bulk power transmission line without having to shed load.

76 Wind is poorly correlated with the peak power because a cold day, when a winter peaking utility such as PSE could be expected to see maximum power demands, might be associated with stagnant air (no wind). That is, wind generation is an energy source but not a firm power source that is available at any time.

- Under the rules of the Northwest Power Pool, PSE must also reserve 5% of hydro and 7% of thermal generation as a contingency reserve. This generation must be available within 10 minutes, and 50% of it must be spinning so that it will be able to pick up loads almost instantaneously. This is also included in the graph as a margin between the available generation and the forecasted load.

These operating margins are required for the region's electric utilities to provide electric power reliably to the people in the areas served by the interconnected utilities in the region. In addition, PSE is required under Washington statutes RCW 18.285 to have the following renewable energy credits: 3% of supply-side resources in place by 2012, 9% in 2016, and 15% in the year 2020.

For comparison, Figure 52 illustrates the peak-hour load forecast for Bellevue for 2010–2030. The forecast is based on the PSE-provided estimate of 475 MW for the year 2010 and the annual peak-hour load-growth values shown in Figure 51 for PSE's total service area.

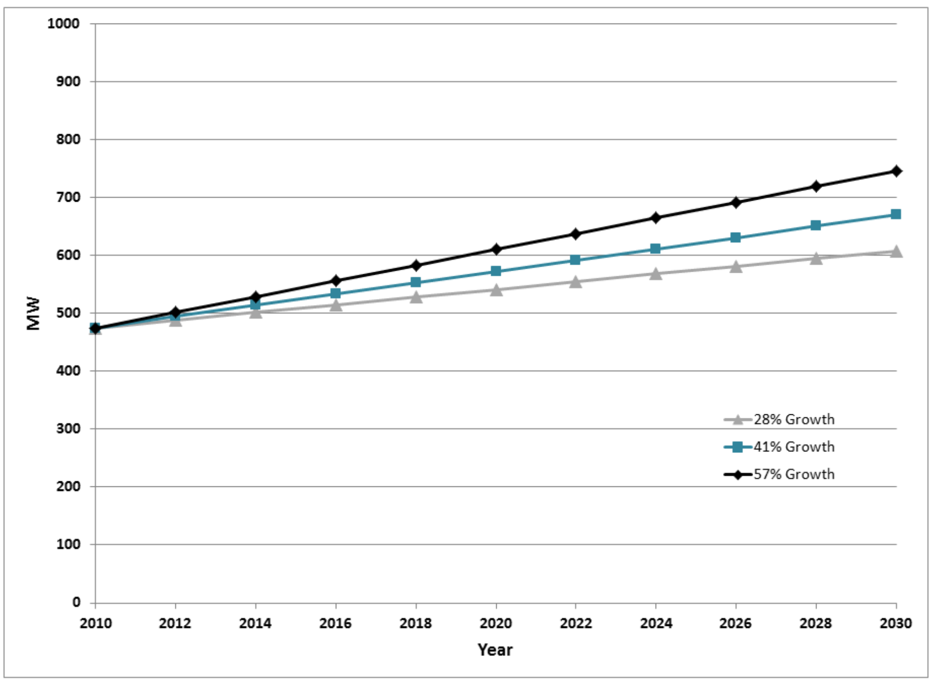


Figure 52. Projected Peak Power Needs for All Substations Feeding Bellevue, Using the Same Growth Rates as Shown in Figure 51.

#### 3.2.2.4 Retirement of Power Supply Agreements

##### 3.2.2.4.1 Resource Plan for the Time Period 2012 through 2020

The lead time for new electric utility facilities could be 10 to 12 years for lines, but the lead time might be only about half that for new, modular combustion turbine plants. When dealing with such long lead times, the utilities have to make decisions for investments in new facilities long before they know for sure that the facilities will be required. Therefore, the planning horizon covering the next 10 years has to be as accurate as possible. In particular, the longest lead time investments have to be planned out in detail and work has to be initiated to enable the investments to be made and the facilities built to meet the needs of the utility's customers. This entails significant risks.

PSE's power capacity needs are shown in Figure 51. This figure shows a decreasing trend for availability of power sources. The following significant reductions in PSE's availability of generation resources over the next 7 years are noted in the planning document:[77]

- A reduction of 387 MW at the end of 2011
- A reduction of 150 MW in February 2012
- A reduction of 125 MW in March 2013
- A reduction of 75 MW in February 2015
- A reduction of 333 MW in February 2015
- A reduction of 298 MW in December 2016
- A reduction of 75 MW in June 2017
- A reduction of 251 MW in March 2018.

Other changes beyond 2018 are also listed in PSE's IRP. By 2020, PSE will have lost a total of about 1,050 MW. As shown in Figure 51, PSE estimates that the generation gap in the year 2020 is going to be 2,686 MW.

##### 3.2.2.4.2 New Power Sources

A review of the PSE IRP was performed to determine PSE's needs for new power sources to meet the current IRP mid-range forecasts. The results of this review are discussed below.

PSE needs to acquire new power sources to make up for the expired power purchase agreements. There are two kinds of sources needed to operate an electric utility reliably. One source is needed to supply power for a few hours during the morning and evening peak power

[77] Reference 9, IRP Chapter 5.

loads.[78] The other is to supply power to the base loads 24 hours a day, 7 days a week. The power sources needed to supply electric power during the peak load periods should be inexpensive to build since they will only be used for short periods of time each day, but need to be able to sustain frequent starts and stops. In this situation, the cost of the fuel is less significant. (If the capital cost for building the peaking units is high, the fuel cost must be very low, which is the situation for pumped storage systems.) The plants used for base load are not required to start and stop frequently, but must operate reliably, efficiently, and continuously. PSE can and must cover the emerging power supply gap for power peaks as well as for base loads. It can achieve this by either 1) building and owning power plants, 2) completing power purchase agreements under long-term contracts, or 3) buying power on the open spot market. According to the IRP, PSE will most likely use all three of these options. The spot market option is the riskiest if a power supply shortage should arise in the region, but until such time, it might provide opportunities for relatively low cost power purchases.

Wind and solar power plants do not fit this mix since they are not reliable power sources available on 24 hours per day, 7 days per week basis. These are energy sources that have to be complemented by conventional power sources that can cycle rapidly up or down to match the variations in available wind and solar power. Therefore, PSE has almost no alternative but to use natural gas for any new generating plants it needs to build, in order to have guaranteed capacity available for its customers.[79]

PSE assumes that the time required to obtain permits for and to build a new gas turbine plant is 4–5 years. Because there is a surplus of power in the Northwest at this time, PSE is not planning to build any new fossil fuel-based power plants, but is using a Request for Proposal to acquire power on the open market. As there is a power surplus in the region, it should be possible for PSE to acquire enough power to cover the gap between the forecasted demand and the availability of generating plants owned or controlled by PSE. However, for the longer term, PSE will probably have to build new power plants. Future prices for power generation can be significantly affected by possible future costs associated with $CO_2$ generation, which also might force a shutdown of the 716 MW Colstrip power plant portion that is owned by PSE. If significant power rate increases should occur in the future because the spot market dries up or new regulations force shut-down of fossil fuel-based power plants (or increases the cost of power from fossil fuel-based plants), this could affect the growth of the City.

### 3.2.3 Transmission

Chapter 7 of the 2011 IRP discusses the needs for reinforcement of PSE's electric transmission system during the next 10 years: 2011 through 2021. No part of the plan addresses needs for a 20-year planning horizon, which is probably appropriate because the uncertainties over such a long time horizon are substantial. Also, it should be possible to complete transmission line

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78 PSE has two daily peaks according to information provided by PSE's planners. One is associated with the morning waking up time period and the other arises during dinner times in the late afternoon and early evening.

79 New hydropower plants are not likely to be built in the Northwest and coal power plants will probably not be an option for the future either. Therefore, the only readily available fuel is natural gas.

projects as needed over a 10-year time period. Therefore, a 10-year rolling planning horizon should be adequate.

PSE anticipates that 200 miles of new transmission lines operating at voltages above 100 kV and upgrading of 300 miles of existing transmission lines will be needed. One of the major uncertainties in the plan is the potential impact of new regulations. For example, new regulations were issued in 2007 through the Energy Policy Act of 2005 regarding electric system reliability, which required PSE to make investments in software and hardware for operation of its 100 kV and above power delivery system.[80] Other uncertainties relate to the use of emerging distributed generation technologies, which might become an acceptable alternative to the use of central electric power stations. If distributed generation becomes cost effective, then the need for long distance power transmission lines will be reduced. Thus, for long-term planning, constant scanning of the environmental and technical factors that can impact the need for power lines is required.

BPA handles about 70% of all of the bulk power transmission in the Pacific Northwest.[81] The transmission system in the Northwest is illustrated in Figure 53. The figure shows PSE's power plant facilities located in eastern and western Washington State. The construction of wind power plants in Eastern Washington and in Idaho (a few but not all of which are shown in the figure) has caused increased demands on the transmission lines leading towards western Washington and Oregon. These lines also carry power from the coal-fired power plants in Wyoming and the hydropower from dams in the basins of the Columbia and Snake Rivers. The corridor along Interstate 5 is also heavily loaded because it is the interface between British Columbia and the lines down along the Pacific Coast toward California. PSE states in the IRP that the region often suffers from transmission system constraints resulting in curtailment of firm contractual transmission rights. This is also discussed in a white paper published by BPA in 2006.[82] The Columbia River treaty also adds to the congestion of the transmission lines in and around Puget Sound.[83] According to the agreement, Canada is entitled, at least until the year 2024, to receive power from the United States as compensation for its cooperation in the construction and operation of the dams along the upper Columbia River basin. At present, the annual entitlement is estimated to be about 550 MW with a peak of about 1,440 MW. This power will flow across the bulk power transmission lines through the Puget Sound and Cascade Mountain corridors. This is difficult to achieve during the winter season since the electric power demands in the region are heaviest during the colder fall and winter months.

[80] Reference 9, Chapter 7, page 7-19.

[81] Reference 9, IRP Appendix E, page E-2.

[82] Reference 15.

[83] Reference 16.

**Figure E-1**
**BPA Transmission System Constraint on PSE Remote Resource Delivery**

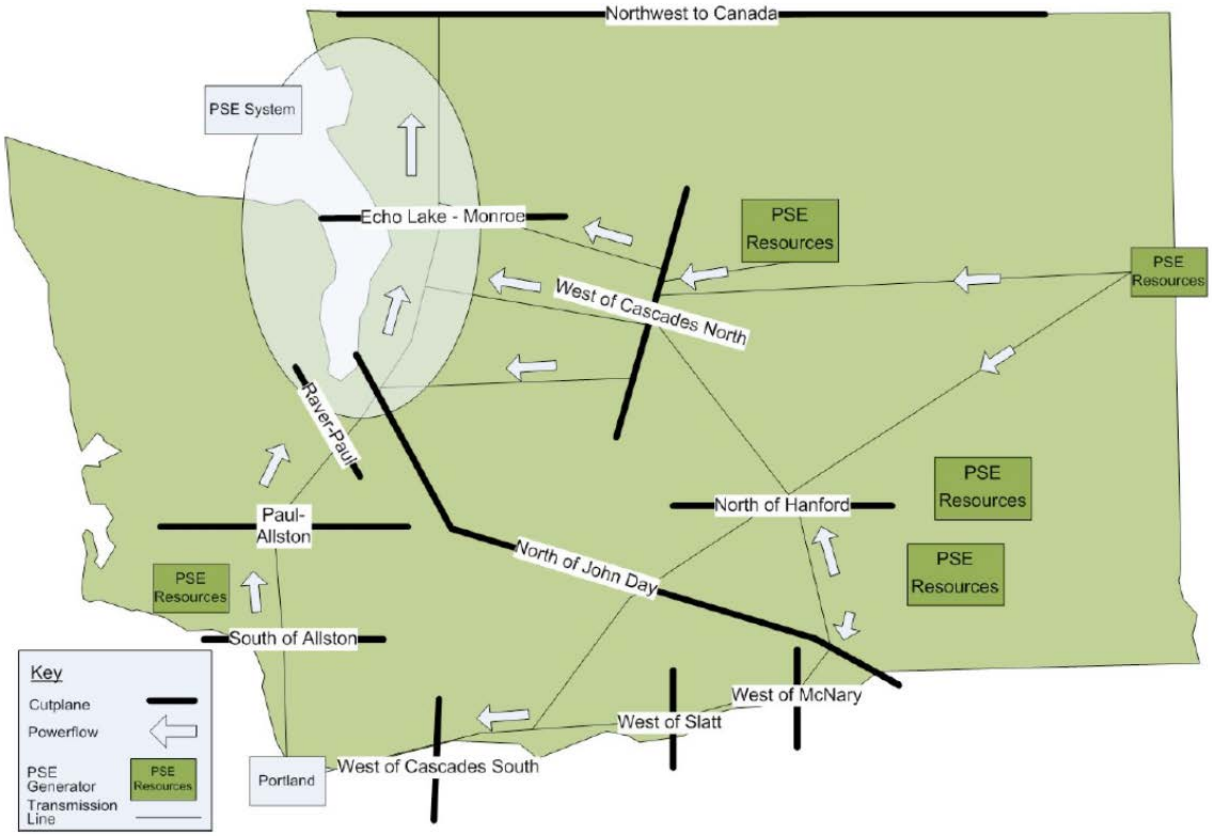


Figure 53. BPA Transmission System Constraint on PSE Remote Resource Delivery[84]

PSE anticipates a need for expanding transmission capacity towards the Mid-Columbia basin. It has rights at present to about 2,300 MW of capacity which is necessary to meet peak load requirements. That is, there is at present sufficient capacity through the Cascades but it is vulnerable to interruptions during severe weather. It would be difficult for PSE to build its own bulk power transmission lines. Therefore, the most likely route will be to work through BPA's network open seasons (NOS) process, which will probably be pursued by PSE through its membership in the Columbia Grid organization. BPA approved the latest NOS in 2008 and is at present pursuing projects to enable power from PSE's Lower Snake River wind power project. BPA is also strengthening the Interstate 5 corridor and the lines west from the McNary Dam, all of which should directly or indirectly help PSE and other utilities operating in the Puget Sound area. However, more is going to be needed.

In its IRP, PSE discusses the demands put on the bulk power transmission systems in the region by the anticipated 5,000 MW of wind power that will be needed to meet the demands from the

84 Reference 9, Appendix E, Figure E-1

regulators for renewable generation in the states of Washington and Oregon. Wind power is challenging for transmission system operators because such power can fluctuate significantly from the scheduled power flows over short time periods. This can lead to voltage instability as well as thermal overloads if no facilities are available to mitigate the fluctuations.

The IRP is as detailed as possible considering the uncertainties surrounding all forecasts relative to the needs for future additions to the bulk power transmission systems in the Northwest. The plan appears to be sound for the next 10 years. Beyond the 10-year horizon, the uncertainties are too numerous to make any plan or forecast credible.[85]

In regards to growth in Bellevue on the 115 kV system supplying power to the City, there are significant reinforcements required to accommodate growth. Growth in the City's Downtown and the Bel-Red corridor requires reinforcement of PSE 115 kV substations and lines feeding the City. The following reinforcements of the 115 kV systems feeding the City are anticipated:

- The Ardmore substation in the City of Redmond is scheduled for completion in 2012. Two spans for a line still need approval from the City to complete this project. Once the Ardmore substation is finished and the two spans built, the Interlaken substation will be decommissioned.
- The Spring District might have four new office towers, which at build out will probably require between 30 MW to 40 MW. PSE currently plans to serve the early loads from a new 25 MVA bank at the Northrup Substation. It is anticipated that a new substation will be needed prior to full build-out of the Spring District and at other sites in the Bel-Red Corridor. This substation is labeled Vernell on PSE's comprehensive plan map.
- Clyde Hill needs to be expanded between 2016 and 2020 to meet anticipated load growth in Downtown, which will require about 50 MW and at least two more transformer banks to feed more power through the west loop corridor. The line through Clyde Hill carries about 130 MW, which is a heavy load for a 115 kV circuit.[86]

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[85] If there is any omission in the plan it would be that it does not discuss how new technologies can be used to utilize the existing transmission lines better because 500 kV lines are typically limited by their electrical characteristics but able to handle higher loads without exceeding their thermal load limits. New technologies, often referred to as FACTS technologies, are available that should enable the loads carried by the lines to be increased at the expense of increased line losses. (FACTS stands for Flexible AC Transmission Systems developed by EPRI in cooperation with U.S. electric utilities, GE, and Westinghouse in the early 1990s. For more details see Hingorani, N.G., and L. Gyugyi. 1999. *Understanding FACTS: Concepts and Technology of Flexible AC Transmission Systems.* Wiley-IEEE Press. Available at: ISBN 978-0-7803-3455-7). However, if the loads are only required for relatively short periods per day or seasonally, systems to increase the electric loading of lines could be installed with a 1.5–2 year lead time. However, unknown contractual or technical barriers might exist, which make these types of installations difficult to accept by stakeholders with an interest in the transmission systems.

[86] A 115 kV circuit using Tern conductors has a maximum rating of 239 MW in the winter so the Clyde Hill circuit is loaded to 54% of maximum winter rating.

- The Lakemont area is at present served via distribution circuits from Somerset, Eastgate, Hazelwood, and Goodes Corner (see Figure 32) Any additional growth in the Lakemont area could not be served from the Eastgate substation because there is no room at this substation for the third transformer bank that would be needed to serve the increased load. There are also indications of business expansions in the Eastgate commercial area, which will have to be considered by the planners. Although tapping the transmission line at Somerset to serve a new Lakemont substation seems like an option, this would, in fact, put too much load on that line.

The permitting process for these needed 115 kV system reinforcements in the City is expected to be lengthy given the size of these projects. Collaboration and cooperation between the City and the City of Redmond is needed to deal with the Bel-Red corridor. Strengthening of the power system feeding the Downtown requires cooperation between PSE, the City, and the business community in the Downtown. Also, projects to handle any increased growth in the Lakewood area, for example, will be significant since the growth would probably require a new substation.

### 3.2.4 Distribution

PSE uses a mixture of short-term and long-term planning to address load growth and reliability issues. Load growth planning includes submission of project proposals to add extra distribution substation capacity including transformers and related switchgear and additional distribution circuits. Reliability planning includes project proposals that generally decrease outage time and/or frequency by providing alternate transmission feeds to distribution substations, by increasing switching capability through additional distribution feeds and switches, by increasing the use of SCADA for remote data gathering and switching, and by proactively replacing troublesome equipment, including replacement of bare overhead conductor with covered overhead conductor.

Load growth within the City has been somewhat stagnant for the past couple of years, and load growth planning for the City is challenging due to a heavy dependence on economic conditions. The Downtown circuits are fed from the Lochleven, Clyde Hill, North Bellevue, and Center substations, (Figure 33) for which the Downtown represents approximately 80% of the load.[87] Figure 54 illustrates the situation for both summer and winter peak loads, and shows that the peak winter load for the substations (including both Downtown and non- Downtown load) is approximately 130 MW. To meet the demand and leave sufficient supply margin for contingency situations, PSE has capacity expansion projects planned that will add 100 MW to the Downtown. Additionally, approximately 30–40 MW of load growth is predicted in the Bel-Red corridor, including the Bel-Red Overland Transportation System (BROTS) light rail system, and growth within both Bellevue and Redmond is expected to impact the distribution systems within both cities.

[87] The 80% figure is calculated from the peak winter and summer load data shown in Figure 54. The data were provided by PSE system planning personnel.

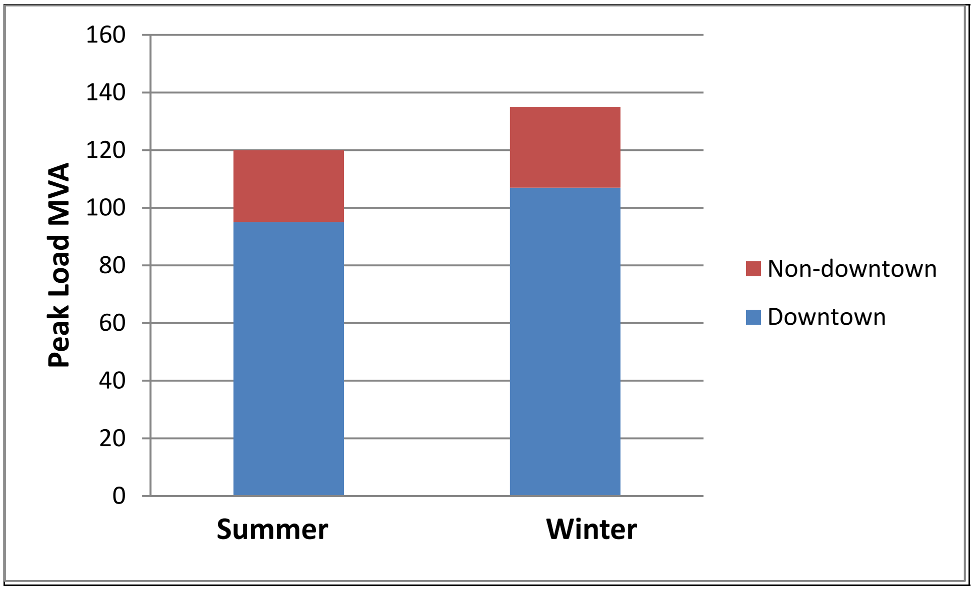


Figure 54. Peak load data for the substations feeding the Downtown, including non-Downtown load (2009 data). The substations are Clyde Hill, Lochleven, North Bellevue, and Center.[87]

The Bellevue outage trends (for both number of outages and customer minutes) generally show a decrease in the period from 2006–2010, no doubt in large part due to PSE's replacement of portions of its older installation, especially underground cables. Planned projects for the near term include a continuation of this process, along with replacement of many trouble-prone distribution switches used to sectionalize the system during outages and to provide alternate feeds. PSE also continues to address overhead line–tree contact by installing covered conductors in many locations, and animal guards where warranted.

PSE has made a commitment toward improving the operation of the distribution system in high density load areas such as the Downtown through its adoption of a structured SCADA modernization plan. An integral part of the plan is the upgrade of distribution switches over several years in the Downtown to allow remote switching via SCADA control. Remote switching is an important part of improved response to outages on the distribution system by allowing increased flexibility in terms of system configuration changes to restore power more quickly to as many customers as possible. Presently there are approximately 100 underground and pad-mounted aboveground switches that serve the Downtown and are candidates for the upgrade. PSE's strategy will be to focus on switches that:

- Are part of the Downtown reliability ring
- Are the first load switches of each circuit
- Serve difficult-to-access circuits, large loads, or that have a significant impact on restoration times
- Serve critical locations.

This investment in infrastructure is scheduled to take place over the next several years. Additionally, pilot testing of an automatic power restoration system is planned for 2012 utilizing some of the distribution switches within the Downtown reliability ring. If this program proves successful, PSE plans to extend its use in the following years. This system should further reduce the time needed to restore power to as many customers as possible as a result of the use of automated switching logic and control of alternate feeds.

The increased use of remote manual control also necessitates upgrading the SCADA system itself. Further discussion of these systems was presented in Section 2.

## 3.2.5 Smart Grid Technology

### 3.2.5.1 Background

Title XIII of the Congressional Energy Independence and Security Act (EISA) of 2007 describes the Smart Grid as follows[88]:

> "Section 1301 establishes a federal policy to modernize the electric utility transmission and distribution system to maintain reliability and infrastructure protection. The term "Smart Grid" refers to a distribution system that allows for flow of information from a customer's meter in two directions: both inside the house to thermostats, appliances, and other devices, and from the house back to the utility. Smart Grid is defined to include a variety of operational and energy measures—including smart meters, smart appliances, renewable energy resources, and energy efficiency resources."

Specifically, the following activities are covered by this legislative act:

- Section 1302 calls for the U.S. Department of Energy (DOE) to report to Congress on the deployment of Smart Grid technologies and any barriers to deployment.
- Section 1303 directs DOE to establish a Smart Grid Advisory Committee and a Smart Grid Task Force to assist with implementation.
- Section 1304 directs DOE to conduct Smart Grid research and development (R&D) and to develop measurement strategies to assess energy savings and other aspects of implementation.
- Section 1305 directs the National Institute of Standards and Technology (NIST) to establish protocols and standards to increase the flexibility of use for Smart Grid equipment and systems.
- Section 1306 directs DOE to create a program that reimburses 20% of qualifying Smart Grid investments.

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88 Reference 17.

- Section 1307 directs states to encourage utilities to employ Smart Grid technology and allows utilities to recover Smart Grid investments through rates.

- Section 1308 requires DOE to prepare a report to Congress on the effect of private wire laws on the development of combined heat and power facilities.

- Section 1309 directs DOE to report to Congress on the potential impacts of Smart Grid deployment on the security of electricity infrastructure and operating capability.

As loosely defined in the Federal Statue, the Smart Grid encompasses development of new standards under the auspices of NIST instead of using the normal voluntary, consensus standards development paths such as IEEE and American National Standards Institute. Furthermore, the legislation includes subsidies for certain R&D projects and it also encourages but does not mandate that states use Smart Grid technologies. Later amendments to EISA also include provisions to support development of alternative energy systems and technologies.

WUTC was enabled to have WUTC staff undergo in-depth training on Smart Grid technologies and applications under an American Recovery and Reinvestment Act grant. It led to a utility Smart Grid reporting rule, a review of utility Smart Grid investment reports, status updates, and pilot Smart Grid and demand-response programs.[89] In order to encourage investor owned utilities (IOUs) in the state of Washington to consider the value of a Smart Grid, the WUTC adopted a rule that requires such utilities to file an biannual Smart Grid Technology Report on Smart Grid technologies they are considering.[90] In regards to electric vehicles, WUTC initiated a work session to consider its role in the development of an electric vehicle infrastructure and other regulatory issues relating to electric vehicles in Washington. This session addressed issues such as whether the resale of electricity at public charging stations ought to be subject to economic regulation, the extent to which existing laws provide protection to consumers who purchase electricity for vehicle recharging, and whether WUTC will need to address additional ratemaking considerations for IOUs (such as time-of-use tariffs).[91] WUTC conducted a foundational study funded by the National Association of Regulatory Commissioners to better understand dynamic pricing and its applicability to Washington regulated electric utilities.

Another example of a regulatory response to EISA is SB17, enacted by the California legislature in 2009, which defines Smart Grids further. This bill recognizes that national or international standards might lead to more cost effective solutions than standards that have limited support from the business community. The bill also establishes that the California Public Utilities Commission (CPUC) has the authority to decide on rate recovery of investments related to Smart Grids, which is also the prerogative of WUTC for the state of Washington. Prior to the EISA in 2004, CPUC directed the three largest California IOUs to submit advanced metering infrastructure (AMI) business cases along with full deployment proposals for the purpose of advancing CPUC's policy to expand demand response in the state. The deployment of smart

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[89] Reference 18.

[90] Reference 19.

[91] Reference 20.

meters is expected to be complete by 2012 in California. PSE has had automated meter reading, which is one of the functions of a smart meter, capability for a long time. Over the past 5 years, CPUC has also initiated Demand Response proceedings in California, which is also covered in WUTC's study. As a result, the IOUs in California operate various demand response programs and dynamic pricing tariffs that are designed to provide incentives to customers to reduce their electricity usage during peak hours. Distributed generation is also a part of CPUC's regulatory mix, which covers distributed generation on both the customer and utility wholesale sides of the electric meter. WUTC is embarking on regulations similar to what other states are doing in response to the EISA.

Recently the security of the communications systems used by the utilities has become a major issue.[92] In the past, the electric utilities relied primarily on their own communications systems for control of their power plants, lines, and substation equipment This made the electric utilities relatively immune from hackers since access to the communication ports was primarily from secure sites under the utilities' control. Because of the transition to more use of public communications systems, multiple issues has arisen on how to keep communications systems for Smart Grids or meters secure. There is a legitimate need for consumers to be able to interrogate the meters to find information about their energy use and to control when and how they use electric energy. Thus, there has to be a public access portal to the system. Because communications tools are changing very rapidly (e.g., wireless and mobile technologies), it can be difficult and costly to maintain users' access to their meters. Public access also enables hackers to break into the systems used for such access and control. There is also an overriding need for the electric utilities to be able to control switchable loads through the smart meters to shave power peaks as a part of the demand response programs. For outage management, the utility's ability to communicate with the meters must not be affected by a communications system overload, which could arise during major emergencies such as during the 2006 storm that caused widespread outages in the Puget Sound area. These issues have national security implications, which are recognized at the federal government level, as well as cost implications for the utilities, which are under the purview of state regulatory agencies. At this time, there is no recognized standard for how to address these issues, which leaves each state and possibly each utility to find their own solutions.

Distributed generation is a part of the Smart Grid mix. Utilities are already well versed in how to safely allow their customers to connect solar systems to the grid. Also, a large number of backup generators are installed to supply power in case of a power outage. The smart meters will enable establishment of more flexible rate schedules, which may include real time pricing structures for the power exchange. Thus, distributed generation does not add any complexity, except that distributed power generation from sources such as solar cells, which are not dispatchable, cannot be included in any demand response function.

Pacific Gas & Electric Company (PG&E) prepared a Smart Grid Deployment Plan for CPUC in June 2011.[93] In this plan, PG&E outlines its vision as follows: "…to provide customers safe, reliable, secure, cost-effective, sustainable and flexible energy services through the integration

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[92] Reference 21.

[93] Reference 22.

of advanced communications and control technologies to transform the operations of our electric network, from generation to the customer's premise." In addition to the regulatory requirements, the strategic objectives driving PG&E's Smart Grid initiative are briefly described as follows:

- Smart meters intended to stimulate customers to use energy more judiciously to achieve cost savings, and third parties to create energy solutions and tools for customers to use.
- Use of demand management to obtain operational efficiency primarily by reducing the demand for power during peak power periods and to tap into the ancillary service markets for efficient use of such resources. Environmental impact related to supply-side energy resources is also an objective.
- Investments to support the emerging market for electric vehicles. This anticipates investment in the T&D systems, plus (possibly) monitoring and metering systems to supply power to electric vehicles.
- Improved forecasting techniques to better match demand and supply of electric energy. This need is stated in anticipation of increased use of renewable energy sources to meet statutory requirements.
- Integration of large-scale renewable energy resources is expected to require investments in new technologies in order to maintain the reliability of the power system in view of the high variability of the power generated by the emerging renewable power sources.
- Enhanced grid outage detection, isolation, and restoration is also a part of the strategy, with anticipated investments into advanced communications technologies and control systems to assist utility operators and repair personnel to locate damaged equipment or outage areas, isolate the problem, and quickly restore power, which will minimize the customer outage times.
- Utilization of advanced monitoring and control technologies for improved equipment condition assessment and possibly incipient fault detection to prevent system problems that might lead to system disruptions.
- Improved system's voltage control to minimize system losses by using advanced technologies, including the use of sensing, telecommunications, and control systems to reduce power losses in the utility delivery system and in customer equipment.
- Continuously monitor technology developments to take advantage of new Smart Grid technologies. This strategic objective includes subjects such as those related to cyber security, new technology testing, standards development, etc., as necessary in order to achieve PG&E's other Smart Grid strategic objectives.

For the most part, these are the objectives that the utility industry has been pursuing for decades. Many of the enumerated objectives drove the R&D programs established by the Electric Power Research Institute (EPRI) beginning in 1973. Some of EPRI's R&D developments resulted in:

- Digital microprocessor-based protective relays used for detection and clearing of electric system equipment faults for both T&D system applications (mid-1980s). As a part of this effort, the use of so called phasor measurement units for improved stability monitoring and control of power systems were demonstrated in the early 1990s.
- New power electronic-based equipment for management of power flows and for voltage control of transmission systems (late 1970s through mid-1990s).
- Equipment and computer tools for thermal loading of transmission lines under emergency conditions (early 1990s).
- Automatic meter reading technologies.
- On-line and off-line tools and methods for management of transformer loading and incipient fault detection in transformers, breakers, and other substation equipment (1980s).
- The development of a unified communication protocol for utilities was initiated in 1986 by EPRI.

Obviously, these technologies have evolved and been improved upon over the years. However, out of the stated objectives, only the following are relatively new issues requiring innovation and new technologies:

- The need for utilities to manage demand by switching customer loads and the possibility for real time pricing of power has led to the need for smart meters with an associated communication system infrastructure.
- The need for forecasting and power system management tools that can operate on a second-to-second or minute-to-minute basis emerged as a result of renewable power systems such as those provided by wind turbines.
- Demand side management tools and systems that can be used for peak power shaving to avoid starting up costly and potentially polluting power plants. The driving force behind this is primarily emerging regulations. These tools will probably also utilize the smart meters to shed loads. It should be noted that these techniques probably have little impact on energy use since the shedding of loads will basically move the energy consumption to time periods after the peak load periods.
- The increased use of public communication networks for power system management, power scheduling, and for interfacing with independent system operators or similar organizations has resulted in cyber security issues, which

were essentially non-existent when the utilities relied almost exclusively on their own communication networks.

- Customer and regulatory demands for improved power system reliability is leading to increased use of remotely operated sectionalizing switches in the power distribution systems. Such systems have been available for over 30 years, so no new technology needs to be developed to achieve these kinds of improvements. However, lower communications system costs are making distribution system automation less costly, although higher reliability often can be better achieved by more frequent tree trimming.

The Smart Grid strategies promulgated by the regulators have not dramatically changed the need for technology, but do enable the utilities to invest in the existing technologies and to get the investments put into the rate bases so they can be recovered by adding the costs to the power users.

#### 3.2.5.2 Electric Vehicles

Electric vehicles represent an emerging and largely unknown load for the utilities. The market acceptance of electric vehicles is uncertain and the demand on the power systems for energy to recharge the batteries in electric vehicles is difficult to foresee. Some of the newer electric vehicles are basically hybrids with larger batteries that enable driving longer distances by having an onboard engine powered by fossil fuels to provide propulsion for the vehicles when the battery is depleted. These are the so called plug-in hybrids. These vehicles might have a range on the electric drive of 15 to 40 miles whereas the vehicles without an onboard fossil fuel-powered engine might have a range of 100 miles or more. The latter type could work as a commute vehicle that might not require charging stations to be available at the place of work unless they are used in cold climates where there will be a need for battery keep-warm type systems during work hours. Using a vehicle with an advertised range of 35 miles at an equivalent fuel use equal to about 90 miles per gallon leads to the following:

- Battery capacity: about 16 kWh[94]
- Charging time @120V: 10 hours
- Estimated charging power assuming 90% battery depletion and 90% charging efficiency: 1.6 kW
- Charging time at 240 V: 4 hours
- Estimated charging power assuming 90% battery depletion and 90% charging efficiency: 4 kW.

94 The energy stored is approximately equal to 1/3 gallon of gasoline if it is generated by a power source that is 100% efficient or about 1 gallon of gasoline if the source is a thermal power plant. In the latter case, the actual energy efficiency is about 35 miles per gallon.

If there are 1,000 vehicles needing recharge each morning after the commute to work, the aggregate load will be about 4 MW over 4 hours or 16 MWh if the recharge time is 4 hours. If a plug-in hybrid is charged between 8 a.m. and noon, the charging might be completed before the peak loads typically occurring after noon.[95] If the vehicles are placed back in the garages after work, the recharging should be delayed to avoid adding to the peak loads related to tasks (such as preparing dinner) associated with the time after working hours. Larger electric vehicles can be expected to require more energy to recharge but smaller-sized true electric vehicles might not need to be recharged during working hours. However, all electric vehicles relying on lithium or similar energy storage technologies will require power to keep the batteries above freezing. Onboard heaters are used for this function. This might add 1–1.5 kW to the power demand but the duty cycle for this depends on how cold the temperature is where the cars are parked. However, this can extend the power demand cycle beyond the charging times estimated above. These needs must be considered in planning to meet the demands of the new plug-in hybrid vehicles and electric vehicles.

#### 3.2.5.3 Smart Grid Benefits

Various estimates of Smart Grid benefits have been published. EPRI has published reports that include cost-benefit calculations.[96] PG&E's Smart Grid document contains estimated benefits too. However, while the costs for the various investment alternatives are fairly predictable, the benefits calculation methodology is not provided in sufficient detail to calculate a cost benefits ratio with any predictable confidence. Most of the benefits must therefore be considered as highly speculative; however, the utilities must invest in Smart Grid technologies if the regulations so require. So, where regulations are the driver for these investments, the benefits are immaterial since the costs will be covered in the rate base.

The fluidity of the Smart Grid concept was recognized by regulators, legislators, and the utilities, and led to the formation of an organization named the Critical Consumer Issues Forum (CCIF) in 2010, which issued a final report in July 2011[97]. CCIF decided to call the initiative Grid Modernization to differentiate it from "Smart Meters." CCIF established 30 principles covering cost/benefits, privacy issues, consumer protection, consumer education, and regulatory issues involving state and federal agencies. The members of CCIF recognized that the benefits of Smart Grid investments might be soft and therefore, concluded that Smart Grid projects should be given close scrutiny to establish that the cost/benefits ratio is sound.

#### 3.2.5.4 PSE's Smart Grid Approach

The Washington State Legislature in WAC 480-100-505(3)(a) defines the "Smart grid function" primarily as a digital communication platform for information gathering, processing, and dissemination. The information is intended to enable the providers and users of electric energy to manage their use of electricity for increased efficiency in the use of electric energy; to detect

[95] PSE has a morning and late afternoon peak power profile. Therefore, PSE might be in a better position to provide charging power later in the morning if it is completed before the afternoon peak power period begins.

[96] Reference 23.

[97] Reference 24.

and manage events causing interruptions and disturbances in the system delivering electric energy; to integrate new distributed energy generators in the electric system; and to manage new loads such as electric vehicles. Reliability improvements are a major driver behind the initiative. The legislation requires electric utilities under the jurisdiction of WUTC to deliver a biannual progress report to WUTC on or before September 1. PSE filed such a report on September 1, 2010, and an updated report should be filed in September 1, 2012.

PSE has developed a Smart Grid initiative in response to the legislation. It defines PSE's initiative in three broad categories: 1) information technology, 2) customer information and energy empowerment, and 3) T&D infrastructure.

PSE was an early adopter of the Smart Grid technologies when it installed AMR in 1998, but the systems used by PSE were stand-alone systems that were not integrated with the rest of PSE's automation systems. In the information technology portion of PSE's Smart Grid initiative, PSE states that it will move toward an enterprise service-oriented architecture as it selects new applications with this architecture already imbedded. This will replace the largely point-to-point fixed communication network with local and wide area networks, which in PSE's terminology, becomes an enterprise service bus. Cyber security and interoperability issues are, according to PSE's document, issues being evaluated.

Part of these developments are an improved CIS, an OMS, and a DMS. PSE has already implemented a number of Smart Grid components and programs, but they are not fully integrated into one network or system. PSE is now evaluating a system to integrate these independent systems. Since the benefits of these Smart Grid initiatives are tentative and uncertain, PSE states that it will be working over the next several years to initiate or continue pilot projects that will allow it to effectively test the capabilities of new technologies and anticipate customer needs. In the T&D infrastructure, PSE's most fundamental Smart Grid initiative will be the continuation of upgrades to aging infrastructure and the completion of planned initiatives targeted to increase reliability for customers and reduce outage duration. The document submitted to WUTC in September 2010 contains a detailed capital investment plan for the 2011 through 2012 time period and also a 10-year horizon for additional investments. These plans have been reproduced in Table 4and Table 5.

**Table 4. 2011–2012 Plan by PSE**[98]

| | |
|---|---|
| **Information Technology/Systems** | • Complete EMS upgrade to increase system security and reliability<br>• Implement OMS: Complete evaluation by 2011, select vendor, implement with completion expected in 2012 |
| **Automated Metering** | • Complete evaluation of migrating to two-way AMI technology from one-way AMR meters in 2011<br>• Pilot and initiate a phased conversion from AMR to AMI, based on evaluation and business drivers |
| **Substation Internet Protocol (IP) Enablement** | • Complete evaluation of pilot to migrate T&D substations to secure IP network<br>• Continue extension of fiber optic cabling throughout T&D network |
| **Customer Energy Use Information and Feedback** | • Continue to review and evaluate proposals; consider the deployment of pilot programs to learn the potential savings and value proposition to customers<br>• Continue implementation of home online tools with PSE customer base |
| **Home Power Cost Monitor Pilot** | • Complete pilot and evaluate results, such as energy savings, technical feasibility, and cost effectiveness<br>• Based on pilot, determine potential broader deployment |
| **Demand Response Pilots** | • Evaluate current residential and commercial demand response pilots, including system performance and customer acceptance for demand response |
| **Home Intelligence/ Automation** | • Consider soliciting proposals for a pilot project |
| **Prepay Billing System Pilot** | • Consider soliciting proposals for a pilot project |
| **Customer Energy Generation** | • No specific technology changes, evaluations, or projects are anticipated in the next 2 years, however, PSE will continue to support customer adoption of small renewable generation<br>• In anticipation of this rapidly growing program (9,000 net metered customers are projected by the end of 2015), evaluate and implement streamlined solutions:<br>– Implement new customer interconnection process improvements<br>– Expand renewable generation section of PSE.com website<br>– Implement policy and process for interconnection for customer generation projects between 100 kW and 2 MW |

98 Reference 19, Appendix B

| | |
|---|---|
| **Electric Vehicles** | • Update review of energy and capacity demands in latest IRP<br>• Study impacts of early electric vehicle adopters on distribution levels and develop plan for changes to planning and customer service models to support mass adoption<br>• Continue collaboration with major customers and public infrastructure in the region to support regional planning of transportation and utility infrastructure, and consumer information on location and use of charging stations<br>• Evaluate the value to customers and the utility from timed or staggered charging based on actual data from early customers; pilot if positive economic case and communications standards and equipment are in place |
| **Transmission Automation and Reliability** | • Evaluate existing automatic transmission schemes for performance and determine the need for new schemes and/or modifications to existing schemes; select projects based on specific benefits and costs and available funding<br>• Continue to upgrade aging/older SCADA systems in transmission substations |
| **Distribution Automation** | • Continue to monitor and learn from the distribution automation systems serving Microsoft<br>• Evaluate and develop pilots in one to two select areas where reliability is an issue |
| **Distribution Supervisory Control and Data Acquisition** | • Continue SCADA installation; select projects based on specific benefit and costs and available funding<br>• Install supervisory control of feeder breakers and ampere readings on all three phases of breakers at critical distribution substations |
| **Recloser Installation** | • Continue to install reclosers on overhead distribution circuits where customers would reliably benefit from the installation<br>• Evaluate and pilot one recloser with communications for remote monitoring and control |
| **Conservation Voltage Reduction** | • Evaluate and develop plan for conservation voltage reduction program, and implement as budget funding allows |

**Table 5. Ten-Year Plan by PSE[99]**

| | |
|---|---|
| **Information Technology/Systems** | • Complete OMS-DMS-EMS-Meter Data Management System (MDMS) integration<br>• Upgrade CIS<br>• Implement enterprise wide GIS<br>• Complete integration of MDMS to Outage and Engineering applications |
| **Automated Metering** | • Continue AMR-AMI conversion, as appropriate |
| **Substation IP Enablement** | • Based on pilot results, migrate T&D substations with DNP (Distributed Network Protocol) to a secure IP network. Upgrade substation remote terminal units from Vanguard, an older, proprietary network protocol, to DNP/IP standard protocol between the T&D substations on a secure IP network with point-to-point communications within the substations<br>• Continue extension of fiber optic cabling throughout T&D network |
| **Customer Energy Use Information and Feedback** | • Continue to review and evaluate proposals; consider the deployment of pilot programs to learn the potential savings and value proposition to customers |
| **Home Power Cost Monitor Pilot** | • Expand application as appropriate, based on pilot evaluation and future applicability |
| **Demand Response Pilots** | • Expand application as appropriate, based on pilot evaluation and future applicability |
| **Home Intelligence/ Automation** | None |
| **Prepay Billing System Pilot** | None |
| **Customer Energy Generation** | • Continue to monitor consumer/market changes and technology advances for program enhancements and/or changes |
| **Electric Vehicles** | • Develop energy and demand forecasts based on already experienced adoption rates and needs<br>• Incorporate electric vehicle loading and forecasts into distribution and transmission planning, and design standards where appropriate<br>• If customer benefits can be demonstrated, scale a program in step with information technology communications and meter rollouts and customer demand |

99 Reference 19, Appendix B

| | |
|---|---|
| **Transmission Automation and Reliability** | • Depending on project-specific benefits and cost, as well as available budget funding, continue toward the goal of having supervisory control of all automatically controlled switches<br>• Continue to upgrade aging/older SCADA systems in transmission substations<br>• Depending on benefit/cost and available budget funding, selectively replace aging components with modernized equipment that will facilitate Smart Grid adaptability |
| **Distribution Automation** | • Expand distribution automation in areas with high critical load and/or reliability concerns |
| **Distribution Supervisory Control and Data Acquisition** | • Continue expansion of functionality with the long-term goal of all distribution substations having SCADA with ampere readings for all three phases at the breakers; and supervisory control of the feeder breakers |
| **Recloser Installation** | • Continue expansion of recloser installation program and expand communications and monitoring capability depending on evaluation, pilot, and benefit/cost |
| **Conservation Voltage Reduction** | • Expand conservation voltage reduction program to appropriate locations where cost-effective implementation yields further energy savings |

The first objective listed in Table 4 covers upgrading of PSE's communication system infrastructure. This is necessary since older systems, which are based on older telephone type technologies, are no longer cost effective or maintainable, and cannot accommodate the needs to communicate with a plethora of new devices used for monitoring and control of the power system and the installed equipment. The new systems are based on communication servers that operate through wide area and local area communication networks. Numerous new products include wireless devices requiring wireless access points. These new communication technologies are required to support almost all of the projects identified for the 2011 and 2012 time period.

The second major objective of the listed projects is geared to improving the reliability of the power system because PSE has not met SAIDI for the years 2007 through 2010. Automatic sectionalizing of distribution system feeders combined with automatic reclosing is a proven method to restore power to as many unaffected power users as possible after a system fault. When this is combined with supervisory control of the distribution system (Distribution SCADA), the operators are given the tools needed to diagnose system faults and to restore power to as many power users as possible before trouble shooters and repair persons are able to get to the fault location. This should, therefore, bring down the SAIDI number for PSE and hopefully bring it in compliance with WUTC rules.

The costs and benefits accruing to PSE and its customers cannot be assessed because the necessary information has been redacted from the available document describing PSE's Smart Grid Initiative Report.

The upgrading of PSE's communication system infrastructure is not expected to be finished in the first 2 years covered by the plan. The 10-year planning horizon anticipates further modernization of the communication and information technology infrastructure. In fact, communication systems are evolving at an accelerated pace. Thus, continued upgrading and replacement of outdated equipment can be expected to be a continuous task well beyond the 10-year horizon.

Improving reliability of the power system can also be expected to be a continuous requirement from power users and regulators. However, there are limits on how much the reliability of the power system can be improved by means of automation and improved fault information. Reliability improvements will also require replacing failing equipment and possibly putting the circuits underground where they are not affected by contact with trees or similar hazards.

A third objective emerging from the 2- to 10-year plan is the need for reducing the power demand when the source of the available energy is costly. However, the plan also anticipates new demands such as those expected if use of electric vehicles expands. The plan also anticipates more distributed generation sources in residential areas. These developments are in their infancy and the net effect on the demand for electric power is still not well known.

The review of PSE's medium-term plan has been performed. This plan defines PSE's required investment needs over the next 10 years to ensure that PSE can reliably supply electric power to its customers. This review, the results of which are described below, address both generation and transmission system needs.

#### 3.2.5.5 Smart Grid Implementation in Bellevue

As Bellevue moves with the rest of the country from the conventional electric delivery system toward eventual Smart Grid architecture, incremental but critical system changes will be an important component of the process. The Smart Grid is driven from the utility perspective by the potential for peak power reductions through switching off and on customer loads. It is also perceived by the power consumers, utilities, and businesses as a need for information and the potential for new business opportunities: the utility needs a tally of each customer's energy use for billing; a customer desires near-real-time pricing of electricity to make decisions about when to use energy; the utility desires timely power use data to set dynamic pricing and drive its peak-shaving program during periods of high demand, and issues commands to disconnect certain loads from the system; a customer wants proper credit for any net distributed generation output that is supplied to the grid, including energy from electric vehicles; and other business enterprises perceived opportunities for selling application software or products that will help consumers with the decision making process. To support these needs, a communications backbone is an integral necessity to any Smart Grid layout. However, the promised Smart Grid benefits might be diminished if the electricity supply at the customer's meter is not highly reliable.

PSE already have the ability to read the energy meters remotely. The Smart Grid technology does not provide any added value with regard to meter readings. However, basic improvements to the electrical power system will be required to take advantage of the benefits, which should be available through the Smart Grid technology mix. The expected enhancements that the

Smart Grid promises to add to the customer experience will potentially enable the utilities to manage system and circuit overloads by reducing the load flows that might enable the utility to avoid a line overload and an outage. This requires investments in control systems on the utility side as well as the user side of the meters for load control. PSE's investment plan anticipates such investments on the utility side of the meters.

One of the basic components of the Smart Grid concept is the ability for the power company and the end user's meter to engage in two-way communications. While the use of AMR was important in its day, the purpose of AMR was to allow remote meter reading without sending out a person to do that job; the communication was still one-way from the meter to PSE. If real-time pricing of electric power and the ability to control customer loads by switching loads on and off proves to be beneficial, then PSE will need to develop a deployment approach for migrating from the AMR concept to an AMI, which consists of a communications backbone and smart meters that can supply frequent power use data to PSE, and that also accepts commands from the DMS for the purposes of controlling loads in the home or place of business. The advantages to this type of operation might be beneficial to both Bellevue's power customers and PSE, if PSE will be able to offer lower rates in return for the ability to disconnect certain appliances during peak use hours. Such peak shaving will help PSE to more effectively balance the energy supply and demand for the City.

PSE is only in the earliest planning stages with regard to smart meter deployment, and the timing will depend on if the cost benefits of the Smart Grid technology is attractive to the consumers. At the present, it appears that the first smart meter installations operating over an upgraded communications system could be several years away.

Distributed generation within Bellevue could become a key component of its Smart Grid architecture. If distributed generation systems become more widespread, then such systems might become another tool for utilities to control peak power flows. This might even involve the use of stored energy in electric vehicles that are plugged into the system.[100]

Action items for the City:

- The City should engage with PSE to ensure that the high value portions of the Smart Grid technologies are implemented in a timely manner for the benefit of the power users in the City.
- At present, there is no plan by either the City or PSE to make the needed investments to support the use of electric vehicles in the City. Since charging of electric vehicles is expected to be a function that should be supported by the Smart Grid technologies, the City should open a dialog with PSE to address issues related to electric vehicle charging systems

[100] Rogers, K.M., et al. 2010. Smart-grid-enabled load and distributed generation as a reactive resource. IEEE Innovative Smart Grid Technologies Conference. January 2010.

# 3.3 Growth Scenario Review (Long Term)

## 3.3.1 Study Approach

A review of PSE's long-term plan has been performed. While this review is similar to the medium-term review, the uncertainties associated with long-range forecasting are substantial. In particular, the impact of new legislations associated with global warming issues might cause drastic changes in the fuel mix available to electric utilities and the price of fuels. Other environmental regulations associated with clean air and water can also cause disruptions in the supply of power. PSE takes these uncertainties into account as much as possible but cannot commit to making new investments to meet unknown requirements. The results of the review are discussed below.

## 3.3.2 New Transmission Access beyond the Year 2020

Chapter 7 of the 2011 IRP discusses the needs for reinforcement of PSE's electric transmission system during the next 10 years, from 2011 through 2021. No part of the plan addresses needs for a 20-year planning horizon, which might be appropriate because the uncertainties over such a long time horizon are substantial. Also, it should be possible to complete transmission line projects as needed over a 10-year time period. Although the needs for power transmission lines beyond the year 2020 are not possible to assess with any certainty, it can be assumed that it is not going to be easier to build overhead, high voltage transmission lines in the future than it is today. The corridor along Interstate 5 is likely to remain heavily loaded since it is the interface between British Columbia and the lines along the Pacific Coast toward California.

PSE states in the IRP that, presently, the region often suffers from transmission system constraints resulting in curtailment of firm contractual transmission rights. This is likely to remain a problem. The Columbia River Treaty also adds to the congestion of the transmission lines in and around the Puget Sound until the year 2024 and possibly beyond.[101] These issues have to be addressed in the 2013 plan.

## 3.3.3 Resource Plan for the Time Period Beyond 2020

The estimated demand for the time period beyond 2020 is much less reliable since major disturbances or uncertainties in the availability and price of fuel, population growth (demographics), technology innovation, legislation, etc. are likely to impact the need for and use of electric power.[102] Therefore, this portion of the plan has to be considered as speculative. Revisions on a biannual basis produce a rolling plan that will over time lead to decisions for new investments beyond the year 2020.

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101 Reference 16.

102 The result of the oil crises in the 1970s was the loss of the U.S. steel industry. Further erosion of U.S. manufacturing has happened over the last few decades as a result of growth of manufacturing capacity in emerging, low labor cost, third world countries. Such changes are difficult to predict, which makes long range forecasting highly uncertain.

As seen in Figure 51, the plan indicates a potential shortfall in power capacity of over 4,000 MW by the year 2031. This is only an indication of the possible need to build or acquire new power plants beginning in the year 2020 if the trend persists.

### 3.3.4 New Power Sources

A review of the PSE IRP has been performed to determine PSE's needs for new power sources to meet the current IRP mid-range forecasts. The results of this review are discussed below.

As is obvious from Figure 51, PSE needs to continue to acquire new power sources beyond the year 2020 to cover the gap between the presently owned or available power sources and the expected demands for power. However, the uncertainties facing the industry make it extremely difficult to forecast the actual needs that far into the future. The macro-economic situation in the near term is difficult to foresee and possible legislation associated with global warming and carbon-dioxide legislations are just two legislative unknowns. Since there would be time to put new plants in place with a 10-year-lead time, the details for how to meet the demands for electric power beyond the year 2020 are left to future planners. The plan to be issued in 2013 will cover only a small portion of the planning horizon past 2020. This plan will also have to cover any needed new transmission lines required to bring the power into PSE's service territory.

### 3.3.5 Fully Built-Out Downtown

Current plans for the ultimate build out of the electrical system feeding the Downtown anticipates a growth of the power system demand from about 100 MW to 200 MW over the next 20 years. The basis for the fully built-out load growth for Downtown and Bel-Red is provided in City and PSE planning information.[103] Additionally, Exponent reviewed the substation current peak loading data for the Bellevue substations provided by PSE along with the PSE loading guidelines document[104] to determine the need for additional capacity to support the build-out scenario. The existing system needs strengthening because one of the main 115 kV lines feeding Downtown passes through the Clyde Hill substation, which already carries about 130 MW. This loading is close to the maximum value allowed under PSE's loading guidelines. This strengthening of the power system feeding Downtown requires cooperation between PSE, the City, and the business community in the Downtown. Based on the current growth models for the Bellevue area, additional capacity will be needed. The following additions are required by the growth plan:

- A switching station on the Sammamish to North Bellevue line is needed to provide a third transmission line to feed power into this area in order to be able to handle the full 200 MW for the Downtown.

[103] References 36 and 37.

[104] Reference 38

- Four transformer banks to support the build-out of the Downtown. These banks are required as the City reaches various growth thresholds in the Downtown. An additional bank will be required for each 25 MVA load increment. It is anticipated that two of the banks may be required prior to 2020 and the other two banks sometime in the future as the Downtown reaches its growth capacity.

- Two transformer banks to support the expected growth and build-out of the Bel-Red area. Again, an additional bank is required for each additional 25 MVA of additional load. It is anticipated that expansion in this area will require one bank within the next 10 years and one in the long-term horizon.

- One to two transformer banks to support growth in the Eastgate and Somerset areas and to improve overall reliability. Depending on the economic recovery, this addition may be required in the short term.

- Upgrade of the 115 kV lines that feed the City to support higher load growth in the region. As stated previously, the need for upgrade of these lines is expected to be required in the 5 to 10-year time frame.

- A third transmission feed into the one of the north side substations is required to support the additional electric demand in the Downtown.

Table 6 indicates a requirement time frame for these additions. The purpose of the time frame is to provide the City with an early warning system for engaging PSE in discussions on these capacity additions. Based on recent experience, it is assumed that these discussions are required 3–5 years in advance of these needs. Recent experience with T&D projects indicates that:

- Transformer additions require 18–24 months to complete from start of engineering to operation. Additional time is required for planning and permitting.

- Line projects may require 4–5 years from the start of engineering to completion since permitting of lines typically requires significant engineering to be completed before the formal permitting process proceeds.

- The City should begin discussions with PSE in regard to the impact of electric vehicles with the associated need for charging stations in the Downtown area of the City.

- The City should initiate discussions with PSE with respect to PSE's plans for implementation of a so called Smart Grid to understand the potential costs and benefits of PSE's Smart Grid initiative.

**Table 6. Major Project Roadmap**

| Capacity Requirement | Action | Potential Need Date | Initiate Early Planning Time Frame |
|---|---|---|---|
| **Downtown** | | | |
| Growth to 125 MVA | Add transformer bank | 2016 | 2012 |
| Growth to 150 MVA | Add transformer bank | 2020 | 2016 |
| Growth to 175 MVA | Add transformer bank | 2026 | 2022 |
| Growth to 200 MVA | Add transformer bank | Post 2026 | Unknown |
| **Bel-Red** | | | |
| Growth to 20 MVA | Add transformer bank | 2018 | 2012 |
| Growth to 40 MVA | Add transformer bank | 2026 | 2022 |
| **Somerset/Eastgate** | | | |
| Growth/Reliability | Add transformer bank | 2018 | 2012 |
| **115 kV System** | | | |
| 50 MVA Need Downtown/Regional Growth | Upgrade 115 kV line | 2018–2022 | 2012 |
| Additional 50 MVA Downtown | Add third transmission feed from north | 2020–2024 | 2015 |

## 3.4 Future System Assessment Recommendations

The future system status has been reviewed using the future plans for growth in Bellevue, PSE's long-range planning, and potential technology innovations. Based on this review, a set of findings and recommendations is provided to the City of Bellevue for their use as an informed stakeholder.

**Recommendation Future 1**: Energy Efficiency Programs

**Finding**: PSE's long-range plans indicate a significant reliance on energy efficiency for management of the peak electric power demand.

**Reliability Actions**: Support for Long-Term Power Supply

**Recommendation Future 1**: The City should lead the electric energy efficiency effort to assist PSE in reaching its peak electric power demand goals to avoid using or building new peak electric power plants. Electric energy efficiency programs require active outreach to the customers and citizens to support various energy efficiency initiatives. The PSE long-term plan has a large reliance on electric energy efficiency.

This is a longer-term issue that will be included in future PSE IRPs. The City should remain active in the IRP process and should begin to understand potential long-term impacts of this strategy.

**Recommendation Future 2**: Smart Grid Initiatives

**Finding**: PSE is initiating Smart Grid programs to comply with WUTC requirements.

**Reliability Actions**: Enabling of reliability impacts of Smart Grid technology.

**Recommendation Future 2**: PSE has identified a series of Smart Grid technology projects that are being considered over the next 2 years. These projects include a range of programs from base infrastructure required to enable the Smart Grid to specific customer-related efforts. Several projects that support development of the infrastructure are currently underway:

- Upgrade of information technology systems
- Upgrade SCADA in transmission substations
- Distribution SCADA on feeder breakers
- Extension of fiber optic cabling through T&D system.

These programs represent upgrades to the PSE infrastructure that are being undertaken on a system-wide basis. Additional programs to enable customer interface applications will be needed. These technologies have been discussed in other recommendations.

An issue with Smart Grid implementation is that PSE must review customer interface applications on a system-wide basis and Bellevue may have different needs and requirements than other parts of the PSE service territory. Security of these communications systems will become a major issue that needs to be resolved before major investments are made in the new technologies.

Therefore, the City should review the overall PSE plan and determine their level of support for the various customer initiatives that would be appropriate for the City to provide. The types of initiatives to be considered are those relating to customer energy management, demand response, and home automation. These technologies are enabled by significant communication system upgrades, but allow for consumers to have greater control over energy usage and expenditure.

**Recommendation Future 3**: Major Project Planning (see Recommendation Role 2 also)

**Finding**: PSE maintains a plan for expansion of the system in Bellevue to support growth of the City and the region. However, as the lead time to permit larger projects (required to add capacity or reinforce the City infrastructure) has grown, it requires that the City understand the projects from a more detailed perspective than just a conceptual framework.

**Finding**: There is the potential for several of the growth-related projects to occur within this decade. The specific projects for consideration are upgrade of the 115 kV lines, additional capacity required for the Bel-Red and Somerset/Eastgate areas, and additional capacity requirements Downtown.

**Reliability Actions**: Conduct major project discussions well in advance of permit applications to ensure sufficient lead time to permit larger projects (required to add capacity or reinforce the City infrastructure).

**Recommendation Future 3**: It is recommended that the City engage PSE in an annual planning workshop around future projects with the intent of understanding the requirements from a City perspective. The Comprehensive Plan includes an electric system plan that can serve as the basis for the annual workshop. The workshop should focus on the following items:

- Current growth projections and electric power use in Bellevue
- Review of current plan applicability (Figure UT.5a from the City of Bellevue Comprehensive Plan)
- Update of the current plan
- Develop actions for capacity projects required to initiate siting and permitting activities within the next 2 years.

An outcome of the workshop should be an updated plan for inclusion in the Comprehensive Plan (if required) and an action plan to move designated projects forward into siting analysis and/or planning.

As a minimum, the following capacity additions have been identified as being needed within the next 5 to 10-year time frame. These capacity additions are based on the proposed growth within Bellevue and an assessment of current loadings on the Bellevue substations.

- Upgrade of existing 115 kV lines to 230 kV
- Addition of transformer banks to support expected growth in various areas of the City (Downtown, Bel-Red, and Somerset/Eastgate)
- Addition of new 115 kV lines to reinforce the overall electric system.

Based on recent Exponent staff experience with T&D capital projects, capacity additions of this magnitude typically require the following project execution times:

- Transformer bank additions require 18−24 months to complete from start of engineering to operation. This project time frame is based on the major material long-lead times (which have been increasing), and typical engineering and construction times. This time frame can be different based on difficulty in working at existing stations or permitting new stations. Also, additional time is required for planning and permitting.

- Line projects may require 4–5 years from the start of engineering to completion since permitting of lines typically requires significant engineering to be completed before the formal permitting process proceeds. The time frame for these projects is dependent on the length of the line segment, the number of jurisdictions involved, and the number of permits required (federal, state, and local). Line projects often require engineering to be completed in order to satisfy permit applications so that these projects have a longer time frame than substation projects.

**Recommendation Future 4**: Long-Range Planning

**Finding**: Both Bellevue and PSE work with various developers and companies to identify new potential facilities in Bellevue. There is an opportunity to share and communicate the results of these planning activities. This exercise relates to longer-term issues that are expected to be addressed in the future.

**Reliability Actions**: Coordination of growth planning and major project activities.

**Recommendation Future 4**: While information is shared for the IRP, and to the extent that information can be shared, it is recommended that a more formal meeting (annually) be held to ensure that all of Bellevue's needs are identified to PSE and that both organizations are coordinated regarding future load demand. This information sharing can also be included in the annual planning meeting.

The City and PSE should synchronize their growth projections for the City by exchanging information on expected projects, expected timing of projects, and coordination actions required by PSE and the City to address these projects. This exchange is meant to be longer-term planning and well in advance of any specific permitting or development activities.

# 4 Role of the City of Bellevue

## 4.1 Study

### 4.1.1 Study Scope

The Role of the City assessment was performed to answer the following question: "what opportunities are available to the City to work with PSE, regulators [WUTC, FERC], and other stakeholders to ensure the needs and expectations of Bellevue's residents and businesses are met relative to the reliability of the power supply?"

### 4.1.2 Study Approach

The Role of the City assessment was performed in the following steps:

- Evaluation of potential interactions with WUTC and other government agencies as it relates to the City's ability to inform decision-makers or to advocate for policy change
- Evaluation of City's interaction with PSE around planning and permitting relative to influencing electric system reliability in Bellevue
- Review of transparency of operations relative to improvements in communication between PSE and its customers as it relates to reliability.

## 4.2 Enhance Role of City as an Informed Stakeholder

### 4.2.1 Regulatory Agencies

#### 4.2.1.1 Study Approach

Prior to discussing the opportunities for Bellevue to interact with regulatory agencies, it is important to understand the regulatory framework under which PSE operates the electric power system and the regulatory framework as it affects the City. A brief summary of the regulatory requirements and their impact on reliability is provided below.

#### 4.2.1.2 Washington Utilities and Transportation Commission

WUTC provides oversight to electric utilities through regulations codified in the WAC Chapter 480-100. As noted in WAC 480-100-001, the purpose of these regulations is "to administer and enforce chapter 80.28 RCW by establishing rules of general applicability and requirements for consumer protection, financial records and reporting, electric metering, and electric safety and standards." The principal statutes that define WUTC's authority and responsibility with respect to electric utilities are found in RCW Title 80.

In determining the opportunity for the City to interact with WUTC, Exponent reviewed the responsibility of the agency to oversee the operation of electric utilities regulated by the agency. These requirements were then reviewed as they relate to PSE activities. Relative to electric system reliability, there are several requirements that are highlighted here:

*PSE-Related Activities*

- PSE is required to publish and communicate rates for electric power delivery through the filing of tariffs and rate schedules with WUTC (WAC 480-100-028 and WAC 480-100-103). Any changes to these tariffs or rate schedules must be presented at public hearings before WUTC and are subject to public hearings (RCW 80.28.020 and WAC 480-100-194). This requires PSE to present its basis for the proposed increases (for its investments and costs for providing services) to WUTC and to justify these expenditures as prudent since these expenditures are the basis for the increases and the means of PSE recovering their investment. The proposed changes are then reviewed by WUTC staff and a decision regarding the proposed changes is issued. While this process introduces risk to PSE's investment plans, the process is not expected to significantly alter PSE's investment program.

  This process of utility commission oversight is common to regulated utilities in the United States. In the case of PSE, they present their request for rate increases after investments are made so they are recovering expenses after they have been incurred. In other states, the rate case proceeding precedes the investments and the level of investment is approved prior to execution of projects. In the case of PSE, this requires that their investments (e.g., capital projects) be considered as prudent uses of capital across their entire system.

- PSE is required to have a rate structure that provides the same rates for similar services. This requirement is based on RCW 80.28.80. This requirement establishes a basis that a utility cannot provide preferred service and that service must be provided on a non-prejudicial basis except for a few special exemptions provided in the RCW. This requirement means that PSE must select projects to maintain their electric system assets from an overall system perspective.

- PSE is required to submit annual reliability reports that provide the service performance to its customers (WAC 480-100-398). This report highlights the current performance as well as actions that PSE will take to improve performance. This report addresses the entire service area. PSE indicates system circuits of concern (top 50) and identifies specific actions for these circuits. For 2010, there were no circuits identified in the Bellevue area (although Lake Hills-23 was on the list in 2009) (Reference 4).

- Through RCW19.285, the state of Washington has required that utilities meet a portion of their generation requirements through the use of renewable technologies. The state has required that at least 15% of generation come from renewable sources by 2020. The intent of this requirement is to encourage the use of renewable energy sources and energy efficiency in the state of Washington. This requirement affects reliability in the sense that PSE must develop a generation mix that satisfies its load demands and its renewable energy portfolio. In the future, as renewable energy sources and distributed energy sources become a bigger power source and a more local source, there will be a challenge to maintain the T&D system within acceptable voltage levels.

- WUTC (WAC 480-100-238) requires utilities to submit an IRP that is intended to present how a utility will meet its system demand and what the mix of generation sources will be. The IRP is required to examine alternatives that allow for meeting future demand at the "lowest reasonable cost." Utilities are also required to address conservation relative to energy reduction from energy efficiency and other means. The requirement is to submit the IRP on a biannual basis.

  PSE provides an IRP defining its strategy to respond to future load scenarios. The current IRP has been referred to previously in Section 3 in discussing future system status.

- Requirements for delivery of power are specified in WAC 480-100-368 and -373 for system frequency and voltage, respectively. The requirements state that the system must be operated at a frequency of 60 cycles per second under normal conditions and the voltage (depending on service class) must be maintained within ±5% of the standard voltage on the distribution feeder. There are additional requirements related to both utility and customer actions to control voltage fluctuation.

  This requirement directly relates to the issue of power quality. PSE is required to deliver voltage within the specified range. For customers who require a tighter band on voltage fluctuations, there are standard technologies employed by the end user at these sites to maintain the required voltage stability. Typically, information technology and manufacturing plants most often use site-specific technologies to control voltage that may interrupt their operations.

*City-Related Activities*

- Through RCW 35.96.040, the state of Washington specifies requirements that allow cities or towns to create local improvement districts and to levy and collect special assessments against the real property benefitting from the conversion of overhead facilities to underground facilities. This requirement directly relates to the funding mechanism required to convert existing overhead facilities. Issues regarding the conversion of overhead lines to underground were presented in Section 2.2.6.4.

- Through RCW 36.70A, the state of Washington requires cities and counties to develop comprehensive land use plans to govern growth management in their jurisdictions, if they are required or choose to plan under RCW 36.07A.040.
- Through RCW 80.32, the state of Washington allows cities to establish franchise agreements with utilities relative to use of city rights-of-way (public roads, streets, and highways).

There are additional requirements in the state of Washington statutes and WUTC regulations that govern interconnections to the electric system, requirements for the renewable portfolio, and purchase of power from qualifying facilities.

#### 4.2.1.3 Western Electricity Coordinating Council

The second organization with oversight responsibility is WECC, which is chartered with ensuring the reliability and security of the bulk electric system in the Western Interconnection. Since PSE has limited bulk transmission assets, their involvement with WECC deals with coordination of their transmission lines with the WECC area. PSE interacts with WECC for operations of its transmission lines at 100 kV and above. WECC provides requirements for operations and maintenance of the transmission system to ensure the reliability, stability, and security of the transmission system in the western United States and Canada. PSE involvement with WECC is mostly from an operations, maintenance, and protection standpoint to ensure that its system operates and coordinates planning with other regional entities. WECC develops standards for the western region based on review and application of NERC reliability standards which defines requirements to maintain reliability of the transmission system in the United States. WECC activities are focused only on transmission and do not reach into the distribution system within Bellevue or other parts of the PSE service territory. However, this interface is important from the transmission standpoint where events on the transmission system can result in significant wide-area outages.

#### 4.2.1.4 Analysis

From a WUTC perspective relative to electric power, cities are considered as any other member of the public. This means that Bellevue has access to the published tariffs and rate schedules of PSE and has the ability to participate in public hearings and to offer comments and opinions relative to these hearings. Therefore, Bellevue’s primary interaction with WUTC is one of being an active participant relative to changes in laws and tariffs that may affect electric system reliability in the State of Washington.

From an overall regulatory perspective, the City has the right to execute franchise agreements with companies that provide utility services to the City. These items are discussed in Section 4.2.2.2.

From the perspective of WECC, Bellevue has no real involvement with this group since it deals with issues on the transmission system (and large generation). WECC, however, does provide a source of information relative to electricity planning in the region and provides short- and long-term views of the electric transmission system. Their planning documents identify needs of the system moving forward and will provide Bellevue with an independent assessment of potential transmission needs in the area that may affect assets providing service to Bellevue or that are located in Bellevue.

#### 4.2.1.5 Recommendations

There are potentially two areas of involvement by Bellevue relative to WUTC:

- Since WUTC operates and oversees all regulated utilities, any changes in fundamental requirements must be driven by state law and enforcement by WUTC must be consistent and fair among all regulated companies. Therefore, Bellevue’s involvement in this aspect is one of informing lawmakers and commissioners regarding matters that affect reliability. However, matters affecting the electric system must be viewed in a global rather than a local context.

- Bellevue does have the opportunity to comment or participate in matters directly affecting PSE and their interaction with WUTC. The City may choose to support or oppose measures for investment brought forward by PSE that support its overall City goals for electric system reliability and service. Again, PSE has to propose its plans to WUTC on a system-wide basis, but Bellevue has the ability to support and advocate for initiatives that meet its goals and objectives.

From an overall regulatory perspective, interaction with the regulatory agencies provides Bellevue with a means of keeping current on plans for the electric system and advocating for projects that meet Bellevue’s objectives.

### 4.2.2 Puget Sound Energy

#### 4.2.2.1 Study Approach

Bellevue’s primary involvement in electric system reliability is through its interaction and collaboration with PSE. There are several areas where Bellevue is actively involved with electric system activities by PSE. The interaction between the City and PSE relative to specific reliability initiatives and outage performance was discussed in Section 2. The major areas of interaction discussed here are planning, permitting, and emergency response.

#### 4.2.2.2 City Policies

Bellevue establishes policies for utilities in the Utilities Element of the Comprehensive Plan[105]. The City provides its long-term vision and plans in its Comprehensive Plan, which provides goals, policies, and plans for all areas and aspects of City operations. The Utilities Element addresses many activities relating to electric reliability, including:

- A high level plan for utility capacity expansion to meet City and regional needs and to guide planning and decision-making
- Coordination of public and private trenching activities (related to the potential for undergrounding opportunities)
- Notification to the City prior to vegetation management in the City rights-of-way
- Required undergrounding of all new electrical distribution facilities
- Encouragement of consolidation of facilities
- Facilitation of conservation and environmentally sensitive energy sources
- Encourage communication with utilities, WUTC, and the City about cost distribution and undergrounding of electric distribution lines.

All of these policies have the potential to impact reliability. Additionally, through the Franchise Agreement between the City and PSE, the City provides requirements for work in the City rights-of-way that are intended to reflect the policies of the Comprehensive Plan. Based on a review of these documents, the City is influencing reliability through its planning and permitting process, its vegetation management policies, the ability to underground new facilities, and coordination of activities to take advantage of joint utility efforts. In the longer term, renewable and alternate energy sources and conservation will factor into the overall electric energy picture in Bellevue.

The recommendations provided in Sections 2 and 3 are consistent with the policies of the Comprehensive Plan. The recommendations are based on focusing the City's efforts on areas that will drive improvements in reliable service to existing and new members (business and residential) of the community, that satisfies the City's goals, and that understands the requirements of PSE as a regulated utility. The recommendations are provided to support City reliability through improved system design (redundancy), expanded use of automation and information technology, and improved communications between the City and PSE on matters affecting reliability and growth.

[105] Reference 26.

#### 4.2.2.3 Planning

Both Bellevue and PSE engage in planning for the City. However, the planning needs for each organization are focused on different areas and concerns. Bellevue planning is required to address services and land use planning across all aspects of city operations, such as impact on land use, rights-of way, roadways, water and sewage, and coordination of projects by other utilities (electric, gas, and telecommunications). Therefore, planning by Bellevue involves the following:

- City growth projections including major facility and capital projects
- Forecast and plans for land use
- Forecast and plans for roadway additions and changes
- Forecast and plans for utility (water, electric, gas, telecommunications) additions and changes
- Forecast and plans for parks and public areas.

PSE focuses on planning for electric and gas system operations. PSE obtains its growth plans and projections from interactions with its various customers including cities, developers, companies, and facility owners. PSE and Bellevue share many of the same customers when it comes to planning for growth in Bellevue.

From the perspective of electric system planning, there are two main elements:

- Overall long-term growth planning to identify the potential for growth in Bellevue and to identify the need for additional electric system capacity.
- Medium-term tactical planning for specific projects that affect the electric distribution system in Bellevue as well as the PSE-owned transmission lines. The long-term plan is based on growth projections in the PSE service territory (Bellevue and surrounding areas) that impact the need for additional service to various areas of the City. The Comprehensive Plan Utilities Element Figures UT.5 and UT.5a present the current view of potential plans for electric expansion in Bellevue to meet future needs.

Discussions with staff in both Bellevue and PSE indicate that the overall growth plan is developed based on individual discussions with prospective developers and then later meetings are held between PSE and Bellevue to ensure that PSE has input from Bellevue relative to preparing their IRP. This level of planning is one of the means that PSE utilizes to project growth and to develop system plans to support growth. Since these are longer-term plans to identify future needs, the major need is to coordinate the results of the planning activities to ensure that PSE is informed by City input relative to growth for inclusion in its long-term planning process.

The medium-term tactical planning is directed at potential projects that may need to be performed in Bellevue on existing or new locations. Typical maintenance or replacement projects are handled through the normal permit process. PSE performs ongoing assessments and studies of its electric system to ensure that the system is capable of handling current and future demands. The PSE plans are based on their projections for future growth in Bellevue and other parts of their system. These medium-term tactical projects are also part of the IRP. The ability to turn the medium-term tactical plans into real projects varies by size and type of project. The projects subject to tactical planning are large expansion projects (substation expansions, new feeders, substation connections) that require significant lead-time to proceed to an actual project. Based on the discussion in Section 3, there will be a need for new facilities as the City grows and reaches its build-out limits.

Bellevue has entered into a Franchise Agreement with PSE[106] that outlines requirements for PSE operation, construction, and support of facilities in Bellevue. The Franchise Agreement outlines the requirements for the various types of projects performed by PSE. The Franchise Agreement and the City Comprehensive Plan Policies include requirements that call for siting reviews of the larger capacity projects. Based on discussions with staff at PSE and Bellevue, the review and update of the utility growth plans in the Comprehensive Plan requires review and update. Since these capacity expansions represent large and complex projects, and given the significant growth expectations of the City, a regular update of the plan is appropriate to ensure that the City and PSE understand the requirements for future growth.

#### 4.2.2.4 Permitting

Once a project is ready to proceed, it then enters the permitting process. For major projects (including those on sensitive site locations per the Comprehensive Plan), the following steps are typically required:

- Pre-application meeting
- Siting analysis that must include three alternatives
- Tentative agreement on an alternative
- Submittal of the application
- City recommendation
- Hearings and appeals, if required
- City Council decision
- Permit issued.

The typical time frame for these types of projects (from initial request to permit) is approximately 3 years and can be longer. Typical smaller projects follow a similar permitting

[106] Reference 27.

process but start with submittal of the application, and the process proceeds in a quicker manner. If the project is on the public right-of-way and is covered by the Franchise Agreement, then issue of the permit is handled through the Franchise Agreement and does not require City Council approval.

#### 4.2.2.5 Analysis

Based on discussions with Bellevue and PSE staff, observations relative to the planning and permitting process are:

- There is good agreement that both parties understand the permitting process and that working relations between the parties is good. However, there is sometimes a need to get new PSE contractors to more quickly understand the process.
- Complete information in the permitting process results in a more routine permit process. Incomplete information tends to slow the process.
- For larger projects, more complete siting analysis information on the alternatives (specifically impacts and mitigation plans) will improve the permitting process.
- There is more public interaction and comment for any large projects, especially for aboveground infrastructure.
- The PSE tariffs are clear and understood by the City relative to services provided under tariff. When multiple non-City utilities are involved in a project, all have Franchise Agreements, and there is some negotiation required to determine who pays for the services depending on the project initiator.
- Future projects are understood at a conceptual level, but the details are not fully appreciated until the permitting process is initiated.
- Coordination between the various utilities requesting right-of-way work could be improved from a planning perspective so that each utility can plan for these opportunities.

#### 4.2.2.6 Recommendations for PSE Interaction

The assessment indicates that there are opportunities to improve the overall knowledge sharing and coordination in the planning and permitting process. While the interactions between the organizations are good due to proximity and history, much of the interaction is based on informal communications. The following recommendations are provided:

- It is recommended that the City engage PSE in an annual planning workshop around large future capital projects. This is the same recommendation that is defined in Section 3. The outcome of these workshops should be an action plan to move projects forward. The intent of this recommendation is to have these major project discussions well in advance of permit applications. PSE has developed and maintains a long-term system planning strategy relative to the electric power system. This plan is generally represented in the IRP. However, as the lead time to permit larger projects (required to add capacity or reinforce the City infrastructure) has grown, it requires that the City understand the projects from a more detailed perspective than just a conceptual framework.

- Both Bellevue and PSE work with various developers and companies to identify new potential facilities in Bellevue. While information is shared for the IRP, and to the extent that information can be shared, it is recommended that a more formal meeting (annually) be held to ensure that all Bellevue needs are identified to PSE and that both organizations are coordinated regarding future load demand. This exercise relates to longer-term issues that are expected to be addressed in the future.

- There are opportunities for multiple utilities to take advantage of projects being performed by one of the utilities. This is a coordination function that is best captured by the City. It is recommended that the City engage their utility partners to identify new projects (both large and small) to attempt to maximize projects in the rights-of-way. This planning activity is intended to take place in advance of permit applications so that the utilities can plan these projects into their annual work. This action also represents a potential means to advance undergrounding of circuits if PSE can take advantage of trenching to add conduits for future use.

### 4.2.3 Transparency of Operations

The transparency of operations is focused on the communications between PSE and its customers during emergency and outage events. The City has a role to play as a representative of the community. However, PSE has also provided transparency in its operations through the information provided around its various business processes, projects, and plans.

#### 4.2.3.1 Emergency Planning

The emergency response programs are well-defined for the both the City of Bellevue and PSE in their respective policies and procedures. The City of Bellevue maintains its emergency response program in its Emergency Operations Plan.[107] The plan supports and is compatible with King County and state of Washington emergency plans, the National Response Framework, and the Regional Disaster Plan for Public and Private Organizations in King County. Bellevue has adopted the National Incident Management System (NIMS) as the basis for incident management. The plan includes roles and responsibilities for the City departments and also discusses non-governmental agency support. In this case, PSE is identified as an

[107] Reference 28.

organization that will provide support during emergency events when appropriate. When requested, PSE will assign a liaison to the EOC, if available. However, PSE does assign a liaison to the King County Emergency Coordination Center (ECC) if a more regional emergency is called. Bellevue has also implemented programs for first responder “GETS” cards that provide priority access through the phone system. A HAM radio system is employed through the Amateur Radio Emergency Service to address situations where phone towers are down and normal (cell) phone communication cannot be used.

PSE maintains its emergency response program in its Corporate Emergency Response Plan.[108] This document outlines how PSE addresses emergency operations for both its electric and gas systems. Similar to Bellevue, PSE maintains an EOC and is in the process of adopting the NIMS protocol. Some key aspects of the PSE Emergency Response Plan include:

- An electric emergency is defined as:
  - 12 distribution circuits out in one region and escalating
  - 30 distribution circuits out system-wide and escalating
  - Poor weather conditions (wind, snow, ice) predicted
  - Earthquake or other hazardous conditions.
- PSE’s overall response strategy is summarized as:
  - Restoration priorities are assigned for each region.
  - Focus on correcting problems that can be fixed quickly and restore the greatest number of customers.
  - Restore first and then repair (based on conditions of the damage). Damaged sections may be de-energized and service may be restored up to the point of damage.
  - Schedule and complete the repairs.
  - Facilities are generally restored in the following order: transmission, distribution substations, distribution feeders, and individual service. PSE maintains a more detailed list in its Corporate Emergency Response Plan document.
- PSE maintains a list of critical facilities and accepts municipality identification of critical facilities. PSE also maintains a list of locations that require priority for medical reasons (nursing homes, individuals).
- PSE maintains someone onsite at the King County ECC to coordinate on regional events.

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108 Reference 29.

- PSE has defined contacts as liaisons with Bellevue even if they do not staff the Bellevue EOC.
- PSE has established agreements with other entities, including their subcontracting partners, to provide resources in an emergency. This includes a Western Region mutual assistance agreement for support from other utilities outside of the area to assist in restoration and repair in a major emergency (such as the 2006 storm event).
- PSE also employs a HAM radio operations system in the event that normal phone service is not available.

The Bellevue and PSE EOCs are similar, but they serve different functions. The PSE plan is related to their service territory and the PSE EOC may be activated without Bellevue needing to activate its own EOC. Similarly, the Bellevue EOC focuses on events in Bellevue, and depending on the emergency conditions, may open without PSE having to activate its center. However, in all cases, there are established interfaces within each organization to provide communication during an emergency. Additionally, both Bellevue and PSE participate in regional emergency planning exercises and have significant information on their websites regarding emergency response.

There are several coordination actions required in order to recover from an electric system emergency outage. Bellevue indicated that they have provided a priority list of critical facilities to PSE so that these are known in advance. Another issue centers on coordination of local city police and fire departments to support PSE crews in getting access to streets and areas to provide assessment, restoration, and repair services. There currently is no formal protocol for handling these interactions in an emergency and they are generally handled informally by requests from PSE to the Bellevue EOC as crews identify needs in the field.

#### 4.2.3.2 Communications with Stakeholders

A major issue during the 2006 winter storm was the lack of communication on the status of the outage and restoration activities. The PSE OMS is currently a manual system as described previously in Section 2.4.6. The system does not currently provide web-based information on specific outage locations and statuses, and the manual process can get overwhelmed in a large outage or emergency.[109] PSE utilizes media outlets to try to communicate during these times; however, this has not been effective in the past at keeping customers at specific locations informed of outage status. Even in a major storm outage (non-emergency), the manual outage management process may be overburdened.

Many utilities are taking lessons learned from major storm events in all parts of the country and are engaging in installation or upgrades to their OMSs. Lessons learned[110] from major storms in

[109] Web-based systems assume that people have access to the Internet, which may not be available during a severe power system outage event.

[110] Reference 35.

the southeast United States indicate the need and the benefits of a fully-integrated computerized system to improve response in major storm events. These integrated systems allow for communication of real-time information to personnel located in multiple locations to facilitate decisions and to update progress. The ability to get visibility into the outage extent and to communicate rapidly with field personnel improves the overall response time. Several other utilities in the Northwest are in the process or have recently upgraded OMSs.

PSE has taken many actions to improve their response to a major event. Some key actions include:

- PSE is currently implementing a major upgrade to its OMS. This upgrade was defined in Section 2.4.6. A key feature of the OMS is that it can automatically locate circuit status visually on a display board that will allow personnel in multiple locations to have access to the data.
- Currently, in a major outage event, where PSE, Bellevue, and King County have activated ECCs and EOCs, communication channels will be strained based on the volume of people needing information. Per their emergency protocols, PSE will communicate from its EOC directly with the King County ECC. The King County ECC communicates with the other governmental entities. Additionally, PSE has liaisons for its various stakeholders and PSE will communicate directly to the City of Bellevue. When completed, the OMS installation should provide a means for faster and more accurate reporting of information.
- The PSE EOC will also issue regular status updates during an emergency. These updates will go to the various EOCs, municipalities, and the news media. The news media (radio) represents a significant distribution channel during major emergency events. PSE also updates its customer call center information to be consistent with releases to the news media. Unfortunately, in a major electric outage, normal communications channels may not be available, and individuals should be equipped with the ability to access the radio news media.

#### 4.2.3.3 Recommendations

The assessment indicates that there are opportunities to improve the communication channel in outage and emergency events. The following recommendations are provided:

- PSE is deploying a new OMS system over the next year that should improve overall outage communications. After deployment, it may be appropriate for selected City personnel involved in emergency response to gain an understanding of the enhanced capabilities in order to better assist in communicating to the Bellevue community.
- There is an opportunity to improve the emergency response and recovery capability between PSE and Bellevue relative to coordination of PSE activities, and Bellevue emergency management, transportation, police, and

fire functions. This opportunity may also include Bellevue staff assisting PSE in identifying damaged areas. It is recommended that the City engage PSE in discussions to develop a formal process for these communications to facilitate response and recovery in the future.

- The improvements in the system over the past 5 years have had a positive impact on reducing outages and duration during normal operation. However, the overall system cannot be hardened sufficiently to prevent major outages for an event similar to the 2006 storm. A storm of this magnitude that impacts the regional transmission system requires significant time to restore power to all customers. It is expected that citizens within the City should be prepared to be without power for up to 3–7 days after this type of event. The City should consider an education campaign to make its citizens aware of the problems and help them to be better prepared to deal with future emergencies.

## 4.3 Role of the City Recommendations

Bellevue's role as an informed stakeholder requires that the City take an active role in becoming informed on matters affecting the reliability and planning for the electric system in Bellevue. This role includes direct communication with PSE as well as other stakeholders regarding electric service. Based on this review, a set of recommendations were described earlier in this section that focus on planning, permitting, emergency or outage management, and regulatory interface. A summary of the assessment is provided below.

Question:

- "What opportunities are available to the City to work with PSE, regulators (WUTC, FERC), and other stakeholders to ensure the needs and expectations of Bellevue's residents and businesses are met relative to the reliability of the power supply?"

**Recommendation 1**: WUTC Interaction

**Finding**: From a WUTC perspective relative to electric power, cities are considered as any other member of the public. Bellevue's primary interaction with WUTC is one of being an active participant relative to changes in laws and tariffs that may affect electric system reliability in the state of Washington.

**Reliability Actions**: Bellevue's ability to be a knowledgeable stakeholder will require assignment of an engineer knowledgeable in the electric power system to foster the City interaction with stakeholders.

**Recommendation 1A**: Bellevue's involvement with WUTC may be one of informing lawmakers and commissioners of matters that the City believes affect the City's electric reliability or general electric service. For issues affecting electric reliability that are of interest to the City:

- A designated individual can be assigned to electric system matters. The individual should remain informed of electric system activities related to WUTC.
- On matters of interest to the City, white papers can be developed for submittal to WUTC on issues affecting electric reliability. This provides a means to provide feedback to WUTC without direct response to hearings. Potential policy matters could be advanced using this approach.

**Recommendation 1B**: Bellevue has the opportunity to comment or participate in matters directly affecting PSE and their interaction with WUTC. Bellevue also has the ability to support and advocate for initiatives that meet its goals and objectives. The recommended actions are:

- The City can support or advocate for PSE positions of interest to Bellevue. As programs and rate discussions take place between WUTC and PSE, the City has the opportunity to advocate for positions that support City goals.
- The City should comment and participate in various programs submitted to WUTC by PSE, where PSE is seeking advisory input from stakeholders including the IRP, Smart Grid plan, and reliability programs.

**Recommendation 2**: Major Project Planning

**Finding**: The assessment indicates a need to review and update the utility growth plans in the Comprehensive Plan. The large capacity projects will require significant lead time for siting analysis and permitting.

**Reliability Actions**: Conduct major project discussions well in advance of permit applications to ensure sufficient lead time to permit larger projects (required to add capacity or reinforce the City infrastructure).

**Recommendation 2**: It is recommended that the City engage PSE in an annual planning workshop around future capacity and expansion projects. The Comprehensive Plan includes an electric system plan that can serve as the basis for the annual workshop. The workshop should focus on the following items:

- Current growth projections and electric power use in Bellevue (see Recommendation Role 3)
- Review of current plan applicability (Figure UT.5a)
- Update of the current plan
- Develop actions for capacity projects required to initiate siting and permitting activities within the next 2 years.

An outcome of the workshop should be an updated plan for inclusion in the Comprehensive Plan (if required), and an action plan to move designated projects forward into siting analysis and/or planning.

As a minimum, the following capacity additions have been identified as being needed within the next 5–10 year time frame:

- Upgrade of the existing 115 kV lines to 230 kV
- Addition of transformer banks to support expected growth in various areas of the City (Downtown, Bel-Red, and Somerset/Eastgate)
- Addition of new 115 kV lines to reinforce the overall electric system.

As previously stated, based on recent Exponent staff experience with T&D capital projects, typical time frames for projects of this size and complexity are as follows:

- Transformer additions require 18−24 months to complete from start of engineering to operation. Additional time is required for planning and permitting.
- Line projects may require 4−5 years from the start of engineering to completion since permitting of lines typically requires significant engineering to be completed before the formal permitting process proceeds.

**Recommendation 3**: Long-Range Planning

**Finding**: Both Bellevue and PSE work with various developers and companies to identify new potential facilities in Bellevue. There is an opportunity to share and communicate the results of these planning activities. This exercise relates to longer-term issues that are expected to be addressed in the future.

**Reliability Actions**: Coordination of Growth Planning and Major Project Activities

**Recommendation 3**: While information is shared for the IRP, and to the extent that information can be shared, it is recommended that a more formal meeting (annually) be held to ensure that all of Bellevue’s needs are identified to PSE and that both organizations are coordinated regarding future load demand. This information sharing can also be included in the annual planning meeting.

The City and PSE should synchronize their growth projections for the City by frequent information exchange on expected projects, expected timing of projects, and coordination actions required by PSE and the City to address these projects. This exchange is meant to assist longer-term planning and should occur well in advance of any specific permitting or development activities.

**Recommendation 4**: Multi-Utility Planning

**Finding**: There are opportunities for multiple utilities to take advantage of projects being performed by one of the utilities.

**Reliability Actions**: This action also represents a potential means to advance undergrounding of circuits if PSE can take advantage of trenching to add conduits for future use.

**Recommendation 4A**: It is recommended that the City engage their utility partners to identify new projects (both large and small) to attempt to maximize projects in the rights-of-way. This planning activity is intended to take place in advance of permit applications so that the utilities can plan these projects into their annual work.

**Recommendation 4B**: The City can take advantage of projects that require trenching to place conduit for future use of potential undergrounding. The existence of conduit may allow for more economic alternatives for undergrounding in the future. This action requires City planning to identify future projects that require trenching and to discuss with PSE the placement of conduit. This will be an ongoing action as projects are defined, but can be coordinated through the City Planning Department. (This action is associated with Recommendation Current 3A).

**Recommendation 5**: Emergency Response Capability

**Finding**: There is an opportunity to improve the emergency response capability between PSE and Bellevue relative to coordination of PSE activities (e.g., Bellevue transportation, police, and fire functions). Currently, the coordination activities are more informal and on an as-needed basis. This opportunity may also include Bellevue staff assisting PSE in identifying damaged areas.

**Reliability Actions**: The ability to improve recovery time in Bellevue after an outage can be improved by better coordination between City first responders and PSE crews.

**Recommendation 5**: The City and PSE should consider the development of a more formal process (procedure) related to response and support activities during an outage. The ability to coordinate activities (especially during a major outage) may include the following activities:

- Locating damage
- Coordination of access to areas of damage
- Access to PSE outage information
- Coordination of recovery plans
- Emergency support to people in need.

The outcome should be an agreement (or procedure) for communication and coordination during large scale events affecting Bellevue.

# 5 Measurement and Monitoring

## 5.1 Metrics

The reliability assessment has presented recommendations for the City to consider moving forward. The implementation of these recommendations, if accepted, require metrics to inform the City of the need for action relative to the achieving the goals of the recommendations. Metrics are developed for the set of recommendations to provide the City with a vehicle for tracking progress.

Metrics are typically classified as “lagging” or “leading” metrics. The “lagging” metrics typically include results, such as SAIFI or SAIDI, that indicate performance in the past. “Leading” metrics are those that predict performance in the future. These metrics provide trends that will provide insight into the future results metrics. For example, if maintenance task completions are falling behind schedule, then it can be anticipated that reliability would experience a decline in the future. These “leading” metrics are the type developed for the City. These metrics allow the City to track progress, chart improvement, and guide the need for further corrective action or improvement. These metrics also provide the City with a basis for a meaningful discussion with PSE as an informed stakeholder.

Proposed metrics from the key observation of the reliability assessment are:

- **Performance- and outage-based:**

  There are many metrics that can be reviewed based on information provided by PSE to the City in the Annual Reliability Report, including:

  – Overall City SAIDI and SAIFI (with and without storms since the trends of these outage types provide different information into the health of the system)

  – Circuit level SAIDI and SAIFI (with and without storms similar to above)

  – Equipment failure trends (frequency and duration)

  – Specific trends on circuits that have undergone reliability projects to review improvements gained

  – Review of specific projects targeted for circuits of concern

  Based on the results in this assessment, the following metrics are recommended for the performance- and outage-based findings:

  – There is significant information provided by PSE in the annual reliability report for Bellevue. A metric can be developed that identifies the circuits of concern in Bellevue. This metric is based on the identification of circuits that exceed the PSE system average or the WUTC Service Quality Index for SAIDI and SAIFI. This metric will provide an indication of circuit-level performance in Bellevue.

- A major focus in the study was the performance of the system in the Downtown. A Downtown SAIDI and SAIFI index can be developed for the circuits feeding the Downtown area to monitor reliability there. This measure will provide a focus for identifying the need for additional projects to support reliability in this dense customer area.

- The study identified two causes of outages with very specific solutions. Underground cable failures are a major contributor to outages and there is a program to replace or remediate the cable. Tree-related events are causing overhead conductor failures and a solution offered is the use of covered conductor (tree wire) to reduce outages on a line. Circuits, which have these solutions applied, can be tracked and trended to determine the effectiveness of the solution. These actions are related to preventing outages and the metric is based on the number of outages on these circuits.

- **Design-based:**

  - There is a need to reinforce the looped system in Bellevue by ensuring appropriate redundancy in the system. This redundancy is achieved through the accomplishment of projects to provide back-up feeds to substations and to provide circuit feeder ties that provide additional sources of power. PSE has identified these projects and the metric is to track projects completed to achieve full redundancy in the system.

  - The deployment of automation is identified as a key benefit to managing reliability. There are three specific distribution automation activities that should be tracked to determine the level of automation on the system. The metric is based on tracking percent automation achieved in areas of distribution breaker SCADA and control, sectionalizing switches connected to SCADA, and switch positions reported in SCADA.

- **Growth-based:**

  - There will be a need for additional capacity as Bellevue grows in various areas. The two critical areas for load growth are Downtown and in the Bel-Red area. Since the lead time to permit these additions is expected to be lengthy, it is important for the City to monitor load in these service areas to identify the timing for engaging PSE in discussions prior to the permit application. A measure that monitors the annual load growth will provide the City with a time frame for action. The City can work with PSE to obtain this information and use this in the annual planning workshops.

The specific metrics for these items are included in Table 7. Upon agreement with the City, specific metric plans can be prepared to allow for tracking and trending of these metrics.

**Table 7. Proposed Metrics**

| No. | Metric | Basis | Comment |
|---|---|---|---|
| 1 | Bellevue Circuits of Concern | Number of Bellevue circuits exceeding PSE system average or WUTC goals for SAIDI and SAIFI. Count of circuits based on information from the Bellevue reliability reports. | The number of circuits exceeding system averages and WUTC goals is a measure of reliability on circuit-level performance and provides trending on reliability. |
| 2 | Downtown Reliability | Reliability indices can be created for the Downtown as a whole by aggregating Downtown circuit performance. This measure is based on the SAIDI and SAIFI information from the annual reports and will monitor performance in the Downtown. | Downtown Bellevue has received significant attention in recent years in improving the reliability of the service to the Downtown. This metric is a measure of Downtown performance to identify concerns and possible additional actions. |
| 3 | Reliability Project Effectiveness | For circuits with reliability projects for underground replacement/remediation and for overhead installation of tree wire, measure the number of outages on these circuits related to these causes. Count of outages (can be taken from Bellevue reliability report). | Underground cable and tree-related events were identified as major causes of outages in Bellevue. Several actions have been proposed to address these issues. This metric provides a basis for review of effectiveness of reliability actions to prevent outages. |
| 4 | System Redundancy | PSE has identified the need to complete redundant feeds into several substations to complete the looped system; and has identified circuits that benefit from installation of switches and feeder ties. Measure of completion of redundancy based on percent of facilities with:<br>• Substations will back-up feed<br>• Circuits with feeder ties/switches | The completion of the looped system as well as reinforcement of circuits provides for greater reliability by improving recovery time and limiting the impacts of outages. |
| 5 | Automation Utilization | Measure extent of automation utilization based on percent of facilities with:<br>• Distribution breakers in the substation with SCADA control<br>• Sectionalizing switches connected to SCADA<br>• Switch positions fed to the SCADA system. | This metric measures the extent of automation installation for these items where it is recommended that 100% of the items have automation. |
| 6 | Power Demand | Power demand in critical growth areas of the City. Electric power usage in Downtown and Bel-Red (based on information from PSE). Measure of power usage in Downtown and Bel-Red to identify the need to kick-off capacity projects. | Given the long-lead time to install major infrastructure additions within Bellevue, this measure will track growth in the critical growth areas of the City to identify the need to open discussions between Bellevue and PSE and to initiate pre-permitting activities. This should be performed in coordination with the annual planning meeting on potential large projects. |

## 5.2 Stakeholder Communications

The City has many avenues available for communicating with its various constituents regarding the electric reliability initiative. There is significant information available relative to work and status of the electric system reliability. A major concern of the various stakeholders is the timeliness of information on matters that affect the residents and businesses in Bellevue. Relative to issues of electric reliability, outage management, and communications, information can be provided for the following:

- Overall electric performance through the PSE reliability report and various statistical analyses that can be performed by the City around projects and outages in the City. This provides a means to inform and educate the constituents regarding issues affecting electric power.
- Early notification of major growth and projects affecting the City electric system based on planning meetings with PSE.
- Information on electric system outage management and response for both normal and storm conditions that provides a means of emergency preparedness and how to communicate in these circumstances.
- Information relative to identifying critical facilities so that PSE is aware of these prior to emergency events.

This information is mostly available today from the City and PSE in various forms, such as website, downloadable documents, emergency preparedness events, direct mailings, etc. The City has the opportunity to develop a communications plan around electric system performance through the use and publishing of the metrics. The City may choose to combine these with other forms of communication to provide a standard form of update and status. The City of Bellevue website provides a vehicle to communicate to its constituents as an informed stakeholder.

# 6 Conclusions

The City retained Exponent to perform an electric system reliability assessment to assist the City in meeting its goals to be an informed stakeholder and to work with PSE to ensure a reliable electric power supply for the City. The study was performed to answer the following questions from the Electric Reliability Study Plan[111]:

1. *"How does PSE's existing system serving Bellevue perform relative to WUTC expectations, industry standards, and peers relative to reliability?"*

   There are over 90 circuits in Bellevue and while the performance on individual circuits can vary, the overall system in Bellevue is reliable.

   Electric system reliability is measured by the availability of the system to deliver electric power to a customer's meter in accordance with voltage and frequency requirements specified by WUTC.[112] Reliability is therefore a measure of the probability that electric power is delivered in accordance with those requirements. Electric system reliability is typically measured based on the frequency (SAIFI) and duration (SAIDI) of outages relative to the number of customers.

   WUTC has established reliability goals for its regulated utilities (service quality indices). Prior to 2010, the measures included SAIFI (frequency of outages per customer) and SAIDI (duration of outages per customer) goals for PSE of 1.3 and 136 minutes, respectively, excluding major storm events. While PSE has not always met the SAIDI goals system-wide, Bellevue's reliability has met the SAIFI and SAIDI goals over the past 5 years. In 2010, the reliability in Bellevue measured 0.44 and 66 minutes, respectively for SAIFI and SAIDI. In 2010, the measure for SAIDI was changed to include a 5-year average including major storm events and PSE met that goal system-wide. They will report this measure for Bellevue's circuits in 2011.

   PSE participates in an industry reliability survey through the IEEE. PSE's overall system reliability performance is typically in the 1st or 2nd quartile on SAIFI (frequency of outages) and 2nd or 3rd quartile in SAIDI (duration of outages) (with the 1st quartile being best performance). PSE's 2010 performance for SAIFI and SAIDI was 0.86 and 129 minutes, respectively, and as shown above, Bellevue had significantly better reliability performance.

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[111] Reference 10.

[112] WAC-480-100.

2. *"What changes relative to facilities, equipment, planning, and emergency operations will improve electric system reliability, communication, and outage response in Bellevue?"*

   While there has been improvement in the reliability of the Bellevue system over the past several years, the following enhancements are required to ensure continued improvement in reliability for the City:

   - Hardening of the Bellevue system to ensure appropriate redundancy to all substations and circuits.
   - Continued focus on underground cable replacement and remediation as well as replacement of older switches and transformers placed in underground vaults.
   - Review of specific circuits within the City that experience lower reliability to identify improvement actions.
   - Accelerate investments in distribution automation (including a DMS, e.g., SCADA) to improve reliability and to enable future technologies.
   - Develop strategies to provide greater opportunities for undergrounding lines experiencing lower reliability due to tree and storm impacts, including review of potential funding mechanisms for overhead to underground conversions and identification of trenching opportunities from other City projects (to include conduit for future use in potential undergrounding).
   - Improvements in the information technology infrastructure for outage management and customer interface to specifically improve communication and outreach to customers during outages on the system.

3. *"Will the City have adequate and reliable power supply to meet future City growth needs?"*

   Based on current plans, the City will have an adequate and reliable power supply to meet the medium-term (5–10 years) and long-term (10–20 years and beyond) growth requirements. The current plan includes:

   - Capacity additions, including upgrade of the 115 kV lines running north-south through Bellevue.
   - Addition of transformer banks to support growth in the Downtown, Bel-Red, and Eastgate/Somerset areas.
   - Upgrade of 115 kV lines to support additional transformer banks.
   - Support of PSE plans to significantly reduce the peak electric power demand through the use of more efficient electric lighting and equipment.

4. *"What opportunities are available to the City to work with PSE, regulators (WUTC, FERC), and other stakeholders to ensure the needs and expectations of Bellevue's residents and businesses are met relative to the reliability of the power supply?"*

   Bellevue's role as an informed stakeholder requires that the City take an active role in becoming informed on matters affecting the reliability and planning for the electric system in Bellevue. This role includes direct communication with PSE as well as other stakeholders regarding electric service. Specific opportunities for the City to engage as an active stakeholder include:

   - WUTC: The City has a role in informing lawmakers and commissioners regarding matters that affect reliability. The City also has the opportunity to comment or participate in matters directly affecting PSE and its interaction with WUTC. It may be possible for Bellevue to support measures for investment brought forward by PSE that support its overall City goals for electric system reliability and service.

   - PSE: The City has many opportunities to proactively interact with PSE on issues related to system reliability, long-term planning, near-term major project planning, Smart Grid initiatives, and emergency planning.

5. *"How can the City measure and monitor whether improvement in reliability is being achieved?"*

   This reliability assessment includes recommendations for the City to consider moving forward. Proposed reliability improvement metrics have also been included to assist the City in measuring and monitoring the implementation and effectiveness of these recommendations.

This reliability study provides the analyses and recommendations to support the City in meeting its goals to be an informed and active stakeholder and to ensure that the City has an adequate and reliable electric system now and into the future.

# Appendix A

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# Appendix A. References

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# Appendix B

## Electric Reliability Basics

# Appendix B. Electric Reliability Basics

A discussion of electric system reliability is included here to provide context for the assessment presented in the main text of this report. This background information presents a basic description of the electric system and reliability and provides an explanation of what drives reliability performance. This information is used for reference throughout the report.

## B.1. Electric System

The electric system consists of generation, transmission, and distribution systems that deliver power from generation stations to the end user. The overall electric system is depicted in Figure B-1.

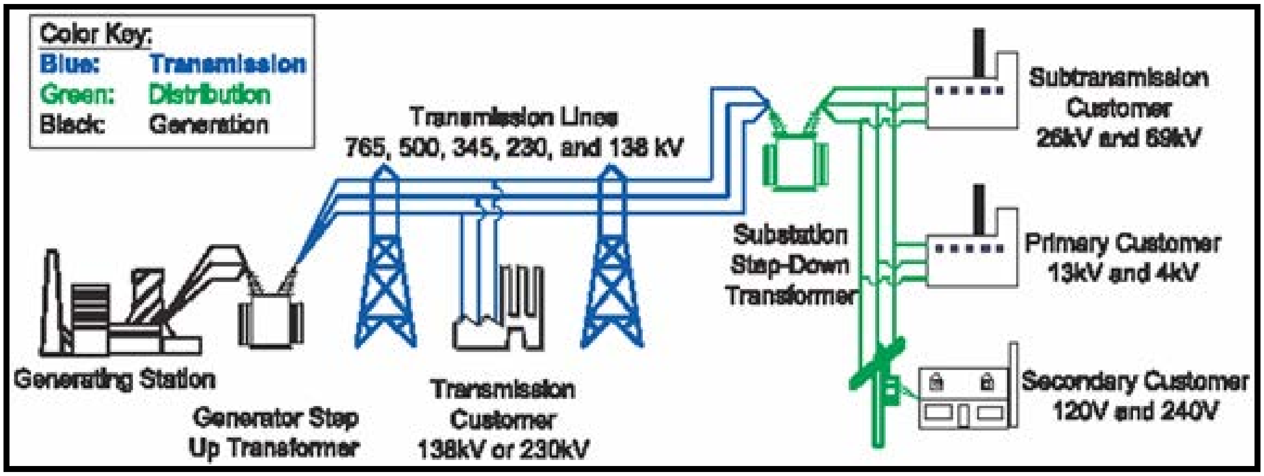


Figure B-1. Electric Power System

The overall electric power system consists of the following major systems:

- **Generation:** The generation system is made up of large base-loaded power plants (hydro, fossil, nuclear), renewable sources (wind, solar), and smaller distributed generation sources. Generation sources are obtained from utility-owned assets as well as purchased power from third parties. The third-party agreements consist of long-term power contracts, as well as short-term market-based power contracts to meet peak demands. Utilities are required to maintain generation assets with sufficient capacity to meet peak electric power demands and reserve margin requirements. Utilities provide long-term forecasts and plans for generation needs through their integrated resource plans.

- **Transmission:** The transmission system delivers electricity from the generation stations at high voltages to the distribution system. Electricity is stepped up from power plant voltage at the generation station switchyards to transmission level voltages and carried to the substations, which step down voltages to distribution level voltages. The transmission system consists of high voltage lines that typically span long distances from the generation stations to the distributions systems. The high voltage transmission systems are the bulk power supply assets and the transmission system operations affect all utilities connected to the system. Therefore, these transmission systems are monitored and coordinated through regional transmission operators. Transmission systems utilize supervisory control and data acquisition (SCADA) systems and Energy Management Systems to monitor and control the operations of the transmission system and the connected power sources. Also, since the transmission lines carry bulk power affecting large customer populations, they are designed with a high degree of redundancy so that there are multiple sources of power provided to transmission substations that feed the distribution system.

- **Distribution:** The distribution system delivers electricity from the transmission substations to the end users. The end users may be industrial, commercial, or residential users and the utility distribution system typically ends at the customer's meter. The distribution system consists of distribution substations which are fed from the transmission substation that step down voltages to distribution level (typically 12.5kV). The distribution voltage is stepped down to a suitable customer voltage through distribution transformers which are fed from the distribution lines.

These three major systems have varying impacts on electric power delivery reliability.

## B.2. Impacts on Reliability

Reliability to the end user is the availability and quality of electric power delivered to their meter. Reliability is impacted by outages on the system that result in a loss of electricity at the meter, as well as variations in voltage characteristics (power quality). While power quality issues are not outages, they may affect the performance of equipment and appliances that are sensitive to voltage fluctuations.

Outages are typically caused by:

- Equipment failures
- Weather-related events (typically wind and storm damage)
- Vegetation-induced faults (e.g., tree branches falling on wires)
- Animal-induced faults (e.g., animal or bird interaction with live components)
- Other types of accidents (e.g., car accidents affecting system assets).

Faults in the electric power system may interrupt delivery of electricity to the end users. A fault produces a disturbance in the electric delivery system that may require the system to shut down for operational and safety reasons. When the fault is identified and corrected, then power delivery can be resumed. This fault identification and correction may be performed by automated systems or by manual intervention. Interruptions on the electric system are classified into several categories:

- Momentary interruptions: These are very short duration outages (industry typically uses less than 1–3 minutes). Power quality occurrences can be categorized as similar to momentary interruptions.
- Sustained interruptions: These are longer duration outages (industry uses greater than 1 – 3 minutes).
- Major interruptions: These are long duration and widespread outages resulting from storms, earthquakes, equipment failures, or other events. These interruptions typically affect a large percentage of the end users.

Relative to measuring reliability, the industry traditionally uses only sustained interruptions in the determination of reliability. However, reporting is often provided for major events or interruptions as a secondary measure. The determination of these reliability measures is discussed later in this section.

The electric system components affect reliability differently. Generation assets are required to be available with sufficient margins that the loss of a power generating facility does not result in outages to end users. For very significant events, such as the northeast outage in 2003, multiple plant shutdowns can result in widespread outages, although these are relatively rare occurrences. Also, if peak electricity demand increases to levels above the generation capacity and reserve margins, then outages can occur. However, for purposes of electric system reliability, generation components do not have a major effect on industry-reported measures of reliability for normal operations.

The transmission system has a very large impact on power delivery and a major event on the transmission system can result in outages for a very large number of customers. However, while a fault or outage of a transmission line or substation has the ability to impact more end users, there are typically sufficient redundancies in transmission assets to minimize the impacts of events on these systems. Additionally, the transmission lines are higher in elevation and usually have larger rights-of-way to reduce the impact of threats to the lines from sources such as trees, animals, and other interactions. Due to these features, transmission assets typically experience far fewer faults than distribution lines; therefore, the transmission system has very little impact on measures of reliability. The ability of the generation and transmission assets to deliver the power demand is more of a longer-term planning concern than a day-to-day reliability concern.

The distribution system directly provides electrical power to customers and is subject to a higher number of faults than generation and transmission assets. Distribution systems are typically designed with less redundancy than the other systems and since this is the system delivering the power to the customers, faults or events on the distribution systems result in outages to customers. Therefore, the potential for local system issues to produce outages is greater than other components in the system. Thus, reliability is primarily governed by distribution system assets.

## B.3. Reliability Measures

Today, reliability is typically measured based on the frequency and duration of outages relative to the number of customers. There are several measures for reporting and measuring electric reliability, such as IEEE Standard definitions[113] or similar approaches to report reliability. These measures include SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index). These indices are calculated by PSE in their reporting as:

- System Average Interruption Frequency Index (SAIFI)
  - SAIFI = (Sum of the number of customers affected by each outage) divided by (Total number of customers served)
- System Average Interruption Duration Index (SAIDI)
  - SAIDI = (Sum of the number of customers interrupted times the number of minutes of each interruption) divided by (Total number of customers served).

These measures are based on the customer base served. SAIFI measures the number of outages that a customer experiences and SAIDI measures the outage duration (minutes) that a customer experiences. Therefore, these measures represent the average number and duration of outages experienced per customer. These measures provide a basis for tracking and trending overall performance and allow for comparison among utilities.

Momentary interruptions (and power quality excursions) are typically not measured or monitored continuously at end user sites and are not included in the reliability calculations. Currently, most utilities do not actively track these momentary outages, but work with customers directly to address them when these issues are identified as problems. Customer sites that are very sensitive to momentary or power quality issues typically develop site-specific solutions to protect their assets and operations.

Additionally, major outages are typically not included in reliability measures since these major outages are not representative of how the electric system normally performs. However, utilities today are providing additional reliability measures that include major outage effects. While these reliability measures allow for tracking and trending performance, they also provide a basis

[113] Reference 11.

for how an electric utility responds to these measures.[114] Utilities use these reliability statistics to identify problem areas and define actions to improve reliability.

## B.4. Reliability Drivers

Since the reliability of the electric system is measured by metrics similar to SAIDI and SAIFI, a key to understanding reliability is defining what factors affect reliability. Electric system reliability relative to the frequency or occurrence of outages is impacted by the following:

- **System Design (Layout):** Distribution system designs vary in the extent of system redundancy (a high level of redundancy means that the system can withstand more contingencies without affecting the customers). In more urban areas, the distribution system may consist of a network that is a highly redundant and allows electricity to be provided from multiple sources (substations). Therefore, a fault on one line may not result in interruptions, since electricity is available from multiple sources. In more rural or less populated areas, the distribution system may be radial. A radial system has limited or little redundancy. A fault on the line will result in an outage of some type. There is only one source (substation) feeding a radial line. Additionally, there are system designs that lie somewhere in between a network and a radial system. Therefore, the overall system design impacts the response of the system to faults and has an impact on the number and duration of outages. System design solutions typically involve additions, modifications, or expansions to the existing system to improve reliability through design. These solutions affect both the occurrence and duration of outages.

- **System Design (Operations):** The degree of automation built into the system has a major impact on reliability. Devices that allow faults to be cleared automatically result in quick power restoration to those not affected by the fault. Also, the degree of automation allows for better knowledge of system status, faster identification of fault locations, and the ability to remotely restore power. Limited automation requires personnel to travel to the fault location and to take manual action to restore power to those who are affected by the fault. Therefore, system operations (and automation) have a significant impact on the number of sustained outages and the duration of outages.

- **Equipment Maintenance and Replacement Programs:** Many outages are produced by equipment failures. Typically, substation equipment failures result in outages which affect more end users since the substations feed multiple circuits. However, looped radial feeds from other substations to distribution circuits, which is the typical circuit topology for most of PSE’s Bellevue distribution system, helps limit outage time to that required to disconnect faulty circuit elements and connect

[114] For example, restoration of power to most of the customers reduces the duration and number of customers affected by an outage more than a long duration outage to a few customers. Since there are financial penalties associated with not meeting the reliability targets to many utilities, restoring power to as many users as possible with a minimum of delay reduces the penalties.

the alternate feed(s). Substation equipment is typically subject to preventive or predictive maintenance to reduce the potential failure of components that impact substation performance. Also, key substation assets are being equipped with continuous monitoring technologies that allow for identification of problems prior to equipment failure. Distribution line equipment is most likely to include maintenance strategies that also consider run-to-failure. Distribution circuits affect a lower number of customers. The distribution assets are typically low-cost and easy to replace items and are traditionally replaced on a set time frame. However, utilities modify their maintenance strategies and programs to direct improvements in parts of the system experiencing higher levels (frequency and duration) of outages.

- **Capital Project Prioritization Programs:** The capital project program includes projects that are capacity expansions, system configuration changes, major equipment replacements, system upgrades, reliability programs, and technology upgrades. The priority of capital projects focusing on system reliability is a major factor in improving reliability. Utility planners review overall system impacts for new and existing infrastructure and projects are selected and budgeted. The ability to trend and analyze outages provides a basis for defining projects and programs and these capital programs have a direct impact on system reliability through minimizing outages.

- **Vegetation Management:** A significant number of faults (and outages) on the overhead distribution system are caused by tree-related events. Utilities conduct tree trimming and vegetation management programs to minimize the impact of faults due to vegetation impacts on power lines. Since this is a primary cause of faults, the effectiveness of the vegetation management program is a key to improved reliability.

- **Animal Abatement:** Similar to vegetation management, utilities conduct animal abatement programs to minimize the potential for outages produced by birds, squirrels, and other animals.

- **Outage Management Programs:** The ability to respond to an outage directly impacts the reliability of the system relative to duration of outages. Keys to effective outage management are the ability to quickly identify outages and to locate faults so that appropriate restoration actions can be taken. The outage management program includes operational visibility into the system, the ability to dispatch crews to fault locations, and the ability to effectively communicate with customers. Overhead line faults might be cleared by automatic reclosing, but underground faults are typically permanent faults that require people to diagnose the problems. Also, many times the fault location has to be inspected before power can be restored.

These work processes are the primary activities that utilities perform to improve overall system reliability.

# Appendix C

## Outage and Equipment Codes

# Appendix C. Outage and Equipment Codes

**Table C-1. Outage Cause Codes**

| Code | Description |
|---|---|
| AO | Accident Other, with Fires |
| BA | Bird/Animal |
| CP | Car-Pole Accident |
| DU | Dig Up–Underground |
| EF | Equipment Failure |
| EO | Electrical Overload |
| FI | Faulty Installation |
| LI | Lightning |
| MW | Manufacturer/Workmanship |
| NYD | Not Yet Determined–Substation |
| OE | Operating Error |
| PO | Partial Outage |
| TF | Tree Off Right-of-way |
| TO | Tree On Right-of-way |
| UN/UU | Unknown Cause |
| VA | Vandalism |

The outage codes utilized in the report are based on a simplified list of codes:

- Equipment failure (EF), which includes code EF only
- Trees and vegetation (T&V), which includes codes TF and TO
- Bird and animal (BA), which includes code BA only
- External accidents (ACC), which includes codes, AO, CP, DU, and VA
- Operations (OPS), which includes EO, OE, and PO
- Other (OTH), which includes FI, LI, MW, NYD, and UN/UU.

## Table C-2. Equipment Codes

| Code | Description | Code | Description | Code | Description |
|---|---|---|---|---|---|
| ACE | All Customer Equipment | OPS | Overhead Pole Stub | UFE | Underground Fused Elbow |
| CDH | Conductor Down and Hot | ORE | Overhead Regulator | UFI | Underground Fault Indicator |
| CFD | Capacitor Bank Fuse Disconnect | OSL | Overhead Street Light | UFJ | Underground J-box |
| CTX | Transformer Instrument (current) | OSP | Overhead Splice | UFO | Underground Fiber Optics |
| DNO | Did Not Operate | OSS | Overhead School Signal | UFS | Underground Fire Signal |
| OAL | Overhead Area Light | OST | Overhead Step Transformer | UGF | Underground Submersible Fuse |
| OAN | Overhead Anchor | OSV | Overhead Service | UGV | Underground Vault |
| OAR | Overhead Arrestor | OSW | Overhead Switch | UHH | Underground Handhole (secondary) |
| OAT | Overhead Auto Transformer | OTF | Overhead Transformer Fuse | UHM | Underground Hammerheads (splices) |
| OCA | Overhead Capacitor | OTH | Other | UIC | Underground Indoor Stress Cone |
| OCE | Overhead Customer Equipment | OTR | Overhead Transformer | UJU | Underground Primary Jumper |
| OCN | Overhead Connector | OTS | Overhead Traffic Control Signal | UMP | Underground Submersible Meter Point |
| OCO | Overhead Conductor | OUP | Overhead to Underground Primary | UNK | Unknown |
| OCR | Overhead Crossarm | OUS | Overhead to Underground Secondary/Service | UOT | Underground Outdoor Termination |
| OFC | Overhead Cut-out | PED | Pedestal (secondary) | UPC | Underground Primary Cable |
| OFI | Overhead Fault Indicator | PFT | Padmount Fast Transformer | UPH | Underground Padmount Phase Shifter |
| OFL | Overhead Flood Light | PMF | Padmount Switch Fuse | UPS | Underground Padmount Switch |
| OFS | Overhead Fire Signal | PMJ | Padmount J-box | UPT | Underground Padmount Transformer |
| OFU | Overhead Line Fuse/ Fuse Link | PMP | Padmount Meter Point | USC | Underground Secondary Cable |
| OGD | Overhead Down Guy | PST | Padmount Step Transformer | USE | Underground Secondary Connection |

**Table C-2.  (cont.)**

| Code | Description | Code | Description | Code | Description |
|---|---|---|---|---|---|
| OGS | Overhead Span Guy | PTF | Padmount Transformer Fuse | USP | Underground Primary Splice |
| OHR | Overhead Recloser | SBF | Substation High Side Bank Fuse | USS | Underground School Signal |
| OHS | Overhead Sectionalizer | SCB | Substation Power Circuit Breaker | USV | Underground Service |
| OIN | Overhead Insulator | SCS | Substation Circuit Switcher | UTC | Underground Terminal Fuse |
| OJU | Overhead Jumper Wire | SPT | Substation Station Power Transformer | UTF | Underground Submersible Transformer Fuse |
| OMP | Overhead Meter Point | SRG | Substation Station Regulator | UTR | Underground Submersible Transformer |
| ONI | Overhead Neutral Isolator | UCU | Underground Copper Communications Cable | UTS | Underground Traffic Control Signal |
| OPB | Overhead Pole | UDC | Underground Dust Cap | UUS | Underground Submersible Switch |
| OPI | Overhead Insulator Pin | UEL | Underground Elbow | XFR | Transformer Unknown Type |
| OPO | Overhead Pole | UFE | Underground Fused Elbow | | |

# Appendix D

## List of Documents Reviewed

# Appendix D. List of Documents Reviewed

## City of Bellevue Documents

1. City of Bellevue City Council's Electric Reliability Interest Statement, July 2008
2. City of Bellevue Comprehensive Plan, Utilities Element
3. Franchise Agreement between Bellevue and PSE, Ordinance No. 5443, May 2003.

## Reliability Reports

4. PSE SQI and Electric Service Reliability Report, 2010 Annual Report, Filed with WUTC March 31, 2011.
5. PSE Electric Service Reliability Report, 2009 Annual Report, Filed with WUTC March 31, 2010.
6. PSE Electric Service Reliability Report, 2008 Annual Report, Filed with WUTC March 31, 2009.
7. PSE Electric Service Reliability Report, 2007 Annual Report, Filed with WUTC March 2008.
8. PSE Electric Service Reliability Report, 2006 Annual Report, Filed with WUTC March 2007.
9. PSE 2006 Bellevue Electric Service Reliability Report, April 7, 2007.
10. PSE 2007 Bellevue Electric Service Reliability Report, May 23, 2008.
11. PSE 2008 Bellevue Electric Service Reliability Report, July 24, 2009.
12. PSE 2009 Bellevue Electric Service Reliability Report, June 24, 2010.
13. PSE 2010 Bellevue Electric Service Reliability Report, May 26, 2011

## Planning Documents

14. Puget Sound Energy Integrated Resource Plan, July 2011
15. "Overview of Growth in City of Bellevue," Joint Presentation by the City of Bellevue and PSE, dated August 14, 2006.
16. "Update of City of Bellevue Land Use Forecasting", Presentation by City of Bellevue, May 6, 2011.

## Emergency Operations

17. City of Bellevue Emergency Operations Plan, July 8, 2008.
18. Emergency Operations Plan: City of Bellevue Evacuation Annex, February 3, 2009.
19. Puget Sound Energy Corporate Emergency Response Plan 2010 – 2011

## Smart Grid Information

20. PSE Smart Grid Technology Report, September 1, 2010.

## Regulatory Documents

21. Revised Code of Washington RCW 80.28 Gas, Electric, and Water Companies
22. Revised Code of Washington RCW 80.32 Electric Franchises and Rights-of-Way
23. Revised Code of Washington RCW 35.96 Electric and Communication Facilities – Conversion to Underground
24. Washington Administrative Code (WAC) 480-100 Electric Companies
25. Washington Administrative Code (WAC) 480-107 Purchase of Electricity from Qualifying Facilities and Independent Power Producers
26. Washington Administrative Code (WAC) 480-108 Interconnection with Electric Generators
27. Washington Administrative Code (WAC) 480-109 Acquisition of Minimum Quantities of Conservation and Renewable Energy
28. Washington Utilities and Transportation Commission Session Rulemaking Electric Vehicles Regulation and Infrastructure (UE-101521/UE-101800)
29. Washington Utilities and Transportation Commission Rulemaking on Smart Grid Reporting (U-090222)

## Other PSE Documents and Information

30. PSE Electric Tariff G Schedule 73 “Conversion to Underground Service for Customers Other Than Government Entities”
31. PSE Electric Tariff G Schedule 74 “Conversion to Underground Service for Government Entities”
32. PSE Electric Tariff G Schedule 80 “General Rules and Provisions”
33. PSE Electric Tariff G Schedule 85 “Line Extensions and Service Lines”
34. “PSE Storm Restoration Review”, KEMA, July 2, 2007.

35. “The GIS/OMS/DMS Projects”, Presentation by {SE, August 1, 2011.

36. PSE Electric Substation Work Practice Standards

37. PSE Electric Relay Work Practice Standards

38. PSE Presentations and Reviews on the Following Topics:

    a. Current Customer Service and Outage Management System (CLX)
    b. Future GIS/OMS/DMS
    c. Current Operations Center
    d. Distribution System Design, Loadings, and Operations
    e. Transmission System Design, Loadings, and Operations
    f. Capital Project Planning and Prioritization
    g. Projects and Reliability Initiatives in Bellevue
    h. Substation and Line Maintenance and Problem Investigations
    i. Emergency Planning
    j. Substation and Line Visual Inspections

## Other Documents

39. Exponent Report “City of Bellevue Phase 2 Electric Reliability Study Plan”, January 2011.

40. Lawrence Berkeley National Laboratory Report LBNL-1092E “Tracking of the Reliability of the U.S. Electric System: An Assessment of Publicly Available Information Reported to State Public Utility Commissions”, J. Eto and K. Hamachi LaCommare; October 2008.

41. IEEE Standard 1366 Guide for Electric Power Distribution Reliability Indices

42. Edison Electric Institute Report “Out of Sight, Out of Mind Revisited”, K. Hall, December 2009

43. General Electric Smallworld Applications

44. San Jose Mercury News “data for cost and energy consumption from article published in the Business Section on September 25 2011.

45. BPA White Paper “Challenge for the Northwest – Protecting and Managing an Increasingly Congested Transmission System,” April 2006.

46. “Discussion Paper: The Columbia River Treaty,” Sea Breeze Pacific, July 2009.

47. Fred Sissine, Coordinator, Specialist in Energy Policy Resources, Science, and Industry Division; December 21, 2007; CRS Report to Congress, "Energy Independence and Security Act of 2007: A Summary of Major Provisions," Order Code RL34294

48. Amy Abel, Specialist in Energy Policy Resources, Science, and Industry Division; December 20, 2007; CRS Report to Congress, "Smart Grid Provisions in HR 6, 110th Congress," Order Code RL342988

49. Pacific Gas And Electric Company, Smart Grid Deployment Plan 2011 – 2020, Smart Grid Technologies Order Instituting Rulemaking 08-12-009, California Public Utilities Commission

50. "Estimating the Costs and Benefits of the Smart Grid, A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid," 2011 EPRI Technical Report.

51. "Radio-Frequency Exposure Levels from Smart Meters: A Case Study of One Model," 2011 EPRI Technical Report.

52. "Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects," 2011 EPRI Technical Update.

53. "A Smarter Transmission Grid," 2011 EPRI Technical Report.

54. Critical Consumers Issues Forum, "Report on Grid Modernization Issues with Focus on Consumers," July2011.

55. Smart Grid Communications Solutions by Sensus 2011.

56. Emerging Energy Research, "Taking Stock of California's New RPS Law," July 28, 2011.

57. "Rural Distribution System Planning Using Smart Grid Technologies," Presentation by Bob Saint, NRECA, at IEEE Rural Electric Power Conference, April 27, 2009.

58. Annual Energy Outlook 2011, DOE/EIA-0383(2011), April 2011.

59. PSE.  Storm-Related Outage Data 2006 – 2010.  (Spreadsheet information provided at request by PSE)

60. J.D. Power and Associates 2011 Electric Utility Customer Satisfaction Study

61. J.D. Power and Associates 2010 Electric Utility Customer Satisfaction Study

# Appendix E

## Circuit Reliability Analysis

# Appendix E. Circuit Reliability Analysis

This appendix provides an assessment of circuit reliability to assist in identifying representative circuits for analysis within Bellevue. The figure below (a copy of Figure 32 in the body of the report) provides the location of substations within Bellevue. The table that follows provides the basis for the circuit selection.

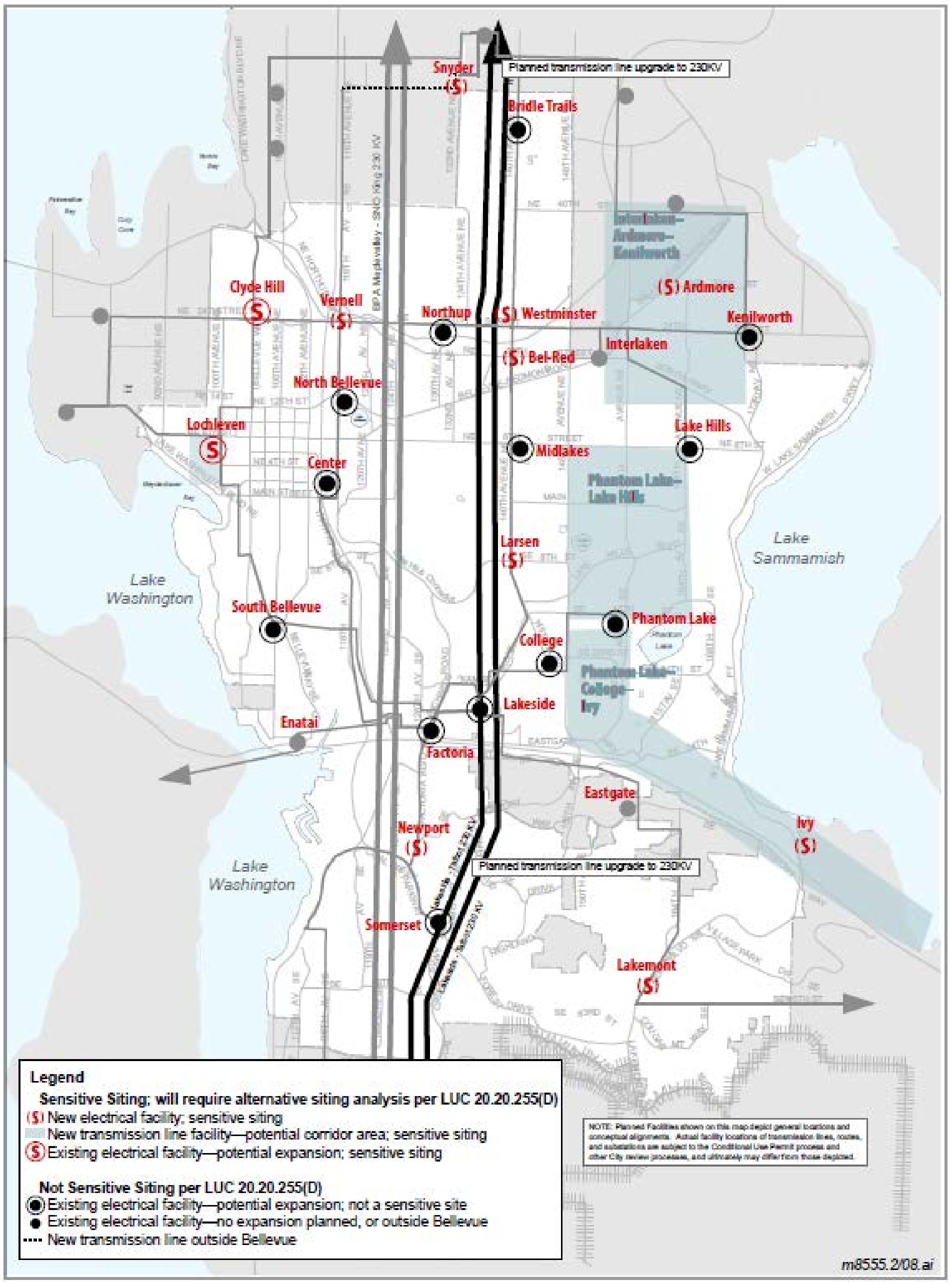


*FIGURE UT.5a*

**New or Expanded Electrical Facilities**

# Appendix E.  Circuit Reliability Analysis

| | | | 2010 | | 2009 | | 2008 | | 2007 | | 2006 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CIRCUIT NAME | CIRCUIT NO. | No. of Customers (2010) | OUTAGES | CUSTOMER MINUTES | OUTAGES | CUSTOMER MINUTES | OUTAGES | CUSTOMER MINUTES | OUTAGES | CUSTOMER MINUTES | OUTAGES | CUSTOMER MINUTES | Total Minutes | Circuit SAIDI | Total Outages | Note |
| Bridal Trails | BTR-24 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 21,756 | 21,756 | | 2 | N.A. |
| Somerset | SOM-01 | | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 600,710 | 0 | 0 | 600,710 | | 1 | Captured multi-circuit event |
| Factoria | FAC-16 | 2 | 0 | 0 | 5 | 359,838 | 10 | 57,441 | 8 | 73,813 | 11 | 46,861 | 537,953 | | 34 | Limited customers |
| Somerset | SOM-16 | 1,274 | 4 | 142,436 | 5 | 18,111 | 11 | 2,193,687 | 13 | 309,921 | 10 | 239,244 | 2,903,399 | 456 | 43 | SOM-16 has higher value, but single event caused most of the minutes in 2008. Therefore, SOM-13 selected based on past 2 years. |
| Factoria | FAC-15 | 7 | 0 | 0 | 0 | 0 | 1 | 11,804 | 0 | 0 | 0 | 0 | 11,804 | 337 | 1 | Limited customers |
| Northrup | NRU-23 | 461 | 4 | 12,167 | 16 | 73,819 | 14 | 404,614 | 9 | 34,991 | 16 | 98,620 | 624,211 | 271 | 59 | Highest NRU circuit and indicated as impacted in 2006 |
| Center | CEN-15 | 213 | 0 | 0 | 0 | 0 | 2 | 1,243 | 3 | 149,017 | 5 | 124,772 | 275,032 | 258 | 10 | Downtown circuit |
| South Bellevue | SBE-22 | 300 | 2 | 15,462 | 3 | 4,145 | 8 | 327,115 | 2 | 405 | 5 | 8,796 | 355,923 | 237 | 20 | Other SBE circuits have higher values, but SBE-26 had a large number of outages and has a high population. |
| Bridal Trails | BTR-22 | 647 | 8 | 37,473 | 10 | 39,768 | 17 | 360,574 | 6 | 8,258 | 18 | 242,977 | 689,050 | 213 | 59 | Highest BTR circuit and indicated as impacted in 2006 |
| College | COL-24 | 20 | 0 | 0 | 2 | 16,933 | 0 | 0 | 1 | 2,203 | 0 | 0 | 19,136 | 191 | 3 | Limited customers |
| Northrup | NRU-27 | 660 | 9 | 11,538 | 7 | 29,526 | 9 | 174,612 | 7 | 108,996 | 6 | 193,100 | 517,772 | 157 | 38 | NRU-23 selected |
| College | COL-26 | 1,720 | 6 | 34,364 | 11 | 70,324 | 13 | 643,970 | 15 | 147,856 | 18 | 360,836 | 1,257,350 | 146 | 63 | Low numbers last two years |
| Lochleven (incl. LLOC-25,26,27 in 2005, 2006) | LOC-34 | 188 | 1 | 426 | 1 | 995 | 1 | 7,875 | 0 | 0 | 8 | 114,808 | 124,104 | 132 | 11 | Downtown circuit |
| Somerset | SOM-13 | 1,026 | 7 | 375,903 | 8 | 129,848 | 5 | 785 | 6 | 29,982 | 9 | 95,343 | 631,861 | 123 | 35 | SOM-16 has higher value, but single event caused most of the minutes in 2008. Therefore, SOM-13 selected based on past 2 years. |
| Phantom Lake | PHA-16 | 1,954 | 9 | 249,092 | 13 | 32,893 | 16 | 316,522 | 14 | 303,861 | 14 | 299,979 | 1,202,347 | 123 | 66 | Selected LHL-23 |
| South Bellevue | SBE-23 | 246 | 1 | 9,090 | 2 | 5,430 | 3 | 112,719 | 4 | 9,663 | 5 | 12,152 | 149,054 | 121 | 15 | Other SBE circuits have higher values, but SBE-26 had a large number of outages and has a high population. |
| Lake Hills | LHL-25 | 2,811 | 12 | 113,322 | 14 | 231,746 | 12 | 191,648 | 15 | 923,174 | 12 | 195,276 | 1,655,166 | 118 | 65 | LHL-25 and LHL-23 have comparable numbers.  LHL-23 selected based on high duration per outage. |
| Northrup | NRU-26 | 173 | 2 | 1,086 | 2 | 794 | 5 | 23,375 | 2 | 10,117 | 7 | 64,760 | 100,132 | 116 | 18 | NRU-23 selected |
| Somerset | SOM-15 | 1,828 | 14 | 76,707 | 14 | 103,766 | 16 | 578,736 | 12 | 58,653 | 12 | 212,663 | 1,030,525 | 113 | 68 | SOM-16 selected |
| Medina | MED-36 | 736 | 8 | 93,388 | 11 | 36,318 | 11 | 42,407 | 7 | 37,203 | 14 | 196,125 | 405,441 | 110 | 51 | Partial circuit in Bellevue |
| South Bellevue | SBE-25 | 1,317 | 8 | 72,311 | 10 | 20,869 | 9 | 517,946 | 8 | 31,382 | 6 | 76,750 | 719,258 | 109 | 41 | Other SBE circuits have higher values, but SBE-26 had a large number of outages and has a high population. |
| Lake Hills | LHL-23 | 1,497 | 3 | 299,300 | 3 | 50,909 | 3 | 382,965 | 5 | 43,627 | 3 | 19,603 | 796,404 | 106 | 17 | LHL-25 and LHL-23 have comparable numbers.  LHL-23 selected based on high duration per outage.  LHL circuit also selected since this is a radial circuit. |
| Clyde Hill | CLY-23 | 608 | 11 | 75,397 | 8 | 59,825 | 14 | 142,412 | 6 | 9,441 | 12 | 26,228 | 313,303 | 103 | 51 | |
| Overlake | OVE-15 | 543 | 16 | 15,571 | 11 | 169,231 | 13 | 74,801 | 12 | 8,342 | 9 | 9,249 | 277,194 | 102 | 61 | |
| South Bellevue | SBE-26 | 1,742 | 15 | 143,380 | 19 | 52,110 | 31 | 463,939 | 30 | 59,716 | 34 | 158,342 | 877,487 | 101 | 129 | Other SBE circuits have higher values, but SBE-26 had a large number of outages and has a high population. |
| Kenilworth | KWH-25 | 1,959 | 20 | 183,308 | 26 | 103,260 | 0 | 0 | 24 | 177,823 | 34 | 509,679 | 974,070 | 99 | 104 | |
| Lochleven | LOC-23 | 2,170 | 6 | 140,036 | 12 | 28,096 | 10 | 267,667 | 11 | 37,448 | 14 | 588,762 | 1,062,009 | 98 | 53 | |
| Phantom Lake | PHA-13 | 1,041 | 13 | 157,821 | 13 | 50,137 | 16 | 16,923 | 8 | 31,572 | 11 | 211,838 | 468,291 | 90 | 61 | |
| Northrup | NRU-14 | 156 | 1 | 23,480 | 0 | 0 | 0 | 0 | 1 | 207 | 2 | 45,860 | 69,547 | 89 | 4 | |
| North Bellevue | NOB-23 | 375 | 2 | 24,826 | 3 | 68,607 | 0 | 0 | 3 | 18,373 | 6 | 53,122 | 164,928 | 88 | 14 | |
| Midlakes | MLK-15 | 977 | 5 | 50,819 | 5 | 244,115 | 5 | 97,933 | 4 | 33,883 | 3 | 1,893 | 428,643 | 88 | 22 | |
| Lake Hills | LHL-22 | 1,085 | 4 | 10,066 | 7 | 2,566 | 13 | 449,802 | 9 | 9,513 | 5 | 959 | 472,906 | 87 | 38 | |
| Evergreen | EVE-23 | 2,561 | 10 | 35,032 | 0 | 0 | 0 | 0 | 28 | 660,667 | 19 | 419,006 | 1,114,705 | 87 | 57 | |
| Bridal Trails | BTR-21 | 1,307 | 8 | 17,107 | 5 | 126,317 | 22 | 248,988 | 8 | 82,606 | 8 | 70,877 | 545,895 | 84 | 51 | |
| Eastgate | EGT-11 | 1,177 | 6 | 81,361 | 11 | 194,631 | 10 | 21,381 | 8 | 66,565 | 15 | 115,433 | 479,371 | 81 | 50 | |
| North Bellevue | NOB-13 | 32 | 1 | 79 | 2 | 12,844 | 0 | 0 | 0 | 0 | 0 | 0 | 12,923 | 81 | 3 | |

# Appendix E.  Circuit Reliability Analysis (cont.)

| | | | 2010 | | 2009 | | 2008 | | 2007 | | 2006 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **CIRCUIT NAME** | **CIRCUIT NO.** | **No. of Customers (2010)** | **OUTAGES** | **CUSTOMER MINUTES** | **OUTAGES** | **CUSTOMER MINUTES** | **OUTAGES** | **CUSTOMER MINUTES** | **OUTAGES** | **CUSTOMER MINUTES** | **OUTAGES** | **CUSTOMER MINUTES** | **Total Minutes** | **Circuit SAIDI** | **Total Outages** | **Note** |
| Eastgate | EGT-12 | 2,599 | 27 | 39,368 | 23 | 449,090 | 21 | 245,206 | 13 | 20,371 | 14 | 276,514 | 1,030,549 | 79 | 98 | |
| Midlakes | MLK-16 | 1,733 | 6 | 10,180 | 7 | 70,043 | 9 | 408,764 | 7 | 89,954 | 11 | 100,725 | 679,666 | 78 | 40 | |
| Eastgate | EGT-28 | 1,585 | 11 | 180,150 | 9 | 182,759 | 14 | 101,861 | 17 | 52,890 | 16 | 84,960 | 602,620 | 76 | 67 | |
| Interlaken | INT-15 | 776 | 2 | 69,168 | 2 | 31,405 | 2 | 62,063 | 3 | 13,469 | 1 | 115,946 | 292,051 | 75 | 10 | |
| North Bellevue | NOB-11 | 193 | 1 | 1,983 | 1 | 31,965 | 2 | 17,386 | 3 | 5,096 | 6 | 15,821 | 72,251 | 75 | 13 | |
| Eastgate | EGT-16 | 465 | 7 | 14,854 | 5 | 6,390 | 3 | 79,129 | 8 | 5,728 | 13 | 61,300 | 167,401 | 72 | 36 | |
| Eastgate | EGT-15 | 351 | 3 | 99,883 | 3 | 7,942 | 3 | 8,524 | 4 | 3,689 | 4 | 5,569 | 125,607 | 72 | 17 | |
| Northrup | NRU-25 | 903 | 10 | 6,274 | 6 | 6,348 | 10 | 57,619 | 8 | 62,114 | 13 | 185,200 | 317,555 | 70 | 47 | |
| Eastgate | EGT-25 | 754 | 6 | 14,104 | 5 | 174,164 | 11 | 8,725 | 9 | 27,627 | 6 | 34,218 | 258,838 | 69 | 37 | |
| Clyde Hill | CLY-27 | 703 | 4 | 8,936 | 5 | 100,215 | 8 | 31,654 | 5 | 12,133 | 7 | 74,342 | 227,280 | 65 | 29 | |
| Lake Hills | LHL-26 | 507 | 6 | 86,110 | 3 | 34,885 | 1 | 2,643 | 3 | 30,718 | 5 | 3,296 | 157,652 | 62 | 18 | |
| Midlakes | MLK-12 | 427 | 2 | 52,454 | 5 | 4,963 | 3 | 11,561 | 8 | 42,490 | 5 | 19,947 | 131,415 | 62 | 23 | |
| Hazelwood | HAZ-12 | 2,126 | 12 | 9,985 | 9 | 6,026 | 15 | 24,529 | 22 | 336,247 | 14 | 260,626 | 637,413 | 60 | 72 | |
| Interlaken | INT-17 | 428 | 1 | 45,475 | 4 | 26,380 | 0 | 0 | 3 | 38,530 | 3 | 17,799 | 128,184 | 60 | 11 | |
| College | COL-25 | 446 | 1 | 5,186 | 0 | 0 | 2 | 13,064 | 3 | 90,877 | 4 | 21,403 | 130,530 | 59 | 10 | |
| Clyde Hill | CLY-26 | 818 | 9 | 32,241 | 6 | 44,079 | 11 | 57,326 | 9 | 70,625 | 9 | 31,144 | 235,415 | 58 | 44 | |
| College | COL-23 | 489 | 1 | 1,728 | 3 | 6,882 | 4 | 60,431 | 1 | 10,736 | 3 | 52,149 | 131,926 | 54 | 12 | |
| Kenilworth | KWH-22 | 640 | 4 | 10,759 | 5 | 4,191 | 10 | 146,814 | 5 | 2,956 | 9 | 3,805 | 168,525 | 53 | 33 | |
| Bridal Trails | BTR-14 | 1,140 | 0 | 0 | 3 | 290,540 | 0 | 0 | 0 | 0 | 0 | 0 | 290,540 | 51 | 3 | |
| North Bellevue | NOB-12 | 471 | 0 | 0 | 3 | 112,053 | 0 | 0 | 0 | 0 | 2 | 5,782 | 117,835 | 50 | 5 | |
| Hazelwood | HAZ-13 | 1,117 | 9 | 20,401 | 7 | 4,675 | 9 | 10,426 | 11 | 70,709 | 13 | 158,472 | 264,683 | 47 | 49 | |
| Somerset | SOM-17 | 1,749 | 2 | 3,695 | 13 | 149,457 | 22 | 39,796 | 2 | 1,330 | 23 | 194,709 | 388,987 | 44 | 62 | |
| Kenilworth | KWH-23 | 665 | 5 | 39,092 | 9 | 22,232 | 4 | 33,782 | 4 | 2,745 | 7 | 49,230 | 147,081 | 44 | 29 | |
| Factoria | FAC-13 | 1,568 | 12 | 50,677 | 18 | 98,635 | 17 | 79,713 | 23 | 47,143 | 26 | 66,336 | 342,504 | 44 | 96 | |
| Eastgate | EGT-27 | 685 | 8 | 12,059 | 11 | 19,783 | 12 | 17,484 | 11 | 12,588 | 7 | 79,222 | 141,136 | 41 | 49 | |
| Overlake | OVE-12 | 674 | 10 | 6,989 | 12 | 21,804 | 10 | 2,714 | 12 | 94,513 | 12 | 10,700 | 136,720 | 41 | 56 | |
| Bridal Trails | BTR-25 | 1,130 | 5 | 39,700 | 0 | 0 | 2 | 5,378 | 1 | 9,472 | 5 | 165,364 | 219,914 | 39 | 13 | |
| Center | CEN-11 | 5 | 0 | 0 | 1 | 969 | 0 | 0 | 0 | 0 | 0 | 0 | 969 | 39 | 1 | |
| Midlakes | MLK-13 | 1,278 | 5 | 13,599 | 5 | 48,919 | 6 | 31,240 | 11 | 43,582 | 9 | 87,461 | 224,801 | 35 | 36 | |
| Kenilworth | KWH-26 | 276 | 1 | 5,696 | 1 | 171 | 0 | 0 | 5 | 22,454 | 2 | 16,312 | 44,633 | 32 | 9 | |
| Center | CEN-14 | 654 | 0 | 0 | 1 | 290 | 5 | 39,177 | 1 | 35,000 | 1 | 29,175 | 103,642 | 32 | 8 | |
| Eastgate | EGT-26 | 115 | 1 | 14,532 | 1 | 175 | 1 | 274 | 1 | 485 | 1 | 1,325 | 16,791 | 29 | 5 | |
| Bridal Trails | BTR-23 | 512 | 0 | 0 | 0 | 0 | 0 | 0 | 3 | 60,277 | 3 | 9,235 | 69,512 | 27 | 6 | |
| Goodes Corner | GOO-13 | 1,745 | 0 | 0 | 0 | 0 | 0 | 0 | 3 | 118,968 | 4 | 93,911 | 212,879 | 24 | 7 | |
| Phantom Lake | PHA-17 | 644 | 4 | 4,778 | 10 | 16,252 | 6 | 18,307 | 9 | 24,274 | 5 | 11,304 | 74,915 | 23 | 34 | |
| North Bellevue | NOB-22 | 35 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3 | 3,933 | 3,933 | 22 | 3 | |
| Phantom Lake | PHA-15 | 176 | 0 | 0 | 2 | 1,901 | 6 | 16,768 | 2 | 271 | 3 | 654 | 19,594 | 22 | 13 | |
| North Bellevue | NOB-24 | 1,080 | 5 | 8,113 | 8 | 33,240 | 9 | 34,138 | 11 | 12,604 | 6 | 31,320 | 119,415 | 22 | 39 | |
| Clyde Hill | CLY-25 | 2,020 | 7 | 29,665 | 5 | 28,025 | 4 | 12,497 | 6 | 12,544 | 6 | 120,672 | 203,403 | 20 | 28 | |
| North Bellevue | NOB-14 | 276 | 0 | 0 | 1 | 24,562 | 0 | 0 | 0 | 0 | 1 | 190 | 24,752 | 18 | 2 | |
| Lochleven | LOC-35 | 187 | 1 | 169 | 3 | 15,481 | 0 | 0 | 1 | 79 | 0 | 0 | 15,729 | 17 | 5 | |
| Center | CEN-25 | 483 | 2 | 10,708 | 3 | 27,106 | 0 | 0 | 0 | 0 | 0 | 0 | 37,814 | 16 | 5 | |
| Houghton | HOU-25 | 485 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 1,167 | 6 | 35,966 | 37,133 | 15 | 8 | |
| Center | CEN-12 | 182 | 1 | 11,486 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 11,486 | 13 | 1 | |
| Factoria | FAC-24 | 89 | 3 | 4,916 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4,916 | 11 | 3 | |
| Factoria | FAC-14 | 287 | 1 | 8,011 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 8,011 | 6 | 1 | |
| Lochleven | LOC-33 | 363 | 2 | 364 | 2 | 7,949 | 0 | 0 | 1 | 1,428 | 0 | 0 | 9,741 | 5 | 5 | |
| North Bellevue | NOB-21 | 519 | 0 | 0 | 2 | 1,397 | 1 | 1,679 | 3 | 3,177 | 3 | 3,845 | 10,098 | 4 | 9 | |
| Factoria | FAC-12 | 1,190 | 8 | 16,275 | 1 | 231 | 1 | 403 | 0 | 0 | 1 | 438 | 17,347 | 3 | 11 | |
| Factoria | FAC-23 | 78 | 1 | 900 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 900 | 2 | 1 | |

## Appendix E.  Circuit Reliability Analysis (cont.)

| | | | 2010 | | 2009 | | 2008 | | 2007 | | 2006 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CIRCUIT NAME | CIRCUIT NO. | No. of Customers (2010) | OUTAGES | CUSTOMER MINUTES | OUTAGES | CUSTOMER MINUTES | OUTAGES | CUSTOMER MINUTES | OUTAGES | CUSTOMER MINUTES | OUTAGES | CUSTOMER MINUTES | Total Minutes | Circuit SAIDI | Total Outages | Note |
| Factoria | FAC-25 | 1,331 | 9 | 10,659 | 1 | 80 | 0 | 0 | 0 | 0 | 0 | 0 | 10,739 | 2 | 10 | |
| Clyde Hill | CLY-22 | 245 | 0 | 0 | 1 | 1,430 | 0 | 0 | 0 | 0 | 0 | 0 | 1,430 | 1 | 1 | |
| Overlake | OVE-13 | 301 | 1 | 160 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 160 | 0 | 1 | |
| Center | CEN-13 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| Center | CEN-22 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| College | COL-22 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| Eastgate | EGT-13 | 7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| Factoria | FAC-21 | 79 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| Lochleven | LOC-22 | 176 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| Lochleven | LOC-24 | 15 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| Lochleven | LOC-25 | 245 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |

### Notes:

1. This table provides an analysis of circuits for selection as representative circuits for the outage assessment.
2. Circuit SAIDI approximated by the summation of outage duration over the past 5 years divided by the number of customers (2010 basis) and averaged over 5 years.  The circuits were then ranked by circuit SAIDI.
3. Total number of outages over the 5 years was also determined to add insight into the selection process.
4. The circuits were then reviewed to select circuits that represented different geographic areas of Bellevue.
5. The circuits in specific areas were reviewed for number of customers to ensure that appropriate customer representation was considered.
6. Circuits selected for representative circuit review are highlighted and explanation provided under “notes”.

# Appendix F

## Reliability Projects in Bellevue

# Appendix F. Reliability Projects in Bellevue

PSE performs a significant number of capital projects around their service area each year. These projects typically include capital replacement (equipment replaced at the end of its useful life), capital improvement (expansion, operations flexibility, system hardening), and reliability (projects aimed at reliability improvements). During discussions with PSE, they indicated the following projects in Bellevue were directly targeted at reliability in the City. Most capital projects will have an indirect benefit on reliability, but the list below is targeted at improved system reliability. The reliability projects are designated as supporting the Downtown if the project has an impact on the Downtown area in Bellevue.

| Year | Location | Project |
|---|---|---|
| 2007 | CEN | CEN-1N reconfiguration (Downtown circuit) |
| 2007 | | Install service (Downtown) |
| 2007 | LOC | LOC-21 (2N) reconfiguration (Downtown circuit) |
| 2007 | CEN | CEN-2N feeder project (Downtown) |
| 2007 | COL | COL-25 BO getaways |
| 2007 | LOC | LOC-3N feeder project (Downtown) |
| 2008 | | 1/0 loop (Downtown) |
| 2008 | KWH | KWH-25 tree wire installation |
| 2008 | LHL | LHL-25 underground rebuild |
| 2008 | CEN | CEN-12 reconfiguration (Downtown) |
| 2009 | NOB | NOB-21 feeder (Downtown) |
| 2009 | LOC | LOC-25 feeder (Downtown) |
| 2009 | CEN | CEN-14 1/0 cable reliability (Downtown) |
| 2009 | CLY | CLY-26 install Vista switch (Downtown) |
| 2009 | NOB | NOB-13 install Vista switch (Downtown) |
| 2009 | SOM/EGT | SOM-13/EGT-12 underground feeder tie |
| 2009 | GOO/EGT | GOO-13/EGT-12 underground feeder tie |
| 2009 | NOB | NOB-12 underground feeder re-route (Downtown) |
| 2009 | CLY | CLY-26 install underground feeder (Downtown) |
| 2009 | CLY | CLY-25 install underground feeder (Downtown) |
| 2009 | FAC | FAC-14 replace conduit and feeder |
| 2010 | CEN | CEN-14 circuit re-route (Downtown) |
| 2010 | LOC | LOC-34 Bellevue Square rebuild (Downtown) |
| 2010 | | Install FI with remote communication (Downtown) |
| 2010 | | Replace failed recloser |
| 2010 | CLY | CLY-25/CLY-26 install feeder tie (Downtown) |
| 2010 | SOM | SOM-13 reliability project add PM switch |

## Appendix F.  Reliability Projects in Bellevue

| Year | Location | Project |
|---|---|---|
| 2010 | CEN | CEN-14 underground reliability project |
| 2010 | EGT/COL | EGT-13/COL-24 feeder tie |
| 2010 | LOC | LOC-23 underground feeder project (Downtown) |
| 2010 | CLY | CLY-2N reliability circuit (Downtown) |
| 2010 | NOB | NOB-22 underground feeder reconfiguration (Downtown) |
| 2010 | CEN | CEN-25 feeder extension |
| 2010 | EGT | EGT-28 feeder tree wire reconductor |
| 2010 | NRU | NRU-23 feeder tree wire |
| 2010 | PHA | PHA-16 remove switch |
| 2010 | NRU | NRU-23 underground conversion of feeder |
| 2010 | NRU | NRU-26 replace switch |
| 2011 | PHA | PHA-13, 16 & 17 underground feeder rebuild |
| 2011 | CLY | CLY-23 1/0 cable replacement |

# Appendix G

## Phase 1 vs. Phase 2 Roadmap

# Appendix G. Phase 1 vs. Phase 2 Roadmap

The table below provides a roadmap for indexing the Phase 1 tasks against the results presented in this reliability study.

| Phase 1 Report | | Phase 2 Report | |
|---|---|---|---|
| Section | Topic | Section | Topic |
| 2.1 Task 1 | Current System Study | 2 | Current System Assessment |
| Subtask 1.1 | Review of PSE Performance | 2.2 | PSE Past and Present Reliability and Outage Performance |
| Subtask 1.2 | Review of PSE System Design | 2.3 | Review of PSE's System Design |
| Subtask 1.2.a | Washington Requirements | 2.3.3 | Washington Requirements |
| Subtask 1.2.b | Power Supply | 2.3.4 | Power Supply |
| Subtask 1.2.c | Transmission Planning | 2.3.5, 2.3.6 | Bulk Transmission/115 kV System |
| Subtask 1.2.d | Distribution Planning | 2.3.7 | Distribution System |
| Subtask 1.3 | Review of PSE Line and Station Design and Maintenance Practices | 2.3.8, 2.4 | Substation Designs/Work Practices |
| Subtask 1.4 | Industry Benchmarks | 2 | Included throughout Section 2 |
| 2.2 Task 2 | Future System Assessment | 3 | Future System Assessment |
| Subtask 2.1 | Short Term | 2.3 | System Design |
| Subtask 2.1.a | Capital Project Investments | 2.3.4/2.3.5 | Power Supply/Transmission |
| Subtask 2.1.b | Short-Term Supply and Demand | 2.3.4/2.3.5 | Power Supply/Transmission |
| Subtask 2.1.c | Life Extension | 2.2.6 | Industry Issues |
| Subtask 2.1.d | WUTC Expectations | 2.3.3 | Regulatory Agencies |
| Subtask 2.1.e | Smart Grid Deployment | 3.2.5 | Smart Grid Technology |
| Subtask 2.1.f | Outage Management and Other Operating Systems | 2.4.6.5/4.2.3.1 | Outage Management/Emergency Management |
| Subtask 2.2 | Medium Term | 3.2 | Medium Term |
| Subtask 2.2.a | Retirement of Power Agreements | 3.2.2 | Generation 3.3 |
| Subtask 2.2.b | New Power Sources | 3.2.2 | Generation |
| Subtask 2.2.c | New Transmission | 3.2.3 | Transmission |
| Subtask 2.2.d | Distribution | 3.2.5 | Distribution |
| Subtask 2.3 | Long Term | 3.3 | Long Term |
| Subtask 2.2.a | Risk Analysis | 3.3.4 | New Power Sources |
| Subtask 2.2.b | Transmission | 3.3.2 | Transmission |
| Subtask 2.2.c | Fully Built-Up Downtown | 3.3.5 | Fully Built-Out Downtown |
| Subtask 2.2.d | Distribution | 3.3.5 | Fully Built-Out Downtown |
| 2.3 Task 3 | Role of the City | 4 | Role of the City |
| Subtask 3.1 | Role as Informed Stakeholder | 4.2 | Role as Informed Stakeholder |

## Appendix G. Phase 1 vs. Phase 2 Roadmap

| Phase 1 Report | | Phase 2 Report | |
|---|---|---|---|
| Section | Topic | Section | Topic |
| Subtask 3.1.a | WUTC | 4.2.1 | Regulatory Agencies |
| Subtask 3.1.b | PSE | 4.2.2 | PSE |
| Subtask 3.1.c | Regulatory Agencies | 4.2.1 | Regulatory Agencies |
| Subtask 3.2 | Transparency | 4.2.3 | Transparency of Operations |
| Subtask 3.2.a | Define | 4.2.3 | Transparency of Operations |
| Subtask 3.2.b | Emergency Plan | 4.2.3.1 | Emergency Planning |
| Subtask 3.2.c | Communications | 4.2.3.2 | Communications with Stakeholders |
| 2.4 Task 4 | Measure and Monitor | 5 | Measurement and Monitoring |
| Subtask 4.1 | Metrics | 5.1 | Metrics |
| Subtask 4.2 | Stakeholder Communication | 5.2 | Stakeholder Communication |

# Appendix H

## Response to Questions

# Eastside Needs Assessment Report

## Transmission System
## King County

*Redacted Draft*

October 2013

Puget Sound Energy

Report prepared by:
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# Section 1 Executive Summary

The analysis discussed in this report verified that there is a transmission capacity deficiency in the Eastside area of Lake Washington which will develop by the winter of 2017-18. This transmission capacity deficiency is expected to increase beyond that date. Cities in the deficiency area include Redmond, Kirkland, Bellevue, Clyde Hill, Medina, Mercer Island, Newcastle and Renton along with towns of Yarrow Point, Hunts Point, and Beaux Arts.

## Assessment Objective

The objective of this needs assessment is to assess the sufficiency of transmission supply within the next 10 years to Puget Sound Energy's customers and communities on the east side of Lake Washington.

As part of the mandatory North American Electric Reliability Corporation (NERC) Compliance Enforcement Program[1], PSE performs an annual comprehensive reliability assessment[2] to determine if any potential adverse impacts to the reliability of delivery of electricity exist on the PSE transmission system. During the 2009 comprehensive reliability assessment[3], PSE determined that there was a transmission reliability supply need developing due to the loss of one of the Talbot Hill Substation[4] transformers.


Since 2009, other issues have also been identified which impact this portion of the PSE system. These issues include concerns over the projected future loading on the Talbot Hill Substation, increasing use of Corrective Action Plans (CAPs) to manage outage risks to customers in this portion of the PSE system, and regional transmission reinforcement needs that were identified by ColumbiaGrid studies to support the movement of power from existing wind generation and hydroelectric generation across the Cascade Mountains to load centers around the Puget Sound.

The study described in this report focused specifically on the central King County portion of the larger PSE system in order to provide a more focused needs assessment. The timing of this study was intended to provide sufficient lead time to implement viable, long term solutions before the issues identified by the study develop. This report discusses the review of the current transmission infrastructure to support the current load and the future load growth in this area.

## Method and Criteria

The studies documented by this report are collectively referred to as the "2013 Eastside Needs Assessment." To assess area supply needs, comprehensive reliability analyses were performed to determine the present and future transmission supply to PSE's Eastside area in King County and the Puget Sound area as a whole. In 2009, as part of



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[1] NERC Reliability Standards for the Bulk Electric Systems of North America

[2] PSE Planning Studies and Assessment TPL-001 to TPL-004 Compliance Report

[3] 2009 PSE Planning Studies and Assessment TPL-001 to TPL-004 Compliance Report

[4] Talbot Hill Substation is located in Renton

the TPL-001 through TPL-004 Compliance Report, PSE's analysis showed that there was a potential thermal violation with the loss of one of the two transformers at Talbot Hill Substation. For the 2013 Eastside Needs Assessment, PSE performed an updated analysis to evaluate if this potential thermal violation would still exist with updated load forecasts. The 2013 Eastside Needs Assessment was performed consistent with the mandatory NERC TPL annual comprehensive analysis. Supplemental performance studies were also performed to provide a clear understanding of the location and causation of these potential thermal violations.

For the 2013 Eastside Needs Assessment, PSE used the WECC 2012 series base cases to develop the 2013-14, 2017-18, and 2021-22 heavy winter cases. These cases were set up to account for normal weather with 100% of the forecasted level of conservation and were updated with the current PSE system configuration and load information. To better understand the extent of the need and risks faced by customers in this portion of the PSE system, sensitivity studies were conducted to evaluate performance under different levels of conservation. Sensitivities studies were also conducted to assess system performance under extreme weather conditions that are expected to occur once every twenty years.

This assessment also reviewed the near and long-term summer cases run for the 2012 NERC Transmission Planning (TPL) standard requirements. For the TPL report, cases had been developed for heavy summer of 2014 and 2018 using the 2012 WECC series base cases. These cases were set up to account for normal summer weather with 100% of the forecasted level of conservation and were updated with the current PSE system configuration and load information.

This analysis covered PSE facilities that are part of the Bulk Electric System (BES) and the interconnected system covered by the Western Electricity Coordinating Council (WECC). BES facilities must be studied in accordance with the latest approved versions of the mandatory NERC Reliability Standards and the WECC Reliability Standards[5]. These standards set forth the specific methods for studying the performance of the transmission system – 100 kV and above – and govern how that system is planned, operated and maintained.

In addition to the mandatory reliability standards, PSE has also issued Transmission Planning Guidelines[6] which describe how to plan and operate PSE's electric transmission system. These guidelines are in place to encourage the optimal use of the transmission system for service to loads and generators while complying with the mandatory standards. These guidelines also support transfers between utilities, when applicable, to support economic use of available resources.

Performance criteria are also established to determine if a need exists to improve the system. These performance criteria serve as a baseline to measure performance and to identify where reinforcements may be needed. The needs documented in this report were determined by whether or not the study area would perform such that it satisfied all approved applicable NERC, WECC and PSE transmission performance criteria[7].

## Study Assumptions

The following key assumptions were adopted to more fully understand the potential reliability impacts:

- The study horizon selected was the ten year period from 2012 to 2022.
- System load levels used the PSE corporate forecast published in June 2012.

[5] TPL-001-WECC-CRT-2 – System Performance Criterion Under Normal Conditions, Following Loss of a Single BES Element, and Following Extreme BES Events

[6] PSE Transmission Planning Guidelines, November 2012

[7] PSE Transmission Planning Guidelines, pages 3-5 & 7, November 2012

- Area forecasts were adjusted by substation to account for expected community developments as identified by PSE customer relations and distribution planning staff.
- Generation dispatch patterns reflected reasonably stressed conditions to account for generation outages as well as expected power transfers from PSE to its interconnected neighbors.
- Winter peak Northern Intertie transfers were 1,500 MW exported to Canada.
- Summer peak Northern Intertie transfers were 2,850 MW imported from Canada.

## Specific Areas of Concern

The 2013 Eastside Needs Assessment was a fresh look at current and future system conditions which did not pre-judge the existence of any specific issues on the PSE system. Since 2009 a variety of concerns have been identified and these were investigated in the analysis. During the course of the analysis, some additional potential problems were identified that also were evaluated. The major issues include:

1. Overload of PSE Facilities in the Eastside Area: Several previous studies had identified potential overloading of transformers at Sammamish and Talbot Hill Substations[8]. These include the 2008 Initial King County Transformation Study, 2009 PSE TPL Planning Studies and Assessment, and the 2012 PSE TPL Planning Studies and Assessment[9]. Those studies indicated that potential thermal violations may occur on facilities from Talbot Hill Substation to Sammamish Substation. The 2013 Eastside Needs Assessment validated those concerns and identified transmission supply needs that focused on two 230-115 kV supply injections into central King County at Sammamish and Talbot Hill Substations. In the 2013 Eastside Needs Assessment the team found:

    - For the winter peak at approximately 5,200 MW (2017-18 in the model) there are two 115 kV elements with loadings above 98% for Category B (N-1) contingencies and five 115 kV elements above 100% for Category C (N-1-1 & N-2) contingencies.

    - For the summer peak at approximately 3500 MW (2018 in the model), there are two 230 kV elements above 100% and two 115 kV elements above 93% loadings for Category B (N-1) Contingencies. Also there are three elements above 100% loading and one above 99% loading for Category C (N-1-1) contingencies.

2. Small Margin of Error to Manage Risks from Inherent Load Forecast Uncertainties: The 2012 Corporate load forecast for winter under normal weather conditions and 100% conservation indicates load increases 138 MW from 2013-14 to 2021-22 (Figure 1-1), or about 17 MW of increased load per year. This annual increase is significantly lower than previous forecasts and is much lower than the 2011 forecast of approximately 22 MW per year[10],

    In extreme weather, system load can be much higher than this forecast. To illustrate, Figure 1-1 shows that the difference in forecast load between normal and extreme winter weather for the year 2014 is actually 497 MW – almost 10 percent of the total PSE load (assuming 100% of the forecast conservation for both). Normal weather represents the projected load at 23° F and extreme weather represents the projected load at 13° F. As the temperature gets close to 13° F, the forecasted load in any given year could easily surpass the entire 138 MW load increase projected for the 10 year study period. This effect has occurred recently on the

[8] Sammamish Substation is located in Redmond. Talbot Hill Substation is located in Renton.

[9] The 2010 and 2011 TPL Planning Studies also identified the Lakeside 230-115 kV transformer as needed and planned for 2016. It did not show up as a deficit in the long term due to being modeled as installed by the long term case year.

[10] 2011 PSE IRP Section H Page H-12 from 2010 to 2017

PSE system. In winter 2009, the system hit an all-time peak of 5038 MW[11] at a temperature of 16° F, which was 194 MW higher than the 2009 forecast for normal weather peak load in 2009 . This 2009 actual peak load level is also higher than the 2012 forecast for normal system peak load in 2021.

The 2013 Eastside Needs Assessment shows a load level of need at approximately 5,200 MW winter peak. To illustrate the importance of conservation in our modeling, the team forecasted PSE load levels under a variety of conditions. If only 75% of forecasted conservation materializes, the 5,200 MW load level would be hit as early as 2015 under normal weather conditions. Even if 100% conservation is achieved, under extreme weather conditions PSE could exceed the 5,200 MW level during the winter 2013-14. These winter peak forecast sensitivities are illustrated in Figure 1-1:

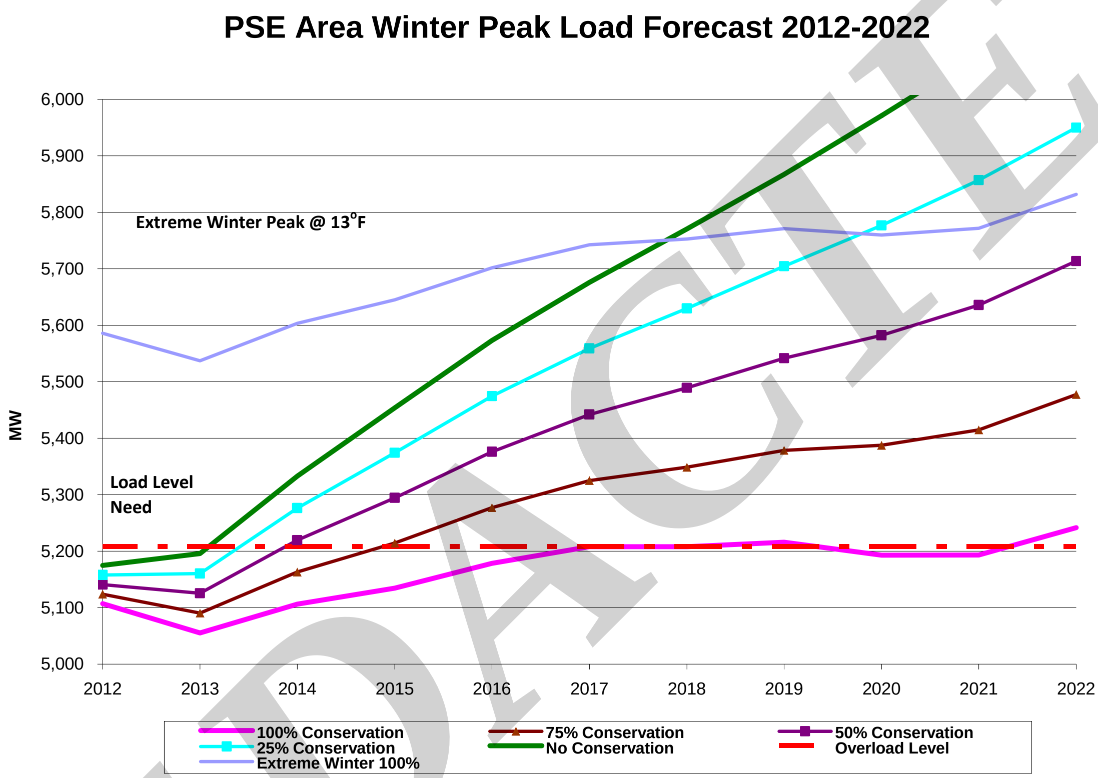


Figure 1-1: Corporate System Load Forecast for Winter 2012 to 2022

The 2013 Eastside Needs Assessment shows a summer load level of need is approximately 3340 MW (Figure 1-2). Summer peak load is calculated for an 86° F peak day. This load level could occur as early as 2014 and becomes more likely with time. While PSE has traditionally been a winter peaking utility, the increase in commercial load has driven summer load growth disproportionately higher than the winter growth in recent years. The projected summer peak growth is on average approximately 37 MW per year. The corporate load forecast does not indicate loading for an "extreme summer" peak, which would be expected to be higher than shown on these projections.



[11] This does not include approximately 270 MW of load on PSE's system served by other transmission providers.

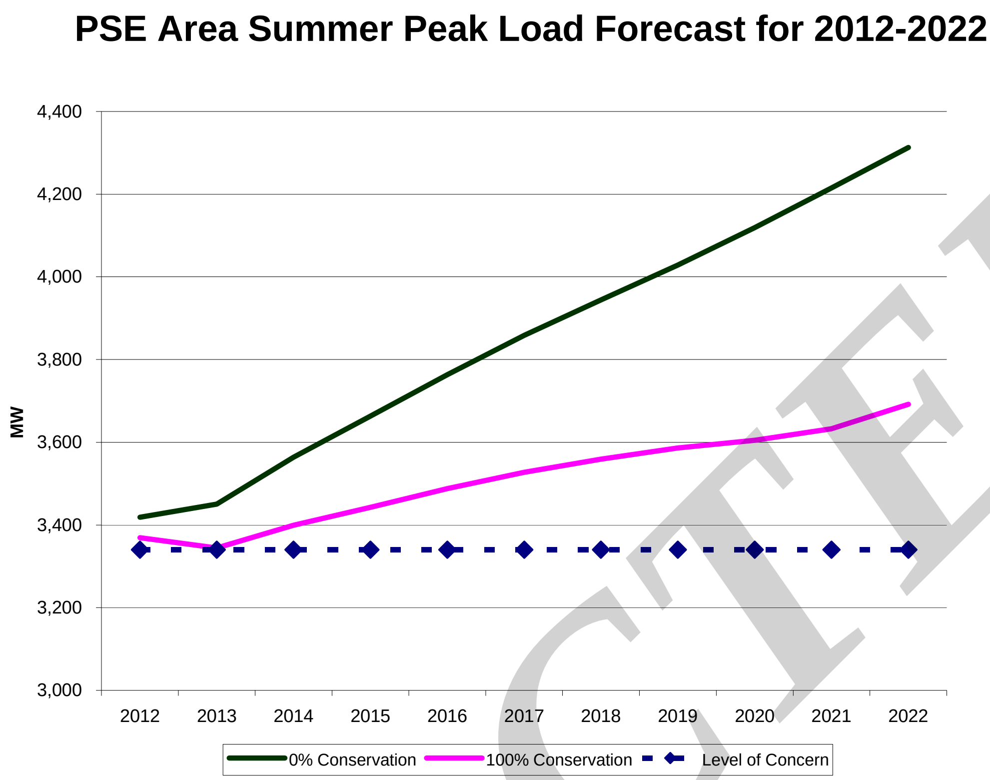


Figure 1-2: Corporate Load Forecast for Summer Peak from 2012 to 2022

3. Increasing Use and Expansion of Corrective Action Plans: An existing CAP in place to prevent overloads in the winter on either of the Talbot Hill transformer banks is increasing outage risk to customers. This CAP is to manually open [redacted], which removes [redacted]. Taking this step reduces the inherent reliability of the network since the transmission system cannot handle as many contingencies without overloads, voltage issues or loss of customers' power.

   As the PSE system load grows, the overload of either Talbot Hill transformer at winter peak may not be sufficiently reduced by this CAP. If loading on the overloading transformer is not reduced by use of the existing CAP, then [redacted] and [redacted] will also be opened. In addition to the reduction in reliability discussed above, opening these four 115 kV lines results in splitting northern King County from southern King County and puts approximately 32,400 customers at risk of outage, being served by just 1 transmission line without a backup line available (i.e., "radial supply"). This action also puts an additional 33,000 customers in Bellevue and Kirkland at risk of outage should there be an outage of [redacted] while the north and south systems are operating separately.

   There are two contingencies in the north end of King County that would trigger a CAP under summer conditions. These contingencies are (1) the loss of [redacted] along with the loss of the [redacted]; and (2) the loss of the [redacted] along with the loss of [redacted]. This CAP would open [redacted]. Taking this action places 33,000 customers at risk of outage should an additional transmission line outage occur. The 33,000 customers are served from two separate lines, so a single line outage would take out approximately half of the 33,000.

4. <u>Emerging Regional Impacts Identified by ColumbiaGrid:</u> ColumbiaGrid was formed in 2006 by regional utilities to improve the operational efficiency, reliability, and planned expansion of the Northwest transmission grid through an open and transparent process. The ColumbiaGrid produces a Biennial Transmission Expansion Plan that addresses system needs in the Pacific Northwest, including the PSE system. The latest report indicated a need to improve the dependability of the transfer capability through the Puget Sound Area. This need occurs during high load conditions and much of the rest of the year as facilities such as transmission lines are taken out of service to do required maintenance and improvements. ColumbiaGrid indicated that a reduced risk of curtailments is needed to reliably deliver power from regional and renewable generation such as PSE's wind generation in eastern Washington, to King County. Also, there are regional commitments to increase flows across the Northern Intertie to 2300 MW that will show up in the ten-year time frame.

   To significantly reduce regional curtailments, ColumbiaGrid identified six specific projects which include installing inductors on the 115 kV system in Seattle, adding a 500-230 kV transformer at BPA's Raver Substation in south King County, and increasing 230 kV south-north transmission capacity along the Eastside.

## Statements of Need

The 2013 Eastside Needs Assessment confirmed that by winter of 2017-18, there is a transmission supply need on the Eastside of Lake Washington which impacts PSE customers and communities in and around Kirkland, Redmond, Bellevue, and Newcastle along with Clyde Hill, Medina, and Mercer Island. The supply need focuses on the two 230 kV supply injections into central King County at Sammamish Substation in the north and Talbot Hill Substation in the south. The transmission supply becomes a need at a PSE load level of approximately 5,200 MW, where overloads will result in operating conditions that will put thousands of Eastside customers at risk of outages. According to PSE projections, demand is expected to exceed this level in winter 2017-18.

The assessment also identified that higher overloads are expected to develop as load grows beyond the 5,208 MW (100% conservation) shown in 2017-18. For example as shown below, if only 75% of the conservation forecast is achieved - equivalent to 5,300 MW load in that same time period, the overloads will have grown. By the end of the 10 year study period, the study indicates that overloads will continue to grow even with all of the projected conservation in effect. These possible overloads will result in more hours operating under conditions that will put thousands of Eastside customers at risk of outages.

Under both load forecast conditions (full conservation and 75% conservation), the overloads occur for both Category B contingencies which are the loss of a single element (i.e., "N-1") and Category C contingencies which are the loss of more than one element, (i.e., "N-1-1" or "N-2"). Table 1-1 shows the overloads expected by 2017-18 for winter peak under normal weather conditions.

Table 1-1: Potential Thermal Violations for 2017-18 Winter Peak with Normal Weather

| | 2017-18 Winter Peak | 2017-18 Winter Peak |
|---|---|---|
| | 5208 MW | 5325 MW |
| Contingency | 100% Conservation | 75% Conservation |
| Cat B (N-1) | Talbot Hill - Lakeside #1 115 kV line – 98.6% | Talbot Hill - Lakeside #1 115 kV line – 99.9% |
| | Talbot Hill - Lakeside #2 115 kV line – 98.4% | Talbot Hill - Lakeside #2 115 kV line – 99.8% |
| | Talbot Hill 230-115 kV transformer #2 – 90.3% | Talbot Hill 230-115 kV transformer #1 – 90.9% |
| | | Talbot Hill 230-115 kV transformer #2 – 92.4% |
| Cat C (N-1-1) | Talbot Hill-Lakeside #1 115 kV Line - 127.8% | Talbot Hill-Lakeside #1 115 kV Line - 129.9% |
| | Talbot Hill-Lakeside #2 115 kV Line - 127.6% | Talbot Hill-Lakeside #2 115 kV Line - 129.7% |
| | Talbot Hill 230-115 kV transformer #1 - 105.7% | Talbot Hill 230-115 kV transformer #1 - 108.1% |
| | Talbot Hill 230-115 kV transformer #2 - 105.7% | Talbot Hill 230-115 kV transformer #2 – 107.6% |
| | Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 110.6% | Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 112.5% |
| | Shuffleton – O'Brien 115 kV Line – 97.9% | Shuffleton – O'Brien 115 kV Line – 99.7% |
| | Shuffleton – Lakeside 115 kV Line – 97.3% | Shuffleton – Lakeside 115 kV Line – 98.9% |
| Cat C (N-2 or Common Mode) | Talbot Hill-Lakeside #1 115 kV Line - 101.5% | Talbot Hill-Lakeside #1 115 kV Line – 100.5% |
| | Talbot Hill-Lakeside #2 115 kV Line - 101.1% | Talbot Hill-Lakeside #2 115 kV Line – 103.0% |
| | Talbot Hill 230-115 kV transformer #1 – 91.8% | Talbot Hill 230-115 kV transformer #1 – 93.8% |
| | Talbot Hill 230-115 kV transformer #2 – 92.8% | Talbot Hill 230-115 kV transformer #2 – 94.4% |
| | | |

The analysis also identified that overload conditions will occur for Summer Peak conditions under normal weather. These overloads can occur as early as 2014 with a load level of approximately 3,300 MW. These overloads increase by the year 2018 when the load is expected to increase to 3,500 MW. Those issues are listed in Table 1-2.

Table 1-2: Potential Thermal Violations for 2014 and 2018 Summer Peak with Normal Weather

| | 2014 Summer Peak | 2018 Summer Peak |
|---|---|---|
| | 3343 MW | 3554 MW |
| Contingency | 100% Conservation | 100% Conservation |
| Cat B (N-1) | Monroe-Novelty Hill 230 kV line - 132.6% | Monroe-Novelty Hill 230 kV line - 133.0% |
| | Maple Valley - Sammamish 230 kV line - 111.4% | Maple Valley - Sammamish 230 kV line - 132.3% |
| | | Talbot Hill - Lakeside #1 115 kV line - 93.9% |
| | | Talbot Hill - Lakeside #2 115 kV line - 93.8% |
| Cat C (N-1-1) | Sammamish 230-115 kV transformer #1 - 95.5% | Sammamish 230-115 kV transformer #1 - 100.7% |
| | Sammamish 230-115 kV transformer #2 - 100.8% | Sammamish 230-115 kV transformer #2 - 106.4% |
| | | Beverly Park - Cottage Brook 115 kV line - 100.5% |
| | | Sammamish - Lakeside #2 115 kV line - 99.8% |

When winter load reaches the point that overloads are possible, PSE or BPA would use CAPs to automatically or manually prevent overloads under the NERC reliability requirements. The CAPs required to prevent N-1-1 overloads would open lines between Sammamish and Talbot Hill. Some of the CAPs place customers at risk of outage due to transmission lines being switched to a radial supply, with no backup transmission line available. Load growth by the end of the 10 year study period will result in additional lines required to be opened, putting over 60,000 customers at risk of resulting outages. Some of the CAPs are set up today as BPA nomograms or PSE manual corrective action plans. If extreme winter weather were to occur today, loading would be high enough that CAPs would be employed to remain NERC compliant.

Future load growth will result in additional lines required to be opened, putting over 60,000 customers at risk of resulting outages. Additional power supply is needed in the central King County area to prevent overloads and outages, see .Figure 1-3.

The diagram below indicates areas at risk of outage if switching is performed to prevent overloads, and then subsequent outages occur on transmission lines that had been switched open. The subsequent outages could be due to radial lines experiencing faults due to car-pole accidents, lightning, or tree limbs. Outages could also occur if PSE dispatchers must drop load to prevent transformer overloads while transmission lines are switched open. In the diagram, green lines indicate a line or transformer whose loss during peak winter load could result in overloads of other system elements. The gold colored lines indicate those lines or transformers at risk of overloading when the green element trips out. The gray shaded areas indicate where customers would be at risk of outage from switching to mitigate the overloads.

This study finds that within the 10 year study period, additional transmission supply to the Eastside is needed to meet future demand growth of the area.




Figure 1-3: Topological View of the Needs Assessment of the Eastside of Lake Washington

# Section 2 Introduction and Background Information

## 2.1 Study Objective

The study objective was to assess the capability of existing transmission infrastructure to supply the communities on the east side of Lake Washington, called the "Eastside", within Puget Sound Energy's (PSE's) central King County area. These communities include Bellevue, Kirkland, Redmond, Mercer Island, and Newcastle as well as the smaller towns along the shore. A review was performed to determine the needs for future transmission supply to the Eastside. This study review was performed due to concerns identified in 2009 TPL studies that were related to the projected future loading on the Talbot Hill Substation, future requirements of the Columbia Grid, and operational issues of PSE's control area. These supply issues were exacerbated by impacts on the PSE system due to Puget Sound Area Northern Intertie (PSANI) related events during winter supply conditions and heavy south to north flows that had been identified in analysis conducted by Columbia Grid.

This present report reviews the entire infrastructure, and design of the transmission system with respect to present and future viability. The following tasks were completed as part of this study review and are discussed in this report: (i) updated the block load forecast of the King County area; (ii) merged this block load forecast into the 2012 PSE system load forecast (iii) conducted future performance simulations of the King County area for the years 2014, 2018 and 2022; (iv) reviewed the Columbia Grid 2013 Biennial Transmission Expansion Plan; and (v) reviewed operational issues with PSE's control area operators; and (vi) aligned the recommendations with the recommendations from the Columbia Grid analysis of PSANI events under heavy south to north flows.

Quanta Technology, LLC., assisted Puget Sound Energy in conducting this study, including research, analysis and documentation.

## 2.2 Background Information

One of the major drivers in the determination of need for additional transmission facilities is the existing load on the system and the projected load growth that is expected to occur. As early as 2008, PSE had indications that additional transmission supply was needed to support the central King County portion of PSE's service territory. In 2008, PSE conducted a King County Transformation Study that indicated increased loading had occurred at the Talbot Hill Substation, which has two 230-115 kV transformers. Concerns were noted that if load continued to grow in the area, then by 2017-18 one transformer would overload if the other transformer tripped off-line. This study used the F2008 Puget Sound Energy Electric Load Forecast.

The needs for additional transmission sources into central King County were confirmed while performing the mandatory NERC 2009 reliability compliance studies. In that analysis, PSE observed a potential thermal issue when there was a bus fault at Talbot Hill Substation. The bus fault caused the overload of a Talbot Hill transformer for the loss of the other transformer for the 2010-2011 winter peak[12]. Based upon the adjusted 2009 PSE load forecast, the peak load modeled in the 2010-2011 Winter peak case was 5,329 MW[13]. For the 2018-2019 Winter peak case a load of 5,765 MW was modeled.

To resolve this equipment overload, a temporary measure of manually switching out two 115-kV lines from Talbot Hill –Lakeside was identified as a Corrective Action Plan (CAP) that could be used to mitigate the overload[14]. The CAP would be used at a PSE load level of approximately 5,300 MW. At that time, PSE implemented the CAP and has been using it in its operations for managing the reliability of service in that area.

[12] Page 13, 2009 PSE Planning Studies and Assessment TPL-001 to TPL-004 Compliance Report

[13] Page 7, 2009 PSE Planning Studies and Assessment TPL-001 to TPL-004 Compliance Report

[14] Page 22, 2009 PSE Planning Studies and Assessment TPL-001 to TPL-004 Compliance Report

In early 2009, PSE's corporate load forecast group responded to the national economic crisis to re-evaluate the projected load forecast. The resulting revision reduced the forecast 2010-11 winter peak by 3% from the previous year's forecast.

In 2009, PSE set their all-time record loads for both the winter and summer seasons. The 2009 winter peak load was 5,038 MW and the 2009 summer peak was 3,509 MW. This compares with a 2009 forecast of 4,973 MW for winter and 3,086 MW for summer. Neither the forecast number nor the peak load includes the 270 MW of transmission level customers used in the area load. It should be noted that the 2009 winter peak forecast assumed a normal winter temperature of 23° F, while the peak load occurred with a temperature of 16°F. For a discussion of the forecast methodology and the limitations on its use, see Section 4.1.5.

## 2.3 King County Area Description

King County is a major load center of the Puget Sound Region. The Eastside area is in central King County and includes the cities of Redmond, Kirkland, Bellevue, Mercer Island, Newcastle and Renton, as well as the smaller towns of Yarrow Point, Hunts Point, Medina, Clyde Hill and Beaux Arts. The greater Eastside area also includes towns and cities to the north and east of the core area which are not a focus of this study: Bothell, Woodinville, Duvall, Carnation, Sammamish, Issaquah, Preston, Fall City, Snoqualmie, and North Bend.


Figure 2-1 Street Map of Eastside Area

The load density of north King County is shown below in Figure 2-2. The map shows that the most densely populated areas, shown in red, of King County are Kenmore, Kirkland, Redmond, Bellevue, and Renton.

The easterly border of King County is along the Cascade Mountain Range, which creates a natural obstacle between the densely populated western Washington communities clustered around Seattle and Tacoma, and the sparsely populated arid region of eastern Washington.

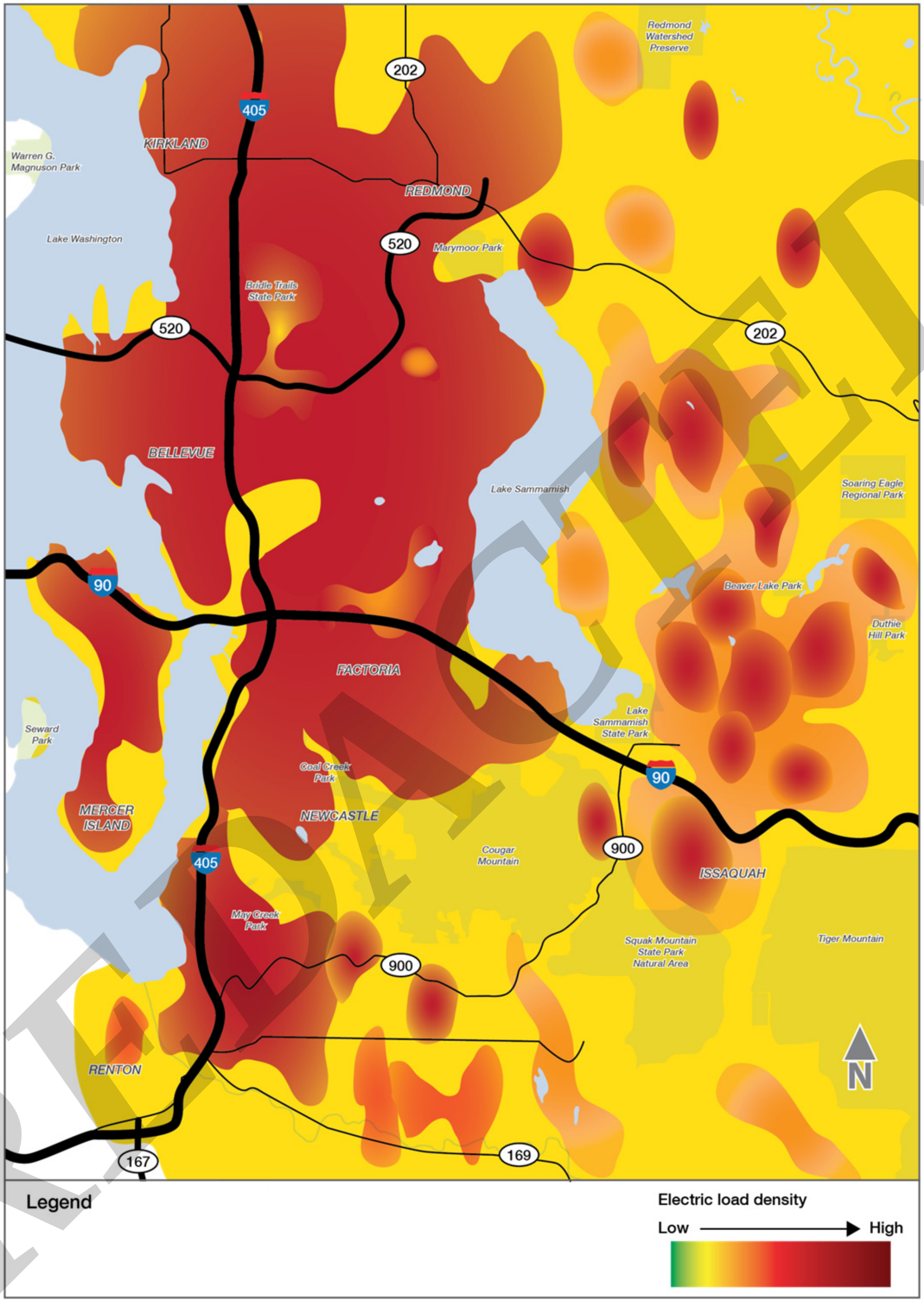


Figure 2-2: King County Load Density Map

The King County load is supplied from Bonneville Power Administration's (BPA) 500 kV sources at Monroe (Monroe), SnoKing (Mill Creek) Maple Valley (Renton), and Covington (Covington) Substations, as well as 500 kV switching stations at Echo Lake (south of Snoqualmie) and Raver (Ravensdale). There is very little generation in King County; a small amount of hydro generation in eastern King County provides less than 5% of the county's peak load requirements. Therefore PSE depends on its transmission system and on transmission interconnections with neighboring utilities to bring power to its load center in King County.

King County also has 230 kV supply from the following substations: Sammamish (Redmond), Novelty Hill (Redmond Ridge), Talbot Hill (Renton), O'Brien (Kent), and Berrydale (Covington). To serve the loads in King County, there are eight 230 kV/115 kV transformers; two at Sammamish, two at Talbot Hill, and one at Novelty Hill, two at O'Brien, and one at Berrydale. North King County load is generally served by Sammamish and Novelty 230 kV sources but due to the interconnecting nature of the system, Talbot Hill transformers serve part of the North King and South King systems. Sammamish and Novelty Hill are both connected to the Monroe-Maple Valley 230 kV line, which is leased from BPA. See Figure 2-3 and Figure 2-4 on the following pages.

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Figure 2-3: Puget Sound Area System Overview One-Line Diagram

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Figure 2-4: Major Electrical Infrastructure Supporting the Eastside Area

The 11 - 115 kV lines out of Lakeside Substation serve 15 substations in Bellevue and 14 substations in Newcastle, Issaquah, Mercer Island, Medina, Kirkland and Redmond, as shown in Figure 2-5. Lakeside Substation is supplied by 230-115 kV transformers at Sammamish and Talbot Hill. Lakeside connects to switching stations at Shuffleton (Renton), Lake Tradition (Issaquah) and Ardmore (Bellevue). In the Eastside area, when regional power flows are from south to north the power serving the Eastside will generally flow from south to north. In this case, power for the Eastside starts at Talbot Hill and flows north to Lakeside and continues to Sammamish Substation. When regional flows are north to south, Talbot Hill will still feed north past Lakeside but power will also flow south out of Sammamish Substation which feeds approximately sixty percent of the load between Sammamish and Lakeside Substations during north-south regional flows. Talbot Hill is a strong source of supply between Lakeside and Sammamish Substations.

*Redacted*

Figure 2-5 One-Line Diagram of Eastside Study Area

All of the 115 kV transmission lines in the Eastside area have been uprated to their maximum capacity ratings, except the two lines to Mercer Island, which operate normally open. PSE has two 115 kV transmission lines on separate structures on a transmission right of way (ROW) between Sammamish and Talbot Hill Substations, which interconnect at Lakeside Substation. There are three 115 kV lines in parallel with this corridor in the north, two lines in parallel in the south, all supplying load to distribution substations.

The Bellevue area is a higher-density load center without a 230 kV bulk transmission source nearby. With 230 kV supplies in the north at Sammamish Substation and the south at Talbot Hill Substation, lower-capacity 115 kV transmission lines bring power to Bellevue from the 230 kV transmission substations in Redmond and Renton.

## 2.4 Study Horizon

PSE has studied the Eastside area for the near-term (years 1-5) and long-term (years 6-10) horizons. Since PSE peaks during the winter season, the reliability analysis focused on the winter peak for years 2013-14, 2017-18, and 2021-22. Summer peak was also analyzed for years 2014 and 2018 for the annual 2012 NERC TPL analysis; the 2012 NERC TPL summer results were included in this study.

# Section 3 Analysis Description

A number of comprehensive reliability analyses were performed to determine the present and future transmission supply to the central King County area. The following detailed studies were performed to assess any adverse conditions to the reliability and operating characteristics of the PSE system or surrounding systems in the context of applicable standards:

2013 Eastside Needs Assessment: Power flow simulations were performed for the near and far-term horizon to determine if there are any thermal or voltage violations to King County's Eastside area. Past studies have shown supply issues to this area. While the recent economic downturn has impacted the future load growth projections of PSE overall, the load within the Eastside continues to grow. This study uses the latest corporate load forecast and adjusts the lumpiness of the load based on PSE's knowledge of future block loads.

2008 Initial King County Transformation Study: Power system simulation studies were performed on the King County system which indicated increased loading at Talbot Hill Substation, pointing to future overloads of either transformer for the loss of the other transformer at Talbot Hill. A bus section fault or loss of one of the lines from BPA Maple Valley Substation could also result in Talbot Hill transformer overloads.

2009 PSE Planning Studies and Assessment-TPL-001 to TPL-004 Compliance Report: As required per the 2009 NERC Compliance Enforcement Program, PSE performed an assessment of the system based on criteria described in NERC Standards TPL-001 through TPL-004. There were a number of potential overloads and voltage violations identified with these studies. The proposed solutions are generally system projects that will mitigate the issues via a topology change, line uprate, or additional transformation. The solutions may also take the form of a Remedial Action Scheme (RAS), as well. PSE demonstrated 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 the contingency conditions.

2012 PSE Planning Studies and Assessment-TPL-001 to TPL-004 Compliance Report:
PSE performed an assessment of the system based on criteria described in NERC Standards TPL-001 through TPL-004. There were a number of potential overloads and voltage violations identified with these studies. The proposed solutions are generally system projects that will mitigate the issues via a topology change, line uprate, or additional transformation. The solutions may also take the form of a Remedial Action Scheme (RAS), as well.

BPA Transformation Study: A study was conducted by PSE in 2010 to review the impact of BPA 500-230 kV transformation at Monroe, Maple Valley or Covington which had been identified by BPA as alternative sites for the new transformer. A Covington transformer plus Lakeside 230-115 kV transformation provides better improvements to stressed contingencies than Covington plus Lake Tradition, Berrydale and Christopher 230-115 kV transformers combined. A Maple Valley transformer would stress PSE's system in the Talbot Hill vicinity more than a Covington transformer.

ColumbiaGrid 2013 Biennial Transmission Expansion Plan: ColumbiaGrid 2013 Biennial Transmission Expansion Plan looks out over a ten-year planning horizon (2013 - 2023) and identifies the transmission additions necessary to ensure that the parties to the ColumbiaGrid Planning and Expansion Functional Agreement can meet their commitments to serve load and meet firm transmission service commitments. The Expansion plan still includes the addition of a Lakeside 230-115 kV transformer in the Ten-Year Plan, and the additional 230-115 kV transformation at Lake Tradition in the long term. The new issues in the 2013 Expansion plan include Northern Intertie transfer issues.

A limitation in the 500/230 kV transformation in the Puget Sound area was noted in previous System Assessments. To resolve this issue, The Puget Sound Area Transmission Expansion Plan and the ColumbiaGrid Ten-Year Plan include a new 500-230 kV transformer at Raver which is scheduled to be installed in 2016.

Study Criteria: The following is a list of the criteria, standards and guides which apply to this needs statement:

1. TPL-001- System Performance Under Normal (No Contingency) Conditions (Category A)
2. TPL-001-WECC-CRT-2 – System Performance Criterion Under Normal Conditions, Following Loss of a Single BES Element, and Following Extreme BES Events:
3. TPL-002 - System Performance Following Loss of a Single Bulk Electric System Element (Category B)
4. TPL-003 - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
5. TPL-004 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)
6. PSE's Transmission Planning Guidelines
7. Northwest Power Pool Coordinated Plan
8. PSE Procedures to Establish and Communicate Operating Limits

# Section 4 Study Assumptions

## 4.1 Steady State Model Assumptions

### 4.1.1 Study Assumptions

The 230 kV Eastside Area steady state models were developed to be representative of the long term projection of the winter peak system demand level to assess reliability performance under heavy load conditions. The model assumptions included consideration of Puget Sound area generation units' unavailability conditions as well as variations in surrounding area transfer level conditions.

The following assumptions are used in the 2013 Eastside Needs Assessment. The primary focus was on the winter peaks for years 2013-14, 2017-18, and 2021-22 utilizing the latest corporate load forecast modified to reflect the lumpiness of the load by substation. The Eastside load is defined as the sum of the MW flows out of the bus on the Talbot Hill end of the Talbot Hill - Lakeside #1 & #2 115 kV lines, Shuffleton end of the Shuffleton - Lakeside 115 kV line, Lake Tradition end of the Lake Tradition - Goodes Corner - Lakeside 115 kV line, and Sammamish end of the Sammamish - Lakeside #1 & #2, Sammamish - North Bellevue - Lakeside, Sammamish - Lochleven - Lakeside, and Sammamish - Ardmore - Lakeside 115 kV lines.

The difference in winter peak load forecasts with 100% conservation from 2013-14 to 2021-22 is 138 MW, which on average, is only approximately 15 MW per year (see Figure 4-1). Sensitivities on the amount of conservation and weather were run to reflect the inherent risks associated with an essentially flat load growth. Figure 4-1 shows the load levels in the study with various levels of conservation.

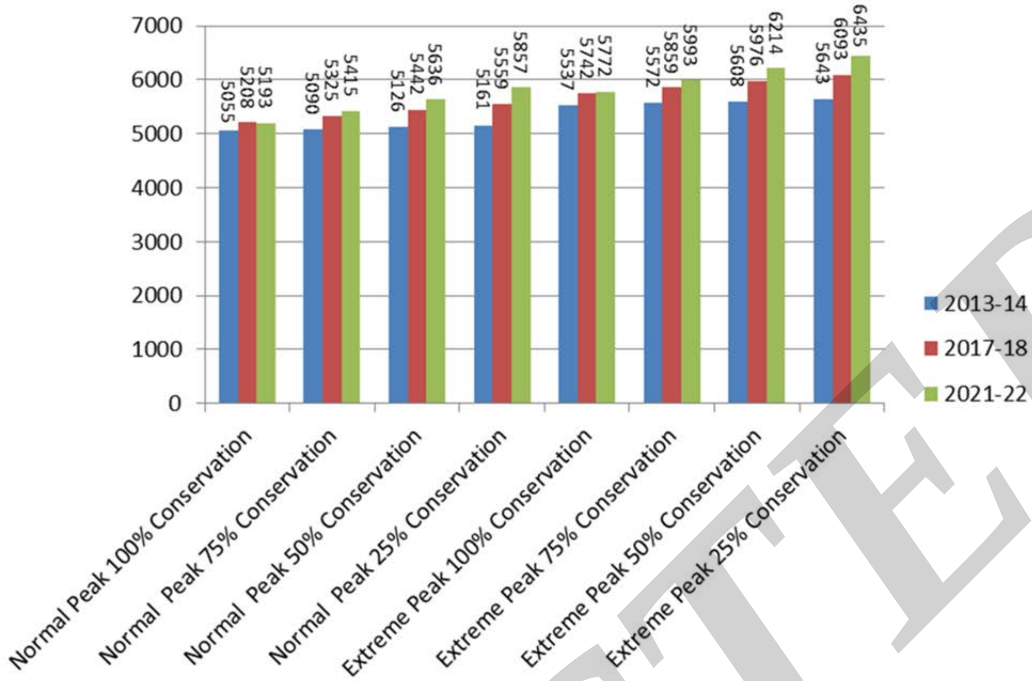


Figure 4-1: Winter Peak Load Growth with Varying Levels of Conservation

The Northern Intertie for the winter peak was modeled with a south to north flow of 1,500 MW into Canada.

The generation dispatches for the winter peak were modeled to reflect the standard way PSE studies the King County area which is to reduce generation in the north of the PSE area to create a greater south to north power flow during contractual flows from the Northwest to Canada. A winter low generation sensitivity case with adjusted Puget Sound area generation was run to identify risks associated with running a no Puget Sound Area generation case.

### 4.1.2 Source of Power Flow Models

The power flow models used in the study were based on WECC base cases created in 2012 for the winters 2012 -13, 2016 -17 and 2021-22 and for summers 2012 and 2017. These base cases are updated annually by all WECC members to reflect expected load forecasts, planned projects, generation changes and system adjustments. The 2012-13 winter case was modified to model the expected 2013-14 winter, the 2016-17 winter case to 2017-18 winter, the 2012 summer case to 2014 summer, and the 2017 summer case to 2018 summer. The cases were updated to reflect the PSE Corporate load forecast as discussed in Section 4.1.5.

The winter cases were then adjusted to reflect the case where the region sees high south to north power flows with no Puget Sound area generation. In previous studies, this scenario was the one that indicated the greatest problems on the Eastside in the winter. For TPL studies, four other scenarios are also studied:

- High South to North flows on the Northern Intertie with high Puget Sound area generation
- High South to North flows on the Northern Intertie and high south to north flows on the Paul - Raver 500 kV line with no Puget Sound area generation
- High North to South power flows on the Northern Intertie with no Puget Sound area generation
- High North to South power flows on the Northern Intertie with high Puget Sound area generation

The summer cases were run through four generation and Northern Intertie scenarios for PSE's 2012 TPL report; the TPL report summer results were used for this study.

The adjusted cases were then tailored for system improvements. Most improvements had been included already in the WECC cases. Additionally, the Seattle City Light (SCL) inductors and the Raver transformer were modeled. The PSE Lakeside 230 kV project was removed from the 2018 summer and 2021-22 winter cases since this project was proposed for perceived Eastside transmission supply need.

The cases were also adjusted for forecasted load in future years. First a block load adjustment was made where expected load is known for substations in King County. Then the system load for each of the study years was scaled to the level forecasted by PSE's Load Forecast Group in 2012.

### 4.1.3 Transmission Topology Changes

Projects added to the Eastside Needs Assessment base case are listed in Section 9 - Appendix B Table B-1 and Table B-2.

### 4.1.4 Generation Additions and Retirements

In addition to the generation increases included in the WECC base case by other utilities, PSE added generation capacity at the Snoqualmie and Lower Baker hydro units in 2013. These increases were modeled in the summer cases. The winter cases used no Puget Sound area generation for low generation scenarios, so the additional hydro generation was not relevant.

### 4.1.5 Forecasted Load (including assumptions concerning energy efficiency, interruptible loads, etc.)

The 2012 PSE Corporate system load forecast was used as a basis for the demand levels modeled in the study. PSE Corporate Load Forecast Group uses econometric regression models (*not end use models*) to forecast use per customer and customer counts for its electric and gas service area. The regression models are developed by customer class, such as residential, commercial, industrial, and so on.

The use-per-customer and customer equations are driven by a number of regional economic, demographic, weather, binary and other independent variables. The forecasts of the underlying economic and demographic variables are developed using information from Moody's Analytics and other regional sources of economic data.

The use per customer equation is driven primarily by historical data and variables such as unemployment rate, total employment, manufacturing employment, real personal income, retail rates and weather variables like heating and cooling degree days. The base forecast created by the regression model is modified appropriately to account for impacts of conservation programs and any known changes to large customers managed by the major accounts group. The conservation estimates prepared by the Integrated Resource Planning team distribute the implementation of conservation measures based on cost effectiveness analyses. The forecast of conservation savings is a major determinant of the final shape of the load forecast.

Customer count growth is driven by historical data and changes in population, household growth, housing permits, total employment and manufacturing employment in PSE's service area.

A major influence on PSE in the early 1990s was Washington's Growth Management Act (GMA). Elements of the GMA provide direction as to where growth and load will locate. PSE's planning process continues to provide input and updates on future planned transmission and distribution facilities for local jurisdiction Comprehensive Plan revisions to support their growth forecasts. Overall, the GMA and the local Comprehensive Plans coupled with PSE Annual Corporate Customer and Sales Forecasts provide a measure of predictability as to where and when construction of planned facilities will be needed.

PSE Annual Corporate Customer and Sales Forecasts include summer and winter peak load forecasts for a 20 year period. These forecasts include both normal and extreme winter load levels, with and without Demand Side Resources (DSR). Forecasts for Network Loads and other T & D service categories are obtained from customers annually for a 10-year period. Transmission Planning uses the most recent normal peak loads as a starting point and checks sensitivities to forecasted load as set forth in the NERC transmission planning requirements[15].

Table 4-1 shows PSE's 20 year load forecasts for the calendar years of 2010 to 2012 for normal (23° F) and extreme weather (13° F) with 100% conservation. PSE Load Forecast is provided for PSE system load, and does not include the 270 MW of Transmission Customer industrial loads. Transmission Customer loads are included in the area load for the TPL and 2013 Eastside Need Assessment. The load forecasts have decreased from the earlier years. The 2013 Eastside Need Assessment used the latest forecast.

From Table 4-1, the total load growth between 2013 and 2021 for normal weather is 138 MW. The difference in load between normal weather and extreme weather for 2013 is 482 MW. If the temperature on the peak day drops from 23° F to 13° F, the load increase would be approximately 3.5 times the total normal load growth over the study period.

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[15] TPL-001-2 R2.1.4: http://www.nerc.com/docs/standards/sar/atfnsdt_recirc_ballot_tpl_001_2_clean_20110711.pdf

Table 4-1: PSE Load Forecasts from 2010 to 2012 for Normal and Extreme Weather

| | Forecasted 2010 | | Forecasted 2011 | | Forecasted 2012 | |
|---|---|---|---|---|---|---|
| Year | Max of Normal Peak w/ DSR | Max of Extreme Peak w/ DSR | Max of Normal Peak w/ DSR | Max of Extreme Peak w/ DSR | Max of Normal Peak w/ DSR | Max of Extreme Peak w/ DSR |
| 2010 | 4,842 | 5,260 | 4,781 | 5,253 | | |
| 2011 | 4,868 | 5,291 | 4,878 | 5,363 | | |
| 2012 | 4,913 | 5,344 | 4,893 | 5,388 | 4,837 | 5,316 |
| 2013 | 4,947 | 5,387 | 4,925 | 5,433 | 4,785 | 5,267 |
| 2014 | 4,961 | 5,407 | 4,965 | 5,487 | 4,836 | 5,333 |
| 2015 | 4,947 | 5,400 | 4,979 | 5,513 | 4,865 | 5,375 |
| 2016 | 4,954 | 5,414 | 5,003 | 5,548 | 4,909 | 5,432 |
| 2017 | 4,967 | 5,434 | 5,023 | 5,579 | 4,938 | 5,472 |
| 2018 | 4,989 | 5,462 | 5,027 | 5,593 | 4,938 | 5,483 |
| 2019 | 5,017 | 5,498 | 5,044 | 5,622 | 4,946 | 5,501 |
| 2020 | 5,063 | 5,551 | 5,025 | 5,615 | 4,923 | 5,490 |
| 2021 | 5,141 | 5,639 | 5,028 | 5,630 | 4,923 | 5,502 |
| 2022 | 5,222 | 5,731 | 5,078 | 5,693 | 4,972 | 5,562 |
| 2023 | 5,302 | 5,821 | 5,149 | 5,775 | 5,039 | 5,641 |
| 2024 | 5,383 | 5,913 | 5,225 | 5,865 | 5,117 | 5,732 |
| 2025 | 5,466 | 6,007 | 5,303 | 5,955 | 5,193 | 5,820 |
| 2026 | 5,547 | 6,099 | 5,382 | 6,047 | 5,266 | 5,905 |
| 2027 | 5,629 | 6,192 | 5,464 | 6,142 | 5,341 | 5,993 |
| 2028 | 5,711 | 6,285 | 5,552 | 6,244 | 5,426 | 6,090 |
| 2029 | 5,795 | 6,380 | 5,645 | 6,351 | 5,515 | 6,192 |
| 2030 | | | 5,490 | 6,091 | 5,605 | 6,296 |
| 2031 | | | | | 5,694 | 6,399 |
| 2032 | | | | | 5,785 | 6,504 |
| 2033 | | | | | 5,878 | 6,610 |

The conservation in MW, by county, utilized in the 2012 forecast is shown below in Table 4-2.

Table 4-2: Conservation in MW, by County

| Conservation Effects by County<br>Normal Peaks (23°F)<br>100% Target Conservation (MW) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Year of Study | King | Thurston | Pierce | Whatcom | Skagit | Island | Kitsap | Kittitas | Jefferson | Total |
| 2012 | 33.0 | 7.8 | 6.9 | 5.2 | 3.4 | 2.1 | 7.4 | 0.8 | 1.3 | 67.9 |
| 2013 | 69.6 | 16.5 | 14.6 | 10.8 | 7.2 | 4.4 | 15.5 | 1.7 | 2.7 | 142.9 |
| 2014 | 112.3 | 26.7 | 23.6 | 17.5 | 11.5 | 7.0 | 24.8 | 2.7 | 4.3 | 230.5 |
| 2015 | 158.5 | 37.8 | 33.2 | 24.6 | 16.2 | 9.9 | 34.8 | 3.9 | 6.1 | 324.9 |
| 2016 | 196.1 | 46.8 | 41.0 | 30.3 | 20.0 | 12.1 | 42.7 | 4.8 | 7.5 | 401.5 |
| 2017 | 233.0 | 55.6 | 48.6 | 35.9 | 23.7 | 14.3 | 50.3 | 5.8 | 8.9 | 476.2 |
| 2018 | 280.4 | 66.9 | 58.3 | 43.1 | 28.4 | 17.2 | 60.1 | 7.1 | 10.7 | 572.1 |
| 2019 | 325.4 | 77.6 | 67.4 | 49.8 | 32.9 | 19.8 | 69.2 | 8.3 | 12.4 | 662.9 |
| 2020 | 389.5 | 92.8 | 80.4 | 59.5 | 39.2 | 23.5 | 82.2 | 10.2 | 14.9 | 792.1 |
| 2021 | 443.5 | 105.6 | 91.2 | 67.5 | 44.6 | 26.6 | 92.8 | 11.7 | 16.9 | 900.4 |
| 2022 | 474.0 | 112.9 | 97.3 | 72.0 | 47.6 | 28.2 | 98.4 | 12.7 | 18.0 | 961.1 |
| 2023 | 495.6 | 118.0 | 101.4 | 75.1 | 49.6 | 29.3 | 102.1 | 13.4 | 18.8 | 1003.4 |
| 2024 | 514.9 | 122.6 | 105.1 | 77.9 | 51.5 | 30.3 | 105.3 | 14.1 | 19.5 | 1041.2 |
| 2025 | 535.1 | 127.3 | 109.0 | 80.7 | 53.3 | 31.3 | 108.5 | 14.7 | 20.3 | 1080.3 |

Figure 4-2 shows the twenty year window of PSE's Winter Normal Peak with 0%, 25%, 50%, 75% and 100% conservation. As Figure 4-2 shows, with 100% conservation, the load levels of PSE are relatively flat for the years of study. The difference between 2013 and 2021 is 138 MW.

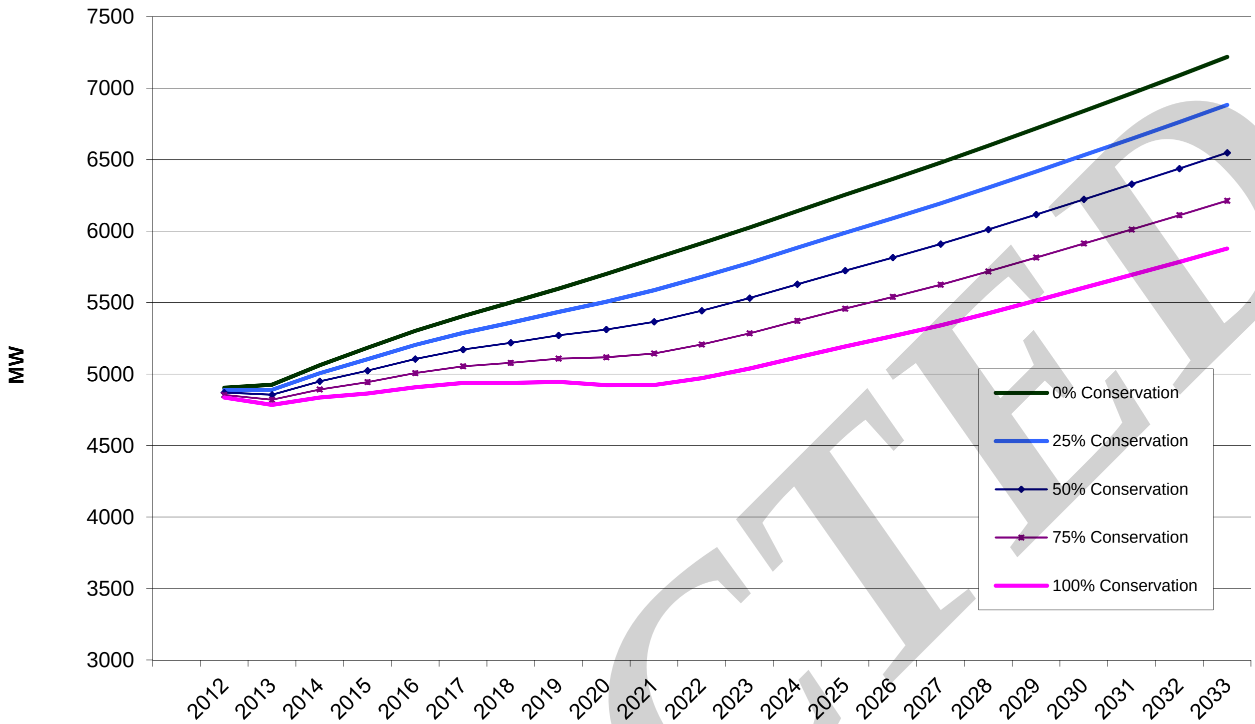



Figure 4-2: Twenty Year Graph of PSE's Forecast Winter Normal Peak with 0%, 25%, 50%, 75% and 100% Conservation



### 4.1.6 Load Levels Studied

For the power flow studies associated with the 230 kV Eastside Needs Assessment, the heavy winter 2013-14, 2017-18 and 2021-22 cases were used. Substation loading for the PowerWorld cases was developed using the substation loading at the time of the January 18, 2012 system peak as a proxy to the distribution of the load. There were a few substations without Supervisory Control and Data Acquisition (SCADA) load readings. Those substations were assigned values based on manual onsite substation load readings during the same load cycle. Both megawatts (MW) and megavars (MVAR) were determined in this manner.

Small Area Load Forecast: PSE distribution planners keep current on developments planned for their respective planning areas. These anticipated new loads are generally known within a 2-5 year time frame; specific projects are not often known with confidence beyond 5 years in advance. PSE planners reviewed such new loads expected in the King County area within the study period and added those expected loads to the historical load for each substation. These small area load adjustments were included in the substation load spread before the company-wide load was scaled to the corporate load forecast.

Transmission Customer Load: The corporate load forecast together with the interconnected Transmission Customer load, or non PSE load, was used to determine future loads for the power flow studies. The Transmission Customer load typically runs between 250 MW and 300 MW. For purposes of this study, 270 MW was used for a typical value. For example, in the year 2013-2014 the winter peak load forecast for the PSE area is 5055 MW which comprises the projected forecast of 4785 MW plus 270 MW of Transmission Customer loads. Loads were developed similarly for years 2017-18 and 2021-22. For completeness, this non-PSE load was included in the 2013 Eastside Needs Assessment and is shown in Table 4-3.

Table 4-3: Winter Peak Load levels studied in the Eastside Needs Assessment

| Area Load Used for Eastside 230 Study | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year Studied | Report | Season | Normal Peak 100% Conservation | Normal Peak 75% Conservation | Normal Peak 50% Conservation | Normal Peak 25% Conservation | Normal Peak 0% Conservation | Extreme Peak 100% Conservation | Extreme Peak 75% Conservation | Extreme Peak 50% Conservation | Extreme Peak 25% Conservation | Extreme Peak 0% Conservation |
| 2013-14 | 2012 E230 | Winter | 5055 | 5090 | 5126 | 5161 | 5196 | 5537 | 5572 | 5608 | 5643 | 5678 |
| 2017-18 | 2012 E230 | Winter | 5208 | 5325 | 5442 | 5559 | 5676 | 5742 | 5859 | 5976 | 6093 | 6210 |
| 2021-22 | 2012 E230 | Winter | 5193 | 5415 | 5636 | 5857 | 6078 | 5772 | 5993 | 6214 | 6435 | 6656 |

Note: PSE Load Forecast is provided for PSE system load, not including the 270 MW of Transmission Customer industrial load. Transmission Customer load is included in the area load for the TPL and Eastside Needs Assessment studies.

Conservation Sensitivities: The winter forecast was adjusted for sensitivities regarding the amount of expected conservation at peak load. PSE's corporate load forecast assumes 100% of the targeted conservation levels are achieved. To understand the reliability risk due to higher than expected load, PSE ran load sensitivity studies which adjusted conservation levels as a proxy for the higher loads. For the load sensitivity studies, conservation was adjusted to 75%, 50%, and 25% of expected values.

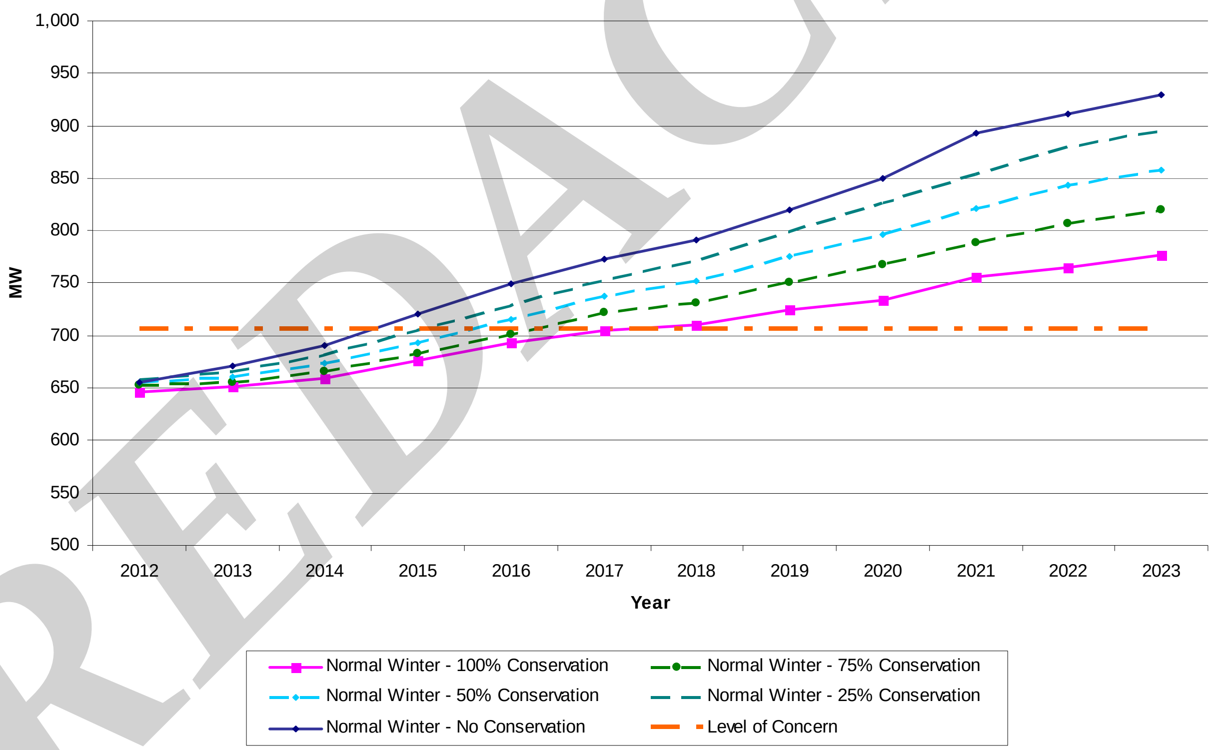



Figure 4-3: Eastside Load Forecast for Normal Winter Load Forecast 2012-2023

### 4.1.7 Load Power Factor Assumptions

The power factor at each substation was based on the MW and MVAR loadings at the time of the January 18, 2012 system peak. As the load levels changed based on the load forecast, the power factor at each substation did not change.

### 4.1.8 Transfer Levels

The NI (Northern Intertie) flows were assumed based on season and historic flows; Winter Peak NI-1500 MW S-N and Summer Peak NI-2850 MW N-S.

### 4.1.9 Generation Dispatch Scenarios

For the winter peak load cases, no PSE and SCL generation west of the Cascades were run. Tacoma Power generation was left on, due certain internal system constraints. The generators off-line in the Eastside Needs Assessment are listed in Table 4-4.

A low-generation case was simulated as a sensitivity. The Puget Sound area generation run during that case is indicated in Table 4-4.

Table 4-4: List of Puget Sound Area Generators Adjusted in the 2013 Eastside Needs Assessment

| Generation Plant | Winter MW Rating | Expected MW Output during Winter Peak for Low-Generation Sensitivity Case | Type | Owner | Transmission Delivery Area |
|---|---|---|---|---|---|
| Enserch | 184.8 | 125 | Natural Gas, Combined Cycle | PSE | Whatcom County |
| Sumas | 139.8 | 0 | Natural Gas, Combined Cycle | PSE | Whatcom County |
| Ferndale | 282.1 | 0 | Natural Gas, Combined Cycle | PSE | Whatcom County |
| Whitehorn | 162.2 | 0 | Natural Gas, Simple Cycle | PSE | Whatcom County |
| Fredonia | 341 | 0 | Natural Gas, Simple Cycle | PSE | Skagit County |
| Sawmill | 31 | 22 | Biomass | Private Owner | Skagit County |
| Upper Baker | 106 | 80 | Hydro Dam | PSE | Skagit County |
| Lower Baker | 78 | 54 | Hydro Dam | PSE | Skagit County |
| Komo Kulshan | 14 | 0 | Hydro Run-of-River | Private Owner | Skagit County |
| March Point | 151.6 | 134 | Natural Gas, Combined Cycle | Shell | Skagit County |
| Ross | 450 | 295 | Hydro Dam | SCL | Snohomish County |
| Gorge | 190.7 | 157 | Hydro Dam | SCL | Snohomish County |
| Diablo | 166 | 160 | Hydro Dam | SCL | Snohomish County |
| South Tolt River | 16.8 | 0 | Hydro Run-of-River | SCL | Northeast King County |
| Snoqualmie | 37.8 | 0 | Hydro Run-of-River | PSE | East King County |
| Twin Falls | 24.6 | 0 | Hydro Run-of-River | Private Owner | East King County |
| Cedar Falls | 30 | 0 | Hydro Run-of-River | SCL | East King County |
| Freddy 1 | 270 | 0 | Natural Gas, Combined Cycle | Atlantic Power/PSE | Pierce County |
| Electron | 20 | 4 | Hydro Run-of-River | PSE | Pierce County |
| Frederickson | 162.2 | 0 | Natural Gas, Simple Cycle | PSE | Pierce County |
| Expected MW output during Winter peak is based off of actual 2011-2012 Winter peak output except for SCL hydro, which is based off of modeled generation levels in WECC winter peak case. | | | | | |

### 4.1.10 Reactive Resource and Dispatch Assumptions

All existing and planned area reactive resources were assumed available and dispatched if conditions called for their dispatch. The reactive output of units was constrained to defined limits and shunt reactive resources were dispatched as conditions required.

### 4.1.11 Conservation Assumptions

PSE employs conservation as a strategic measure to manage energy requirements and provide customer benefits. Conservation programs have been funded for over 20 years and are projected to continue to receive strong funding in the next 20 years. PSE's Energy Efficiency Group has demonstrated the efficacy of its funded programs on a continuing basis. As a result, conservation is included in PSE's Integrated Resource Plan (IRP) as a cost-effective source of new energy.

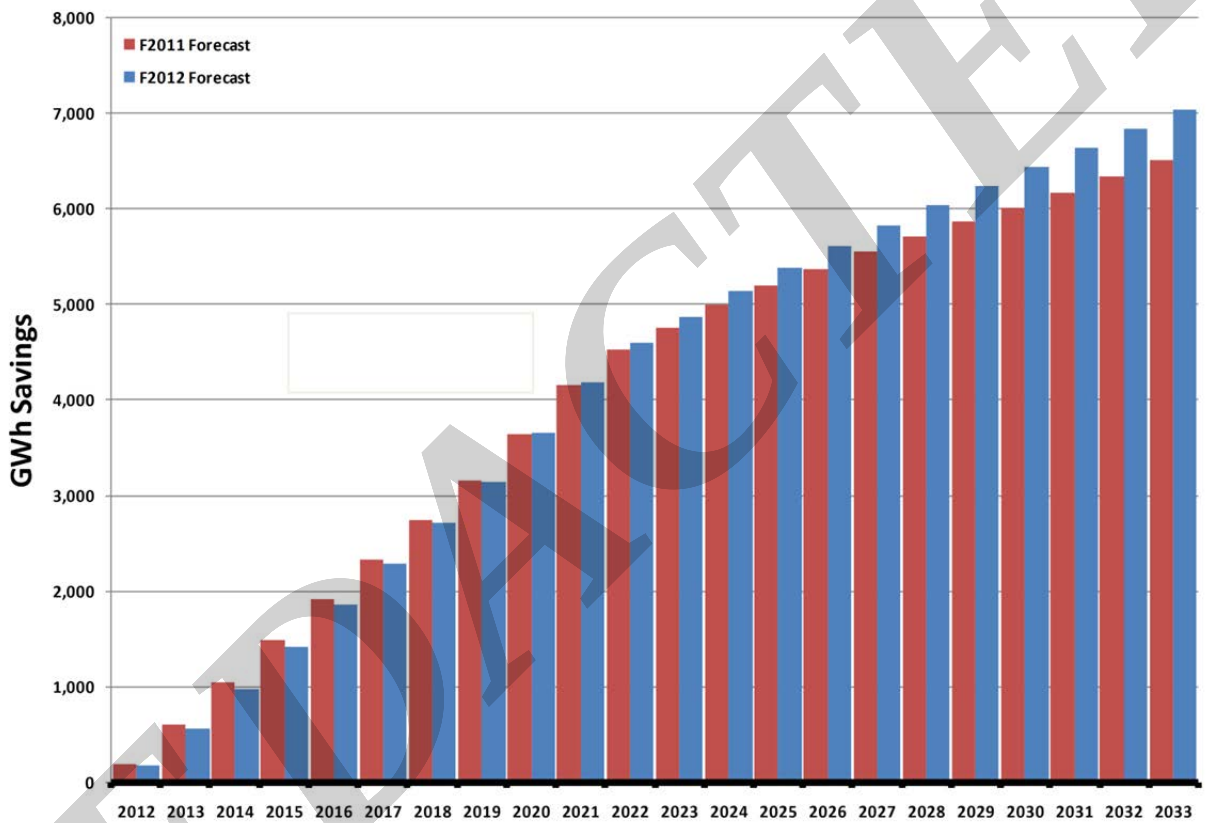



Figure 4-4: PSE Conservation Forecast in 20 year Horizon Measured in Gigawatt-Hours; Comparison of 2012 Forecast to 2011 Forecast

### 4.1.12 Explanation of Operating Procedures and Other Modeling Assumptions

PSE's Transmission Planning group has prepared a CAP that instructs PSE Transmission Operators to take certain actions in the event of either Talbot Hill 230-115 kV transformers overloading. While the CAP was initiated to address the potential for either transformer to exceed its emergency rating, the CAP can also be used to address the event of either transformer exceeding its operating limit as well.

The CAP instructs the PSE Transmission Operators to open the Talbot Hill – Lakeside #1 & #2 115 kV lines if either Talbot Hill 230-115 kV transformer overloads. The contingency that would cause the transformers to overload would be a double-contingency (N-1-1) loss of a Talbot Hill transformer and the Berrydale transformer during high winter loading.

With future load growth, the CAP may be expanded to state that if the transformer overload is not sufficiently reduced or the Shuffleton – Lakeside 115 kV line overloads as a result of [redacted], then the Transmission operation should open [redacted]

While none of these planned actions would drop load in a system normal configuration, the opening of [redacted] exposes three substations supplying 16,000 customers [redacted] and three substations supplying 17,000 customers on [redacted] to an outage on the lines, as shown in Figure 4-5. Furthermore, if [redacted] are opened, North and Central King County is at risk of manual load shedding for an N-1-1 loss of [redacted]. See Figure 4-5 below that shows areas in jeopardy of outage when transmission lines are opened under the CAP's to prevent overloads of the Talbot Hill and Sammamish transformers.

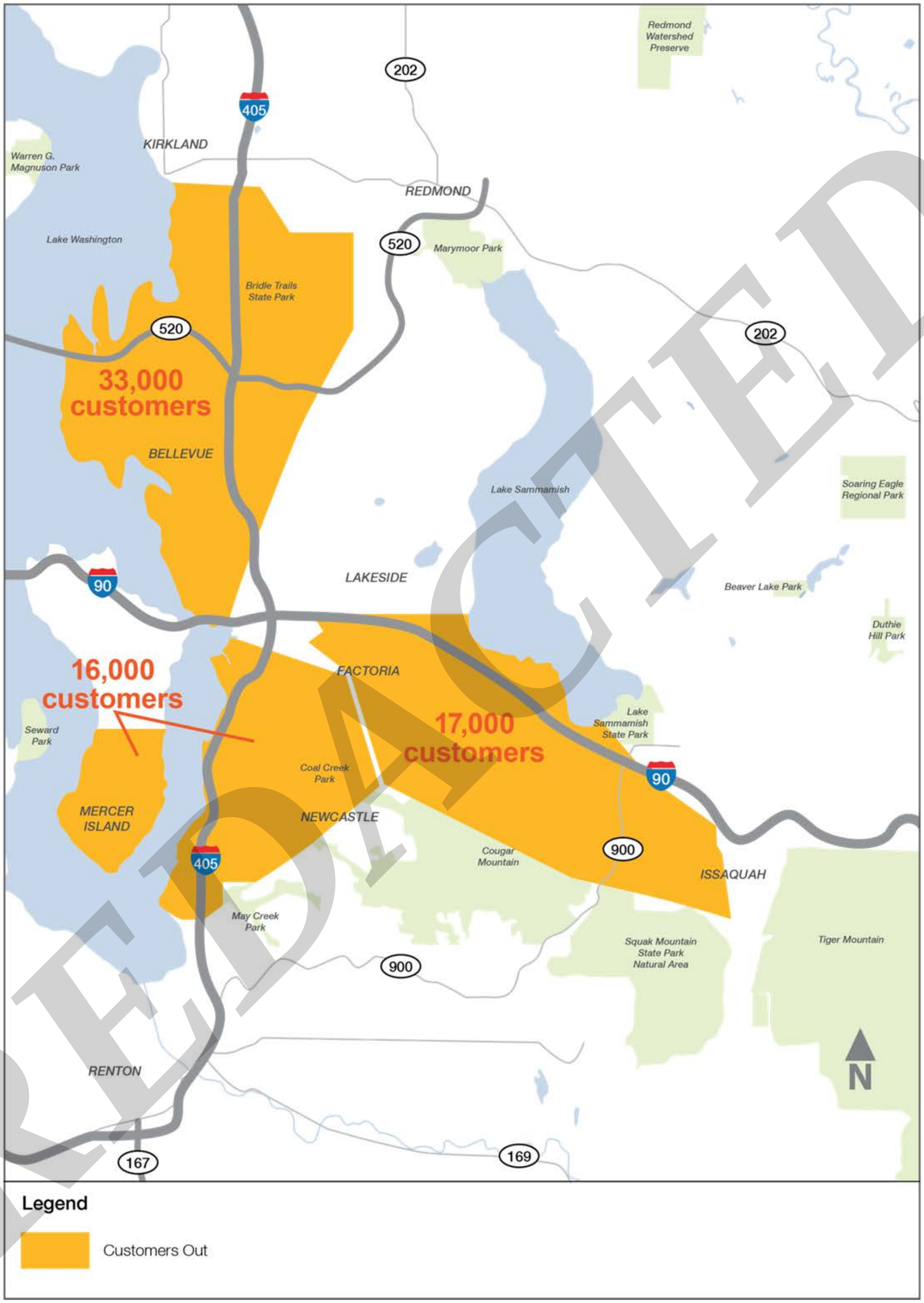



Figure 4-5: Topological View of the Needs Assessment of the Eastside of Lake Washington

If, with future load growth, the Talbot Hill 230-115 kV transformers are at risk of overloading for an N-1 loss of one transformer during Winter peak conditions, then the CAP described above would be implemented as a pre-emptive, pre-contingent measure to ensure that overloads don't materialize. In this case [redacted] would be opened during winter peak conditions, regardless of the loading on the Talbot Hill transformers.

There is also a CAP intended for use during the summer peak in the event of the loss of [redacted]. The CAP instructs the PSE Transmission Operators to open [redacted].

While none of these planned actions would drop load in a system normal configuration, the opening of the transmission lines exposes seven substations supplying 23,000 customers on [redacted] and [redacted] to a subsequent outage on the lines. The total customer impact of 33,000 is shown in Figure 4-5.

With future load growth, the CAP may be expanded to state that if the associated overloads are not sufficiently reduced, then the Transmission Operator should also open [redacted].

While none of these additional actions would drop load in a system normal configuration, the opening of [redacted] exposes one substation supplying 6,000 customers on [redacted] and seven substations supplying 23,000 customers on [redacted] to a subsequent outage on the lines.

In the King County area, PSE has eight transmission transformers, any one of which, when tripped, could trigger a CAP. The customers at risk of outages due to the CAPs described above are supplied by four of the eight transmission transformers, located at Talbot Hill and Sammamish. When a transformer trips, it takes substantial time to test and replace: 18-24 hours typically for testing, and 3-5 weeks to replace the damaged transformer with a spare transformer.  This is a long duration of exposure if CAPs must be employed during the transformer outage.

## 4.2 Changes in Study Assumptions

The Bothell - SnoKing 230 kV #1 & #2 lines, owned by SCL, overloaded for various outages in all cases. These overloads were excluded from the results page, as SCL is planning to upgrade these lines whether or not the Eastside 230 kV project is built. Furthermore, the Eastside 230 kV project scope is not expected to significantly alleviate these line overloads.

SCL's Maple Valley - SnoKing 230 kV #1 & #2 lines overloaded for various outages in all cases; these overloads were observed in the base case and were expected to also occur in the more extreme cases. However, these overloads were caused in large part by the loss of [redacted]. BPA has winter operating procedures in place that will protect against these overloads through use of nomograms.

The [redacted] contingencies did not solve for the majority of the cases, due to the high South to North flows on the Northern Intertie. Therefore, the overloads in more extreme cases were not listed, as the contingency did not solve. The potential issues caused by the high South to North flows are managed through the use of nomograms by BPA.

Certain local 115 kV PSE system overloads within King County were excluded from the listed results, as they were clearly a local system problem that did not contribute to the need for the Eastside 230 kV project. The following systems or lines were excluded: Moorlands three line system, Asbury three line system, Krain Corner 115-55 kV system, and Novelty Hill - Stillwater - Cottage Brook 115 kV lines. These are known system issues with planned projects that are independent in nature from the Eastside 230 kV project.

# Section 5 Performance Requirements

## 5.1 Planning Standards and Criteria

This study examined thermal overloads for Category A (N-0), Category B (N-1) and Category C (N-2 and N-1-1) outages as required by NERC, WECC and PSE Transmission Planning Guidelines. PSE plans for winter and summer peak, such that no thermal or voltage violations result. While the peaks occur for just a few hours per year, there are many more hours each year where operating flexibility is impacted by system capacity. PSE plans for normal summer and winter temperatures, which are 23ºF in winter and 86ºF in summer. PSE also studies extreme winter peak temperature (13ºF) as an indicator of future deficiencies.

> NERC TPL-001- System Performance Under Normal (No Contingency) Conditions (Category A): PSE shall demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, 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 the conditions defined in Category A of Table 1[16].
>
> NERC TPL-002 – System Performance Following Loss of a Single Bulk Electric System Element (Category B): 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 the contingency conditions as defined in Category B of Table 1[17].
>
> Category B outages can occur at any time when a single element trips off line. The NERC TPL Standards Table 1 Category B states that there should be no loss of load or curtailed firm transfers with the exception outlined in footnote b of Table 1[18]. Utilities may only shed directly-connected ("consequential") load to stay compliant. Non-consequential load loss is not allowed for Category B events for BES level less than 300 kV. The system shall remain stable. Cascading or uncontrolled islanding shall not occur. Therefore any overloads showing up for a Category B event are very serious.
>
> NERC TPL-003 – System Performance Following Loss of Two or More Bulk Electric System Elements (Category C): PSE shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems 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

[16] Table 1 TPL-001 - System Performance Under Normal (No Contingency) Conditions (Category A)

[17] Table 1 TPL-002 - System Performance Following Loss of a Single Bulk Electric System Element (Category B)

[18] Footnote b Table 1 - An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of the Contingency, and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table 1[19] .

Category C outages have subcategories of N-2 and N-1-1. An N-2 outage is when a single event trips multiple facilities, such as a transmission bus fault tripping all breakers on the bus or a double-circuit transmission line outage. Breaker failure is also included as a Category C outage. For these outages, there is no time allowed for operator response, but the utility is allowed to have automatic processes to shed non-consequential load to stay compliant.

An N-1-1 Category C outage is a Category B outage followed by a period of time to manually adjust the system to a secure state, followed by a second Category B outage. PSE utilizes 30 minutes to make manual system adjustments after the first outage occurs, to prevent overloads upon the second outage event.

TPL-001-WECC-CRT-2: System Performance Criterion Under Normal Conditions, Following Loss of a Single BES Element, and Following Extreme BES Events. System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and that systems continue to be modified or upgraded as necessary to meet present and future system needs.

PSE Transmission Planning Guidelines, November 2012: The Transmission Planning Guidelines explain the criteria and standards used to assess the ability of Puget Sound Energy's existing and future electric transmission system, and how they are applied to provide safe and reliable service at reasonable cost. The guidelines address both specific and general issues the transmission planner needs to consider. There may be issues specific to site, project, region, or customer that will require plans to be developed on a case-by case basis. However, the Transmission Planning Guidelines are structured in a way that will help achieve consistency across the PSE transmission system.

## 5.2 Performance Criteria

### 5.2.1 Steady State Thermal and Voltage Limits

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 assumes 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, tension and sag criteria. PSE's operating practice is to shift or shed load or dispatch generation to avoid reaching an emergency limit.

System steady state voltages and post contingency voltage deviation shall be within acceptable limits. For PSE system the acceptable limits are: the steady state voltage levels are not above 105% or below 90% for any bus, the voltage deviation for Category B events does not exceed 5%, and the voltage deviation for multiple contingency Category C events does not exceed 10%.[20]

[19] Table 1 TPL-003 - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)

[20] PSE Transmission Planning Guidelines, November 2012, page 7

### 5.2.2 Steady State Solution Parameters

Devices with automatic settings were allowed to adjust automatically for base case runs, reflecting manual operation by Transmission Operators where appropriate: LTC's, phase-shifters, and shunt reactive devices. During contingency runs, LTC and phase-shifter operations were disabled. Shunt reactive devices with known fast-acting schemes were allowed to switch. Inter-area AGC was enabled for the analysis since generation or load loss simulations for the Eastside Needs Assessment were all modeled within the Northwest area and AGC response would be expected for those conditions.

Table 5-1: Study Solution Parameters

| Case | Area Interchange | Transformer LTCs | Phase Angle Regulators | SVDs & Switched Shunts |
|---|---|---|---|---|
| Base | Tie Lines Regulating | Stepping | Regulating or Statically Set | Regulating |
| Contingency | Tie Lines Regulating | Disabled | Disabled | Regulating |

## 5.3 System Testing

### 5.3.1 System Design Conditions and Sensitivities Tested

Four base scenarios were developed for the additional winter studies run for the 2013 Eastside Needs Assessment. The study plan is shown in Figure 5-1.

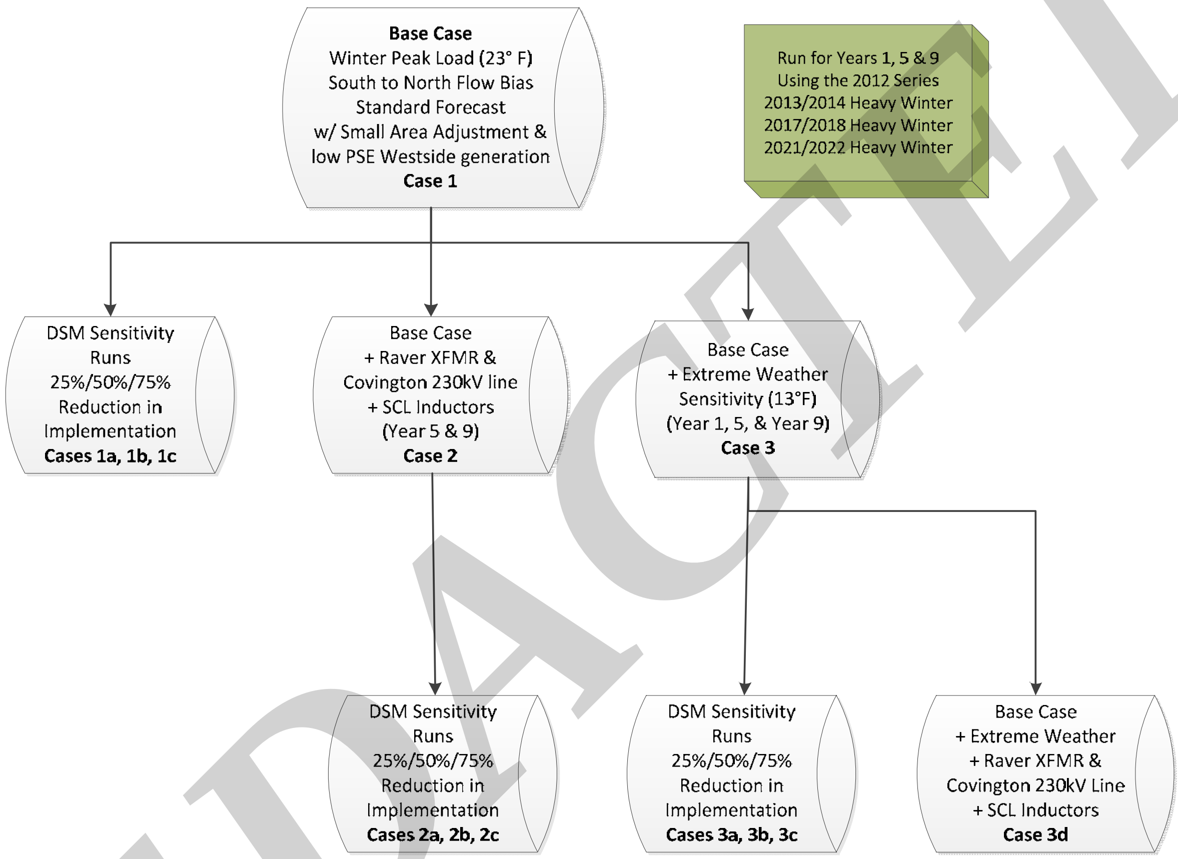



Figure 5-1: Eastside Project Need Validation Study Plan

Case 1 represents base years 2013-14, 2017-18, and 2021-22 winter peaks, normal weather adjusted by substation to reflect the lumpiness of the load. Case 1 includes a south to north bias of 1500 MW with low PSE generation in the Puget Sound area.

Case 2 represents 2017-18 and 2021-22 with additions of a 500 kV/230 kV transformer at Raver, a Raver to Covington 230 kV line, and 115 kV series inductors to the Broad Street - Massachusetts and Broad Street - East Pine 115 kV underground cables in Seattle City Light.

Case 3 represents extreme weather for Case 1.

Case 3d represents extreme weather for Case 2.

The winter cases were run with no generation in the Puget Sound area, a case which PSE normally runs for the annual TPL assessment. However, since it is an extreme case, a low-generation case was run for the 2013 Eastside Needs Assessment as a sensitivity to determine whether some of the violations seen during the power flows could be offset by running generation. The generation levels for the low-generation sensitivity case are shown in Table 4-4, in the column labeled “Expected MW Output during Winter Peak for Low-Generation Sensitivity Case.”

Sensitivities on the amount of conservation realized were performed for each of the cases above, to indicate the possible additional violations that could occur should conservation be achieved at a level below the projection or if economic growth should be higher than forecast. This was done because the 10 year load forecast with full projected conservation had such a flat growth profile. The load levels were adjusted to reflect 75%, 50%, and 25% conservation as a proxy for higher loads.  The case assumptions are summarized in Table 5-2.

Table 5-2: Winter and Summer Case Study Assumptions

| Winter and Summer Case Study Assumptions | | | | | | |
|---|---|---|---|---|---|---|
| Case Name | Amount of Conservation | System Load | Eastside Load | Northern Intertie | PSE/SCL Westside Gen | Other Adjustments Modeled |
| 1 100% Conservation 2013-14 Winter | 100% | 5055 MW | 652 MW | 1500 MW Export | 0 MW | Saint Clair 230-115 kV transformer; Talbot Hill - Berrydale #1 line uprate; Starwood autotransformer removal with Tacoma Power voltage increase |
| 1 75% Conservation 2013-14 Winter | 75% | 5090 MW | 656 MW | 1500 MW Export | 0 MW | Saint Clair 230-115 kV transformer; Talbot Hill - Berrydale #1 line uprate; Starwood autotransformer removal with Tacoma Power voltage increase |
| 2 100% Conservation 2017-18 Winter | 100% | 5208 MW | 706 MW | 1500 MW Export | 0 MW | Block load allocated per King Co Dist. Planers; Planned improvements include 2013 adjustments + Alderton 230-115 kV transformer; Beverly Park 230-115 kV transformer; Raver 500-230 kV transformer; SCL series inductors |
| 2 75% Conservation 2017-18 Winter | 75% | 5325 MW | 722 MW | 1500 MW Export | 0 MW | Block load allocated per King Co Dist. Planers; Planned improvements include 2013 adjustments + Alderton 230-115 kV transformer; Beverly Park 230-115 kV transformer; Raver 500-230 kV transformer; SCL series inductors |
| 2 100% Conservation 2021-22 Winter | 100% | 5126 MW | 756 MW | 1500 MW Export | 0 MW | Block load allocated per King Co Dist. Planers; Planned improvements include 2017-18 adjustments |
| 2 75% Conservation 2021-22 Winter | 75% | 5415 MW | 789 MW | 1500 MW Export | 0 MW | Block load allocated per King Co Dist. Planers; Planned improvements include 2017-18 adjustments |
| 3 100% Conservation 2013-14 Extreme Winter | 100% | 5537 MW | 718 MW | 1500 MW Export | 0 MW | Saint Clair 230-115 kV transformer; Talbot Hill - Berrydale #1 line uprate; Starwood autotransformer removal with Tacoma Power voltage increase |
| 3d 100% Conservation 2017-18 Extreme Winter | 100% | 5742 MW | 782 MW | 1500 MW Export | 0 MW | Block load allocated per King Co Dist. Planers; Planned improvements include 2013 adjustments + Alderton 230-115 kV transformer; Beverly Park 230-115 kV transformer; Raver 500-230 kV transformer; SCL series inductors |
| 3d 100% Conservation 2021-22 Extreme Winter | 100% | 5772 MW | 845 MW | 1500 MW Export | 0 MW | Block load allocated per King Co Dist. Planers; Planned improvements include 2013 adjustments + Alderton 230-115 kV transformer; Beverly Park 230-115 kV transformer; Raver 500-230 kV transformer; SCL series inductors |
| 2014 Heavy Summer | 100% | 3343 MW | 516 MW | 2850 Import | 2171 MW | Saint Clair 230-115 kV transformer; Talbot Hill - Berrydale #1 line uprate; Starwood autotransformer removal with Tacoma Power voltage increase |
| 2018 Heavy Summer | 100% | 3554 MW | 552 MW | 2850 Import | 2276 MW | Planned improvements include 2013 adjustments + Alderton 230-115 kV transformer; Beverly Park 230-115 kV transformer; White River - Electron Heights 115 kV line re-route into Alderton; White River 2nd bus section breaker; Lake Hills - Phantom Lake 115 kV line; Sammamish-Juanita 115 kV line |

### 5.3.2 Steady State Contingencies / Faults Tested

The above cases were tested based on Category A, B, and C contingencies described in the NERC TPL, and WECC standards and PSE's Transmission Planning Guidelines. Descriptions of the type of contingencies tested are listed in Table 5-3.

Table 5-3: Summary of NERC, WECC and/or PSE Category Contingencies Tested

| NERC<br>WECC<br>PSE<br>Categories | Description of Outaged Element(s) | Contingencies Modeled |
|---|---|---|
| A | All lines in-service | N/A |
| B<br>A-2; 6.1 a.<br>PP4; 3.1 a. | Loss of a generator, transmission circuit, transformer or single pole DC line | Category B contingencies included all PSE and interconnected transmission lines and transmission transformers, |
| C<br>A-2; 6.1 a.<br>PP4; 3.1 a. | Normally loss of a bus or circuit breaker;<br>or<br>loss of any category B element followed by another category B element with system adjustments between events;<br>or<br>loss of any two circuits of a multi circuit tower line or loss of a bipolar DC line;<br>or<br>a stuck breaker with delayed clearing of a generator, transmission circuit, transformer or bus section. | Category C: N-2 contingencies included all common-structure double circuit lines, all transmission buses and bus sections with 3 or more transmission elements, and all stuck transmission breakers.<br><br>Category C: N-1-1 included a pairwise combination of all Category B elements followed by all other Category B elements. |
| D<br>A-2; 6.1 a.<br>PP4; 3.1 a. | Loss of a generator, transmission circuit, transformer or bus section;<br>or<br>other transmission planning entity selected critical outage<br>or<br>loss of a category B element followed by loss of any two circuits of a multi circuit tower or a stuck breaker | Category D was not performed in this study |

# Section 6 Results of Analysis

## 6.1 Overview of Results

The following sections describe the results of the analysis. The thermal loading percentages described below are based on a percentage of the emergency rating for each facility.

### 6.1.1 N-0 Thermal and Voltage Violation Summary

For all cases, there are no thermal or voltage violations for the all lines in (N-0) state.

2013-14 – Case 1-Winter Peak, Normal Weather: For all elements in service (N-0) state, there were no thermal or voltage violations for 2013-14 winter peak, normal weather with all levels of conservation modeled (i.e. 100%, 75%, 50%, or 25%)

2013-14 – Case 3-Winter Peak, Extreme Weather: For all elements in service (N-0), there were no thermal or voltage violations for 2013-14 winter peak, extreme weather, with all levels of conservation modeled (i.e. 100%, 75%, 50%, or 25%) conservation.

2017-18 – Case 2-Winter Peak, Normal Weather: For all elements in service (N-0), there were no thermal or voltage violations for 2017-18 winter peak, normal weather, with all levels of conservation modeled (i.e. 100%, 75%, 50%, or 25%) conservation.

2017-18 – Case 3-Winter Peak, Extreme Weather: For all elements in service (N-0), there were no thermal or voltage violations for 2017-18 winter peak, extreme weather, with all levels of conservation modeled (i.e. 100%, 75%, 50%, or 25%) conservation.

2021-22 – Case 2-Winter Peak, Normal Weather: For all elements in service (N-0), there were no thermal or voltage violations for 2021-22 winter peak, normal weather, with all levels of conservation modeled (i.e. 100%, 75%, 50%, or 25%) conservation.

2021-22 – Case 3-Winter Peak, Extreme Weather: For all elements in service (N-0), there were no thermal or voltage violations for 2021-22 winter peak, extreme weather, with all levels of conservation modeled (i.e. 100%, 75%, 50%, or 25%) conservation.

### 6.1.2 2013-14 Thermal Summaries: Winter Peak, Normal and Extreme Weather & Summer Peak Normal Weather

Table 6-1 shows the summary of results for categories B (N-1) and C (N-1-1 & N-2) for 2013-14 winter and 2014 summer peaks with normal weather. Table 6-1 shows that for the winter peak, normal weather, 100% conservation, (PSE Load 5,055 MW), there are no Category B thermal violations but there are five (5) potential thermal violations in the King County area for Category C contingencies. Those five potential violations are as follows and highlighted in yellow in

Table 6-2.

1. Talbot Hill - Lakeside #1 115 kV Line
2. Talbot Hill - Lakeside #2 115 kV Line
3. Talbot Hill 230-115 kV transformer #1
4. Talbot Hill 230-115 kV transformer #2
5. Talbot Hill - Boeing Renton - Shuffleton 115 kV Line

Those Category C contingencies can be mitigated by operational procedures and re-dispatching. Also, Table 6-1 lists six (6) additional facilities within the King County area, which are operating from 90% to 100% of the emergency operating limits and are above the operating limits. Those facilities are highlighted in gray on

Table 6-2.

1. White River 230-115 kV transformer #2 – 97.4%
2. White River 230-115 kV transformer #1 – 96.9%
3. Talbot Hill - Berrydale #1 115 kV line – 96.0%
4. Berrydale 230-115 kV transformer – 92.4%
5. O'Brien 230-115 kV transformer #2 – 94%
6. O'Brien 230-115 kV transformer #1 – 93.2%

Table 6-2 also shows potential thermal overloads of elements outside of PSE's service area. Two lines of notice include Maple Valley - SnoKing #1 & #2 230 kV lines, which pass through the Eastside of King County.

For the 2014 summer peak normal weather, (PSE load of 3343 MW), high generation in the north and high imports from British Columbia (Table 6-1), there is one (1) potential Category B (N-1) thermal violation (Monroe - Novelty Hill 230 kV line) and for the same case with no generation in the north there is one (1) potential Category B thermal violation (Maple Valley - Sammamish 230 kV line). Those potential over loads are the result of losing [redacted]. Those facilities are owned by BPA. There is also one (1) potential Category C (N-1-1) potential thermal violation (Sammamish 230-115 kV transformer #2).

Table 6-3 show the potential impact of extreme winter weather with 100% and 50% conservation in 2013-14, (PSE load of 5,537 MW and 5,608 MW respectively). There are no potential Category B thermal violations, but there are three (3) elements which are operating at 90% or greater of the emergency limits and are above the operating limits; Talbot Hill 230-115 kV transformer #1, Talbot Hill 230-115 kV transformer #2, and White River 230-115 kV transformer #2.

Table 6-1: Summary of Elements above Emergency and Operating Limits: 2013-14 Winter Peak, Normal Weather & Summer Peak Normal Weather

| Year of Study | Normal or Extreme Weather | Case Conditions | Amount of Conservation/ System Load | Type of Contingency | Elements above Emergency Limit | Elements > 90% of Emergency Limit or above Operating Limit |
|---|---|---|---|---|---|---|
| 2013-14 Winter | Normal | South-North NI Flow No Western Generation | 100% 5055 MW | N-1 | | |
| 2013-14 Winter | Normal | South-North NI Flow No Western Generation | 100% 5055 MW | N-1-1 | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>Talbot Hill-Boeing Renton-Shuffleton 115 kV Line | White River 230-115 kV transformer #2<br>White River 230-115 kV transformer #1<br>Talbot Hill-Berrydale #1 115 kV line<br>Berrydale 230-115 kV transformer<br>O'Brien 230-115 kV transformer #2<br>O'Brien 230-115 kV transformer #1 |
| 2013-14 Winter | Normal | South-North NI Flow, No Western Generation | 100% 5055 MW | N-2 or Common Mode | | Talbot Hill-Lakeside #2 115 kV Line<br>Berrydale 230-115 kV transformer |
| 2013-14 Winter | Normal | South-North NI Flow, No Western Generation | 75% 5090 MW | N-1 | | |
| 2013-14 Winter | Normal | South-North NI Flow No Western Generation | 75% 5090 MW | N-1-1 | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill-Boeing Renton-Shuffleton 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2 | White River 230-115 kV transformer #2<br>White River 230-115 kV transformer #1<br>Talbot Hill-Berrydale #1 115 kV line<br>Berrydale 230-115 kV transformer<br>O'Brien 230-115 kV transformer #2<br>O'Brien 230-115 kV transformer #1 |
| 2013-14 Winter | Normal | South-North NI Flow, No Western Generation | 75% 5090 MW | N-2 or Common Mode | | Talbot Hill-Lakeside #2 115 kV Line<br>Berrydale 230-115 kV transformer |
| 2013-14 Winter | Normal | South-North NI Flow, No Western Generation | 50% 5126 MW | N-1 | | |
| 2013-14 Winter | Normal | South-North NI Flow, No Western Generation | 50% 5126 MW | N-1-1 | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill-Boeing Renton-Shuffleton 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2 | White River 230-115 kV transformer #1<br>White River 230-115 kV transformer #2<br>Talbot Hill-Berrydale #1 115 kV line<br>Berrydale 230-115 kV transformer<br>O'Brien 230-115 kV transformer #2<br>O'Brien 230-115 kV transformer #1 |
| 2013-14 Winter | Normal | South-North NI Flow, No Western Generation | 50% 5126 MW | N-2 or Common Mode | | Talbot Hill 230-115 kV transformer #2<br>Talbot Hill-Lakeside #2 115 kV Line<br>Berrydale 230-115 kV transformer |
| 2014 Heavy Summer | Normal | Hi Gen, Hi Import from BC | 100% 3343 MW | N-1 | Monroe-Novelty Hill 230 kV line | |
| 2014 Heavy Summer | Normal | No Gen, Hi Export to BC | 100% 3343 MW | N-1 | Maple Valley - Sammamish 230 kV line | |
| 2014 Heavy Summer | Normal | No Gen, Hi Export to BC | 100% 3343 MW | N-1-1 | Sammamish 230-115 kV transformer #2 | Sammamish 230-115 kV transformer #1 |

Table 6-2: Elements above Emergency and Operating Limits: 2013-14 Winter Peak, 100% Conservation, Normal Weather, Thermal Loadings (Redacted)

| Case | Category | Worst Contingency | Owner of Facilities Out | Element(s) | Owner of Overloaded Facilities | Percent Overload |
|---|---|---|---|---|---|---|
| 2013-14 Winter | B | [redacted] | BPA | Maple Valley - SnoKing #1 230 kV line | SCL | 110.0% |
| 2013-14 Winter | B | [redacted] | BPA | Maple Valley - SnoKing #2 230 kV line | SCL | 107.8% |
| 2013-14 Winter | C | [redacted] | BPA | Maple Valley - SnoKing #1 230 kV line | SCL | 124.0% |
| 2013-14 Winter | C | [redacted] | BPA | Maple Valley - SnoKing #2 230 kV line | SCL | 123.8% |
| 2013-14 Winter | C | [redacted] | BPA | Talbot Hill - Lakeside #1 115 kV line | PSE | 97.1% |
| 2013-14 Winter | C | [redacted] | BPA | Talbot Hill - Lakeside #2 115 kV line | PSE | 96.9% |
| 2013-14 Winter | C | [redacted] | PSE | Berrydale 230-115 kV transformer | PSE | 96.6% |
| 2013-14 Winter | C | [redacted] | BPA & SCL | Maple Valley - SnoKing #1 230 kV line | SCL | 146.7% |
| 2013-14 Winter | C | [redacted] | BPA & SCL | Maple Valley - SnoKing #2 230 kV line | SCL | 145.0% |
| 2013-14 Winter | C | [redacted] | PSE | Talbot Hill 230-115 kV transformer #1 | PSE | 100.9% |
| 2013-14 Winter | C | [redacted] | BPA & PSE | Talbot Hill - Lakeside #1 115 kV line | PSE | 115.2% |
| 2013-14 Winter | C | [redacted] | BPA & PSE | Talbot Hill - Lakeside #2 115 kV line | PSE | 115.1% |
| 2013-14 Winter | C | [redacted] | BPA & PSE | Talbot Hill - Boeing Renton - Shuffleton 115 kV line | PSE | 101.1% |

Table 6-2: Elements above Emergency and Operating Limits: 2013-14 Winter Peak, 100% Conservation, Normal Weather, Thermal Loadings (Redacted) (CONTINUED)

| | | | | | | |
|---|---|---|---|---|---|---|
| 2013-14 Winter | C | [redacted] | PSE | Talbot Hill 230-115 kV transformer #2 | PSE | 100.5% |
| 2013-14 Winter | C | [redacted] | PSE | White River 230-115 kV transformer #2 | PSE | 97.4% |
| 2013-14 Winter | C | [redacted] | PSE | White River 230-115 kV transformer #1 | PSE | 96.9% |
| 2013-14 Winter | C | [redacted] | PSE | Talbot Hill - Berrydale #1 115 kV line | PSE | 96.0% |
| 2013-14 Winter | C | [redacted] | PSE | Berrydale 230-115 kV transformer | PSE | 92.4% |
| 2013-14 Winter | C | [redacted] | PSE | O'Brien 230-115 kV transformer #2 | PSE | 94.0% |
| 2013-14 Winter | C | [redacted] | PSE | O'Brien 230-115 kV transformer #1 | PSE | 93.2% |

Table 6-3: Summary of Elements above Emergency and Operating Limits: 2013-14 Winter Peak, Extreme Weather

| Year of Study | Normal or Extreme Weather | Case Conditions | Amount of Conservation/ System Load | Type of Contingency | Elements above Emergency Limit | Elements > 90% of Emergency Limit or above Operating Limit |
|---|---|---|---|---|---|---|
| 2013-14 Winter | Extreme | South-North NI Flow No Western Generation | 100% 5537 MW | N-1 | | Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>White River 230-115 kV transformer #2 |
| 2013-14 Winter | Extreme | South-North NI Flow No Western Generation | 50% 5608 MW | N-1-1 | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill-Boeing Renton-Shuffleton 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>White River - Lea Hill - Berrydale 115 kV line<br>Talbot Hill-Berrydale #1 115 kV line<br>Berrydale 230-115 kV transformer<br>O'Brien 230-115 kV transformer #1<br>O'Brien 230-115 kV transformer #2<br>White River 230-115 kV transformer #1<br>White River 230-115 kV transformer #2 | Shuffleton-Lakeside 115 kV line<br>O'Brien 115 kV North bus section breaker<br>O'Brien - Asbury 115 kV line<br>Shuffleton - President Park - Lake Tradition 115 kV line |
| 2013-14 Winter | Extreme | South-North NI Flow No Western Generation | 50% 5608 MW | N-2 or Common Mode | Talbot Hill-Lakeside #2 115 kV Line<br>Berrydale 230-115 kV transformer | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2 |

### 6.1.3 2017-18 Thermal Summaries: Winter Peak, Normal and Extreme Weather & Summer Peak Normal Weather

Table 6-4 shows the summary of results for categories B (N-1) and C (N-1-1 & N-2) for 2017-18 winter and summer peaks with normal weather.

Table 6-4 shows that for the winter peak, normal weather, 100% conservation, (PSE load of 5,208 MW), there are no potential Category B thermal violations but there are three (3) facilities which are loaded from 90% to 100% of the emergency ratings. These facilities are highlighted in gray in Table 6-5.

1. Talbot Hill - Lakeside #1 115 kV line – 98.6%
2. Talbot Hill - Lakeside #2 115 kV line – 98.4%
3. Talbot Hill 230-115 kV transformer #2 – 90.3%

If 50% of conservation is achieved, (PSE load of 5,442 MW), the number of potential Category B thermal overloads increase to two (2) facilities.

1. Talbot Hill - Lakeside #1 115 kV Line
2. Talbot Hill - Lakeside #2 115 kV Line

There are six (6) potential thermal violations (same as 2013-14) of PSE lines or transformers in the King County area for Category C contingencies.  These facilities are highlighted in yellow on Table 6-5, which shows that the potential thermal overloads vary up to a high of 128%. Overloads caused by BPA facility outages which are controlled by BPA generation dispatch are not highlighted.

1. Talbot Hill - Lakeside #1 115 kV Line
2. Talbot Hill - Lakeside #2 115 kV Line
3. Talbot Hill 230-115 kV transformer #1
4. Talbot Hill 230-115 kV transformer #2
5. Talbot Hill - Boeing Renton - Shuffleton 115 kV Line
6. Maple Valley - Sammamish 230 kV Line

If 75% of conservation is achieved, (PSE load of 5,325 MW), the number of potential Category C thermal overloads increase to seven (7) facilities and some occur for more than one Category C contingency.

1. Talbot Hill - Lakeside #1 115 kV Line
2. Talbot Hill - Lakeside #2 115 kV Line
3. Talbot Hill - Boeing Renton - Shuffleton 115 kV Line
4. Talbot Hill 230-115 kV transformer #1
5. Talbot Hill 230-115 kV transformer #2
6. White River - Lea Hill - Berrydale 115 kV line
7. Maple Valley - Sammamish 230 kV line

If 50% of conservation is achieved, (PSE load of 5,442 MW), the number of potential Category C thermal overloads increase to ten (10) facilities and some occur for more than one Category C contingency.

1. Talbot Hill- Lakeside #1 115 kV Line
2. Talbot Hill- Lakeside #2 115 kV Line
3. Talbot Hill - Boeing Renton-Shuffleton 115 kV Line
4. Talbot Hill 230-115 kV transformer #1
5. Talbot Hill 230-115 kV transformer #2
6. Maple Valley - Sammamish 230 kV line
7. White River - Lea Hill - Berrydale 115 kV line
8. Talbot Hill - Berrydale #1 115 kV line
9. Shuffleton - O'Brien 115 kV line
10. Shuffleton - Lakeside 115 kV line

For the 2018 summer peak, normal weather, (PSE load of 3,554 MW), high generation in the north and high imports from British Columbia (Table 6-12), there are two (2) potential Category B (N-1) thermal violations (Monroe - Novelty Hill 230 kV line and Maple Valley - Sammamish 230 kV line) and there are three (3) potential Category C (N-1-1 & N-2) thermal violations (Beverly Park - Cottage Brook 115 kV line, Sammamish 230-115 kV transformer #1, and Sammamish 230-115 kV transformer #2). The sections of the Monroe - Novelty Hill 230 kV line and Maple Valley - Sammamish 230 kV line that may overload are owned by BPA.

Table 6-6 shows the results of the generation sensitivity case for 2017-18, in which 1,031 MW of Puget Sound area generation was turned on. For the winter peak, normal weather, 100% conservation, (PSE load of 5,208 MW), and Puget Sound generation of 1,031 MW, there are no potential Category B thermal violations. There are four (4) potential Category C (N-1-1) violations remaining above the emergency limits (Talbot Hill - Lakeside #1 & #2 115 kV lines, and Talbot Hill 230-115 kV transformers #1 and #2). Running this level of generation also resulted in a new transformer operating above 90% for an N-1-1 contingency; the Sammamish transformer #2 will be above 90% if there are outages of both Sammamish transformer #1 and the Novelty Hill transformer. In general, turning on 1,000 MW of generation in the northern part of the Puget Sound area can have a significant impact in reducing transmission line overloads, but minor impact for transformer overloads.

Table 6-7 shows that for the 2017-18 winter peak, extreme weather, (PSE load of 5,742 MW), no generation in the north and high exports to British Columbia, there are two (2) potential Category B (N-1) thermal violations (Talbot Hill - Lakeside #1 & #2 115 kV lines (99.2% & 98.6%)); and there are twelve (12) potential Category C (N-1-1 & N-2) thermal violations.

The operational solution to temporarily remedy the potential overloads on Talbot Hill #1 transformer for the Category C loss of the North Talbot Hill 230 kV bus during extreme winter weather is to open breakers preemptively [redacted]. When that occurs there is added risk of losing load with the next N-1 contingency.

Table 6-4: Summary of Elements above Emergency and Operating Limits: 2017-18 Winter Peak, Normal Weather & Summer Peak Normal Weather

| Year of Study | Normal or Extreme Weather | Case Conditions | Amount of Conservation/ System Load | Type of Contingency | Elements above Emergency Limit | Elements > 90% of Emergency Limit or above Operating Limit |
|---|---|---|---|---|---|---|
| 2017-18 Winter | Normal | South-North NI Flow No Western Generation | 100% 5208 MW | N-1 | | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill 230-115 kV transformer #2 |
| 2017-18 Winter | Normal | South-North NI Flow No Western Generation | 100% 5208 MW | N-1-1 | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>Talbot Hill-Boeing Renton-Shuffleton 115 kV Line<br>Maple Valley-Sammamish 230 kV line | Talbot Hill-Berrydale #1 115 kV line<br>White River - Lea Hill - Berrydale 115 kV Line<br>Shuffleton-O'Brien 115 kV line<br>Shuffleton-Lakeside 115 kV line<br>Berrydale 230-115 kV transformer<br>O'Brien 230-115 kV transformer #2<br>O'Brien 230-115 kV transformer #1 |
| 2017-18 Winter | Normal | South-North NI Flow No Western Generation | 100% 5208 MW | N-2 or Common Mode | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line | Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>Berrydale 230-115 kV transformer |
| 2017-18 Winter | Normal | South-North NI Flow No Western Generation | 75% 5325 MW | N-1 | | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2 |
| 2017-18 Winter | Normal | South-North NI Flow No Western Generation | 75% 5325 MW | N-1-1 | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill-Boeing Renton-Shuffleton 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>White River - Lea Hill - Berrydale 115 kV line<br>Maple Valley - Sammamish 230 kV line | Talbot Hill-Berrydale #1 115 kV line<br>Shuffleton-O'Brien 115 kV line<br>Shuffleton-Lakeside 115 kV line<br>Berrydale 230-115 kV transformer<br>O'Brien 230-115 kV transformer #2<br>O'Brien 230-115 kV transformer #1<br>O'Brien 115 kV North bus section breaker<br>O'Brien-Asbury 115 kV line |
| 2017-18 Winter | Normal | South-North NI Flow No Western Generation | 75% 5325 MW | N-2 or Common Mode | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line | Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>Berrydale 230-115 kV transformer |
| 2017-18 Winter | Normal | South-North NI Flow No Western Generation | 50% 5442 MW | N-1 | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line | Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>Talbot Hill-Boeing Renton-Shuffleton 115 kV Line |
| 2017-18 Winter | Normal | South-North NI Flow No Western Generation | 50% 5442 MW | N-1-1 | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill-Boeing Renton-Shuffleton 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>Maple Valley-Sammamish 230 kV line<br>White River - Lea Hill - Berrydale 115 kV line<br>Talbot Hill-Berrydale #1 115 kV line<br>Shuffleton - O'Brien 115 kV line<br>Shuffleton-Lakeside 115 kV line | Berrydale 230-115 kV transformer<br>O'Brien 230-115 kV transformer #2<br>O'Brien 230-115 kV transformer #1<br>O'Brien 115 kV North bus section breaker<br>O'Brien - Asbury 115 kV line<br>Shuffleton - President Park - Lake Tradition 115 kV line |
| 2017-18 Winter | Normal | South-North NI Flow No Western Generation | 50% 5442 MW | N-2 or Common Mode | Talbot Hill-Lakeside #2 115 kV Line | Talbot Hill-Lakeside #1 115 kV Line<br>Berrydale 230-115 kV transformer<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2 |
| 2018 Heavy Summer | Normal | Hi Gen, Hi Import from BC | 100% 3554 MW | N-1 | Monroe-Novelty Hill 230 kV line | |

Table 6-4: Summary of Elements above Emergency and Operating Limits: 2017-18 – Winter Peak, Normal Weather & Summer Peak Normal Weather (CONTINUED)

| | | | | | | |
|---|---|---|---|---|---|---|
| 2018 Heavy Summer | Normal | No Gen, Hi Export to BC | 100% 3554 MW | N-1 | Maple Valley - Sammamish 230 kV line | Talbot Hill-Lakeside #1 115 kV line<br>Talbot Hill-Lakeside #2 115 kV line |
| 2018 Heavy Summer | Normal | Hi Gen, Hi Import from BC | 100% 3554 MW | N-1-1 | Beverly Park - Cottage Brook 115 kV line<br>Sammamish 230-115 kV transformer #1<br>Sammamish 230-115 kV transformer #2 | Novelty Hill 230-115 kV transformer |
| 2018 Heavy Summer | Normal | Hi Gen, Hi Import from BC | 100% 3554 MW | N-2 or Common Mode | | Sammamish-Lakeside #2 115 kV line |

Table 6-5: Elements above Emergency and Operating Limits: 2017-18 Winter Peak, 100% Conservation, Normal Weather, Thermal Loadings (Redacted)

| Case | Category | Worst Contingency | Owner of Facilities Out | Element(s) | Owner of Overloaded Facilities | Percent Overload |
|---|---|---|---|---|---|---|
| 2017-18 Winter | B | [redacted] | BPA | Maple Valley - SnoKing #1 230 kV line | SCL | 119.3% |
| 2017-18 Winter | B | [redacted] | BPA | Maple Valley - SnoKing #2 230 kV line | SCL | 118.2% |
| 2017-18 Winter | B | [redacted] | BPA | Talbot Hill - Lakeside #1 115 kV line | PSE | 98.6% |
| 2017-18 Winter | B | [redacted] | BPA | Talbot Hill - Lakeside #2 115 kV line | PSE | 98.4% |
| 2017-18 Winter | B | [redacted] | PSE | Talbot Hill 230-115 kV transformer #2 | PSE | 90.3% |
| 2017-18 Winter | C | [redacted] | BPA | Maple Valley - SnoKing #1 230 kV line | SCL | 123.9% |
| 2017-18 Winter | C | [redacted] | BPA | Maple Valley - SnoKing #2 230 kV line | SCL | 123.3% |
| 2017-18 Winter | C | [redacted] | PSE | Talbot Hill - Lakeside #2 115 kV line | PSE | 101.1% |
| 2017-18 Winter | C | [redacted] | BPA | Talbot Hill - Lakeside #1 115 kV line | PSE | 101.5% |
| 2017-18 Winter | C | [redacted] | PSE | Talbot Hill 230-115 kV transformer #1 | PSE | 91.8% |
| 2017-18 Winter | C | [redacted] | PSE | Talbot Hill 230-115 kV transformer #2 | PSE | 92.8% |
| 2017-18 Winter | C | [redacted] | PSE | Berrydale 230-115 kV transformer | PSE | 93.6% |
| 2017-18 Winter | C | [redacted] | BPA & SCL | Maple Valley - SnoKing #1 230 kV line | SCL | 176.6% |

Table 6-5: Elements above Emergency and Operating Limits: 2017-18 Winter Peak, 100% Conservation, Normal Weather, Thermal Loadings (Redacted) (CONTINUED)

| | | | | | | |
|---|---|---|---|---|---|---|
| 2017-18 Winter | C | [redacted] | BPA & SCL | Maple Valley - SnoKing #2 230 kV line | SCL | 157.8% |
| 2017-18 Winter | C | [redacted] | BPA & PSE | Talbot Hill - Lakeside #1 115 kV line (Redispatch not enough) | PSE | 127.8% |
| 2017-18 Winter | C | [redacted] | BPA & PSE | Talbot Hill - Lakeside #2 115 kV line (Redispatch not enough) | PSE | 127.6% |
| 2017-18 Winter | C | [redacted] | PSE | Talbot Hill 230-115 kV transformer #1 (Redispatch not enough) | PSE | 105.7% |
| 2017-18 Winter | C | [redacted] | BPA & PSE | Talbot Hill - Boeing Renton - Shuffleton 115 kV line (Redispatch not enough) | PSE | 110.6% |
| 2017-18 Winter | C | [redacted] | PSE | Talbot Hill 230-115 kV transformer #2 (Redispatch not enough) | PSE | 105.7% |
| 2017-18 Winter | C | [redacted] | PSE | Talbot Hill - Berrydale #1 115 kV line | PSE | 97.6% |
| 2017-18 Winter | C | [redacted] | PSE | White River - Lea Hill - Berrydale 115 kV line | PSE | 98.0% |
| 2017-18 Winter | C | [redacted] | BPA & PSE | Shuffleton - O'Brien 115 kV line | PSE | 97.9% |
| 2017-18 Winter | C | [redacted] | PSE | Berrydale 230-115 kV transformer | PSE | 93.8% |
| 2017-18 Winter | C | [redacted] | BPA & SCL | Maple Valley - Sammamish 230 kV line | BPA | 104.4% |

Table 6-6: Elements above Emergency and Operating Limits: 2017-18 Winter Peak, 100% Conservation, Normal Weather, Low Generation Sensitivity Case, Thermal Loadings (Redacted)

| | | | | | | No Gen | With Gen |
|---|---|---|---|---|---|---|---|
| Case | Category | Worst Contingency | Owner of Facilities Out | Element(s) | Owner of Overloaded Facilities | % Overload | % Overload |
| 2017-18 Winter | B | [redacted] | PSE | Talbot Hill 230-115 kV transformer #2 | PSE | 90.3% | 87.4% |
| 2017-18 Winter | B | [redacted] | BPA | Maple Valley - SnoKing #1 230 kV line | SCL | 119.3% | 86.5% |
| 2017-18 Winter | B | [redacted] | BPA | Maple Valley - SnoKing #2 230 kV line | SCL | 118.2% | 84.2% |
| 2017-18 Winter | B | [redacted] | BPA | Talbot Hill - Lakeside #1 115 kV line | PSE | 98.6% | 84.1% |
| 2017-18 Winter | B | [redacted] | BPA | Talbot Hill - Lakeside #2 115 kV line | PSE | 98.4% | 83.9% |
| 2017-18 Winter | C | [redacted] | BPA | Maple Valley - SnoKing #1 230 kV line | SCL | 123.9% | 89.0% |
| 2017-18 Winter | C | [redacted] | BPA | Maple Valley - SnoKing #2 230 kV line | SCL | 123.3% | 87.1% |
| 2017-18 Winter | C | [redacted] | PSE | Talbot Hill - Lakeside #2 115 kV line | PSE | 101.1% | 87.2% |
| 2017-18 Winter | C | [redacted] | BPA | Talbot Hill - Lakeside #1 115 kV line | PSE | 101.5% | 85.8% |
| 2017-18 Winter | C | [redacted] | PSE | Berrydale 230-115 kV transformer | PSE | 93.6% | 90.2% |
| 2017-18 Winter | C | [redacted] | PSE | Talbot Hill 230-115 kV transformer #1 | PSE | 91.8% | 89.3% |
| 2017-18 Winter | C | [redacted] | PSE | Talbot Hill 230-115 kV transformer #2 | PSE | 92.8% | 90.5% |
| 2017-18 Winter | C | [redacted] | BPA & SCL | Maple Valley - SnoKing #1 230 kV line | SCL | 176.6% | 112.9% |
| 2017-18 Winter | C | [redacted] | BPA & SCL | Maple Valley - SnoKing #2 230 kV line | SCL | 157.8% | 110.9% |
| 2017-18 Winter | C | [redacted] | BPA & PSE | Talbot Hill - Lakeside #1 115 kV line | PSE | 127.8% | 108.7% |

Table 6-6: Elements above Emergency and Operating Limits: 2017-18 Winter Peak, 100% Conservation, Normal Weather, Low Generation Sensitivity Case, Thermal Loadings (Redacted) (CONTINUED)

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 2017-18 Winter | C | [redacted] | BPA & PSE | Talbot Hill - Lakeside #2 115 kV line | PSE | 127.6% | 108.5% |
| 2017-18 Winter | C | [redacted] | PSE | Talbot Hill 230-115 kV transformer #2 | PSE | 105.7% | 102.2% |
| 2017-18 Winter | C | [redacted] | PSE | Talbot Hill 230-115 kV transformer #1 | PSE | 105.7% | 102.0% |
| 2017-18 Winter | C | [redacted] | BPA & PSE | Talbot Hill - Boeing Renton - Shuffleton 115 kV line | PSE | 110.6% | 98.8% |
| 2017-18 Winter | C | [redacted] | PSE | Talbot Hill - Berrydale #1 115 kV line | PSE | 97.6% | 96.5% |
| 2017-18 Winter | C | [redacted] | PSE | White River - Lea Hill - Berrydale 115 kV line | PSE | 98.0% | 94.8% |
| 2017-18 Winter | C | [redacted] | PSE | Berrydale 230-115 kV transformer | PSE | 93.8% | 93.0% |
| 2017-18 Winter | C | [redacted] | PSE | O'Brien 230-115 kV transformer #2 | PSE | 93.9% | 91.3% |
| 2017-18 Winter | C | [redacted] | PSE | O'Brien 230-115 kV transformer #1 | PSE | 93.1% | 90.5% |
| 2017-18 Winter | C | [redacted] | PSE | Sammamish 230-115 kV transformer #2 | PSE | 83.8% | 90.3% |
| 2017-18 Winter | C | [redacted] | BPA & PSE | Shuffleton - O'Brien 115 kV line | PSE | 97.9% | 86.4% |
| 2017-18 Winter | C | [redacted] | BPA & PSE | O'Brien 115 kV North bus section breaker | PSE | 92.5% | 85.0% |
| 2017-18 Winter | C | [redacted] | BPA & PSE | Shuffleton - Lakeside 115 kV line | PSE | 97.3% | 83.6% |
| 2017-18 Winter | C | [redacted] | BPA & SCL | Maple Valley - Sammamish 230 kV line | BPA | 104.4% | 76.7% |

Table 6-7: Summary of Elements above Emergency and Operating Limits: 2017-18 Winter Peak, Extreme Weather

| Year of Study | Normal or Extreme Weather | Case Conditions | Amount of Conservation / System Load | Type of Contingency | Elements above Emergency Limit | Elements > 90% of Emergency Limit or above Operating Limit |
|---|---|---|---|---|---|---|
| 2017-18 Winter | Extreme | South-North NI Flow<br>No Western Generation | 100%<br>5742 | N-1 | Talbot Hill-Lakeside #1 115 kV Line 99.1%<br>Talbot Hill-Lakeside #2 115 kV Line 98.9% | Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>Talbot Hill - Boeing Renton - Shuffleton 115 kV line |
| 2017-18 Winter | Extreme | South-North NI Flow<br>No Western Generation | 100%<br>5742 | N-1-1 | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill-Boeing Renton-Shuffleton 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>White River - Lea Hill - Berrydale 115 kV line<br>Shuffleton-Lakeside 115 kV line<br>Talbot Hill-Berrydale #1 115 kV line<br>Berrydale 230-115 kV transformer<br>O'Brien 115 kV North bus section breaker<br>O'Brien 230-115 kV transformer #1<br>O'Brien 230-115 kV transformer #2 | O'Brien - Asbury 115 kV line<br>Shuffleton - President Park - Lake Tradition 115 kV line<br>White River 230-115 kV transformer #1<br>White River 230-115 kV transformer #2<br>Sammamish 230-115 kV transformer #2 |
| 2017-18 Winter | Extreme | South-North NI Flow<br>No Western Generation | 75%<br>5859 | N-1 | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line | Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>Talbot Hill - Boeing Renton - Shuffleton 115 kV line<br>Berrydale 230-115 kV transformer |
| 2017-18 Winter | Extreme | South-North NI Flow<br>No Western Generation | 75%<br>5859 | N-1-1 | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill-Boeing Renton-Shuffleton 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>White River - Lea Hill - Berrydale 115 kV line<br>Shuffleton-Lakeside 115 kV line<br>Talbot Hill-Berrydale #1 115 kV line<br>Berrydale 230-115 kV transformer<br>O'Brien 115 kV North bus section breaker<br>O'Brien 230-115 kV transformer #1<br>O'Brien 230-115 kV transformer #2 | O'Brien - Asbury 115 kV line<br>Shuffleton - President Park - Lake Tradition 115 kV line<br>White River 230-115 kV transformer #1<br>White River 230-115 kV transformer #2<br>Sammamish 230-115 kV transformer #2<br>Shuffleton - O'Brien 115 kV line<br>O'Brien - Midway #1 115 kV line<br>Talbot Hill - Lake Tradition #1 115 kV line<br>Sammamish 230-115 kV transformer #1 |
| 2017-18 Winter | Extreme | South-North NI Flow<br>No Western Generation | 75%<br>5859 | N-2 or Common Mode | Berrydale 230-115 kV transformer<br>Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2 | Shuffleton - O'Brien 115 kV line<br>Talbot Hill - Boeing Renton - Shuffleton 115 kV line<br>O'Brien - Midway #1 115 kV line |
| 2017-18 Winter | Extreme | South-North NI Flow<br>No Western Generation | 50%<br>5967 MW | N-1 | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill 230-115 kV transformer #1 (99.6%)<br>Talbot Hill 230-115 kV transformer #2 (99.9%) | Berrydale 230-115 kV transformer<br>Talbot Hill - Boeing Renton - Shuffleton 115 kV line |
| 2017-18 Winter | Extreme | South-North NI Flow<br>No Western Generation | 50%<br>5967 MW | N-1-1 | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill-Boeing Renton-Shuffleton 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>White River - Lea Hill - Berrydale 115 kV line<br>Shuffleton-Lakeside 115 kV line<br>Talbot Hill-Berrydale #1 115 kV line<br>Berrydale 230-115 kV transformer<br>O'Brien 115 kV North bus section breaker<br>O'Brien 230-115 kV transformer #1<br>O'Brien 230-115 kV transformer #2 | Shuffleton-Lakeside 115 kV line<br>O'Brien 115 kV North bus section breaker<br>O'Brien - Asbury 115 kV line<br>Shuffleton - President Park - Lake Tradition 115 kV line<br>White River 230-115 kV transformer #1<br>White River 230-115 kV transformer #2<br>Shuffleton-O'Brien 115 kV line<br>Sammamish 230-115 kV transformer #2 |
| 2017-18 Winter | Extreme | South-North NI Flow<br>No Western Generation | 50%<br>5967 MW | N-2 or Common Mode | Berrydale 230-115 kV transformer<br>Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2 | Talbot Hill 230-115 kV transformer #2<br>Shuffleton - O'Brien 115 kV line<br>Talbot Hill - Boeing Renton - Shuffleton 115 kV line<br>O'Brien - Midway #1 115 kV line<br>O'Brien 230-115 kV transformer #2 |

### 6.1.4 2021-22: Winter Peak, Normal & Extreme Weather Thermal Summaries

Table 6-8 shows the summary of results for categories B (N-1) and C (N-1-1 & N-2) for 2021-22 winter and summer peaks with normal weather.

Table 6-9 indicates that the PSE load level for the winter peak, normal weather, 100% conservation, for 2021-22 is 5,193 MW. There are no potential Category B (N-1) thermal violations but there are five (5) elements with loadings from 90% to 100% of the emergency ratings. Those facilities are highlighted in gray on Table 6-9.

1. Talbot Hill - Lakeside #1 115 kV Line – 95.2%
2. Talbot Hill - Lakeside #2 115 kV Line – 95.1%
3. Talbot Hill 230-115 kV transformer #1 – 91.0%
4. Talbot Hill 230-115 kV transformer #2 – 91.5%
5. Talbot Hill - Boeing Renton - Shuffleton 115 kV Line – 91.5%

For Category C (N-1-1) contingencies there are six (6) elements above the emergency limits and an additional six (6) elements with loadings above 90% of their emergency limits. Those facilities are highlighted in yellow for overloads.

1. Talbot Hill - Lakeside #1 115 kV Line
2. Talbot Hill - Lakeside #2 115 kV Line
3. Talbot Hill 230-115 kV transformer #1
4. Talbot Hill 230-115 kV transformer #2
5. Talbot Hill - Boeing Renton - Shuffleton 115 kV Line
6. Shuffleton - Lakeside 115 kV Line

The PSE load level for the winter peak, normal weather, 75% conservation, for 2021-22 is 5,415 MW. Table 6-8 indicates that there are no potential Category B (N-1) thermal violations but there are five (5) elements with loadings above 90% of the emergency ratings (Talbot Hill-Lakeside #1 & 2 115 kV Lines, Talbot Hill 230-115 kV transformers #1 & 2, and Talbot Hill-Boeing Renton-Shuffleton 115 kV Line). For Category C (N-1-1) contingencies there are ten (10) elements above the emergency limits and an additional five (5) elements with loadings above 90% of their emergency limits.

Table 6-10 shows that for the 2021-22 winter peak, extreme weather, (PSE load of 5,772 MW), no generation in the north and high exports to British Columbia, there are four (4) potential Category B (N-1) thermal violations (Talbot Hill - Lakeside #1 & #2 115 kV lines, Talbot Hill-Boeing Renton-Shuffleton 115 kV line, and the Talbot Hill 230-115 kV transformer #1). There are fourteen (14) potential Category C (N-1-1 & N-2) thermal violations.

The extreme winter cases are run as an indication of the flexibility and robustness of the electric transmission system in a near or far future year. As shown in Tables 6-7 and 6-10, the increased load to be expected with extremely cold weather could lead to many more overloads than those projected with loads during normal weather, even with reduced conservation effects. While most utilities, including PSE, do not construct facilities on the basis of extreme seasonal temperatures, it does serve as an indicator of system stresses further into the future.

Table 6-8: Summary of Elements above Emergency and Operating Limits: 2021-22 Winter Peak, Normal Weather

| Year of Study | Normal or Extreme Weather | Case Conditions | Amount of Conservation/ System Load | Type of Contingency | Elements above Emergency Limit | Elements > 90% of Emergency Limit or above Operating Limit |
|---|---|---|---|---|---|---|
| 2021-22 Winter | Normal | South-North NI Flow<br>No Western Generation | 100%<br>5193 MW | N-1 | | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>Talbot-Boeing Renton-Shuffleton 115 kV Line |
| 2021-22 Winter | Normal | South-North NI Flow<br>No Western Generation | 100%<br>5193 MW | N-1-1 | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot-Lakeside Hill #2 115 kV Line<br>Talbot Hill-Boeing Renton-Shuffleton 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>Shuffleton-Lakeside 115 kV line | White River - Lea Hill - Berrydale 115 kV Line<br>Berrydale 230-115 kV transformer<br>O'Brien 230-115 kV transformer #2<br>O'Brien 230-115 kV transformer #1<br>O'Brien 115 kV North bus section breaker<br>Talbot Hill-Berrydale #1 115 kV line |
| 2021-22 Winter | Normal | South-North NI Flow<br>No Western Generation | 100%<br>5193 MW | N-2 or Common Mode | Talbot Hill-Lakeside #2 115 kV Line | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>Berrydale 230-115 kV transformer |
| 2021-22 Winter | Normal | South-North NI Flow<br>No Western Generation | 75%<br>5415 MW | N-1 | | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill-Boeing Renton-Shuffleton 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2 |
| 2021-22 Winter | Normal | South-North NI Flow<br>No Western Generation | 75%<br>5415 MW | N-1-1 | Talbot Hill-Berrydale #1 115 kV line<br>Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill-Boeing Renton-Shuffleton 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>White River - Lea Hill - Berrydale 115 kV line<br>Shuffleton-Lakeside 115 kV line<br>Berrydale 230-115 kV transformer<br>O'Brien 230-115 kV transformer #2 | O'Brien 230-115 kV transformer #1<br>O'Brien 115 kV North bus section breaker<br>O'Brien-Asbury 115 kV line<br>Shuffleton-President Park - Lake Tradition 115 kV line<br>Shuffleton-O'Brien 115 kV Line |
| 2021-22 Winter | Normal | South-North NI Flow<br>No Western Generation | 75%<br>5415 MW | N-2 or Common Mode | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Berrydale 230-115 kV transformer | Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>Shuffleton - O'Brien 115 kV Line<br>Talbot Hill-Boeing Renton-Shuffleton 115 kV Line |
| 2021-22 Winter | Normal | South-North NI Flow<br>No Western Generation | 50%<br>5636 MW | N-1 | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line | Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>Berrydale 230-115 kV transformer<br>Talbot Hill - Boeing Renton - Shuffleton 115 kV line |
| 2021-22 Winter | Normal | South-North NI Flow<br>No Western Generation | 50%<br>5636 MW | N-1-1 | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill-Boeing Renton-Shuffleton 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>White River - Lea Hill - Berrydale 115 kV line<br>Talbot Hill-Berrydale #1 115 kV line<br>Shuffleton-Lakeside 115 kV line<br>Berrydale 230-115 kV transformer<br>O'Brien 230-115 kV transformer #1<br>O'Brien 230-115 kV transformer #2<br>O'Brien 115 kV North bus section breaker | O'Brien - Asbury 115 kV line<br>Shuffleton - President Park - Lake Tradition 115 kV line<br>Shuffleton-O'Brien 115 kV line<br>Sammamish 230-115 kV transformer #2<br>White River 230-115 kV transformer #1<br>White River 230-115 kV transformer #2<br>O'Brien-Midway #1 115 kV Line |
| 2021-22 Winter | Normal | South-North NI Flow<br>No Western Generation | 50%<br>5636 MW | N-2 or Common Mode | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Berrydale 230-115 kV transformer<br>Talbot Hill 230-115 kV transformer #1 | Talbot Hill-Boeing Renton-Shuffleton 115 kV Line<br>Talbot Hill 230-115 kV transformer #2<br>Shuffleton - O'Brien 115 kV line |

Table 6-9: Elements above Emergency and Operating Limits: 2021-22 Winter Peak, 100% Conservation, Normal Weather, Thermal Loadings (Redacted)

| Case | Category | Worst Contingency | Owner of Facilities Out | Element(s) | Owner of Overloaded Facilities | Percent Overload |
|---|---|---|---|---|---|---|
| 2021-22 Winter | B | [redacted] | PSE | Talbot Hill - Lakeside #1 115 kV line | PSE | 95.2% |
| 2021-22 Winter | B | [redacted] | PSE | Talbot Hill - Lakeside #2 115 kV line | PSE | 95.1% |
| 2021-22 Winter | B | [redacted] | PSE | Talbot Hill 230-115 kV transformer #1 | PSE | 91.0% |
| 2021-22 Winter | B | [redacted] | PSE | Talbot Hill 230-115 kV transformer #2 | PSE | 91.5% |
| 2021-22 Winter | B | [redacted] | PSE | Talbot Hill - Boeing Renton - Shuffleton 115 kV line | PSE | 91.5% |
| 2021-22 Winter | C | [redacted] | PSE | Talbot Hill - Lakeside #2 115 kV line | PSE | 107.1% |
| 2021-22 Winter | C | [redacted] | PSE | Talbot Hill - Lakeside #1 115 kV line | PSE | 96.8% |
| 2021-22 Winter | C | [redacted] | PSE | Berrydale 230-115 kV transformer | PSE | 95.5% |
| 2021-22 Winter | C | [redacted] | PSE | Talbot Hill 230-115 kV transformer #2 | PSE | 93.2% |
| 2021-22 Winter | C | [redacted] | PSE | Talbot Hill 230-115 kV transformer #1 | PSE | 93.6% |
| 2021-22 Winter | C | [redacted] | PSE | Shuffleton - O'Brien 115 kV line | PSE | 90.0% |
| 2021-22 Winter | C | [redacted] | PSE | Talbot Hill - Berrydale #1 115 kV line | PSE | 97.6% |
| 2021-22 Winter | C | [redacted] | PSE | Talbot Hill 230-115 kV transformer #1 | PSE | 108.1% |

Table 6-9: Elements above Emergency and Operating Limits: 2021-22 Winter Peak, 100% Conservation, Normal Weather, Thermal Loadings (Redacted) (CONTINUED)

| | | | | | | |
|---|---|---|---|---|---|---|
| 2021-22 Winter | C | [redacted] | PSE | Talbot Hill - Lakeside #1 115 kV line | PSE | 117.8% |
| 2021-22 Winter | C | [redacted] | PSE | Talbot Hill - Lakeside #2 115 kV line | PSE | 117.7% |
| 2021-22 Winter | C | [redacted] | PSE | Talbot Hill - Boeing Renton - Shuffleton 115 kV line | PSE | 107.6% |
| 2021-22 Winter | C | [redacted] | PSE | Talbot Hill 230-115 kV transformer #2 | PSE | 107.0% |
| 2021-22 Winter | C | [redacted] | PSE | White River - Lea Hill - Berrydale 115 kV line | PSE | 99.7% |
| 2021-22 Winter | C | [redacted] | PSE | Shuffleton - Lakeside 115 kV line | PSE | 100.8% |
| 2021-22 Winter | C | [redacted] | PSE | Berrydale 230-115 kV transformer | PSE | 96.1% |
| 2021-22 Winter | C | [redacted] | PSE | O'Brien 230-115 kV transformer #1 | PSE | 94.3% |
| 2021-22 Winter | C | [redacted] | PSE | O'Brien 230-115 kV transformer #2 | PSE | 95.1% |
| 2021-22 Winter | C | [redacted] | PSE | O'Brien 115 kV North bus section breaker | PSE | 94.6% |
| 2021-22 Winter | C | [redacted] | PSE | O'Brien - Asbury 115 kV line | PSE | 90.9% |

Table 6-10: Summary of Elements above Emergency and Operating Limits: 2021-22 Winter Peak, Extreme Weather Thermal Loadings

| Year of Study | Normal or Extreme Weather | Case Conditions | Amount of Conservation/ System Load | Type of Contingency | Elements above Emergency Limit | Elements > 90% of Emergency Limit or above Operating Limit |
|---|---|---|---|---|---|---|
| 2021-22 Winter | Extreme | South-North NI Flow No Western Generation | 100% 5772 MW | N-1 | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill-Boeing Renton-Shuffleton 115 kV Line<br>Talbot Hill 230-115 kV transformer #1 | Berrydale 230-115 kV transformer<br>Talbot Hill 230-115 kV transformer #2 |
| 2021-22 Winter | Extreme | South-North NI Flow No Western Generation | 100% 5772 MW | N-1-1 | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill-Boeing Renton-Shuffleton 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Talbot Hill 230-115 kV transformer #2<br>White River - Lea Hill - Berrydale 115 kV line<br>Shuffleton-Lakeside 115 kV line<br>Talbot Hill-Berrydale #1 115 kV line<br>Berrydale 230-115 kV transformer<br>O'Brien 115 kV North bus section breaker<br>O'Brien 230-115 kV transformer #1<br>O'Brien 230-115 kV transformer #2<br>O'Brien - Asbury 115 kV line<br>Shuffleton-O'Brien 115 kV line | Shuffleton - President Park - Lake Tradition 115 kV line<br>White River 230-115 kV transformer #1<br>White River 230-115 kV transformer #2<br>Sammamish 230-115 kV transformer #1<br>Sammamish 230-115 kV transformer #2<br>Talbot Hill-Lake Tradition #1 115 kV Line<br>O'Brien-Metro Renton – Talbot Hill 115 kV Line<br>O'Brien – Christopher #1 115 kV Line |
| 2021-22 Winter | Extreme | South-North NI Flow No Western Generation | 100% 5772 MW | N-2 or Common Mode | Talbot Hill-Lakeside #1 115 kV Line<br>Talbot Hill-Lakeside #2 115 kV Line<br>Talbot Hill 230-115 kV transformer #1<br>Shuffleton-O'Brien 115 kV line<br>Berrydale 230-115 kV transformer | Talbot Hill-Boeing Renton-Shuffleton 115 kV Line<br>Talbot Hill 230-115 kV transformer #2<br>O'Brien 230-115 kV transformer #2<br>O'Brien - Midway #1 115 kV line |

### 6.1.5 Summary of Potential Thermal Violations

Based on Table 6-11, below, the PSE Winter load level where King County starts to have significant issues is approximately 5200 MW. The elements which are the most susceptible to potential overloads for the winter peak loads are in the Talbot Hill and Lakeside Substation areas.

The sensitivity cases with 75% conservation instead of 100% conservation indicate system performance concerns with higher winter loads. Those sensitivity studies show even higher overloads of the elements already overloaded in the 100% conservation cases. In general, should loads grow faster than forecast, or conservation not provide anticipated peak load relief, the potential overloads will be higher than the results reported. Even when the corporate load does not increase from 2017-18 to 2021-22, the Eastside load has grown, resulting in an increased number of potential violations.

Table 6-11: Summary of Potential Thermal Violations for Winter Peak Load Season

| Contingency | 2013-14<br>5055 MW<br>100% Con | 2013-14<br>5090 MW<br>75% Con | 2017-18<br>5208 MW<br>100% Con | 2017-18<br>5325 MW<br>75% Con | 2021-22<br>5193 MW<br>100% Con | 2021-22<br>5415 MW<br>75% Con |
|---|---|---|---|---|---|---|
| Cat B (N-1) | | | Talbot Hill - Lakeside #1 115 kV line – 98.6% | Talbot Hill - Lakeside #1 115 kV line – 99.9% | Talbot Hill - Lakeside #1 115 kV line – 95.2% | Talbot Hill - Lakeside #1 115 kV line – 99.2% |
| | | | Talbot Hill - Lakeside #2 115 kV line – 98.4% | Talbot Hill - Lakeside #2 115 kV line – 99.9% | Talbot Hill - Lakeside #2 115 kV line – 95.1% | Talbot Hill - Lakeside #2 115 kV line – 99.1% |
| | | | Talbot Hill 230-115 kV transformer #2 – 90.3% | Talbot Hill 230-115 kV transformer #1 – 90.9% | Talbot Hill 230-115 kV transformer #1 – 91.0% | Talbot Hill 230-115 kV transformer #1 – 94.7% |
| | | | | Talbot Hill 230-115 kV transformer #2 – 92.4% | Talbot Hill 230-115 kV transformer #2 – 91.5% | Talbot Hill 230-115 kV transformer #2 – 93.6% |
| | | | | | | Talbot Hill - Boeing Renton - Shuffleton 115 kV line - 95.4% |
| Cat C (N-1-1) | Talbot Hill-Lakeside #1 115 kV Line - 115.2% | Talbot Hill-Lakeside #1 115 kV Line - 115.9% | Talbot Hill--Lakeside #1 115 kV Line - 127.8% | Talbot Hill-Lakeside #1 115 kV Line - 129.9% | Talbot Hill--Lakeside #1 115 kV Line - 117.8% | Talbot Hill--Lakeside #1 115 kV Line - 122.9% |
| | Talbot Hill-Lakeside #2 115 kV Line - 115.1% | Talbot Hill-Lakeside #2 115 kV Line - 115.8% | Talbot Hill--Lakeside #2 115 kV Line - 127.6% | Talbot Hill-Lakeside #2 115 kV Line - 129.7% | Talbot Hill-Lakeside #2 115 kV Line - 117.7% | Talbot Hill-Lakeside #2 115 kV Line - 122.8% |
| | Talbot Hill 230-115 kV transformer #1 - 100.9% | Talbot Hill 230-115 kV transformer #1 - 101.6% | Talbot Hill 230-115 kV transformer #1 - 105.7% | Talbot Hill 230-115 kV transformer #1 - 108.1% | Talbot Hill 230-115 kV transformer #1 - 108.1% | Talbot Hill 230-115 kV transformer #1 - 112.8% |
| | Talbot Hill 230-115 kV transformer #2 - 100.5% | Talbot Hill 230-115 kV transformer #2 - 101.6% | Talbot Hill 230-115 kV transformer #2 - 105.7% | Talbot Hill 230-115 kV transformer #2 – 107.6% | Talbot Hill 230-115 kV transformer #2 - 107.0% | Talbot Hill 230-115 kV transformer #2 - 109.8% |
| | Talbot Hill-Boeing Renton-Shuffleton 115 kV Line -101.1% | Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 101.7% | Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 110.6% | Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 112.5% | Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 107.6% | Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 112.3% |
| | | | | White River - Lea Hill - Berrydale 115 kV line - 100.2% | White River - Lea Hill - Berrydale 115 kV line - 99.7% | White River - Lea Hill - Berrydale 115 kV line - 104.0% |
| | | | | Maple Valley - Sammamish 230 kV line - 100.5% | | Talbot Hill-Berrydale #1 115 kV line - 101.9% |
| | | | | | | Shuffleton-Lakeside 115 kV line - 105.2% |
| | | | | | | Berrydale 230-115 kV transformer - 100.8% |
| | | | | | | O'Brien 230-115 kV transformer #2 - 100.2% |
| | | | | | | O'Brien 230-115 kV transformer #1 - 99.4% |
| Cat C (N-2 or Common Mode) | | | Talbot Hill-Lakeside #1 115 kV Line - 101.5% | Talbot Hill-Lakeside #1 115 kV Line - 103.0% | Talbot Hill - Lakeside #1 115 kV line – 96.8% | Talbot Hill-Lakeside #1 115 kV Line – 100.7% |
| | | | Talbot Hill-Lakeside #2 115 kV Line - 101.1% | Talbot Hill-Lakeside #2 115 kV Line - 100.5% | Talbot Hill - Lakeside #2 115 kV line – 107.1% | Talbot Hill-Lakeside #2 115 kV Line - 111.7% |
| | | | | | Talbot Hill 230-115 kV transformer #1 – 93.6% | Talbot Hill 230-115 kV transformer #1 – 97.3% |
| | | | | | Talbot Hill 230-115 kV transformer #2 – 93.2% | Talbot Hill 230-115 kV transformer #2 – 95.1% |
| | | | | | Berrydale 230-115 kV transformer - 95.5% | Berrydale 230-115 kV transformer - 100.2% |

Based on Table 6-12 below, the PSE summer load level where King County starts to have significant issues is approximately 3,500 MW. The elements which are the most susceptible to potential overloads for the summer peak loads are in the Sammamish Substation area.

Table 6-12: Summary of Potential Thermal Violations for Summer Peak Load Season

| Contingency | 2014<br>3343 MW<br>100% Con | 2018<br>3554 MW<br>100% Con |
|---|---|---|
| Cat B (N-1) | Monroe-Novelty Hill 230 kV line - 132.6% | Monroe-Novelty Hill 230 kV line - 133.0% |
| | Maple Valley - Sammamish 230 kV line - 111.4% | Maple Valley - Sammamish 230 kV line - 132.3% |
| | | Talbot Hill - Lakeside #1 115 kV line - 93.9% |
| | | Talbot Hill - Lakeside #2 115 kV line - 93.8% |
| Cat C (N-1-1) | Sammamish 230-115 kV transformer #2 - 100.8% | Beverly Park - Cottage Brook 115 kV line - 100.5% (Have solution) |
| | Sammamish 230-115 kV transformer #1 - 95.5% | Sammamish 230-115 kV transformer #1 - 100.7% (Have solution) |
| | | Sammamish 230-115 kV transformer #2 - 106.4% (Have solution) |
| Cat C (N-2) | | Sammamish - Lakeside #2 115 kV line - 99.8% |

### 6.1.6 Temporary Mitigations and Associated Risks

Based on the analysis described above there are a number of system events that require the Transmission Operators to implement operating procedures in place to temporarily reduce or mitigate the potential thermal violations. Table 6-13 indicates mitigation needed for each of the winter overload contingencies identified in 2017-18.

Table 6-13: Mitigations for Worst Winter 2017-18 Contingencies

| Contingency | 2013-14 Winter Peak<br>5208 MW<br>100% Conservation | 2017-18 Winter Peak<br>5208 MW<br>100% Conservation | 2017-18 Winter Peak<br>5325 MW<br>75% Conservation | Contingency Causing Overload | Mitigation Plan - Worst Contingency | Customers at Risk |
|---|---|---|---|---|---|---|
| Cat B (N-1) | | Talbot Hill - Lakeside #1 115 kV line – 98.6% | Talbot Hill - Lakeside #1 115 kV line – 99.9% | [redacted] | [redacted] | None |
| | | Talbot Hill - Lakeside #2 115 kV line – 98.4% | Talbot Hill - Lakeside #2 115 kV line – 99.9% | [redacted] | [redacted] | None |
| | | Talbot Hill 230-115 kV transformer #2 – 90.3% | Talbot Hill 230-115 kV transformer #2 – 92.4% | [redacted] | [redacted] | None |
| | | | Talbot Hill 230-115 kV transformer #1 – 90.9% | [redacted] | [redacted] | None |
| Cat C (N-1-1) | Talbot-Lakeside #1 115 kV Line - 115.2% | Talbot-Lakeside #1 115 kV Line - 127.8% | Talbot-Lakeside #1 115 kV Line - 129.9% | [redacted] | [redacted] | 49,000 for line outage, 33,000 for transformer outage |
| | Talbot-Lakeside #2 115 kV Line - 115.1% | Talbot-Lakeside #2 115 kV Line - 127.6% | Talbot-Lakeside #2 115 kV Line - 129.7% | [redacted] | [redacted] | 49,000 for line outage, 33,000 for transformer outage |
| | Talbot Hill 230-115 kV transformer #1 - 100.9% | Talbot Hill 230-115 kV transformer #1 - 105.7% | Talbot Hill 230-115 kV transformer #1 - 108.1% | [redacted] | [redacted] | More lines may need to be opened for next N-1-1 contingencies |
| | Talbot Hill 230-115 kV transformer #2 - 100.5% | Talbot Hill 230-115 kV transformer #2 - 105.7% | Talbot Hill 230-115 kV transformer #2 – 107.6% | [redacted] | [redacted] | More lines may need to be opened for next N-1-1 contingencies |
| | Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 101.1% | Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 110.6% | Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 112.5% | [redacted] | [redacted] | 23,000 for line outage, 33,000 for transformer outage |

Table 6-13: Mitigations for Worst Winter 2017-18 Contingencies (CONTINUED)

| | | | | | | |
|---|---|---|---|---|---|---|
| | | O'Brien 230-115 kV transformer #1 - 93.1% | O'Brien 230-115 kV transformer #1 - 94.9% | [redacted] | [redacted] | More lines may need to be opened for next N-1-1 contingencies |
| | | O'Brien 230-115 kV transformer #2 - 93.9% | O'Brien 230-115 kV transformer #2 - 95.7% | [redacted] | [redacted] | More lines may need to be opened for next N-1-1 contingencies |
| | | Berrydale 230-115 kV transformer - 93.8% | Berrydale 230-115 kV transformer - 96.0% | [redacted] | [redacted] | More lines may need to be opened for next N-1-1 contingencies |
| | | Talbot Hill-Berrydale #1 115 kV line - 97.6% | Talbot Hill-Berrydale #1 115 kV line - 99.8% | [redacted] | [redacted] | 32,000 for line outage, 50,000 for transformer outage |
| | | Shuffleton - Lakeside 115 kV line - 97.3% | Shuffleton - Lakeside 115 kV line - 98.9% | [redacted] | [redacted] | None |
| | | | White River - Lea Hill - Berrydale 115 kV line - 100.2% | [redacted] | [redacted] | 32,000 for line outage, 50,000 for transformer outage |
| | | | Maple Valley - Sammamish 230 kV line - 100.5% | [redacted] | [redacted] | None |
| Cat C (N-2 or Common Mode) | | Talbot-Lakeside #1 115 kV Line - 101.5% | Talbot-Lakeside #1 115 kV Line - 103.0% | [redacted] | [redacted] | 32,000 for line outage, 50,000 for transformer outage |
| | | Talbot-Lakeside #2 115 kV Line - 101.1% | Talbot-Lakeside #2 115 kV Line - 100.5% | [redacted] | [redacted] | None |
| | | Talbot Hill 230-115 kV transformer #1 - 91.8% | Talbot Hill 230-115 kV transformer #1 - 93.8% | [redacted] | [redacted] | None |
| | | Talbot Hill 230-115 kV transformer #2 - 92.8% | Talbot Hill 230-115 kV transformer #2 - 94.4% | [redacted] | [redacted] | None |

The following table indicates mitigation needed for each of the summer overload contingencies identified in 2018.

Table 6-14: Mitigation for Worst Summer 2018 Contingencies

| Contingency | 2014 Summer Peak 3343 MW 100% Conservation | 2018 Summer Peak 3554 MW 100% Conservation | Contingency Causing Overload | Mitigation | Customers at Risk |
|---|---|---|---|---|---|
| Cat B (N-1) | Monroe-Novelty Hill 230 kV line - 132.6% | Monroe-Novelty Hill 230 kV line - 133.0% | [redacted] | [redacted] | None |
| | Maple Valley - Sammamish 230 kV line - 111.4% | Maple Valley - Sammamish 230 kV line - 132.3% | [redacted] | [redacted] | None |
| | | Talbot Hill - Lakeside #1 115 kV line - 93.9% | [redacted] | [redacted] | None |
| | | Talbot Hill - Lakeside #2 115 kV line - 93.8% | [redacted] | [redacted] | None |
| Cat C (N-1-1) | Sammamish 230-115 kV transformer #2 - 100.8% | Sammamish 230-115 kV transformer #2 - 106.4% | [redacted] | [redacted] | 33,000 |
| | Sammamish 230-115 kV transformer #1 - 95.5% | Sammamish 230-115 kV transformer #1 - 100.7% | [redacted] | [redacted] | 33,000 |
| | | Beverly Park - Cottage Brook 115 kV line - 100.5% | [redacted] | [redacted] | 27,000 |
| Cat C (N-2) | | Sammamish - Lakeside #2 115 kV line - 99.8% | [redacted] | [redacted] | None |



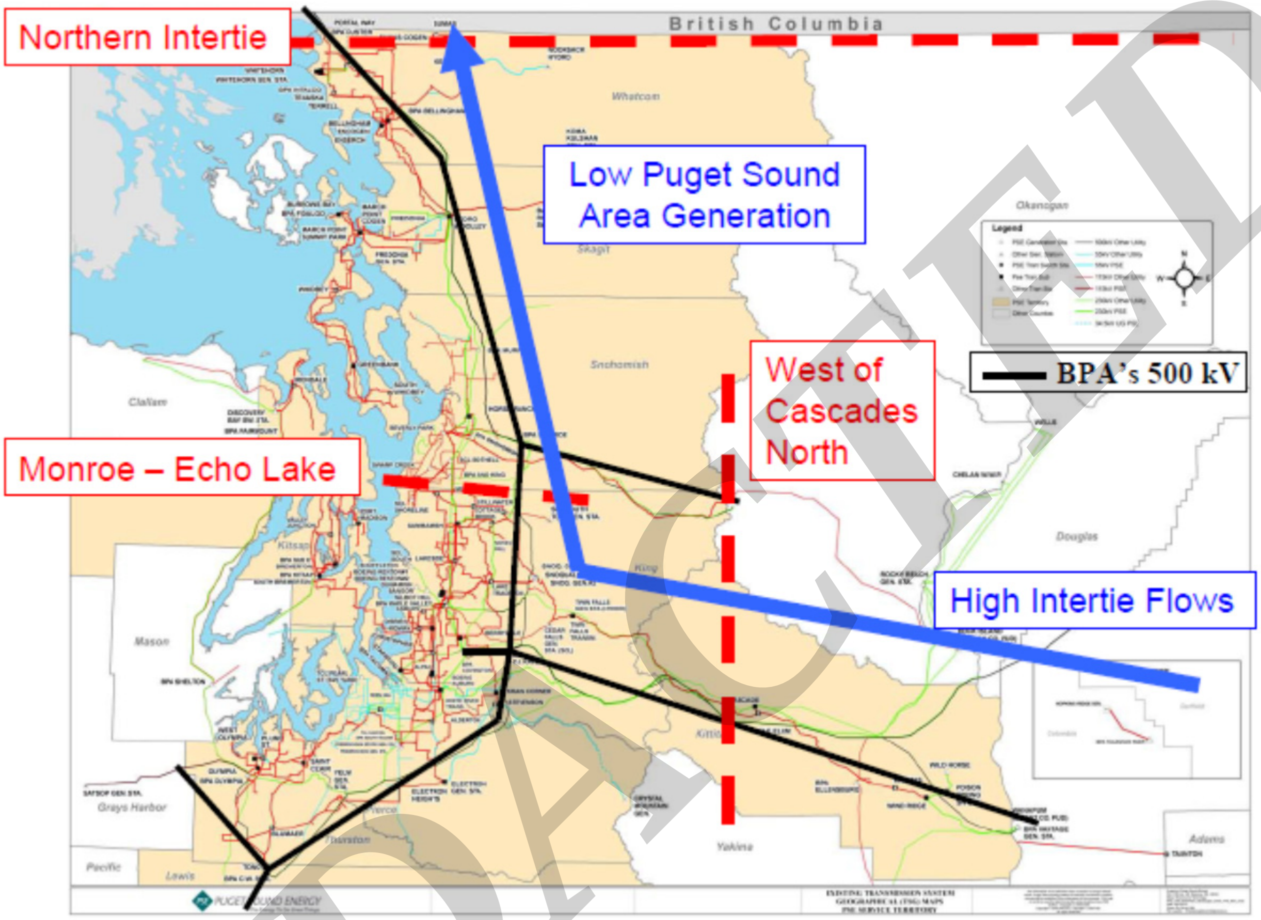
## 6.2 Other Assessment Criteria Compliance

### 6.2.1 Columbia Grid

As stated in the ColumbiaGrid 2012 System Assessment[21], ColumbiaGrid was formed with seven founding members in 2006 to improve the operational efficiency, reliability, and planned expansion of the northwest transmission grid. Eleven parties have signed ColumbiaGrid's Planning and Expansion Functional Agreement (PEFA) to support and facilitate multi-system transmission planning through an open and transparent process. ColumbiaGrid's primary grid planning activity is to develop a biennial transmission expansion plan that looks out over a ten-year planning horizon and identifies the transmission additions necessary to ensure that the parties to the ColumbiaGrid Planning and Expansion Functional Agreement can meet their commitments to serve load and transmission service commitments. A significant feature of the transmission expansion plan is its single-utility planning approach. The plan has been developed as if the region's transmission grid were owned and operated by a single entity. This approach results in a more comprehensive, efficient, and coordinated plan than would otherwise be developed if each transmission owner completed a separate independent analysis.

[21] ColumbiaGrid 2012System Assessment, page 1 – Executive Summary, July 2012

The capacity of the Northern Intertie path in the north to south direction is 2,850 MW on the west- side and 400 MW on the east-side with a combined total transfer capability limit of 3,150 MW (Figure 6-2). The total capacity of the path in the south to north direction is 2,000 MW, with a limit of 400 MW on the east-side (Figure 6-1). Both of these directional flows can impact the ability of the system to serve loads in the Puget Sound area.

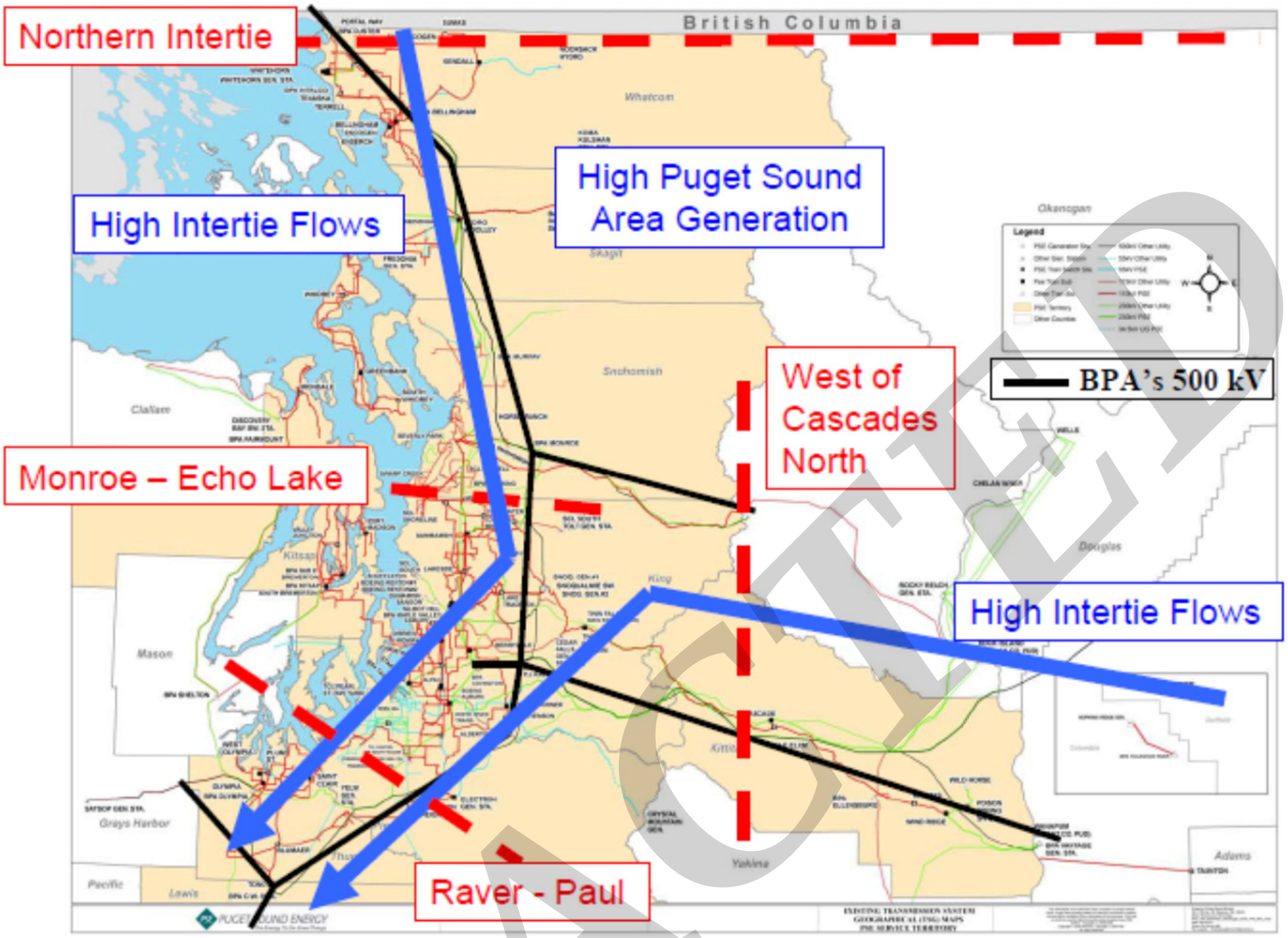


[22]

Figure 6-1: Winter Power Flow resulting from Northern Intertie



[22] PSE Attachment K, Puget Sound Area Transmission Meeting, PSE Presentation Slide #9, Dec 18, 2012



[23]

Figure 6-2: Summer Power Flow Resulting from Northern Intertie

The major issues in the PSE area were identified in the 2012 System Assessment, dated July 2012. The Assessment documented that: BPA is making commitments to increase flows across the Northern Intertie to 2,300 MW through the Network Open Season that will show up in the ten-year time frame. 200 MW of this new commitment is planned to be scheduled on the east side of the Northern Intertie at Nelway. Therefore in the ten- year summer cases this flow will increase to 2,300 MW to cover the additional commitments that are being made on the Northern Intertie including the 200 MW on the east side of the tie at Nelway.

### 6.2.2 2009 TPL Study Results

Issues associated with loading in the Talbot Hill area under winter conditions and south-north regional transmission flows were first shown in the 2009 TPL study. (The previous year's TPL study had noted high loading on Talbot Hill transformers, although these were not identified as Category B or C overloads in any of the study years used for the 2008 TPL.) As a result, PSE identified short-term mitigation in the form of CAPs and also began studying options for improving the power supply in the central King County area.

Load forecasts used in the 2009 TPL study followed corporate forecasts published in December 2008. There was an updated forecast in June 2009 which projected lower normal peaks. Due to the conservative approach used in the TPL report, it is deemed that the change in the peak loads would not influence any TPL results.

[23] PSE Attachment K, Puget Sound Area Transmission Meeting, PSE Presentation Slide #10, Dec 18, 2012

The 2009 TPL Study assumed no generation in Puget Sound Area as opposed to minimum generation in earlier reports - for the low generation scenarios. Also, the NI (Northern Intertie) flows were assumed realistic based on season and historic flows. This information is tabulated in Table 6-15.

The winter season in years 2010 (2010-11) and 2019 (2018-19) was studied both in Northern Intertie (NI) import and export conditions. Loads used were 1 in 2 year winter peak. The summer season in years 2010 and 2019 was also studied both in Northern Intertie (NI) import and export conditions. Loads used were 1 in 2 year summer peak. PSE's system load peaks during the winter season; summer represents reduced-load conditions. For the near-term cases winter peak load of 5,329 MW and summer peak load of 3,417 MW is modeled. For the long-term cases a winter peak load of 5,765 MW and summer peak load of 3,678 MW is modeled. To cover a broad range of operating conditions, Northern Intertie flows and PSE generation levels were varied in all case studies.

Table 6-15 shows the different scenarios used for the study.

**Table 6-15: Scenarios for the 2009 TPL Study**

| WECC case | Base case | Northern Intertie flows (North-South (N-S) or South –North (S-N) | Puget Sound Area Generation |
|---|---|---|---|
| 2009 HS3A APPROVED OPERATING CASE | 2010HS-A | N-S 2850/300 MW | Full generation |
| 2009 HS3A APPROVED OPERATING CASE | 2010HS-B | N-S 2850/300 MW | No generation |
| 2009 HS3A APPROVED OPERATING CASE | 2010HS-C | S-N 2000/0 MW | Full generation |
| 2009 HS3A APPROVED OPERATING CASE | 2010HS-D | S-N 2000/0 MW | No generation |
| 2009-10 HW2 OPERATING CASE | 2010-11HW-A | S-N 1500/300 MW | No generation |
| 2009-10 HW2 OPERATING CASE | 2010-11HW-B | S-N 1500/300 MW | Full generation |
| 2009-10 HW2 OPERATING CASE | 2010-11HW-C | N-S 1450/0 MW | No generation |
| 2009-10 HW2 OPERATING CASE | 2010-11HW-D | N-S 1450/0 MW | Full generation |
| 2019 HEAVY SUMMER 1 BASE CASE | 2019HS-A | N-S 2850/300 MW | Full generation |
| 2019 HEAVY SUMMER 1 BASE CASE | 2019HS-B | N-S 2850/300 MW | No generation |
| 2019 HEAVY SUMMER 1 BASE CASE | 2019HS-C | S-N 2000/0 MW | Full generation |
| 2019 HEAVY SUMMER 1 BASE CASE | 2019HS-D | S-N 2000/0 MW | No generation |
| 2018-19 HW1 BASE CASE | 2018-19HW-A | S-N 1500/300 MW | No generation |
| 2018-19 HW1 BASE CASE | 2018-19HW-B | S-N 1500/300 MW | Full generation |
| 2018-19 HW1 BASE CASE | 2018-19HW-C | N-S 1450/0 MW | No generation |
| 2018-19 HW1 BASE CASE | 2018-19HW-D | N-S 1450/0 MW | Full generation |

The 2009 TPL study indicated that as soon as the winter of 2010-11, during south-north regional transmission flows with low Puget Sound Area generation, a Category C loss [redacted] or a Category C loss of [redacted] could overload the Talbot Hill transformer #2. The [redacted] outage would load the Talbot Hill transformer to 101% of its emergency limit, which could be mitigated by dispatching generation. The [redacted] outage was shown to result in a 107% load on Talbot Hill transformer #2, which would be mitigated by instituting a CAP to open [redacted]. Installation of 230-115 kV transformation in central King County was identified as a long-term mitigation and studies commenced as to best transformation location and associated system improvements.

# Section 7 Conclusions on Needs Assessment

This 2013 Eastside Needs Assessment has shown that PSE is facing a transmission capacity deficiency on the Eastside of Lake Washington. Overloads of Talbot Hill and Sammamish transformers as well as several 115 kV lines point to the need for a new power supply centered in the Eastside area. By the fall of 2017, additional 230-115 kV transformation or generation integrated at the 115 kV level will be required in the Eastside area to relieve the overloads predicted in this study. Depending on the location of a new transformer, additional 115 kV or 230 kV line capacity will also be required.

In multiple contingencies studied, different parts of the transmission system will overload or will be close to overloading within the 10 year study period. When the regional power flows are south to north, as is typical in the winter, there are potential overloads in the Talbot Hill Substation area, on both transformers and transmission lines. When the regional power flows are north to south, as is typical in the summer, there are potential overloads in the Sammamish Substation area. In each case, it is the need to provide power to PSE communities in the Eastside area that is stressing the local power system.

The Eastside area has no utility generation sources. In King County, local generation covers less than 10% of the peak load. Therefore the King County area is quite dependent on transmission interties to Bonneville Power Administration and other neighboring utilities that can transport bulk power from generation located north, south and east of King County, primarily in the east. Bulk power is most often transported at 230 kV or higher voltage. This study has indicated possible overloads of existing 230 kV lines in future years. A 2012 Columbia Grid study has also indicated the need for additional 230 kV capacity in the King County area.

The core area of the Eastside in Bellevue is eight miles from any 230-115 kV source. This has placed a strain on the two nearest substations providing 230-115 kV transformation to the Eastside: Sammamish and Talbot Hill Substations. Continuing load growth in the Eastside area would increase the overload problems being shown in the first 5 years of the study.

This study examined thermal overloads for Category A (N-0), Category B (N-1) and Category C (N-2 and N-1-1) outages as required by NERC, WECC and PSE Transmission Planning Guidelines.

At approximately 5,200 MW PSE system load, as forecast for 2017-18 winter, multiple elements are at risk of overload. If the load growth is higher or conservation goals are not achieved as projected, the overloads will be higher and occur sooner.

PSE uses CAPs to automatically or manually prevent overloads under the NERC reliability requirements. The CAPs required to prevent N-1-1 overloads would open lines between Sammamish and Talbot Hill. Some of the CAPs place customers at risk of outage due to transmission lines being switched into a radial mode, with a feed from just one end. In the future, load growth will result in additional lines required to be opened, putting over 60,000 customers at risk of subsequent outages.

This analysis has shown a transmission capacity deficiency in the Eastside area of Lake Washington will develop by the winter of 2017-18. This transmission capacity deficiency will continue to increase beyond that date.

# Appendix A: Load Forecast

**Table A-1: 2012 Annual Peak Load Forecast Distribution**

| Year | 100% Conservation | | Net of 100% Conservation | | | Gross of Conservation (0% Conservation) | | |
|---|---|---|---|---|---|---|---|---|
| | Normal 23º | Extreme 13º | Normal Peak (23º) | Extreme Peak (13º) | ERM Peak (PSO) | Normal Peak (23º) | Extreme Peak (13º) | ERM Peak (PSO) |
| 2012 | 68 | 68 | 4,837 | 5,316 | 5,316 | 4,905 | 5,384 | 5,384 |
| 2013 | 140 | 140 | 4,785 | 5,267 | 5,267 | 4,926 | 5,408 | 5,408 |
| 2014 | 226 | 226 | 4,836 | 5,333 | 5,333 | 5,063 | 5,560 | 5,560 |
| 2015 | 319 | 319 | 4,865 | 5,375 | 5,375 | 5,184 | 5,694 | 5,694 |
| 2016 | 394 | 394 | 4,909 | 5,432 | 5,432 | 5,303 | 5,826 | 5,826 |
| 2017 | 468 | 468 | 4,938 | 5,472 | 5,472 | 5,406 | 5,940 | 5,940 |
| 2018 | 562 | 562 | 4,938 | 5,483 | 5,483 | 5,500 | 6,045 | 6,045 |
| 2019 | 651 | 651 | 4,946 | 5,501 | 5,501 | 5,597 | 6,152 | 6,152 |
| 2020 | 778 | 778 | 4,923 | 5,490 | 5,490 | 5,701 | 6,268 | 6,268 |
| 2021 | 885 | 885 | 4,923 | 5,502 | 5,502 | 5,808 | 6,386 | 6,386 |
| 2022 | 944 | 944 | 4,972 | 5,562 | 5,562 | 5,916 | 6,506 | 6,506 |
| 2023 | 986 | 986 | 5,039 | 5,641 | 5,641 | 6,025 | 6,627 | 6,627 |
| 2024 | 1,023 | 1,023 | 5,117 | 5,732 | 5,732 | 6,140 | 6,754 | 6,754 |
| 2025 | 1,061 | 1,061 | 5,193 | 5,820 | 5,820 | 6,254 | 6,881 | 6,881 |
| 2026 | 1,100 | 1,100 | 5,266 | 5,905 | 5,905 | 6,365 | 7,004 | 7,004 |
| 2027 | 1,138 | 1,138 | 5,341 | 5,993 | 5,993 | 6,479 | 7,131 | 7,131 |
| 2028 | 1,172 | 1,172 | 5,426 | 6,090 | 6,090 | 6,598 | 7,262 | 7,262 |
| 2029 | 1,203 | 1,203 | 5,515 | 6,192 | 6,192 | 6,718 | 7,396 | 7,396 |
| 2030 | 1,236 | 1,236 | 5,605 | 6,296 | 6,296 | 6,840 | 7,531 | 7,531 |
| 2031 | 1,270 | 1,270 | 5,694 | 6,399 | 6,399 | 6,964 | 7,668 | 7,668 |
| 2032 | 1,305 | 1,305 | 5,785 | 6,504 | 6,504 | 7,090 | 7,808 | 7,808 |
| 2033 | 1,341 | 1,341 | 5,878 | 6,610 | 6,610 | 7,219 | 7,951 | 7,951 |

**Table A-2: 2012 Annual Peak Load Forecast for Eastside Area**

| | Normal Peaks (23 °F) Net of Conservation | | | Extreme Peaks (13 °F) Net of Conservation | | | Normal Peaks (23 °F) Gross of Conservation | | Extreme Peaks (13°F) Gross of Conservation | |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | Eastside % of King Co | Eastside | King | Eastside % of King Co | Eastside | King | Eastside | King | Eastside | King |
| 2012 | 27.5 | 646 | 2,348 | 27.4 | 709 | 2,586 | 655 | 2,381 | 718 | 2,619 |
| 2013 | 27.5 | 652 | 2,371 | 27.5 | 718 | 2,615 | 671 | 2,440 | 737 | 2,685 |
| 2014 | 27.5 | 660 | 2,399 | 27.5 | 729 | 2,652 | 691 | 2,512 | 760 | 2,764 |
| 2015 | 28.0 | 676 | 2,413 | 28.0 | 748 | 2,672 | 720 | 2,572 | 793 | 2,831 |
| 2016 | 28.5 | 694 | 2,434 | 28.5 | 769 | 2,699 | 750 | 2,630 | 825 | 2,896 |
| 2017 | 28.8 | 706 | 2,448 | 28.8 | 782 | 2,719 | 773 | 2,681 | 849 | 2,952 |
| 2018 | 29.0 | 710 | 2,449 | 29.0 | 790 | 2,725 | 792 | 2,729 | 872 | 3,006 |
| 2019 | 29.5 | 724 | 2,454 | 29.5 | 807 | 2,735 | 820 | 2,779 | 903 | 3,061 |
| 2020 | 30.0 | 733 | 2,445 | 30.0 | 820 | 2,732 | 850 | 2,834 | 937 | 3,122 |
| 2021 | 30.9 | 756 | 2,449 | 30.8 | 845 | 2,742 | 893 | 2,892 | 982 | 3,187 |
| 2022 | 30.9 | 765 | 2,476 | 31.0 | 861 | 2,776 | 912 | 2,950 | 1,008 | 3,251 |
| 2023 | 30.9 | 777 | 2,514 | 31.0 | 874 | 2,821 | 930 | 3,010 | 1,028 | 3,317 |
| 2024 | 30.9 | 790 | 2,558 | 31.0 | 890 | 2,871 | 949 | 3,073 | 1,050 | 3,387 |
| 2025 | 30.9 | 804 | 2,602 | 31.0 | 906 | 2,922 | 969 | 3,137 | 1,072 | 3,458 |
| 2026 | 30.9 | 818 | 2,646 | 31.0 | 922 | 2,973 | 989 | 3,201 | 1,094 | 3,530 |

NOTES:

1. Normal and Extreme County Peaks taken from PSE F2012: Electric County Peaks worksheet.
2. Eastside Normal and Extreme Peaks for years 2013, 2017 and 2021 are taken from the E230 Project worksheet: Eastside Load. The King County load was adjusted for expected block loads known to PSE Planning within the 10-year study period.
3. The Eastside load is calculated for years 2013, 2017 and 2021 based on the expected block loads with interpolation being used to calculate the in between years.

# Appendix B: Upgrades Included in Base Cases

**Table B-1: Projects Added to the Eastside Needs Assessment Winter Base Case**

| 2013-14 | 2017-18 | 2021-22 |
|---|---|---|
| Beverly Park - Cottage Brook breaker replacement | Beverly Park - Cottage Brook breaker replacement | Beverly Park - Cottage Brook breaker replacement |
| Cottage Brook - Moorlands line reconductor | Cottage Brook - Moorlands line reconductor | Cottage Brook - Moorlands line reconductor |
| Saint Clair 230-115 kV transformer | Saint Clair 230-115 kV transformer | Saint Clair 230-115 kV transformer |
| Talbot Hill - Berrydale #1 line uprate | Talbot Hill - Berrydale #1 line uprate | Talbot Hill - Berrydale #1 line uprate |
| Starwood autotransformer removal / Tacoma Power voltage increase | Starwood autotransformer removal / Tacoma Power voltage increase | Starwood autotransformer removal / Tacoma Power voltage increase |
| | Alderton 230-115 kV transformer | Alderton 230-115 kV transformer |
| | Lake Holm Substation (block load) | Lake Holm Substation (block load) |
| | Beverly Park 230-115 kV transformer | Beverly Park 230-115 kV transformer |
| | Sensitivity Study 2: Raver 500-230 kV transformer | Sensitivity Study 2: Raver 500-230 kV transformer |
| | Sensitivity Study 2: SCL series inductors | Sensitivity Study 2: SCL series inductors |

**Table B-2: Projects Added to the Summer NERC TPL Base Case for the Eastside Area**

| 2014 | 2018 |
|---|---|
| Beverly Park - Cottage Brook breaker replacement | Beverly Park - Cottage Brook breaker replacement |
| Cottage Brook - Moorlands line reconductor | Cottage Brook - Moorlands line reconductor |
| Saint Clair 230-115 kV transformer | Saint Clair 230-115 kV transformer |
| Talbot Hill - Berrydale #1 line uprate | Talbot Hill - Berrydale #1 line uprate |
| Starwood autotransformer removal / Tacoma Power voltage increase | Starwood autotransformer removal / Tacoma Power voltage increase |
| | Alderton 230-115 kV transformer |
| | White River - Electron Heights 115 kV line re-route into Alderton |
| | White River 2nd bus section breaker |
| | Lake Hills - Phantom Lake 115 kV line |
| | Lake Holm Substation (block load) |
| | Cumberland Substation 115 conversion (block load) |
| | Beverly Park 230-115 kV transformer |

# Appendix C: Quanta Technology and Puget Sound Energy Author Biographies

Quanta Technology assisted Puget Sound Energy in conducting this study, including research, analysis and documentation. Quanta Technology is an expertise-based, independent consulting company providing business and technical expertise to the energy and utility industries. They assist with deploying strategic and practical solutions to improve a company's business performance. Their mission is to provide value to clients in every engagement with the industry-best technical and business expertise, holistic and practical advice, and industry thought leadership.

Thomas J. Gentile, PE, *Quanta Technology Vice President Transmission Strategy,* is based in Massachusetts and has over 36 years of experience and proven leadership with transmission and distribution system planning, analysis, engineering, program/project management and interfacing with RTOs/ISOs and regulatory agencies. Mr. Gentile has participated in various planning, operating and market committees at NERC, NPCC, NYISO and ISO-NE. Tom received MSEE and BSEE degrees from Iowa State University and Northeastern University. He is a registered professional engineer in the State of Massachusetts.

Donald J. Morrow, PE, *Quanta Technology Partner, Senior Vice President of Corporate Strategy and Quanta Technology Expert*, has more than 30 years of utility and consulting experience. During the course of his career, Don has held a wide range of technical and management responsibilities including system planning, control area operations, transmission operations, energy trading, maintenance scheduling, operator training, protection, distribution operations, energy management systems and natural gas dispatch. Don received his BSEE and MBA from the University of Wisconsin, Madison. Don developed the transmission practice at Quanta Technology and he has led several transmission planning projects since 2006, including the SPP EHV Overlay study, the Smartransmission Project (www.smartstudy.biz), and Companhia de Electricidade de Macau in Macua, China. He is a registered professional engineer in the states of Wisconsin and Arkansas.

Carol O. Jaeger, PE, *Puget Sound Energy Consulting Engineer*, *Transmission Planning*, has over 30 years experience in transmission and distribution planning, distribution design, and substation design and operations. She received her BSEE from the University of Washington and is a registered professional engineer in the state of Washington.

Zach Gill Sanford, *Puget Sound Energy Engineer, Transmission Planning*, has over 4 years experience in transmission planning and NERC compliance. He received his BSEE from the University of Washington.

# Supplemental Eastside Needs Assessment Report

## Transmission System
## King County



April 2015

Puget Sound Energy

Report prepared by:
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# Executive Summary

This document summarizes the changes to the Eastside Needs Assessment Report dated October 2013, based upon the recent updates to the Puget Sound Energy (PSE) load forecast, system topology, facility ratings, changes affecting the Northern Intertie as the monitored flowgate for the Puget Sound Area Northern Intertie ("PSANI") issues, and changes to the Seattle City Light (SCL) system. This is a supplemental document that should be read in concert with the 2013 Eastside Needs Assessment Report ("2013 Needs Assessment").

The 2013 Needs Assessment concluded that there is a transmission capacity deficiency in the Eastside area which will develop by the winter of 2017-18. The assessment also concluded that the transmission capacity deficiency will continue to get worse as load grows. The 2013 Needs Assessment identified a number of concerns related to this transmission capacity deficiency, which included:

- Overload of PSE facilities in the Eastside area under certain contingencies
- Increasing use and expansion of Corrective Action Plans ("CAPs") to manage these overloads
- Inherent load forecast uncertainties which leave a small margin for error for the CAPs to be effective

The supplemental studies, utilizing the updated information discussed in this report, verified that there is still a transmission capacity deficiency in the Eastside area that will develop by the winter of 2017-18 and require the expanded use of CAPs to manage overloads for certain contingencies. In addition, the studies continued to show that this transmission capacity deficiency is expected to increase beyond that date. Cities in the deficiency area include: Redmond, Kirkland, Bellevue, Clyde Hill, Medina, Mercer Island, Issaquah, Newcastle, and Renton, along with towns of Yarrow Point, Hunts Point, and Beaux Arts.

The supplemental studies also verified that a transmission capacity deficiency still develops by the summer of 2018. However, the supplemental study showed that transmission capacity deficiency is actually worse than what was identified in the 2013 Needs Assessment. In the 2013 Needs Assessment, CAPs were required to mitigate the transmission capacity deficiency but load shedding was not required. In the supplemental study, both CAPs and load shedding are required to mitigate the transmission deficiency.

# 1. Introduction

This document summarizes the changes and results to the Eastside Needs Assessment dated October 2013, based upon the recent updates to the PSE load forecast, system topology, facility ratings, changes affecting the use of the Northern Intertie as the monitored flowgate for PSANI issues, and changes to the SCL system. This document also presents a comparison of the results using the updated information. The method, criteria, and key assumptions are the same as utilized in the 2013 Needs Assessment with the exception of those items discussed below.

# 2. Differences between the 2013 and 2015 Needs Assessments

## 2.1 Changes to the Power Flow Cases which have Minimal Impact

There are three changes that have minimal impact on the results of the supplemental study.

### 2.1.1 WECC Base Case Differences

Each year, Western Electric Coordinating Council (WECC), in coordination with its members, develops a set of “base cases” to model the bulk electric system. These base cases include the most up-to-date electrical system information for the entire WECC model including updated loads, generators, transmission lines, etc. All electric providers use these base cases as starting points to study their proposed system improvements and to understand the potential impacts to the regional electric grid, thereby ensuring no adverse impacts to the reliability and operating characteristics of its system or any surrounding system. The 2013 Needs Assessment was based on WECC base cases for the winter peak for years 2013-14, 2017-18, and 2021-22. Summer peak was analyzed for years 2014 and 2018 for the annual 2012 NERC TPL analysis.

For the 2015 Needs Assessment analysis, PSE utilized WECC winter peak base cases for the years 2019-20 and 2023-24. A 2017-18 case was developed from the 2019-20 base case. Summer peak base cases included the 2020 and 2024 WECC base cases. A 2018 summer case was developed from the 2020 base case.

### 2.1.2 Topology Changes in the Base Case

The studies within the 2015 Needs Assessment included all projects in the 2013 Needs Assessment, which are listed in Section 9 and Appendix B Tables B-1 and B-2 of the 2013 Needs Assessment. Changes in topology between the previous set of study cases and the current study cases are included in Appendix A of this report. Based on our analysis, no topology changes listed in Appendix A significantly impacted the study results. There was one change, the Talbot 230-115 kV transformer #1 replacement, which increased the winter normal and emergency limits from 383 MW and 464 MW to 398 MW and 484 MW respectively.

### 2.1.3 Northern Intertie vs. North of Echo Lake and South of Custer Flowgates

Prior to 2013, Bonneville Power Administration (BPA) used the West-Side Northern Intertie as the monitored flowgate for electricity transfers between the Puget Sound area and British Columbia. A one-line diagram of this flowgate is included in Appendix D. This flowgate was managed through the use of nomograms that would dictate the amount of capacity available on the Northern Intertie based on varying Puget Sound area generation levels, expected load levels, ambient temperature, and the next worst contingency. Nomograms were published on this Path for flows in both the north-south direction and the south-north direction. The amount of power that could be transferred between the Northwest and BC Hydro's system on the West-Side Northern Intertie was somewhat dependent on generation in the Puget Sound area. Transmission across the Northern Intertie would be curtailed if it was found that conditions would not support transfers, both in real time and in the operations planning timeframe. In February of 2013, BPA moved away from using the Northern Intertie as the basis for determining available transfer capability through the Puget Sound area and instead developed two new flowgates. These flowgates are the South of Custer (SOC) flowgate, used for determining acceptable north-south transfer levels through the Puget Sound area and the North of Echo Lake (NOEL) flowgate, used for determining acceptable south-north transfer levels. The lines that make up these new flowgates are included in Table 2-1. One-line diagrams of these updated flowgates are also included in Appendix D. These changes are used operationally to monitor flows that do not impact the study results but help determine and prevent adverse reliability impacts when power is flowing between the Northwest and BC Hydro's system.

**Table 2-1: Definitions of PSANI Flowgates**

| North of Echo Lake (NOEL) Flowgate Definition: | South of Custer (SOC) Flowgate Definition: |
|---|---|
| Echo Lake – SnoKing Tap 500 kV | Monroe – Custer #1 & #2 500 kV |
| Echo Lake – Maple Valley 500 kV | Murray – Custer 230 kV |
| Covington – Maple Valley 230 kV | Bellingham – Custer 230 kV |

## 2.2 Changes to the Power Flow Cases which had Substantial Impact

There are three changes that have a substantial impact on the results of the 2013 Needs Assessment. They are described below.

### 2.2.1 PSE has updated the Facility Ratings for all transmission lines in the system

For the 2013 Needs Assessment analysis, PSE used an Electric Power Research Institute (EPRI) tool called DYNAMP to establish transmission line facility ratings. By 2014, DYNAMP was no longer supported and PSE converted to a program called PLS–CADD. As a result of the conversion to this new tool, the transmission line facility ratings increased over the ratings used in the previous assessment. This increase in line ratings had an impact on post-contingency loadings, effectively reducing the percentage of overloads on facilities throughout the PSE system.

For example, the winter Emergency Facility Rating of the Talbot-Lakeside 115 kV line increased from 238.6 MVA to 249 MVA. In the 2017-18 Heavy Winter case, actual post-contingency MVA loading on the line for the worst Category B contingency in the 2013 Needs Assessment was 235.3 MVA or 98% of the 238.6 MVA line rating in the case. Actual post-contingency MVA loading on the line for the worst Category B contingency in the current study case was 218.3 MVA, or 87.6% of the 249 MVA line rating used in the case. If the line rating had not changed, loading in the current case would be 91.5% of the rating. Overloads seen on this line decreased by approximately 4% due to the change in line rating.

### 2.2.2 Seattle City Light Load Levels Decreased

In 2014, Seattle City Light made some corrections and adjustments to the load levels used in the WECC power flow base cases. These changes resulted in decreased Seattle City Light load levels.

### 2.2.3 Differences in load forecast levels utilized in the 2013 and 2015 Needs Assessments

The following briefly describes the PSE load forecasting process and the resulting differences between the 2012 and 2014 load forecast that were used in the 2013 and 2015 Needs Assessments.

PSE's service territory is very diverse, and hence, PSE experiences highly variable growth across its service territory. For the 2014 load forecast, PSE prepared a more detailed county-by-county forecast than had been done previously. The 2014 load forecast disaggregated the system wide forecast to county and sub-county regions to examine reasonableness from both system and sub-system perspectives. A small area forecast was also performed to focus on the Eastside study area.

PSE used data from PSE's electric demand and consumption history and federal and local government sources as inputs to develop an econometric load forecast using econometric-time series approach. PSE's electric demand and energy consumption history was also used to forecast future trending. Regional temperature taken at the National Oceanic and Atmospheric Administration (NOAA) station at SeaTac International Airport during the system peak was used to compare peak load reading. The load readings were normalized to 23˚ F, which was used as a 1-in-2 year normal ambient temperature at the time of system peak. Forecasts were also performed for a 1-in-20 year (or extreme temperature) forecast at 13˚ F.

To perform the system and county level forecasts, population data was also taken from the US Census as well as the US Bureau of Economic Analysis (BEA) and WA State Office of Financial Management (OFM). Employment data was taken from BEA, US Bureau of Labor Statistics (BLS), and Washington State Employment Security Department. Additionally, historic and forecasted US level data was from Moody's Analytics. At the sub-county level, population and employment data were obtained from Puget Sound Regional Council (PSRC) and WA State OFM.

PSE used the population and employment forecast evaluated by the PSRC for King, Pierce, and Kittitas counties. Population data was also taken from the US Census as well as the US BEA and WA State OFM. Employment forecast data were taken from the US BLS and PSRC.

To augment the data provided by the government agencies, PSE provided information about expected significant new loads, known as "block loads," over the next few years. This information was used for the first three years of the forecast period at full value, then at 50% value for the next three years. After six years, the forecast block loads were considered to be included in the data available on employment and population provided by the forecasting agencies so no additional load was added to the load forecast after year six.

Once an econometric forecast was developed for each county, or for the company as a whole, the peak demand and energy consumption were reduced by a forecast amount of conservation based on conservation target determined as optimal from the 2013 Integrated Resource Plan (IRP). This conservation target includes energy efficiency programs, Energy Independence and Security Act (EISA), distribution efficiency, and demand response. PSE has not implemented an active demand response program, so the demand response included in this forecast consisted of conservation programs and intrinsic conservation due to measures required by modern building codes.

It should be noted that a segment of PSE's transmission customers were not included in the corporate load forecast. These are interconnection or high voltage customers who connect to PSE for transmission service, but do not purchase energy from PSE. Approximately 250-300 MWs are required by the transmission customers on a nearly continuous basis.

There are some differences between the 2012 and 2014 load forecast worth noting:

a. The 2012 load forecast assumed faster recovery of the US economy from the recession than the 2014 load forecast.
b. The 2014 load forecast used updated US population growth forecast from the US Bureau of Census, which is lower compared to what was used in the 2012 load forecast.
c. Because of slower housing recovery, customer growth and customer counts in the 2014 load forecast are lower than the 2012 load forecast.
d. Peak load growth and peak load levels for the system and for King County are projected to be lower in the 2014 load forecast as compared to the 2012 load forecast.
e. Based on PSRC's population and employment growth forecasts, Eastside peak loads in the 2014 load forecast are projected to grow by 2.4% per year in the next 10 years, which is driven by growth in the commercial sector and high density residential sector. Also, updates to block loads over the study period influenced the load growth in the Eastside area.

The following tables show the comparison between the 2012 and 2014 system corporate load forecast and a breakdown by county of the 2014 corporate load forecast.

Table 2-2: Comparison of PSE's 2012 and 2014 Corporate Load Forecast

| PSE Corporate Load Forecast | | | | |
|---|---|---|---|---|
| | Forecasted 2012 | | Forecasted 2014 | |
| Year | Max of Normal Peak w/ DSR | Max of Extreme Peak w/ DSR | Max of Normal Peak w/ DSR | Max of Extreme Peak w/ DSR |
| 2012 | 4,837 | 5,316 | | |
| 2013 | 4,785 | 5,267 | | |
| 2014 | 4,836 | 5,333 | 4,803 | 5,255 |
| 2015 | 4,865 | 5,375 | 4,820 | 5,283 |
| 2016 | 4,909 | 5,432 | 4,844 | 5,317 |
| 2017 | 4,938 | 5,472 | 4,891 | 5,377 |
| 2018 | 4,938 | 5,483 | 4,891 | 5,385 |
| 2019 | 4,946 | 5,501 | 4,904 | 5,406 |
| 2020 | 4,923 | 5,490 | 4,856 | 5,365 |
| 2021 | 4,923 | 5,502 | 4,850 | 5,366 |
| 2022 | 4,972 | 5,562 | 4,863 | 5,388 |
| 2023 | 5,039 | 5,641 | 4,888 | 5,421 |
| 2024 | 5,117 | 5,732 | 4,961 | 5,504 |
| 2025 | 5,193 | 5,820 | 5,029 | 5,581 |
| 2026 | 5,266 | 5,905 | 5,085 | 5,645 |
| 2027 | 5,341 | 5,993 | 5,148 | 5,716 |
| 2028 | 5,426 | 6,090 | 5,224 | 5,802 |
| 2029 | 5,515 | 6,192 | 5,302 | 5,889 |
| 2030 | 5,605 | 6,296 | 5,376 | 5,972 |
| 2031 | 5,694 | 6,399 | 5,444 | 6,049 |
| 2032 | 5,785 | 6,504 | 5,512 | 6,126 |
| 2033 | 5,878 | 6,610 | 5,580 | 6,203 |
| 2034 | | | 5,649 | 6,282 |

**Table 2-3: PSE's 2014 Corporate Peak Load Forecast by County**

| 2014 PSE Corporate Peak Load Forecast by County | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | King | Thurston | Pierce | Whatcom | Skagit | Island | Kitsap | Kittitas | Total PSE |
| 2014 | 2391 | 549 | 498 | 374 | 265 | 144 | 524 | 59 | 4803 |
| 2015 | 2410 | 550 | 500 | 373 | 263 | 143 | 523 | 59 | 4820 |
| 2016 | 2427 | 552 | 503 | 372 | 262 | 143 | 524 | 61 | 4844 |
| 2017 | 2458 | 557 | 508 | 375 | 262 | 143 | 526 | 62 | 4891 |
| 2018 | 2454 | 559 | 510 | 375 | 260 | 143 | 526 | 64 | 4891 |
| 2019 | 2465 | 561 | 511 | 375 | 259 | 143 | 526 | 65 | 4904 |
| 2020 | 2445 | 555 | 506 | 371 | 254 | 140 | 518 | 66 | 4856 |
| 2021 | 2443 | 555 | 505 | 370 | 252 | 140 | 516 | 68 | 4850 |
| 2022 | 2454 | 557 | 506 | 370 | 251 | 139 | 516 | 70 | 4863 |
| 2023 | 2472 | 559 | 508 | 371 | 250 | 139 | 517 | 71 | 4888 |
| 2024 | 2515 | 567 | 515 | 376 | 252 | 141 | 522 | 74 | 4961 |
| 2025 | 2555 | 574 | 521 | 380 | 253 | 142 | 527 | 76 | 5029 |
| 2026 | 2590 | 580 | 526 | 384 | 254 | 143 | 531 | 78 | 5085 |
| 2027 | 2628 | 586 | 531 | 388 | 255 | 144 | 536 | 80 | 5148 |
| 2028 | 2675 | 594 | 538 | 392 | 256 | 145 | 541 | 82 | 5224 |
| 2029 | 2723 | 601 | 545 | 397 | 258 | 146 | 547 | 84 | 5302 |
| 2030 | 2769 | 609 | 551 | 402 | 259 | 147 | 553 | 87 | 5376 |
| 2031 | 2814 | 615 | 555 | 406 | 260 | 148 | 557 | 88 | 5444 |
| 2032 | 2859 | 621 | 559 | 410 | 261 | 149 | 562 | 90 | 5512 |

The 2013 Needs Assessment used PSE's 2012 corporate load forecast as the basis for the analyses and adjusted the load based on PSE's knowledge of future block loads and non-PSE customers supplied by PSE. In PSE's 2012 corporate load forecast, the forecast was provided for PSE's system as a whole, and sub-area forecasts were proportionally derived from this overall forecast. For the 2015 Needs Assessment, PSE's 2014 corporate load forecast was used and was also adjusted for non-PSE load supplied by PSE. This 2014 corporate load forecast provided an overall PSE system forecast and it also included bottom-up sub-area load forecasts for the King County and Eastside areas.

Table 2-4 below lists the Eastside and King County load levels for the cases used in the 2013 Needs Assessment and Table 2-5 lists the load levels using the 2014 load forecast. Comparing the results of the load levels for winter 2017-18, the total load level for PSE's system is 46 MW less using the 2014 load forecast (5162 MW) than the 2012 forecast (5208 MW). Using the 2014 load forecast, the King County area, without the Eastside load, is 27 MW higher (1854 MW – 1881 MW) and the Eastside area is 11 MW less than 2012 forecast (699 MW–688 MW). The remaining reduction is distributed over the rest of PSE.

**Table 2-4 Eastside and King County Load Levels Using 2012 Load Forecast in MW**

| Case | King County (excluding Eastside) | Eastside | Remainder of system | Total |
|---|---|---|---|---|
| 17-18HW | 1854 | 699 | 2654 | 5208 |
| 18HS | 1258 | 550 | 1744 | 3552 |
| 21-22HW | 1862 | 748 | 2548 | 5193 |

**Table 2-5: Eastside and King County Load Levels Using 2014 Load Forecast in MW**

| Case | King County (excluding Eastside) | Eastside | Remainder of system | Total |
|---|---|---|---|---|
| 17-18HW | 1881 | 688 | 2592 | 5162 |
| 17-18EHW | 2091 | 728 | 2828 | 5647 |
| 18HS | 1379 | 538 | 1707 | 3625 |
| 19-20HW | 1858 | 708 | 2609 | 5175 |
| 19-20EHW | 2084 | 749 | 2843 | 5676 |
| 20HS | 1373 | 561 | 1747 | 3681 |
| 23-24HW | 1817 | 764 | 2577 | 5158 |
| 23-24EHW | 2053 | 804 | 2833 | 5691 |
| 24HS | 1399 | 618 | 1800 | 3817 |

## 2.3 Base Cases Used for Analysis

The WECC base cases are updated annually. The cases available for this update were Heavy Winter 2019-20 and 2023-24 and Heavy Summer 2020 and 2024. All other cases were derived from those WECC cases. Table 2-6 below includes a comparison of the cases utilized in the 2013 Needs Assessment and the 2015 Needs Assessment study cases using 2014 updated data.

Table 2-6: Comparison of the Cases Utilized in the Eastside Needs Assessment

| Case | 2012 | 2014 |
|---|---|---|
| 2013-14 Heavy Winter | ✓ | -- |
| 2017-18 HW SN 100% Cons | ✓ | ✓ |
| 2017-18 HW SN 75% Cons | ✓ | -- |
| 2017-18 HW SN 50% Cons | ✓ | -- |
| 2019-20 HW SN 100% Cons | -- | ✓ |
| 2021-22 HW SN 100% Cons | ✓ | -- |
| 2021-22 HW SN 75% Cons | ✓ | -- |
| 2021-22 HW SN 50% Cons | ✓ | -- |
| 2021-22 HW SN Extreme 100% Cons | ✓ | -- |
| 2021-22 HW SN Extreme 75% Cons | ✓ | -- |
| 2023-24 HW SN 100% Cons | -- | ✓ |
| 2014 HS NS | ✓ | -- |
| 2018 HS NS | ✓ | ✓ |
| 2018 HS SN | ✓ | -- |
| 2024 HS NS | -- | ✓ |
| 2024 HS SN | -- | ✓ |

## 2.4 Points of Clarification from the 2013 Needs Assessment

### 2.4.1 Use of Corrective Action Plans (CAPs)

PSE uses operating procedures, such as corrective action plans (CAPs), to prevent any loss of firm load, either intentionally or due to a credible outage condition while remaining compliant with mandatory NERC/WECC reliability requirements. CAPs are generally considered temporary in nature with the understanding that permanent solutions are forthcoming. NERC Standard TPL-001-4 allows CAPs to be used to meet the performance requirements for most N-1-1 and N-2 contingencies while specifying how long they will be needed as part of the CAPs.

### 2.4.2 Use of Load Shedding

While NERC and WECC allow dropping "non-consequential[1]" load for certain contingencies, intentionally dropping firm load for an N-1-1 or N-2 contingency to meet its federal planning requirements is not a practice that PSE endorses. All load modeled in the Needs Assessment studies was firm load and PSE does not consider any of its firm requirements to be non-consequential. This is consistent with the view of most utilities. It is also consistent with the views of virtually all community officials who do not consider intentionally blacking out segments of customers as a responsible way to operate a modern electricity delivery system.

PSE's concern about using load shedding for N-1-1 contingencies is best illustrated by the outage of two 230 kV-115 kV transformers in the Eastside area. Losing two 230 kV-115 kV transformers could result in the other remaining 230 kV-115 kV transformers being overloaded. In this scenario, simply re-dispatching PSE generation does not reduce these transformer overloads below the emergency rating. A transformer outage would require a minimum 24-hour outage to test and re-energize the transformer. Further, if the outaged transformer tests bad, then it must be replaced, and this can take up to another five to seven weeks. This scenario results in a significant amount of time to place PSE customers at risk either with CAPs or with exposure to load shedding.

To illustrate how other utilities in WECC address load shedding, the CAISO Planning Standards indicates in their Section 6, Planning for High Density Urban Load Area:

> *"Increased reliance on load shedding to meet these needs would run counter to historical and current practices, resulting in general deterioration of service levels. For local area long-term planning, the ISO does not allow non-consequential load dropping in high density urban load areas in lieu of expanding transmission or local resource capability to mitigate NERC TPL-001-4 standards P1-P7 contingencies and impacts on the 115 kV or higher voltage systems….In the near-term planning, where allowed by NERC standards, load dropping, including high density urban load, may be used to bridge the gap between real-time operations and the time when system reinforcements are built."*

## 3. Results of 2015 Needs Assessment

The detailed results of the 2015 Needs Assessment are shown in Appendix A for winter peak conditions and Appendix B for summer peak conditions. The results verified that there is a transmission capacity deficiency in the Eastside area that will develop by the winter of 2017-18. This transmission capacity deficiency in the Eastside area is expected to increase beyond that date.

Using the same methodology as the 2013 Needs Assessment, the supplemental analysis shows that a transmission capacity deficiency develops at a winter Eastside area load of 688 MW, requiring the use of CAPs, and worsens at an Eastside area load of 708 MW, requiring both the use of CAPs and exposing some PSE customers to load shedding. The transmission capacity deficiency also develops at a summer Eastside area load of 538 MW.

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[1] Non-Consequential Load is defined as Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment. Consequential Load is defined as all Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Similar to the 2013 results, there were a significant number of overloads that showed up in the results of power flow studies due to outages of high voltage lines owned by other utilities that interconnect to PSE. Most of these are outages in BPA's 230 kV or 500 kV network. BPA and the other interconnected utilities have operating procedures in place to prevent overloads of area facilities, including PSE lines and equipment. For example, the most frequent external contingency that causes PSE overloads is an outage of the [redacted]. BPA operates the interchange flows and generation levels so that this [redacted] line outage does not cause overloads. Therefore, overloads resulting from this [redacted] BPA line were not considered as necessary for PSE to resolve.

In addition, a number of overloads of area transmission lines can be partially mitigated by adjusting PSE generation levels in Western Washington. As such, this type of generation re-dispatch costs more than the optimal generation levels that PSE would elect, thereby driving up customer costs. Therefore, while these system adjustments are not a desirable operating condition, they are acknowledged as an available action to mitigate these types of overloads while remaining NERC compliant.

There are still a number of transmission transformer overloads which cannot be addressed by dispatching generation, similar to the 2013 Needs Assessment. These transformer overloads will require CAPs in the future to shift load; at some point the CAPs will be expanded to include load shedding in order to remain NERC compliant.

## 3.1 Winter Analysis

Utilizing the 2014 load forecast and the results of the winter analysis, Figure 3-1 shows two system capacity lines for the Eastside area – both of which are reflected on the graph as dashed red lines. These lines highlight the area of concern where the 2015 Needs Assessment indicates violations of the mandatory performance requirements developed for certain contingencies that put customer reliability at risk. The area of concern starts at an Eastside area load of 688 MW in the winter of 2017-18 and continues to 708 MW in the winter of 2019-20. The 2015 Needs Assessment established that a transmission capacity deficiency exists at an Eastside area load level of 688 MW that requires the use of CAPs to manage Category C overloads in winter of 2017-18. The 2015 Needs Assessment also established that the transmission capacity deficiency continues to worsen at an Eastside area load level of 708 MW, which requires the use of additional CAPs by winter of 2019-20. These additional CAPs placed approximately 63,200 customers at risk of losing power due to being served radially. By the winter of 2023-24 the CAPs will require load shedding affecting approximately 16,800 customers to prevent thermal violations under certain conditions.

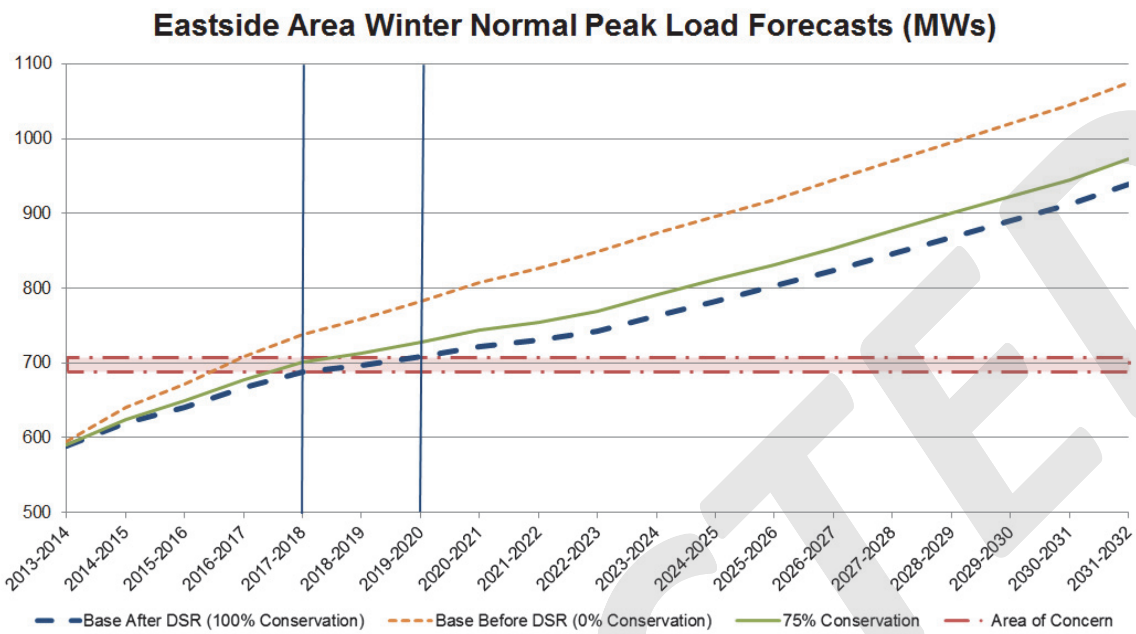


**Figure 3-1: Capacity Need Results with 2015 Updated Information**

The area of concern shown in Figure 3-1 is consistent with the 706 MVA level of concern identified for the Eastside area in the 2013 Needs Assessment. This value was reflected in the graph shown in Figure 4-3 of the 2013 Needs Assessment (where the units were mislabeled as “MW”). The actual MW value for the level of concern was 699 MW in the 2013 Needs Assessment. The 699 MW value reflected the load level of the Eastside area in the winter of 2017-18 in the previous study where the power flows indicated violations of the mandatory performance requirements that put customer reliability at risk. For ease of reference, this figure is repeated below as Figure 3-2.

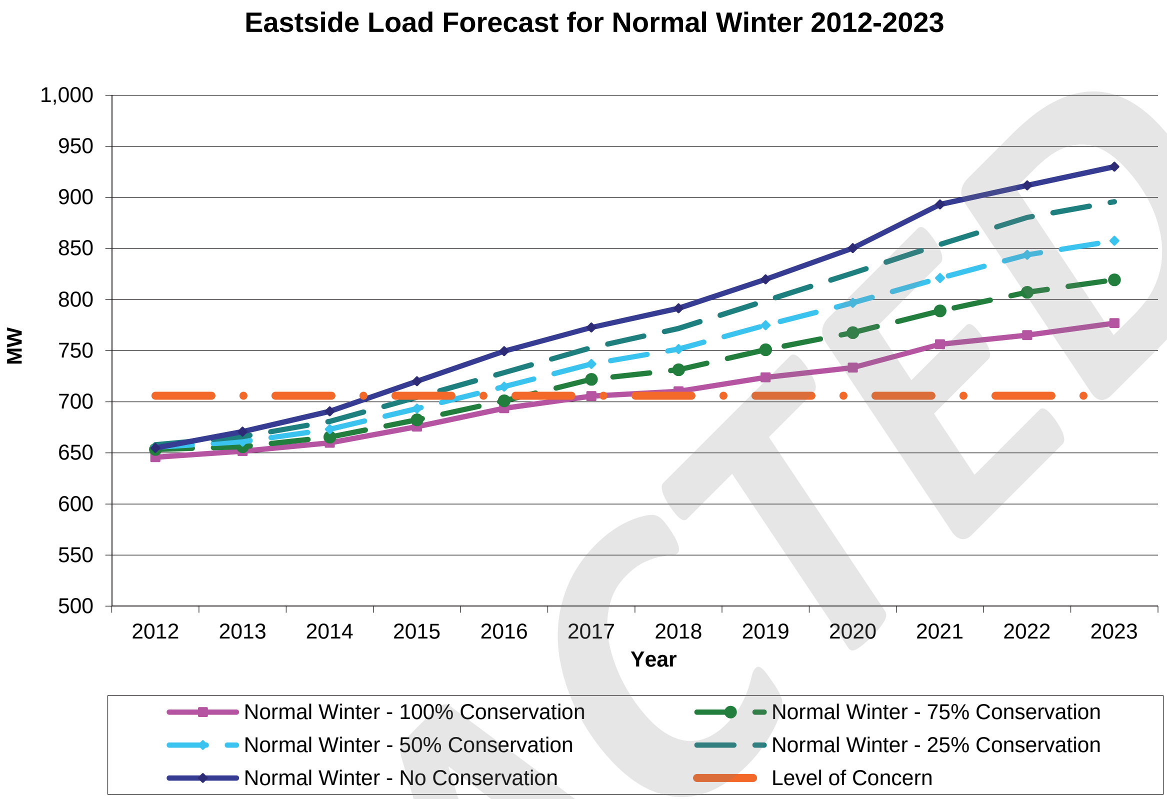


**Figure 3-2: Level of Concern for Eastside Area Load in 2013 Needs Assessment**

As the winter summary in Table 3-1 shows, CAPs are needed throughout the study period. As noted above, CAPs are required starting in the winter of 2017-18 to manage overloads on five elements from 12 Category C contingencies. By 2019-20, the overloads on these same five elements will be created from 18 Category C contingencies, which require additional CAPs to manage and which place approximately 63,200 customers at risk by placing them on radial feeds. By 2023-24 the overloads on these same five elements will be caused by 40 Category C contingencies, which require the use of even more CAPs and place approximately 68,800 customers at risk. In addition, by 2023-24 load shedding of approximately 133 MW will be needed to maintain a reliable and secure transmission system.

**Table 3-1: Winter Power Flow Summary Comparison of 2013 and 2015 Needs Assessment**

| Winter Power Flow Summary | | | | | | |
|---|---|---|---|---|---|---|
| | 2012 Load Forecast | | | 2014 Load Forecast | | |
| | 2013-14 Winter<br>5055 MW<br>100% Conserv-ation<br>Eastside Load = 545 MW | 2017-18 Winter<br>5208 MW<br>100% Conserv-ation<br>Eastside Load = 699 MW | 2021-22 Winter<br>5193 MW<br>100% Conserv-ation<br>Eastside Load = 748 MW | 2017-18 Winter<br>5162 MW<br>100% Conserv-ation<br>Eastside Load = 688 MW | 2019-20 Winter<br>5175 MW<br>100% Conserv-ation<br>Eastside Load = 708 MW | 2023-24 Winter<br>5158 MW<br>100% Conserv-ation<br>Eastside Load = 764 MW |
| **Elements Above Emergency Limit:** | | | | | | |
| Category B (N-1) | 0 | 0 | 2 | 0 | 0 | 0 |
| Category C (N-1-1 & N-2) | 5 | 6 | 5 | 5 | 5 | 5 |
| Corrective Action Plans Required | Yes | Yes | Yes | Yes | Yes | Yes |
| Customers at Risk from Corrective Action Plans | 0 | 68,800 | 76,300 | 0 | 63,200 | 68,800 |
| Customers at Risk from Load Shedding | 0 | 0 | 4,400 | 0 | 0 | 16,800 |
| Load Shed MW | 0 | 0 | 22 | 0 | 0 | 133 |
| **Elements Above Normal Limit or 90% of Emergency Limit:** | | | | | | |
| Category B (N-1) | 0 | 4 | 6 | 0 | 3 | 3 |
| Category C (N-1-1 & N-2) | 6 | 7 | 8 | 7 | 6 | 5 |
| **Contingencies that cause post-contingency loading above 100% of Emergency Limit:** | | | | | | |
| Category B (N-1) | 0 | 0 | 1 | 0 | 0 | 0 |
| Category C (N-1-1 & N-2) | 13* | 23* | 37* | 12 | 18 | 40 |

* Note: There were additional contingencies in the study using the 2012 Load Forecast that resulted in overloads between 100% and 104%. In the supplemental study, overloads on the PSE lines between 100% and 104% were eliminated to account for the change in line ratings from 2012 to 2014. Those overloads are not included in the 2012 Load Forecast counts provided in this table.

Detailed results of the winter analysis are shown in Appendix A.

## 3.2 Summer Analysis

The 2013 Needs Assessment showed a PSE area summer load level of need at approximately 3340 MW. This need was illustrated in Figure 1-2 of that document and is included as Figure 3-3 below for ease of reference.

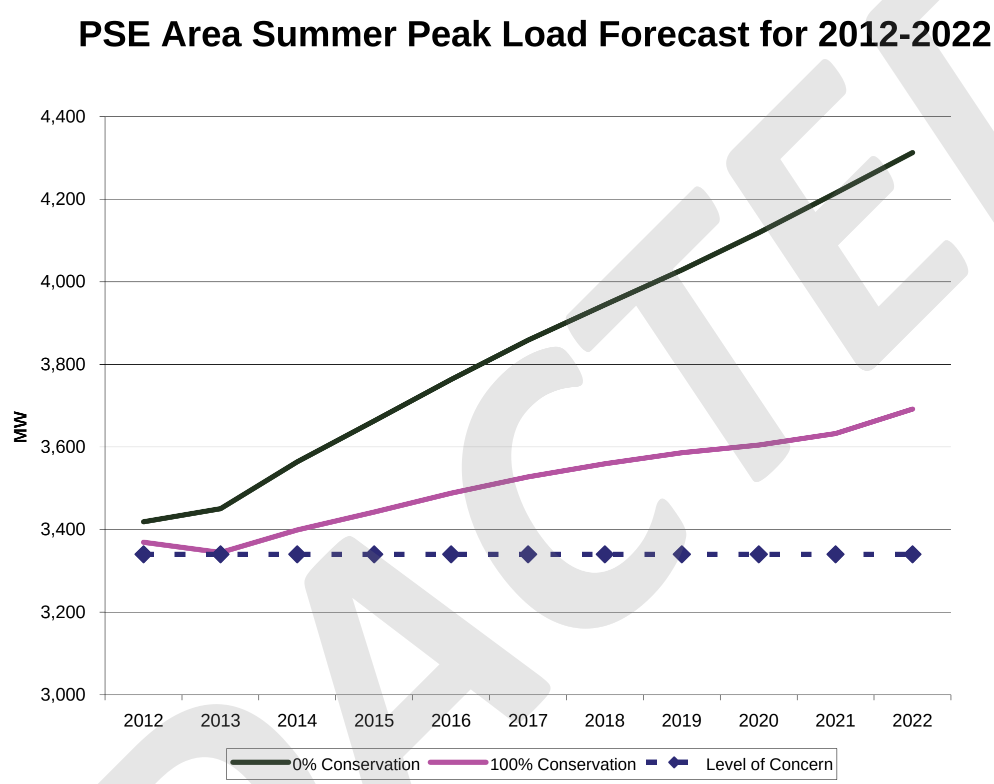


**Figure 3-3: PSE Area Summer Peak Load Forecast for 2012-2022**

The 2013 Needs Assessment, analyzed the summer of 2018, had a PSE area summer peak of approximately 3,552 MW. That 2013 assessment found there were two 230 kV elements above 100% and two 115 kV elements above 93% loadings for Category B (N-1) contingencies. Also, there were three elements above 100% loading and one above 99% loading for Category C (N-1-1) contingencies. In the 2013 Needs Assessment, the 3,552 MW system load corresponds to an Eastside Area load level of 550 MW. In the 2013 Needs Assessment, we identified that CAPs were needed to manage the Category C (N-1-1) contingencies and that up to 33,000 customers would be put at risk when those CAPs were utilized.

The 2015 Needs Assessment shows an Eastside summer load level of need at approximately 538MW. This need is shown in Figure 3-4 below.

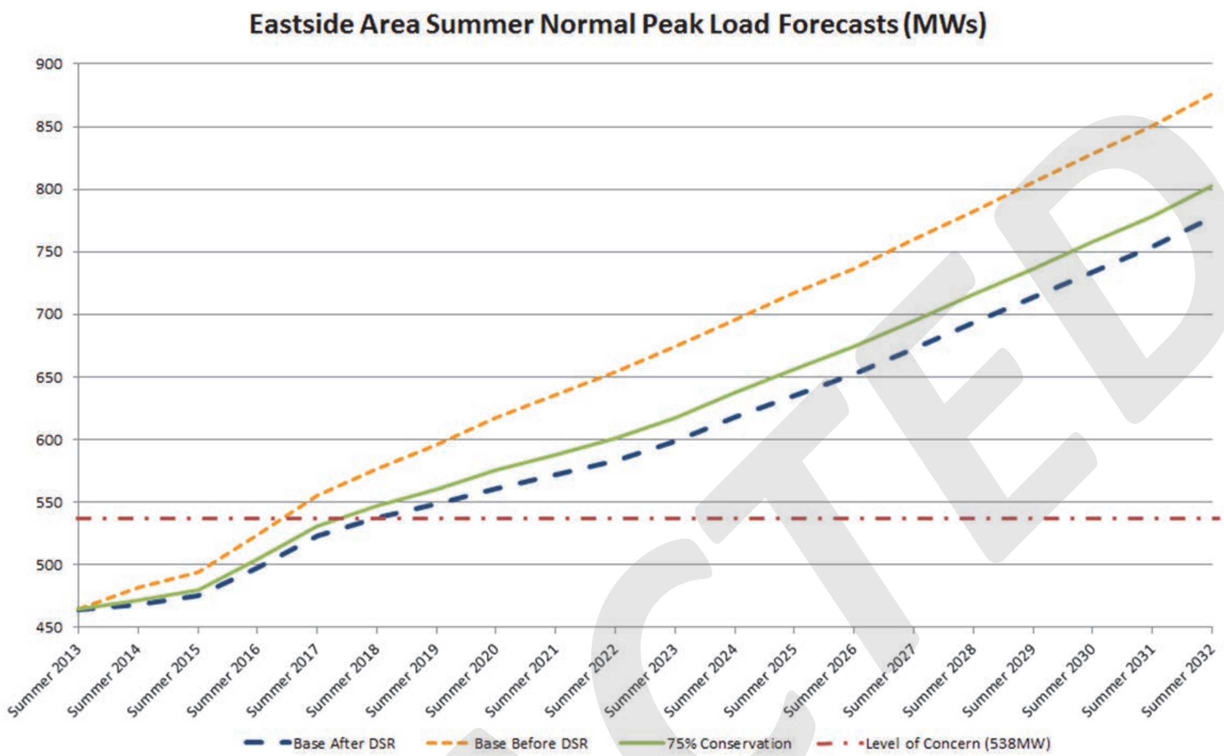


**Figure 3-4: Eastside Summer Peak Load Forecast for 2012-2023**

Table 3-2 summarizes the results of the 2015 Needs Assessment and it shows that the amount of customers at risk for losing power will increase to approximately 68,800 by the summer of 2018. The 2015 Needs Assessment also shows that load shedding of approximately 74 MW will be needed to maintain a reliable and secure transmission system starting in the summer 2018, increasing to approximately 78 MW in 2020 and approximately 123 MW by 2024. The number of contingencies that cause post-contingency loading above 100% Emergency Limit is six by the summer of 2018 and grows to nine by 2024.

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**Table 3-2: Summer Power Flow Summary Comparison of October 2013 and 2015 Updated Results**

| Summer Power Flow Summary | | | | |
|---|---|---|---|---|
| | **2012 Load Forecast** | **2014 Load Forecast** | | |
| | **2018 Summer**<br>**3552 MW**<br>**100% Conservation**<br>**Eastside Load = 550 MW** | **2018 Summer 3625 MW 100%** Conserv-ation **Eastside Load = 538 MW** | **2020 Summer 3681 MW 100%** Conserv-ation **Eastside Load = 561 MW** | **2024 Summer 3817 MW 100%** Conserv-ation **Eastside Load = 618 MW** |
| **Elements Above Emergency Limit:** | | | | |
| Category B (N-1) | 2[1] | 1[1] | 2[1] | 2[1] |
| Category C (N-1-1 & N-2) | 3 | 5[2] | 5[2] | 5[2] |
| Corrective Action Plans Required | Yes | Yes | Yes | Yes |
| Customers at Risk from Corrective Action Plans | 62,800 | 68,800 | 68,800 | 68,800 |
| Customers at Risk from Load Shedding | 0 | 10,900 | 10,900 | 12,700 |
| Load Shed MW | 0 | 74 | 78 | 123 |
| **Elements Above Normal Limit or 90% of Emergency Limit:** | | | | |
| Category B (N-1) | 4 | 1 | 2 | 2 |
| Category C (N-1-1 & N-2) | 4 | 6 | 6 | 6 |
| **Contingencies that cause post-contingency loading above 100% of Emergency Limit:** | | | | |
| Category B (N-1) | 2 | 2 | 2 | 2 |
| Category C (N-1-1 & N-2) | 8 | 6 | 7 | 9 |

[1] These elements are BPA transmission lines leased by PSE

[2] These elements include 1 BPA transmission line leased by PSE

Detailed results of the summer analysis are shown in Appendix B.

# 4. Conclusions of the 2015 Needs Assessment using the 2014 PSE Load Forecast

The project date of need will remain the same at the winter of 2017-18 due to these key risk factors:

- The 2017-18 winter power flow cases still require the use of CAPs to mitigate transmission transformer overloads with load risk beginning between 2017-18 to 2019-20.
- The number of contingencies requiring the use of CAPs steadily increases as load grows.
- The forecast uses a 1-in-2 year weather forecast. Colder weather will result in higher load levels.
- 100% conservation may not be achieved, which would result in a higher load level. Even if 100% conservation is achieved, it may not be in the appropriate locations and magnitudes assumed for this assessment.
- There is only 20 MW difference on the Eastside between the winters of 2017-18 and 2019-20, and in the winter of 2019-20 with over 60,000 customers are at risk.
- By the summer of 2018, studies show that 68,800 customers will be at risk of outages and 10,900 customers at risk of load shedding using CAPs to mitigate transmission transformer overloads.
- Load shedding becomes an increasingly necessary action as load grows.

# 5. Statement of Need

The 2015 Needs Assessment reconfirmed that, by winter of 2017-18, there is a transmission capacity deficiency on the Eastside that impacts PSE customers and communities in and around Kirkland, Redmond, Bellevue, Issaquah, Newcastle, and Renton along with Clyde Hill, Medina, and Mercer Island. The transmission deficiency focuses on the two 230 kV supply injections into central King County at Sammamish substation in the north and Talbot Hill substation in the south. The transmission capacity becomes a need at an Eastside winter load level of approximately 688 MW, where overloads will result in operating conditions that require CAPs to manage. By winter of 2019-20, at an Eastside load level of approximately 706 MW, additional CAPs are required that will put approximately 63,200 Eastside customers at risk of outages. These results are summarized in Table 3-1 above.

The 2015 Needs Assessment also reconfirmed that by summer of 2018, there will be a transmission capacity deficiency on the Eastside which impacts PSE customers and communities in and around Kirkland, Redmond, Bellevue, Issaquah, and Newcastle along with Clyde Hill, Medina, and Mercer Island. By summer of 2018, CAPs will be required to manage overloads under certain Category C contingencies and the use of these CAPs will place approximately 68,800 customers at risk and will require 74 MW of load shedding, affecting approximately 10,900 customers. These results are summarized in Table 3-2 above.

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# Appendix A. 2015 Needs Assessment Results for Winter Peak Season

**Table A-1: Summary of Potential Thermal Violations for Winter Peak Load Season**

| 2013-14<br>5055 MW<br>100% Con<br>Eastside Load = 545 MW | | 2017-18<br>5208 MW<br>100 % Con<br>Eastside Load = 699 MW | | 2021-22<br>5193 MW<br>100% Con<br>Eastside Load = 748 MW | | 2017-18<br>5162 MW<br>100% Conservation<br>Eastside Load = 688 MW | | 2019-20<br>5175 MW<br>100% Conservation<br>Eastside Load = 708 MW | | 2023-24<br>5153 MW<br>100% Conservation<br>Eastside Load = 764 MW | | 2023-24 Extreme<br>5690 MW<br>100% Conservation<br>Eastside Load = 804 MW | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Category B: N-1 Contingency Results | | | | | | | | | | | | | |
| [redacted] | Overload | [redacted] | Overload | [redacted] | Overload | [redacted] | Overload | [redacted] | Overload | [redacted] | Overload | [redacted] | Overload |
| | | [redacted] | Talbot Hill - Lakeside #1 115 kV line – 98.6% | [redacted] | Talbot Hill - Lakeside #1 115 kV line – 97.4% | [redacted] | Talbot Hill - Lakeside #1 115 kV line – 87.7%[3] | [redacted] | Talbot Hill - Lakeside #1 115 kV line – 91.1% | [redacted] | Talbot Hill - Lakeside #1 115 kV line – 96.1% | [redacted] | Talbot Hill - Lakeside #1 115 kV line – 101.0% |
| | | [redacted] | Talbot Hill - Lakeside #2 115 kV line – 98.4% | [redacted] | Talbot Hill - Lakeside #2 115 kV line – 97.2% | [redacted] | Talbot Hill - Lakeside #2 115 kV line – 87.5% | [redacted] | Talbot Hill - Lakeside #2 115 kV line – 90.9% | [redacted] | Talbot Hill - Lakeside #2 115 kV line – 92.4% | [redacted] | Talbot Hill - Lakeside #2 115 kV line – 97.1% |
| | | [redacted] | Talbot Hill 230-115 kV transformer #1 – 89.0% | [redacted] | Talbot Hill 230-115 kV transformer #1 – 91.0% (see footnote 4) | [redacted] | Talbot Hill 230-115 kV transformer #1 – 85.1%[4] | [redacted] | Talbot Hill 230-115 kV transformer #1 – 85.6% | [redacted] | Talbot Hill 230-115 kV transformer #1 – 87.1% | [redacted] | Talbot Hill 230-115 kV transformer #1 – 95.9% |
| | | [redacted] | Talbot Hill 230-115 kV transformer #2 – 90.3% | [redacted] | Talbot Hill 230-115 kV transformer #2 – 91.5% | [redacted] | Talbot Hill 230-115 kV transformer #2 – 89.3% | [redacted] | Talbot Hill 230-115 kV transformer #2 – 90.2% | [redacted] | Talbot Hill 230-115 kV transformer #2 – 92.8% | [redacted] | Talbot Hill 230-115 kV transformer #2 – 101.9% |

[2] All contingencies involving loss of the Monroe – Echo Lake – SnoKing 500 kV three-terminal line are unsolvable in the 21-22HW case without modeling the Intalco load tripping RAS. Study results reflect opening all Intalco loads, totaling about 300 MW, to get the case to a solvable state. Opening these loads slightly changes line flows in the case and may contribute to the decrease in post-contingency line loading.

[3] Decrease in post-contingency line loading can be attributed to lower area load, lower SCL load and increased line ratings between the 2012 study and the current study.

[4] The Talbot 230/115 kV transformer #1 is scheduled to be replaced in 2015 and the new expected ratings and impedance were included in the 2014 cases.

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| 2013-14<br>5055 MW<br>100% Con<br>Eastside Load = 545 MW | | 2017-18<br>5208 MW<br>100 % Con<br>Eastside Load = 699 MW | | 2021-22<br>5193 MW<br>100% Con<br>Eastside Load = 748 MW | | 2017-18<br>5162 MW<br>100% Conservation<br>Eastside Load = 688 MW | | 2019-20<br>5175 MW<br>100% Conservation<br>Eastside Load = 708 MW | | 2023-24<br>5153 MW<br>100% Conservation<br>Eastside Load = 764 MW | | 2023-24 Extreme<br>5690 MW<br>100% Conservation<br>Eastside Load = 804 MW | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | [redacted] | Sammamish-Lakeside #1 115 kV Line - 104.7% | | | | | | | | |
| | | | | [redacted] | Sammamish-Lakeside #2 115 kV Line - 104.5% | | | | | | | | |

## Category C: N-1-1 Contingency Results

| [redacted] | Overload | [redacted] | Overload | [redacted] | Overload | [redacted] | Overload | [redacted] | Overload | [redacted] | Overload | [redacted] | Overload |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| [redacted] | Talbot Hill-Lakeside #1 115 kV Line - 115.2% | [redacted] | Talbot Hill--Lakeside #1 115 kV Line - 127.5% | [redacted] | Talbot Hill--Lakeside #1 115 kV Line – 125.9% | [redacted] | Talbot Hill--Lakeside #1 115 kV Line – 113.3% | [redacted] | Talbot Hill-Lakeside #1 115 kV Line – 117.4% | [redacted] | Talbot Hill - Lakeside #1 115 kV line – 123.9% | [redacted] | Talbot Hill - Lakeside #1 115 kV line – 130.5% |
| [redacted] | Talbot Hill-Lakeside #2 115 kV Line - 115.1% | [redacted] | Talbot Hill--Lakeside #2 115 kV Line - 127.7% | [redacted] | Talbot Hill-Lakeside #2 115 kV Line – 125.8% | [redacted] | Talbot Hill-Lakeside #2 115 kV Line – 113.1% | [redacted] | Talbot Hill-Lakeside #2 115 kV Line – 117.3% | [redacted] | Talbot Hill-Lakeside #2 115 kV Line – 120.8% | [redacted] | Talbot Hill-Lakeside #2 115 kV Line – 127.2% |
| [redacted] | Talbot Hill 230-115 kV transformer #1 - 100.9% | [redacted] | Talbot Hill 230-115 kV transformer #1 – 105.8% | [redacted] | Talbot Hill 230-115 kV transformer #1 - 108.1% | [redacted] | Talbot Hill 230-115 kV transformer #1 – 101.0% | [redacted] | Talbot Hill 230-115 kV transformer #1 – 101.3% | [redacted] | Talbot Hill 230-115 kV transformer #1 – 103.1% | [redacted] | Talbot Hill 230-115 kV transformer #1 – 113.7% |
| [redacted] | Talbot Hill 230-115 kV transformer #2 - 100.5% | [redacted] | Talbot Hill 230-115 kV transformer #2 - 105.7% | [redacted] | Talbot Hill 230-115 kV transformer #2 - 107.0% | [redacted] | Talbot Hill 230-115 kV transformer #2 – 104.6% | [redacted] | Talbot Hill 230-115 kV transformer #2 – 105.4 % | [redacted] | Talbot Hill 230-115 kV transformer #2 – 108.1% | [redacted] | Talbot Hill 230-115 kV transformer #2 – 118.5% |

| 2013-14<br>5055 MW<br>100% Con<br>Eastside Load = 545 MW | | 2017-18<br>5208 MW<br>100 % Con<br>Eastside Load = 699 MW | | 2021-22<br>5193 MW<br>100% Con<br>Eastside Load = 748 MW | | 2017-18<br>5162 MW<br>100% Conservation<br>Eastside Load = 688 MW | | 2019-20<br>5175 MW<br>100% Conservation<br>Eastside Load = 708 MW | | 2023-24<br>5153 MW<br>100% Conservation<br>Eastside Load = 764 MW | | 2023-24 Extreme<br>5690 MW<br>100% Conservation<br>Eastside Load = 804 MW | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| [redacted] | Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 101.1% | [redacted] | Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 110.4% | [redacted] | Talbot Hill-Boeing Renton-Shuffleton 115 kV Line – 110.5% | [redacted] | Talbot Hill-Boeing Renton-Shuffleton 115 kV Line – 101.1% | [redacted] | Talbot Hill-Boeing Renton-Shuffleton 115 kV Line – 103.0% | [redacted] | Talbot Hill-Boeing Renton-Shuffleton 115 kV Line – 102.9% | [redacted] | Talbot Hill-Boeing Renton-Shuffleton 115 kV Line – 110.2% |
| [redacted] | White River - Lea Hill - Berrydale 115 kV line - 91.7% | [redacted] | White River - Lea Hill - Berrydale 115 kV line – 98.0% | [redacted] | White River - Lea Hill - Berrydale 115 kV line - 99.7% | [redacted] | White River - Lea Hill - Berrydale 115 kV line – 90.6% | [redacted] | White River - Lea Hill - Berrydale 115 kV line – 92.0% | [redacted] | White River - Lea Hill - Berrydale 115 kV line – 88.4%[4] | [redacted] | White River - Lea Hill - Berrydale 115 kV line – 98.2% |
| Category C: N-2 and Common Mode Contingency Results | | | | | | | | | | | | | |
| [redacted] | Overload | [redacted] | Overload | [redacted] | Overload | [redacted] | Overload | [redacted] | Overload | [redacted] | Overload | [redacted] | Overload |
| | | [redacted] | Talbot Hill-Lakeside #1 115 kV Line - 101.5% | [redacted] | Talbot Hill - Lakeside #1 115 kV line – 96.8%[5] | [redacted] | Talbot Hill-Lakeside #1 115 kV Line – 89.9% | [redacted] | Talbot Hill-Lakeside #1 115 kV Line – 92.3% | [redacted] | Talbot Hill-Lakeside #1 115 kV Line – 98.9% | [redacted] | Talbot Hill-Lakeside #1 115 kV Line – 102.3% |
| | | [redacted] | Talbot Hill-Lakeside #2 115 kV Line - 102.1% | [redacted] | Talbot Hill - Lakeside #2 115 kV line – 107.1%[6] | [redacted] | Talbot Hill-Lakeside #2 115 kV Line – 94.5% | [redacted] | Talbot Hill-Lakeside #2 115 kV Line – 99.4% | [redacted] | Talbot Hill-Lakeside #2 115 kV Line – 103.4% | [redacted] | Talbot Hill-Lakeside #2 115 kV Line – 107.7% |
| | | [redacted] | Talbot Hill 230-115 kV transformer #1 – 91.8% | [redacted] | Talbot Hill 230-115 kV transformer #1 – 93.6% | [redacted] | Talbot Hill 230-115 kV transformer #1 – 88.1% | [redacted] | Talbot Hill 230-115 kV transformer #1 – 88.2% | [redacted] | Talbot Hill 230-115 kV transformer #1 – 90.1% | [redacted] | Talbot Hill 230-115 kV transformer #1 – 99.6% |

[5] Using the 2012 load forecast in the 2021-22 Heavy Winter case, this contingency is unsolvable, even with the Intalco load tripping RAS modeled.

[6] N-2: ADJ Talbot – Lake Tradition #1 & Talbot – Lakeside #1 115 kV was second most limiting contingency and overloaded this element by 106.6%. It is possible that, as load drops, the limiting contingency will change.

| 2013-14<br>5055 MW<br>100% Con<br>Eastside Load = 545 MW | | 2017-18<br>5208 MW<br>100 % Con<br>Eastside Load = 699 MW | | 2021-22<br>5193 MW<br>100% Con<br>Eastside Load = 748 MW | | 2017-18<br>5162 MW<br>100% Conservation<br>Eastside Load = 688 MW | | 2019-20<br>5175 MW<br>100% Conservation<br>Eastside Load = 708 MW | | 2023-24<br>5153 MW<br>100% Conservation<br>Eastside Load = 764 MW | | 2023-24 Extreme<br>5690 MW<br>100% Conservation<br>Eastside Load = 804 MW | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | [redacted] | Talbot Hill 230-115 kV transformer #2 – 92.8% | [redacted] | Talbot Hill 230-115 kV transformer #2 – 93.2% | [redacted] | Talbot Hill 230-115 kV transformer #2 – 93.14% | [redacted] | Talbot Hill 230-115 kV transformer #2 – 92.6% | [redacted] | Talbot Hill 230-115 kV transformer #2 – 95.7% | [redacted] | Talbot Hill 230-115 kV transformer #2 – 104.8% |
| | | [redacted] | Berrydale 230-115 kV transformer – 93.6% | [redacted] | Berrydale 230-115 kV transformer - 95.5% | [redacted] | Berrydale 230-115 kV transformer – 95.6% | [redacted] | Berrydale 230-115 kV transformer – 87.6% | [redacted] | Berrydale 230-115 kV transformer – 88.3%[7] | [redacted] | Berrydale 230-115 kV transformer – 96.7% |

[7] BF: White River 115 kV bus section breaker resulted in loading the Berrydale 230/115 kV transformer to 87.3% for this case. As loading shifts off of the Berrydale transformer, the White River BSBF is less critical.

# Appendix B. Supplemental Needs Assessment Results for Summer Peak Season

**Table B-2: Summary of Potential Thermal Violations for Summer Peak Load Season**

| 2014<br>3343 MW<br>100% Con | | 2018<br>3554 MW<br>100% Con<br>Eastside Load = 550 MW | | 2018<br>3625 MW<br>100% Conservation<br>Eastside Load = 538 MW | | 2020<br>3681 MW<br>100% Conservation<br>Eastside Load = 561 MW | | 2024<br>3813 MW<br>100% Conservation<br>Eastside Load = 618 MW | |
|---|---|---|---|---|---|---|---|---|---|
| **Category B: N-1 Contingency Results** | | | | | | | | | |
| [redacted] | Overload | [redacted] | Overload | [redacted] | Overload | [redacted] | Overload | [redacted] | Overload |
| [redacted] | Monroe-Novelty Hill 230 kV line - 132.6% | [redacted] | Monroe-Novelty Hill 230 kV line - 133.0% | [redacted] | Monroe-Novelty Hill 230 kV line – 143.9% | [redacted] | Monroe-Novelty Hill 230 kV line – 143.1% | [redacted] | Monroe-Novelty Hill 230 kV line – 139.8% |
| [redacted] | Maple Valley - Sammamish 230 kV line - 111.4% | [redacted] | Maple Valley - Sammamish 230 kV line - 132.3% | [redacted] | N/A | [redacted] | Maple Valley - Sammamish 230 kV line – 110.0%[9] | [redacted] | Maple Valley - Sammamish 230 kV line – 116.4% |
| | | [redacted] | Talbot Hill - Lakeside #1 115 kV line - 93.9% | [redacted] | N/A | [redacted] | Talbot Hill - Lakeside #1 115 kV line – 81.5% | [redacted] | Talbot Hill - Lakeside #1 115 kV line – 87.8% |
| | | [redacted] | Talbot Hill - Lakeside #2 115 kV line - 93.8% | [redacted] | N/A | [redacted] | Talbot Hill - Lakeside #2 115 kV line – 81.3% | [redacted] | Talbot Hill - Lakeside #2 115 kV line – 87.6% |
| **Category C: N-1-1 Contingency Results** | | | | | | | | | |
| [redacted] | Overload | [redacted] | Overload | [redacted] | Overload | [redacted] | Overload | [redacted] | Overload |

[8] Loading reported on the Maple Valley – Sammamish 230 kV and Talbot Hill – Lakeside #1 & #2 115 kV lines occurred for a Heavy Summer condition with south-to-north transfers through the system. A 2018 Heavy Summer case with south-to-north flows was not available for this study. Due to consistency in the 2020 Heavy Summer and 2024 Heavy Summer with the results encountered in 2012 (see footnote 8 for discrepancies found in this case), the 2018 case was not developed and run.

[9] The 2012 TPL study modeled the Northern Intertie gen tripping scheme which trips Whitehorn and Fredonia generation and runs back Mica and Revelstoke generation in BC. Tripping this generation in a south-to-north condition without tripping the Northern Intertie exacerbates this overload. If the limiting contingency is run without the RAS in place, overloads on the Maple Valley – Klahanie line are only 106%.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| [redacted] | Sammamish 230-115 kV transformer #1 - 95.5% | [redacted] | Sammamish 230-115 kV transformer #1 - 100.03% | [redacted] | Sammamish 230-115 kV transformer #1 – 104.2% | [redacted] | Sammamish 230-115 kV transformer #1 – 108.1% | [redacted] | Sammamish 230-115 kV transformer #1 – 109.4% |
| [redacted] | Sammamish 230-115 kV transformer #2 - 100.8% | [redacted] | Sammamish 230-115 kV transformer #2 - 106.4% | [redacted] | Sammamish 230-115 kV transformer #2 - 110.1% | [redacted] | Sammamish 230-115 kV transformer #2 – 114.3% | [redacted] | Sammamish 230-115 kV transformer #2 – 115.6% |
| | | | | [redacted] | Novelty Hill 230/115kV Transformer #2 - 102% | [redacted] | Novelty Hill 230/115kV Transformer #2 - 103% | [redacted] | Novelty Hill 230/115kV Transformer #2 - 100% |
| | | [redacted] | Beverly Park - Cottage Brook 115 kV line – 101.4% | [redacted] | Beverly Park - Cottage Brook 115 kV line – 110.5% | [redacted] | Beverly Park - Cottage Brook 115 kV line – 110.2% | [redacted] | Beverly Park - Cottage Brook 115 kV line – 106.4% |

## Category C: N-2 and Common Mode Contingency Results

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| [redacted] | Overload | [redacted] | Overload | [redacted] | Overload | [redacted] | Overload | [redacted] | Overload |
| | | [redacted] | Sammamish - Lakeside #2 115 kV line - 99.8% | [redacted] | Sammamish – Lakeside #2 115 kV – 90.8% | [redacted] | Sammamish - Lakeside #2 115 kV line 95.4% | [redacted] | Sammamish - Lakeside #2 115 kV line 99.2% |
| | | | | [redacted] | Monroe-Novelty Hill 230 kV line – 143.6% | [redacted] | Monroe-Novelty Hill 230 kV line – 143.1% | [redacted] | Monroe-Novelty Hill 230 kV line – 139.9% |

# Appendix C. Upgrades Included in Base Cases



**Table C-3: Projects Added to the Eastside Needs Assessment Winter Base Case**

| 2017-18 | 2019-20 | 2023-24 |
|---|---|---|
| Bothell – SnoKing reconductor | Bothell – SnoKing reconductor | Bothell – SnoKing reconductor |
| Cumberland substation reconfigured to 115 kV | Cumberland substation reconfigured to 115 kV | Cumberland Substation reconfigured to 115 kV |
| White River – Electron Heights reroute to Alderton | White River – Electron Heights reroute to Alderton | White River – Electron Heights reroute to Alderton |
| Talbot 230/115 kV transformer #1 replacement | Talbot 230/115 kV transformer #1 replacement | Talbot 230/115 kV transformer #1 replacement |
| Spurgeon substation, Similk substation & Maxwelton substation | Spurgeon substation, Similk substation & Maxwelton substation | Spurgeon substation, Similk substation & Maxwelton substation |
| Carpenter substation removed | Carpenter substation removed | Carpenter substation removed |
| Bus section breakers at BPA Olympia and BPA Tacoma | Bus section breakers at BPA Olympia and BPA Tacoma | Bus section breakers at BPA Olympia and BPA Tacoma |
| Switched shunt at Paul 500 kV, Broad St. 115 kV | Switched shunt at Paul 500 kV | Switched shunt at Paul 500 kV |

**Table C-4: Projects Added to the Summer NERC TPL Base Case for the Eastside Area**

| 2018 | 2020 | 2024 |
|---|---|---|
| Bothell – SnoKing reconductor | Bothell – SnoKing reconductor | Bothell – SnoKing reconductor |
| Cumberland substation reconfigured to 115 kV | Cumberland substation reconfigured to 115 kV | Cumberland substation reconfigured to 115 kV |
| Talbot 230/115 kV transformer #1 replacement | Talbot 230/115 kV transformer #1 replacement | Talbot 230/115 kV transformer #1 replacement |
| White River – Electron Heights reroute to Alderton | White River – Electron Heights reroute to Alderton | White River – Electron Heights reroute to Alderton |
| Spurgeon substation, Similk substation | Spurgeon substation, Similk substation | Spurgeon substation, Similk substation |
| Denny Way substation Phase 1 | Denny Way substation Phase 1 | Denny Way substation Phase 1 & Phase 2 |
| Bus section breakers at BPA Olympia, BPA Tacoma and BPA Covington | Bus section breakers at BPA Olympia, BPA Tacoma and BPA Covington | Bus section breakers at BPA Olympia, BPA Tacoma and BPA Covington |
| Raver 500-230 kV Transformer | Raver 500-230 kV Transformer | Raver 500-230 kV Transformer |
| Switched shunt at Paul 500 kV | Switched shunt at Paul 500 kV | Switched shunt at Paul 500 kV |
| Switched shunt at Lake Tradition 115 kV removed | Switched shunt at Lake Tradition 115 kV removed | Switched shunt at Lake Tradition 115 kV removed |

# Appendix D. West-side Northern Intertie, North of Echo Lake and South of Custer Flowgate One-Line Diagrams



**REDACTED**

**Figure D-1: One-Line Diagram – West-Side Northern Intertie**

**REDACTED**

**Figure D-2: One-Line Diagram - North of Echo Lake**

**REDACTED**

**Figure D-3: One-Line Diagram - South of Custer**

# Independent Technical Analysis
# of
# Energize Eastside

## for the

## City of Bellevue, WA

**April 28, 2015**
**Version 1.3**

Prepared by
Utility System Efficiencies, Inc.

# Table of Contents

# 1. Executive Summary

Utility System Efficiencies, Inc. (USE) was engaged by the City of Bellevue in December, 2014 to conduct an independent technical analysis of the purpose, need, and timing of the Energize Eastside project. Energize Eastside (EE) is Puget Sound Energy's (PSE's) proposed project to build a new electric substation and new higher–capacity (230 kilovolt) electric transmission lines in the East King County area, which encompasses Bellevue, Clyde Hill, Medina, Mercer Island, Newcastle, the towns of Yarrow Point, Hunts Point, and Beaux Arts, and portions of Kirkland, Redmond, and Renton (the Eastside). The transmission lines would extend from an existing substation in Redmond to one in Renton (See Figure 3.1).

The goals of the technical analysis were to determine:

- Is there a need for this project to address growth in Bellevue? In answering this question, the analysis included determining if PSE's load forecast is reasonable, and if their studied contingencies were reasonable. Here, reasonable is defined as just, rational, appropriate, ordinary, or usual in the circumstances.[1] If the actions or data are consistent with industry practice, it is deemed reasonable.
- Is the EE project needed to address the reliability of the electric grid on the Eastside? This question assesses the purpose of the project and its timing. In other words, is the need a local issue?
- Is there a need for the project to address regional flows, with imports/exports to Canada (ColumbiaGrid[2])? This question is examined in Appendix B, Optional Technical Analysis.

This independent technical analysis (ITA) included reviewing EE documentation, examining the forecast and growth assumptions, reviewing historical demand (MW load) of the area, reviewing weather volatility, and assessing potential variability from the forecast assumptions used in the EE study. The ITA reviewed PSE's forecasting methodology, the major elements that made up the forecast, and decisions made in the forecasting procedure (including choices on what elements or variables to include). The ITA compared PSE's forecast variables with typical industry forecast variables. The ITA also looked at the assumptions that PSE used in electrically modeling the Energize Eastside area, including generation assumptions, local loads, and regional flows. The ITA reviewed PSE's powerflow cases[3] to determine whether the modeling in the cases was consistent with the forecast, and whether the outage scenarios resulted in PSE's identified transmission deficiency.

The optional technical analysis (OTA) at Appendix B examined several hypothetical scenarios, called sensitivity studies. The OTA looked at the effect of a) reducing load growth in the Eastside area, b) reducing load growth in King County while keeping the Eastside growth the same, c) increasing Puget Sound area generation, and d) reducing the Northern Intertie[4] flow to zero (no transfers to Canada). Reduced Northern Intertie flow was examined only to assess the relative impact of local need

[1] http://www.nolo.com/dictionary/reasonable-term.html
[2] ColumbiaGrid (single word) is a regional transmission planning organization with a footprint encompassing Oregon, Washington, parts of Idaho and Montana.
[3] powerflow case: Computer model of the electric grid representing a snapshot in time with a specific scenario of electric load, generation, and equipment, including what is in service and what isn't.
[4] Northern Intertie - transmission interconnection between Washington and British Columbia (also called Path 3.)

versus regional need and does not reflect a realistic planning scenario. The OTA also looked at the impact of an Extreme Winter forecast.

A key purpose of the ITA and the OTA was to provide an increased level of *understanding* of the purpose, need and timing of the EE project to the City Council and community stakeholders. Over the course of the project, dozens of questions were received from various stakeholders. City staff filtered stakeholder comment through the Task's scope, and submitted the need related questions to USE (Other comments as appropriate were directed to the Environmental Impact Statement (EIS) process, the Integrated Resource Plan[5] (IRP) process, etc.). A Q & A discussion is included at the end of each section of the ITA. All questions analyzed are also set forth in Appendix D.

**Disclaimer**: This report seeks to describe the findings in terms that a non-expert can understand. Thus, some descriptions or definitions may not be exact, in an effort to make the general concept clear. However, some questions received required a higher level of technical detail. Again, the effort was made to simplify the explanations while still providing a helpful response. A glossary is provided in Appendix A.

Results:

IS THERE A NEED FOR THIS PROJECT TO ADDRESS GROWTH IN BELLEVUE? YES.

The ITA examined the forecasting methodology used by PSE in its 2014 forecast, completed in February 2015. The 2014 forecast methodology provided improved visibility of where growth was occurring within PSE's service area. The PSE forecast shows a growing peak load demand[6] of 2.4% per year for years 2014 – 2024.

The typical utility industry forecast is composed of 1) weather normalization[7], 2) economic and demographic data, 3) application of end-use data[8] including conservation and efficiency measures, and 4) adjustment for large specific load additions (such as for a new building).

The ITA concludes that PSE has followed industry practice in forecasting its demand load, incorporating the four major components of forecasting:

- PSE incorporated weather normalizing. The variables used in the weather normalizing process were typical based on industry practice.
- PSE used typical data set elements and multiple data sources for its economic/demographic data as shown in Table 6.1, acquiring data at the county level, and for the Eastside area at the census track level, in order to differentiate growth rates within the service territory. Data on jobs and

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[5] Integrated Resource Plan - A comprehensive and long-range road map for meeting the utility's objective of providing reliable and least-cost electric service to its customers while addressing applicable environmental, conservation and renewable energy requirements. A process used by utility companies to determine the mix of Supply-Side Resources and Demand-Side Resources that will meet electricity demand at the lowest cost. The IRP is often developed with input from various stakeholder groups.

[6] MW demand

[7] Weather normalization is a process that adjusts actual energy (MWh) or demand (peak MW) values to what would have happened under normal weather conditions. Normal weather conditions are expected on a 50 percent probability basis (i.e., there is a 50 percent probability that the actual peak realized will be either under or over the projected peak).

[8] End-use: How is the electricity being used? What appliances are used? What efficiency measures are employed? What load can be controlled or interrupted? Utilities and cities can influence electric end-use through Demand-Side Management technologies and practices, city code changes, efficiency programs or incentives, awareness campaigns, et cetera. The end-use data is generally limited to new DSR measures. Historical end-use data is generally not captured due to the difficulty in acquiring it (surveys, etc.).

employment in the Eastside region were obtained by PSE from the Puget Sound Regional Council and the WA State Office of Financial Management, and included census tract level analysis. PSE employed regression analysis[9] at this step, an industry standard computer analysis technique, to determine the forecast before new conservation measures and block load adjustments. (The computerized regression analysis was not analyzed as part of this study, but the technique is a computerized estimation of the best fit of the variables to the given data.)

- PSE acquired/developed significant end-use data via their IRP process, including over four thousand Demand Side Resources (DSR) measures, incorporated National and State requirements on conservation and RPS, and optimized the achievable, technical measures with a resultant 100% Conservation scenario which projects 135 MW of winter peak DSR by 2031.
- PSE gathered block load data (major projects) and utilized short-term forecast adjustments (1-year ramp in based on certificates of occupancy and 2-year ramp-out) to account for the impact on demand.

No forecast is perfect, but by following industry practice, the ITA concludes that PSE used reasonable methods to develop the forecast. PSE's resultant forecast shows the Eastside area growing at a higher level than at the county and system level, and these growth rates are based on the data it received.

PSE is applying the Northwest US practice (as does Seattle City Light (SCL)) of basing projects on a normal 50/50 forecast (actual load will be more than forecast half the time, and less than forecast half the time). This 50/50 forecast is less conservative than scenarios utilized by many other electric utilities elsewhere in the country. Basing projects on an adverse weather scenario is more conservative, but seeks to ensure that the lights stay on given the adverse weather event.

### IS THE EE PROJECT NEEDED TO ADDRESS THE RELIABILITY OF THE ELECTRIC GRID ON THE EASTSIDE? YES.

Although the new 2014 forecast resulted in an 11 MW decrease in the Eastside area's 2017/18 winter forecast, the reduced loading still resulted in several overloaded transmission elements in winter 2017/2018, which drive the project need.

Although the corrective action plan (CAP) required in the 2017/18 winter to avoid facility overload doesn't require dropping load (turning off customers' power), by winter 2019/20 approximately 63,200 customers are at risk of losing power. In addition, by summer 2018, studies show that customers will be at risk of outages and load shedding[10] due to CAPs used to mitigate transmission overloads. Despite the possibility of an in-service date shift to summer 2018 from winter 2017/18, balancing a six month delay in a complex and multi-year EIS process (which can have its own delays) against the risk of an adverse winter and less realized conservation (which could increase 2017/18 winter loading to a point where customers are at risk of load

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[9] Regression analysis is a statistical process for estimating the relationships among variables. It seeks to determine the strength of the relationship between one dependent variable (usually denoted by Y) and a series of other changing variables (known as independent variables). It is also known also as curve fitting or line fitting because a regression analysis equation can be used in fitting a curve or line to data points. It includes many techniques for modeling and analyzing variables.

[10] Load shedding - An intentional electrical power shutdown to a portion of the system (customers experience an outage) to protect the network from a greater impact or from potential damage.

shedding), suggests it is reasonable to maintain the schedule for the existing project in-service date.

Several hypothetical scenarios were studied as part of the Optional Technical Analysis (OTA). Each one showed overloads in the 2017/18 timeframe, indicating project need in order for PSE to meet federal regulatory requirements for system reliability. The OTA results showed that reducing the Eastside area growth from 2.4% to 1.5% per year in the period from winter 2013/14 to winter 2017/18 still resulted in project need. Reducing PSE's King County growth while keeping the Eastside growth the same similarly resulted in a project need. Turning on additional generation in the Puget Sound area also resulted in a project need. (See Appendix B.)

IS THE PROJECT NEEDED TO ADDRESS REGIONAL GRID POWER FLOWS, SPECIFICALLY POWER FLOWS ON THE NORTHERN INTERTIE (TO AND FROM CANADA)? The project is necessary to address local need.

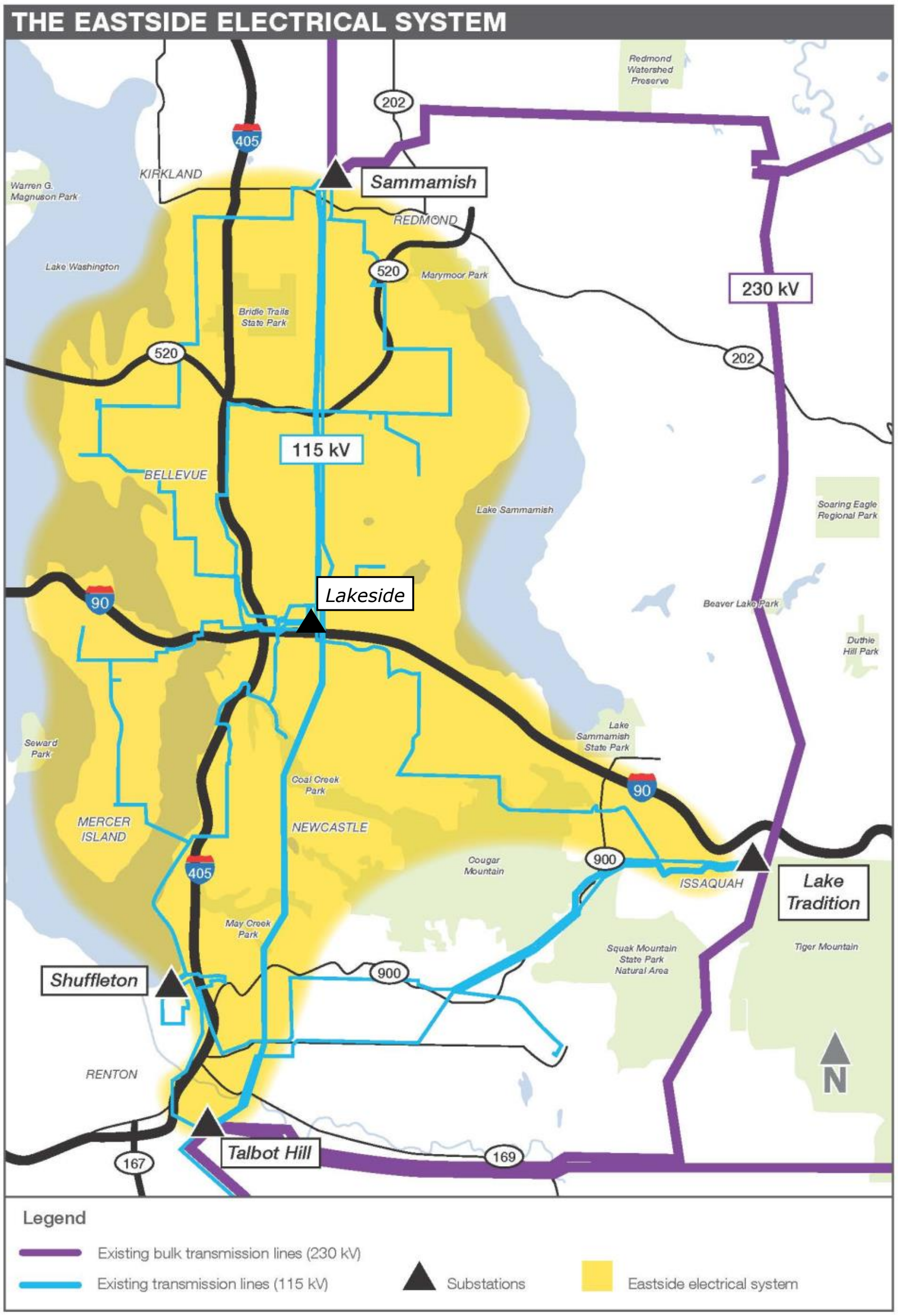
The Optional Technical Analysis examined this issue by reducing the Northern Intertie[11] flow to zero (no transfers to Canada). Although this scenario is not actually possible due to extant treaties, it was modeled to provide data on the drivers for the EE project, to examine if regional requirements might be driving the need. The results showed that in winter 2017/18, even with the Northern Intertie adjusted to zero flow, the Talbot Hill 230/115 kV transformer #2 would still be overloaded by several contingencies (several different outage scenarios). Again, the projected overloads indicate a project need at the local level to meet reliability regulations. (See Appendix B for more details.)

[11] Northern Intertie - transmission interconnection between Washington and British Columbia (Also called Path 3.)

## 2. Eastside Area

The Eastside area is highlighted in yellow below, and was defined electrically as the area served by the 115 kV transmission lines that connect with the Lakeside Transmission Substation. Geographically it is bounded by Lake Washington and Lake Sammamish. The area is also north of PSE's Talbot Hill Substation and south of PSE's Sammamish Substation.

**Figure 3.1: Eastside Area (Figure provided by PSE)**



# 3. 2013 Eastside Needs Assessment Report

This section is included in the ITA report because PSE's 2013 Needs Assessment report is public whereas there is no updated PSE report documenting the 2014 forecast results as of the date of this writing.

The "Eastside Needs Assessment Report", published in October 2013 by PSE, focused on the central King County portion of PSE's service territory. It was based on PSE's corporate forecast which was published in June, 2012. The study determined that there was a transmission capacity deficiency in the Eastside area that would develop by the winter of 2017/2018.

Key Assumptions in PSE's 2013 Study:

- System load levels used the PSE corporate forecast published in June 2012.
- Area forecasts were adjusted by substation to account for expected community developments as identified by PSE customer relations and distribution planning staff.
- Generation dispatch patterns reflected reasonably stressed conditions to account for generation outages as well as expected power transfers from PSE to its interconnected neighbors.
- Winter peak Northern Intertie transfers were 1,500 MW exported to Canada.
- Summer peak westside Northern Intertie transfers were 2,850 MW imported from Canada.

Per PSE's 2013 study report, specific areas of concern for the 2017/2018 winter are shown in Table 4.1 below. The table lists the overloaded elements within each category of contingency.

Each of the three contingency types (N-1, N-1-1, and N-2) shown below are part of the required study process and are defined in the report glossary.

**Table 4.1: PSE's 2013 Study Report: 2017/2018 Overloaded Elements**

| | 2017/2018 Normal Winter (23° F)<br>100% Conservation | | |
|---|---|---|---|
| | Type of Contingency | | |
| Transmission Line or Transformer | N-1 | N-1-1 | N-2 |
| Talbot Hill - Lakeside #1 115 kV line | | OL | OL |
| Talbot Hill - Lakeside #2 115 kV line | | OL | OL |
| Talbot Hill 230-115 kV transformer #1 | | OL | |
| Talbot Hill 230-115 kV transformer #2 | | OL | |
| Talbot Hill-Boeing Renton-Shuffleton 115 kV line | | OL | |
| Shuffleton – O'Brien 115 kV line | | | |
| Shuffleton – Lakeside 115 kV line | | | |

OL = Overload of Emergency Rating.

PSE's 2013 Needs Assessment report drove many need-related Stakeholder questions about the forecast, the weather scenarios, the regional scenarios, exports and imports to Canada, the outage contingencies studied and whether they were needed, the probability of having the issues, etc. PSE develops a new forecast every two years, and in February, 2015, PSE completed their new forecast with actuals through 2014. They have since restudied the situation with the new forecast. The remainder of this ITA report will relate the questions received to the new forecast and the new results.

# 4. Energy versus Demand

Forecasts are developed for both energy and demand. A useful analogy is to compare energy to a car odometer and demand to a car speedometer.

- Energy (kWh) is analogous to an odometer reading, which is a cumulative measure of total miles traveled over time. Energy is a cumulative measure of total power produced or consumed over time.

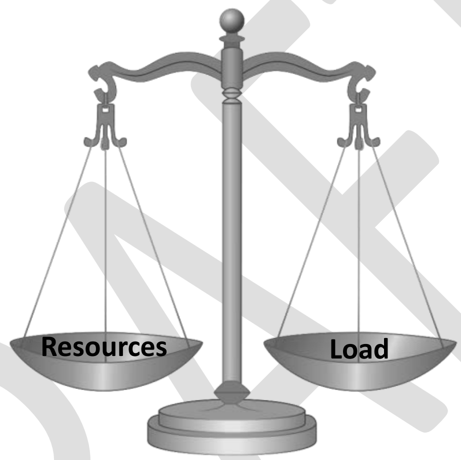
Demand (kW) is analogous to a speedometer reading, which shows a snapshot of the speed at a precise moment. Demand is a snapshot of power required or power used. Peak demand is the highest demand that will be required at any particular moment during a period of time. An odometer doesn't indicate how fast someone drives, but does indicate how much driving has been done. Similarly, an energy forecast (kWh) indicates increases or decreases in the use of electricity, but doesn't indicate peak usage (kW).

Bellevue's Resource Conservation Manager (RCM) program stats on declining energy use are reflecting a decline in the average use per customer. The DSM programs, solar, etc. are showing success with this decline. But, that is one piece of the story - the energy piece on a per customer basis. The number of customers continues to increase, and the aggregate peak usage (peak demand), is continuing to increase. Growth in peak demand drives the size and amount of infrastructure required and drives the issue of grid reliability.

# 5. Typical Electric Forecast Elements

The typical utility industry forecast is composed of four main parts which will each be further explained later in this section: 1) adjustment for weather, 2) economic and demographic data, 3) application of end-use data, including energy efficiency and conservation effects, and 4) adjustment for large specific load additions (such as for a new building).

Resource planning is a related activity which provides direction on some of the forecasting elements. Resource planning (ensuring there are sufficient generation and conservation/efficiency resources to serve the customer load) requires a load forecast to know how much load one must serve. The resources must balance the load.




National Level

There are NERC Reliability Standards which pertain to the collection of data necessary to analyze the resource needs to serve peak demand while maintaining a sufficient margin to address operating events. One Standard (NERC MOD-021-1) requires that "forecasts shall each clearly document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demands, and Direct Control Load Management) are addressed." Another Standard (NERC MOD-019-0.1) requires "forecasts of interruptible demands and Direct Control Load Management (DCLM) data".

State Level

There are state requirements for resource planning, which identifies generation resources and conservation/efficiency measures to serve the customer load. State Law (RCW 19.280.030), identifies the requirements of a resource plan, and states that the integrated resource plan must include:

> "(1)(a) A range of forecasts, for at least the next ten years or longer, of projected customer demand which takes into account econometric data[12] and customer usage;"

[12] Econometrics is the application of mathematics and statistical methods to economics. The data to which it is applied is called econometric data. Econometrics tests hypotheses and forecasts future trends by applying statistical and mathematical theories to economics. It's concerned with setting up mathematical models and testing the validity of economic relationships to measure the strengths of various influences.

> "(1) (b) An assessment of commercially available conservation and efficiency resources. Such assessment may include, as appropriate, high efficiency cogeneration, demand response and load management programs, and currently employed and new policies and programs needed to obtain the conservation and efficiency resources;"

Item 1(a) above requires econometric and end-use data in the forecast. Item 1(b) requires that the forecast account for conservation and efficiency resources. Both are industry practices.

Resources consist of Supply-Side Resources (conventional generation plants, renewables, etc.) and Demand-Side Resources (resources that reduce the demand (load)).

## 5.1. Simplified Description of the Forecasting Procedure

1) <u>Weather Normalizing.</u>

The North American Electric Reliability Corporation (NERC[13]) provides direction at the national level for normalizing the demand (MW) forecast to account for weather impact.

> "The fundamental test for determining the adequacy of the Bulk Electric Power System (BEPS) is to determine the amount of resources and the certainty of these resources to be available to serve peak demand while maintaining a sufficient margin to address operating events. This test requires the collection and aggregation of demand forecasts on a normalized basis. This is defined as a forecast that has been adjusted to reflect normal weather conditions and is expected on a 50 percent probability basis, also known as a 50/50 forecast (i.e., there is a 50 percent probability that the actual peak realized will be either under or over the projected peak). This forecast can then be used to test against more extreme conditions." [14]

Normalizing the forecast seeks to remove the variation in load due to weather related factors including the temperature at the time of the peak, the temperature on the days prior to the peak, whether the peak occurred on a weekend, a weekday, a holiday, etc. Reactions to these variables vary throughout the United States, yet for a localized area there will be a typical reaction that can be calculated. These are addressed when normalizing the forecast. For example, many office buildings use less power on the weekend or on a holiday. Moreover, some residential customers will put up with a short cold or hot spell, but if it lasts "too long", they will be more likely to increase their use of heating or air conditioning.

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[13] NERC: North American Electric Reliability Corporation. NERC is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards as one of its duties. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico.

[14] NERC, Normalizing "NERC | MOD C White Paper | April 24, 2014", page 5 http://www.nerc.com/pa/Stand/Project%20201004%20Demand%20Data%20MOD%20C/MOD_C_White_Paper_Redline_20140424.pdf

In addition to calculating the normalized peaks, industry also typically calculates an adverse or extreme peak. Many utilities utilize a 90/10 forecast[15] to justify projects, some use an 80/20 forecast to justify projects. Utilities in the Northwest area of the United States typically base their projects on the normal (50/50) forecast, although they develop a 95/05 forecast (1-in-20) for reference.

A typical industry source for the weather data is a National Oceanic and Atmospheric Administration (NOAA) weather station. Some utilities may have their own weather recording data.

*Stakeholder Questions on weather adjustment*

*Q1.Please explain weather adjustment. Is it reasonable/appropriate?*

- A *Please see the above discussion.*
- A *Weather adjustment is reasonable and appropriate, and is required by NERC.*

2) DEVELOP A MATHEMATICAL RELATIONSHIP (EQUATION) BETWEEN A) THE ECONOMIC AND DEMOGRAPHIC DATA AND B) EITHER ENERGY USAGE (KWH) OR ELECTRIC DEMAND (KW).

For each customer class (e.g. industrial, commercial and residential), estimate the relationship between electricity consumption (usage) or demand, and the major variables that affect it (e.g. population, price, economic growth, etc.). This relationship is usually developed first, without accounting for new Demand-Side Resources (DSR), in order to show the effect of the DSR on the forecast.

Econometrics utilizes multiple sources of data. Table 5.1 lists examples of data sets that may be used in the econometric modeling.

**Table 5.1: Examples of Data Used in Econometric Models**

| Example Data Sets used in Econometrics |
|---|
| Household Size |
| Population |
| Customer Count by Customer Class |
| Employment (Manufacturing, Non-Manufacturing, by NAICS Code[16], etc.) |
| GDP (Gross Domestic Product) |
| GMP (Gross Metropolitan Product) − a measure of the size of the economy of a metropolitan |
| Personal Income |

[15] 90/10 forecast: 90% probability that the weather will be less severe and a 10% probability that the weather will be more severe. This is also called a 1-in-10 forecast.

[16] NAICS - The North American Industry Classification System (NAICS) is the standard used by Federal statistical agencies in classifying business establishments for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. business economy (Source: Census.gov)

3) <u>ACCOUNT FOR END-USE DATA INCLUDING ENERGY EFFICIENCY AND CONSERVATION EFFECTS (TYPICALLY FROM AN INTEGRATED RESOURCE PLAN (IRP))</u>

End-Use Analysis projects the quantity and use of electricity-using equipment (or a subset of them) to make a forecast or to revise one. *End-use analysis is responsive to consumer changes in kinds of equipment and allows analysis of conservation programs, energy efficiency improvements, building code modifications, increase in household electronics or typical housing square footage, etc. It breaks the data into user sectors and needs an extensive inventory of data. It readily reflects changes in the factors that influence consumption, but requires detailed assumptions on the use going forward.*

Utilities and cities can influence electric end-use through Demand-Side Management technologies and practices, city code changes, efficiency programs or incentives, awareness campaigns, et cetera. Example end-use programs are listed below.

- Residential mass market lighting and appliances
- Residential HVAC replacement
- Residential new construction
- Residential retrofits
- Commercial/Industrial lighting, equipment, HVAC
- Customized programs for larger customers
- Demand Response incentive/enabling programs
- Pricing—interruptible, time of use pricing, real time pricing

Demand-Side Management (DSM) can be broken into two components: energy efficiency and Demand Response. Energy efficiency attempts to permanently reduce the demand for energy in intervals ranging from seasons to years and concentrates on end-use energy solutions. Demand Response is designed to change on-site demand for energy in intervals from minutes to hours, targeting the lowering of electric demand/energy use during peak periods by transmitting changes in prices, load control signals or other incentives to end-users to reflect existing production and delivery costs.

When end-use factors are taken into account in the forecast, there will be multiple variables representing different elements of end-use. Some may offset others. For example, the U.S. Department of Energy noted that "Homes built between 2000 and 2005 used 14% less energy per square foot than homes built in the 1980s and 40% less energy per square foot than homes built before 1950. However, larger home sizes have offset these efficiency improvements."[17]

When utilized, the IRP process is where the end-use data is analyzed. The IRP is a comprehensive and long-range road map and is where a utility examines both Supply-Side and Demand-Side options with the objective of providing reliable and least-cost electric service to its customers while addressing applicable environmental, conservation and renewable energy requirements. Because energy efficiency is generally a low-cost resource, the IRP tends to incorporate energy efficiency as a utility system resource and reduce the need for additional Supply-Side resources.

The end-use data is generally limited to new DSR measures. Historical end-use data is not usually captured due to the difficulty in acquiring it.

[17] "Buildings Energy Data Book", US Department of Energy

4) ADJUST FOR BLOCK LOADS (MAJOR LOAD ADDITIONS)

Known large load additions would be added to or removed from the forecasted load. This could include new large commercial buildings, major customers leaving the area, etc.

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The above forecast discussion represents the system forecast, referring to the forecast for the utility's entire service area. A system forecast may be broken into sub-areas at the utility's discretion, or separate forecasts may be developed for sub-areas. Various scenarios may be modeled, to examine higher or lower conservation levels, adverse weather, et cetera.

### 5.2. Utilizing the System Forecast in Powerflow Cases

In order to conduct studies on the transmission system, the substation loads are calibrated to the system forecast. Once calibrated, the substation loads are modeled in the transmission planning cases for study. Multiple seasons and years may be studied.

# 6. PSE's Forecast Methodology

PSE updates their load forecasts every two years. In early February, 2015, PSE completed their 2014 forecast which included historical data through 2014, and thus included the summer 2014 peak and the winter 2013/2014 peak. This new forecast was based on a new methodology. PSE shifted from a predominately system-wide view to a county by county examination. Particular focus was placed on King County, where the Eastside study area was further separated out from King County using census tract data to develop a separate Eastside forecast. This new forecast methodology provided improved visibility of where growth was occurring and where it wasn't. Consequently, after conferring with the City, USE decided to wait for the new forecast, with its improved visibility of the Eastside area, as well as its more recent actual load information.

The review of PSE's forecast methodology in this report is specific to PSE's 2014 forecast.

## *6.1. Weather Adjustment (Weather Normalizing)*

PSE's 2014 system forecast incorporated weather normalizing consistent with industry practice.

PSE's weather normalizing process tests the following major variables via regression analysis. The regression analysis process selects out the variables that result in the best fit to the data.

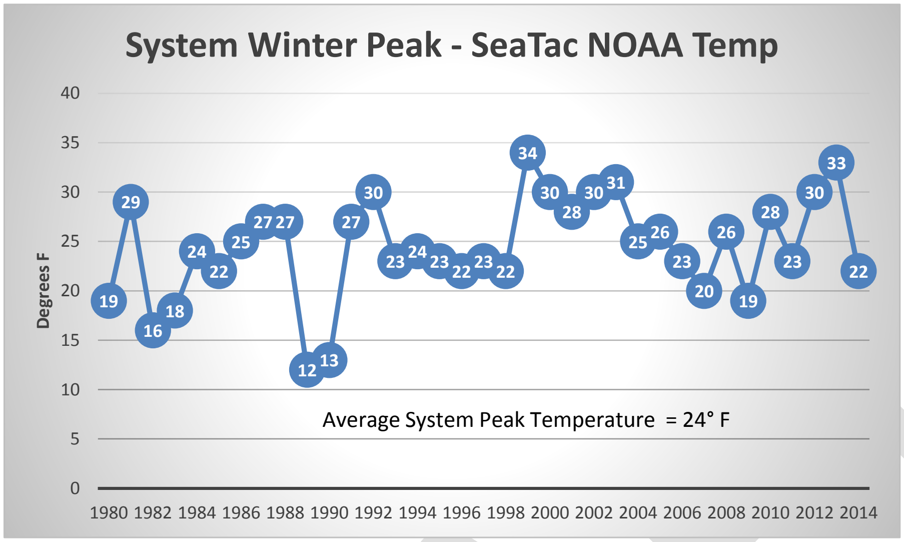
- Peak hourly load for the month
- Maximum hourly load on each of the three days prior to the peak day
- Minimum and maximum temperature on the peak day
- The minimum temperature on each of the three days prior to the peak day
- The average temperature on the peak day
- The average temperature on each of the three days prior to the peak day
- Temperature 1, 2, and 3 hours before the peak
- Temperature at the peak hour
- Total monthly load
- Average monthly temperature
- The season the peak occurred in
- Whether the average temperature on the peak day, or the day before, fell below a certain threshold (cold snap variables)
- Whether it is an El Niño
- Day of the week

The factors PSE uses to normalize the effect of weather are quite typical for electric forecasting. Some utilities use humidity as a variable, PSE does not. PSE stated it did not consider humidity a significant factor. Realistically, humidity is less likely to be a factor in the winter. Heating the cold air lowers the relative humidity[18], so it feels dryer.

[18] Relative humidity is the amount of water vapor present in air. It is expressed as a percentage of the amount needed for saturation at the same temperature. Thus relative humidity varies with temperature.

PSE utilizes the SeaTac NOAA weather station for weather data. Figure 6.1 shows the historic winter system peak[19] actual temperatures through winter 2013/2014.

**Figure 6.1: Historical Temperature Data**




PSE has defined their winter season as November 1 – February 28, and the normal temperature at which PSE's winter load peaks is 23° F (normal peak load temperature). PSE also defines an extreme winter peak load that has a probability of occurring once every twenty years and occurs at a temperature of 13° F. Although PSE develops the extreme winter forecast and models the effect, they only use it as an indicator of future deficiencies. PSE does not use the extreme winter forecast to justify transmission projects, they only use the normal forecast to justify projects. (Utilities in the Northwest area, including Seattle City Light (SCL), use the normal forecast for justifying projects. Many utilities outside this area use an adverse forecast to justify projects.)

<u>Comments:</u>

PSE uses a normal peak load temperature of 23° F. The average winter peak load temperature since 2008 is 24°F, though examining a longer span of time may show that it is 23° F. It is likely that a 1° shift upwards in temperature would reduce the normal winter forecast, but it may not be significant. One could say the normal forecast is a bit conservative. On the other hand, PSE does not use any type of adverse weather (anything worse than a 50/50 forecast) to justify a project. Many utilities design their system based on adverse weather, such as a 90/10 or 80/20 scenario where the forecast is exceeded 10% or 20% of the time. Per the Western Electricity Coordinating Council (WECC) Data Collection Manual (2014), NERC has requested that each Balancing Authority provide a 90/10 forecast. In NERC's 2014-2015 Winter Reliability Assessment, it recommends that scenarios should be assessed that reflect severe winter conditions, such as a "... higher-than-normal peak load (e.g. 90/10 forecast)." PSE does study a 95/5 (1 in 20) extreme winter, but does not use it to justify projects

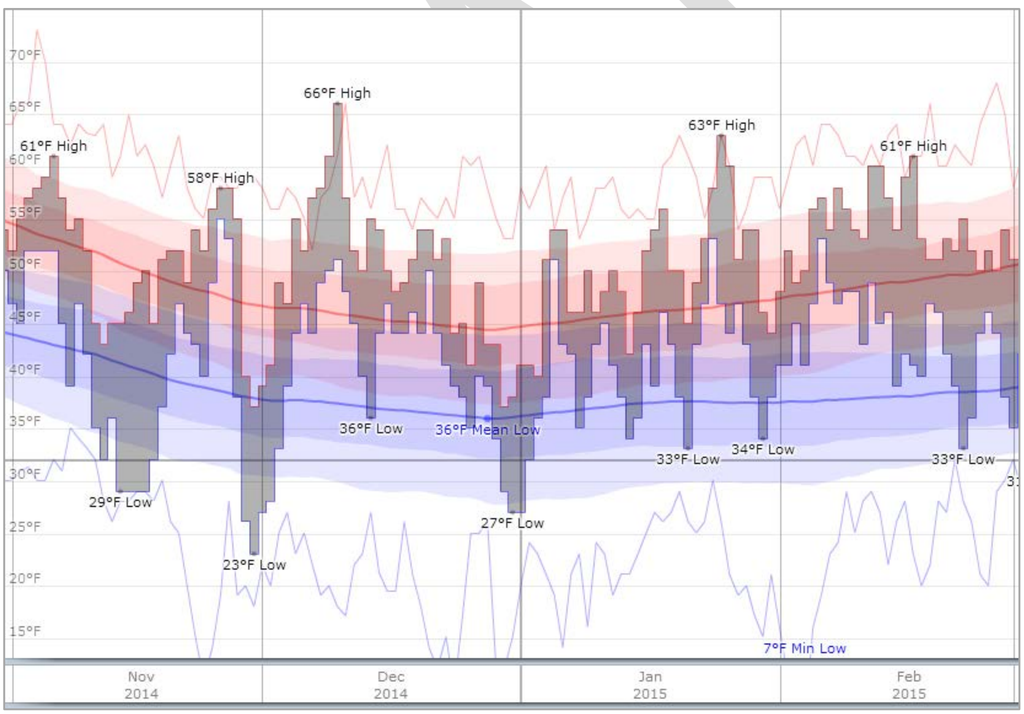
PSE uses one weather station for their service area. Some utilities use more than one weather station to reflect significant weather differences in their service territory.

[19] A system peak refers to the peak demand. In winter, this would be driven by low temperatures.

PSE feels there is not enough weather variation within their service territory to require using more than one weather station. In addition, they expressed concern that the while the SeaTac weather station is very reliable, not all the weather stations are maintained as well and there might be data reliability issues.

Although the 2014/2015 winter peak period ended February 28th, the winter peak data is not yet available. The data verification and normalizing process is not complete and typically occurs mid-year, but it is known that the 2014/15 winter peak was an unusually warm one. Figure 6.2 is taken from Weatherspark.com, and simply shows the highs and lows for each day during the winter season. The very lowest temperature for the entire season was 23°F on November 30th at 2am, per Weatherspark.com. PSE's winter peak (demand) typically occurs either in the morning between 7am and 9am or in the late afternoon/early evening between 4:30pm and 7pm. In either case the winter system peak would have occurred at a warmer temperature. Does this drive any change? At this point, no. It is expected that actual temperatures will not be the same as the defined "normal" temperature. A single data point is unlikely to change a trend. When PSE revises their forecast in two years, they will have two more data points and will recheck the trends through a new regression analysis.

**Figure 6.2: Historical Temperature Data 2014/15 Winter Season – Weatherspark.com**




## 6.2. *PSE's Econometric Modeling*

PSE incorporates economic and demographic data into their forecast, subdivided by customer class, using typical data set elements. See Table 6.1 for the sources of data used in their model.

### Table 6.1: Data used in PSE's Economic/Demographic Model

| Data Set | Historical Data Frequency | Source of Historical Data | Source of Forecasted Data |
|---|---|---|---|
| County Level Employment | | | |
| Labor Force, Employment, Unemployment Rate | Quarterly | US Bureau of Labor Statistics (BLS) | PSE's Economic/Demographic Model |
| Total Non-Farm Employment<br>Goods Producing & Service Providing Sectors | Monthly | WA State Employment Security Department (ESD), using data from Quarterly Census of Employment & Wages | |
| County Level Personal Income | | | |
| Personal Income, Wages and Salaries | Yearly | US Bureau of Economic Analysis (BEA) | PSE's Economic/Demographic Model |
| County Level Population and Households | | | |
| Population (thousands) | Yearly | US BEA/ WA State Office of Financial Management (OFM) | PSE's Economic/Demographic Model |
| Households, Single-family & Multi-Family (thousands.) | Annual forecasts | US Census | |
| Household size, Single- and Multi-family (number) | Quarterly | Building Industry Association of Washington | |
| Eastside Area by Census Tracts | | | |
| Population | Yearly | WA State Office of Financial Management (OFM), 9/28/14 | PSRC data, April 2014 |
| Employment | Yearly | PSRC, June 2014 | PSRC data, April 2014 |
| US Level Macroeconomy | | | |
| GDP ($ x Billions, in year 2000 $), Industrial Production Index | Quarterly | Moody's | Moody's |
| Employment (mils.), Unemployment Rate (%) | | | |
| Personal Income ($ x Billions)<br>Wages & salary disbursements, Other Income | | | |
| CPI (82-84=1.00[20]), consumer expenditures deflator (2000=1.0) | | | |
| Housing Starts (millions) | | | |
| Population (millions) | | | |
| T-bill rate, 3 months (%), Conventional mortgage rage (%) | | | |

The Puget Sound Regional Council (PSRC) intends for the City of Bellevue to be a hub for regional growth. In their Vision 2040 Regional Growth Strategy report, PSRC designated five Metropolitan Cities to serve as the focal point for accommodating population and employment growth. These are Bellevue, Bremerton, Everett, Seattle, and Tacoma. The strategy is for the Metropolitan Cities "... to accommodate 32 percent of regional population growth and 42 percent of regional employment growth by the year 2040." It was also noted that it would be in the spirit of the strategy for them to accommodate an even higher percentage.

In addition, the City of Bellevue provided the following information on expected population and employment growth. "Currently there are an estimated 11,000 residents living in Downtown, and that number is expected to grow to 19,000 by 2030. Currently there are about 45,000 jobs within Downtown and that number is expected to increase to 70,300 by 2030."

Given the above, one could expect a higher growth in the Eastside area than in some of the other areas served by PSE.

[20] The average of the 1982-1984 data is set to 1.00

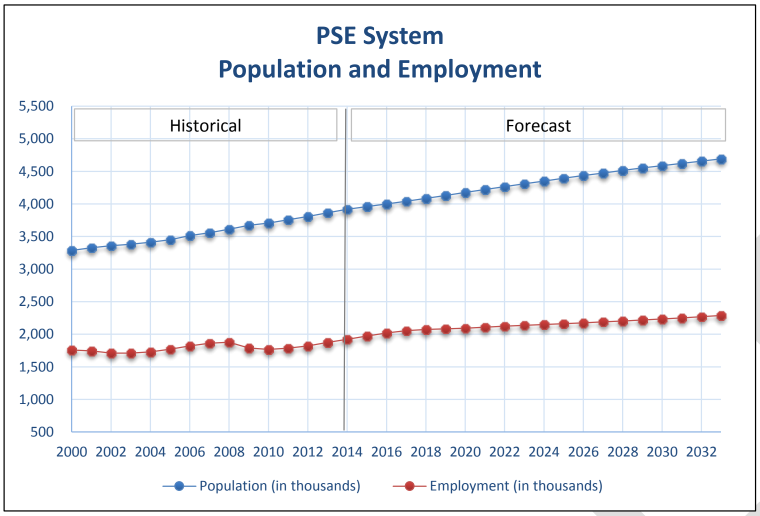
The following graphs display the historic and forecasted data for population, employment, and customer count, provided by PSE. Data is shown for the PSE service territory, PSE's portion of King County, and Eastside. The graphs for Eastside were developed from data sets at the census tract level. Graphs for these data sets are provided for comparison of growth rates between Eastside, King County and the PSE service territory.

The historic graph data for the PSE system goes back to 2000, and includes Jefferson County up until March 2013. The historic graph data for King County and Eastside only goes back to 2006. The Eastside customer count graphs are missing the actual data for year-end 2013; PSE recently updated their billing system with a new IT company, and not all of their customer reports were available at the time of the 2014 forecast.

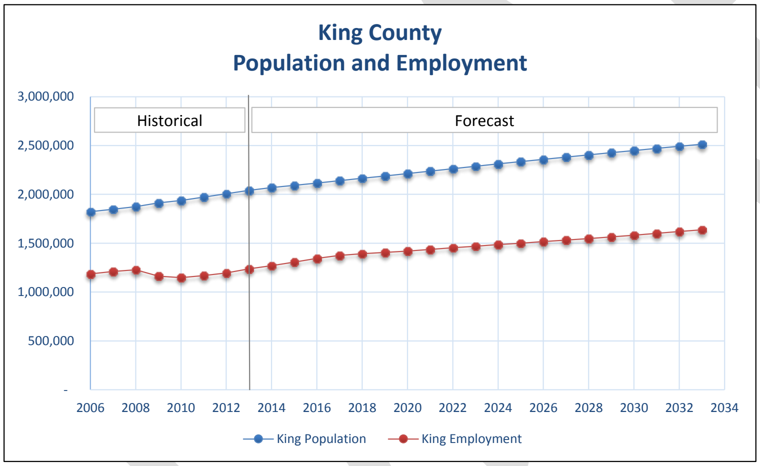
Because the system graph data goes back to 2000, it shows the trend prior to the recession. The King County and Eastside graph data only goes back to 2006, so the historical trend is obscured by the recession.

Employment and population are increasing. (Data provided by PSE. See Table 6.1 for original data sources.)

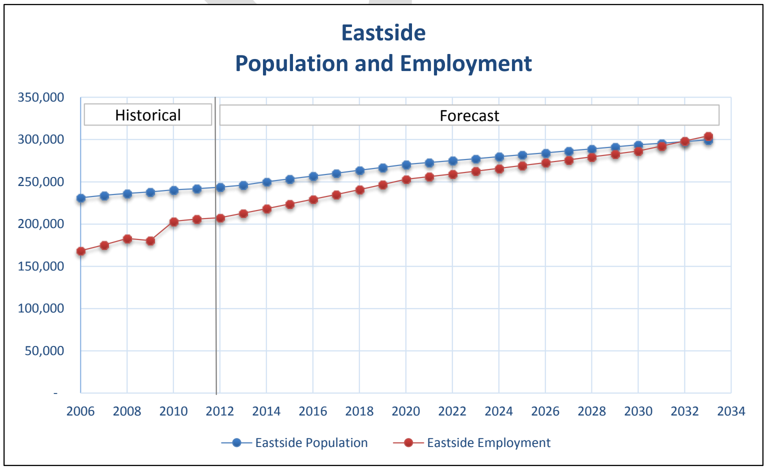
## Figure 6.3: Population and Employment - PSE Service Territory




## Figure 6.4: Population and Employment – King County

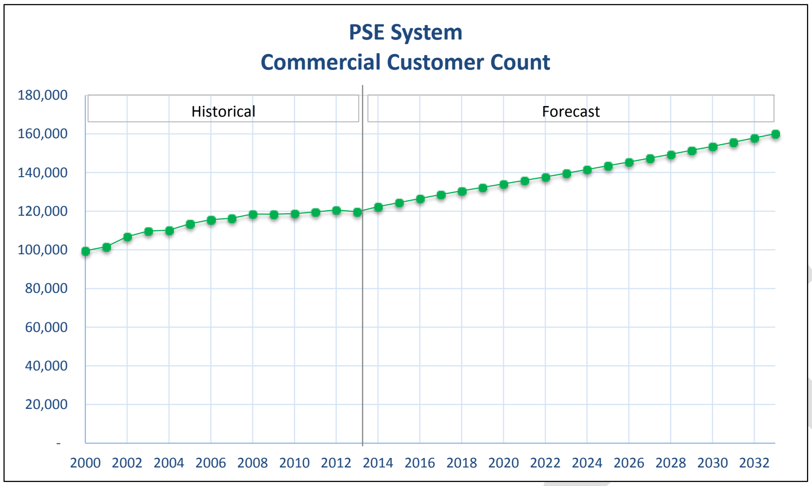



## Figure 6.5: Population and Employment – Eastside



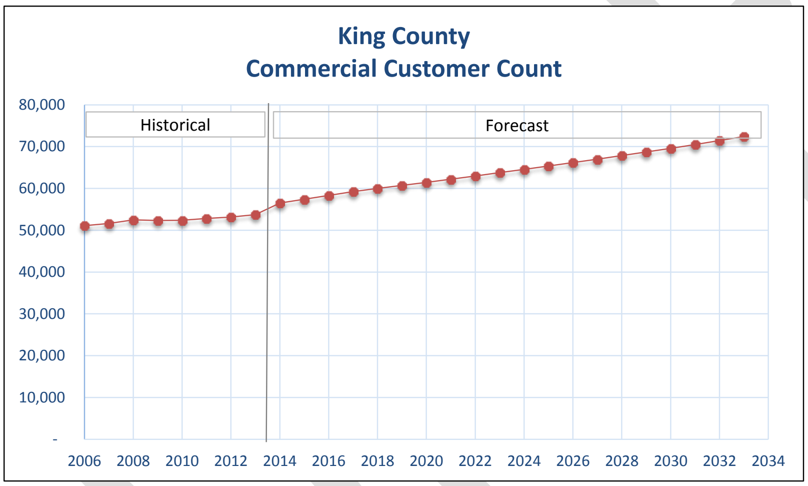
Forecasts for the commercial customer counts are increasing.

### Figure 6.6: Commercial Customer Count - PSE Service Territory

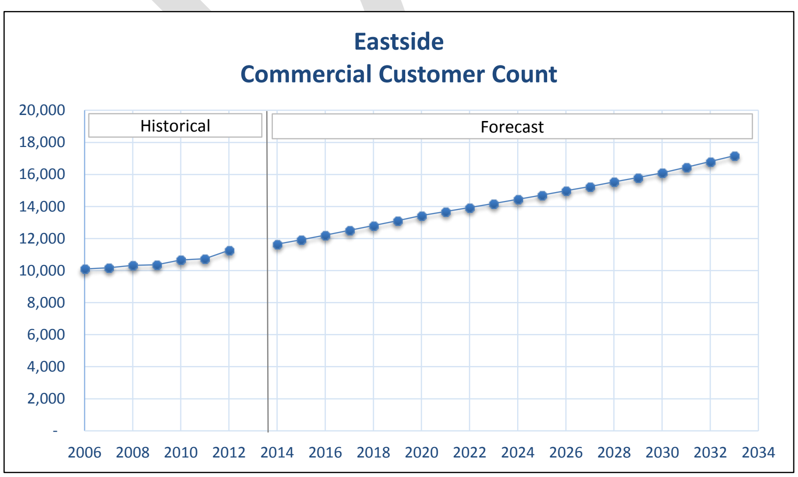



The PSE system data goes back to 2000 and shows the trend prior to the recession. The King County and Eastside data only goes back to 2006, so the historical trend is obscured by the recession.

### Figure 6.7: Commercial Customer Count – King County

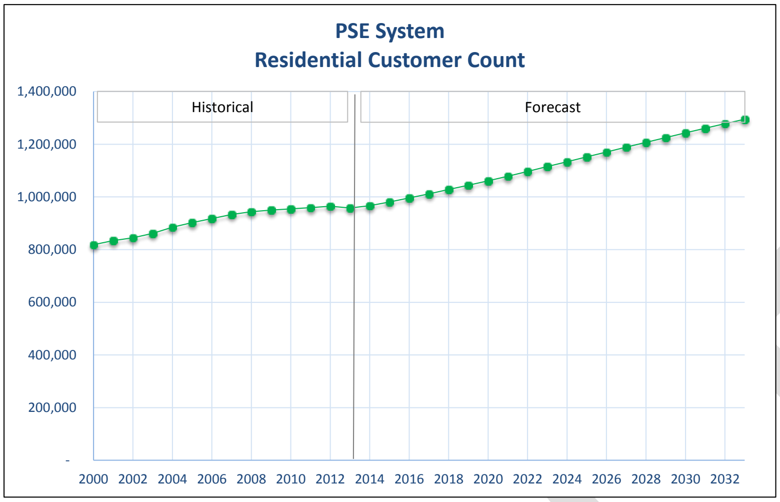



### Figure 6.8: Commercial Customer Count – Eastside



Forecasts for the residential customer counts are increasing.

**Figure 6.9: Residential Customer Count - PSE Service Territory**




The PSE system data goes back to 2000 and shows the trend prior to the recession. The King County and Eastside data only goes back to 2006, so the historical trend is obscured by the recession.

**Figure 6.10: Residential Customer Count – King County**

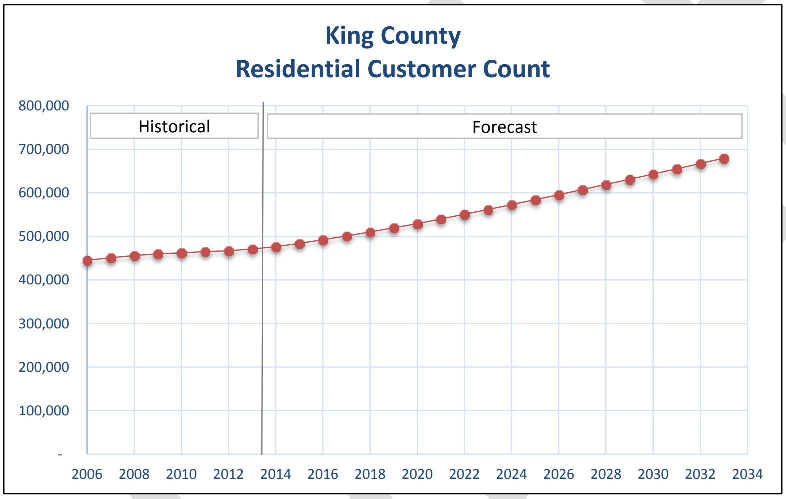
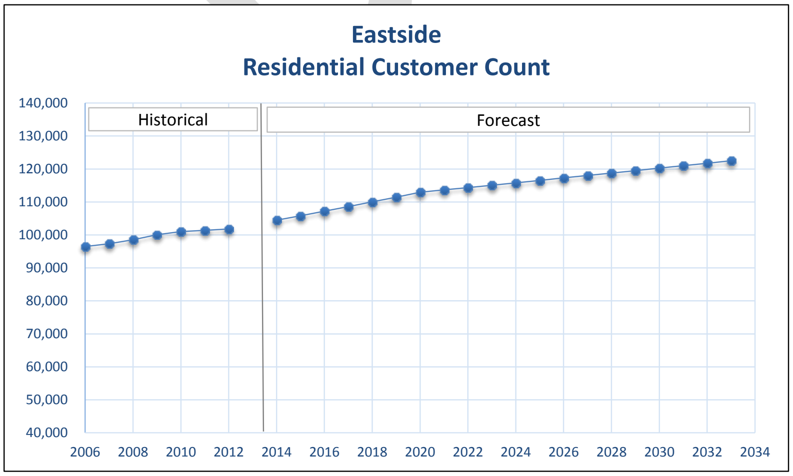



**Figure 6.11: Residential Customer Count – Eastside**



The industrial customer count is continuing to decline as more industrial customers move out of the area and more commercial moves in.

Industrial customers include warehousing.

**Figure 6.12: Industrial Customer Count - PSE Service Territory**

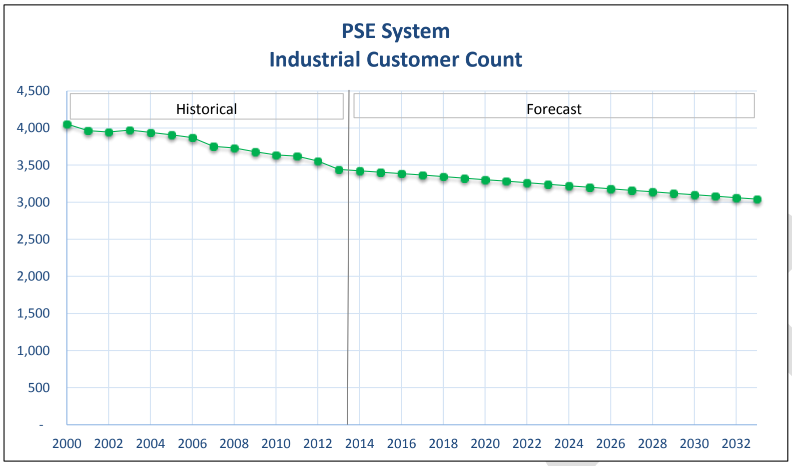



**Figure 6.13: Industrial Customer Count – King County**

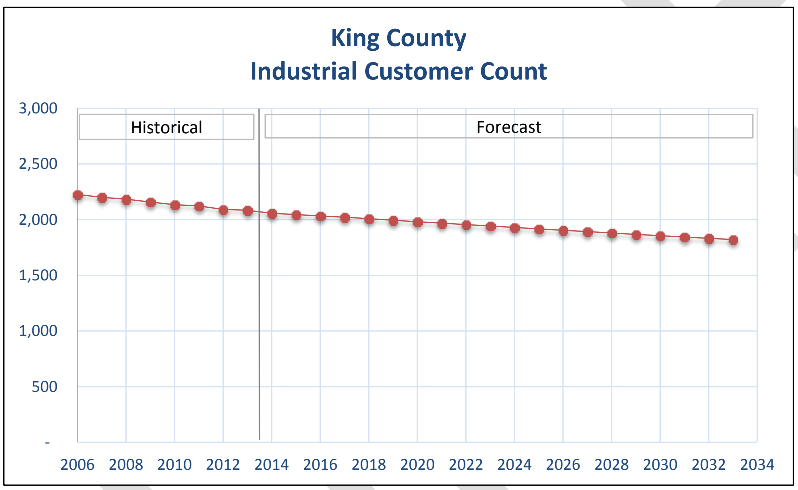
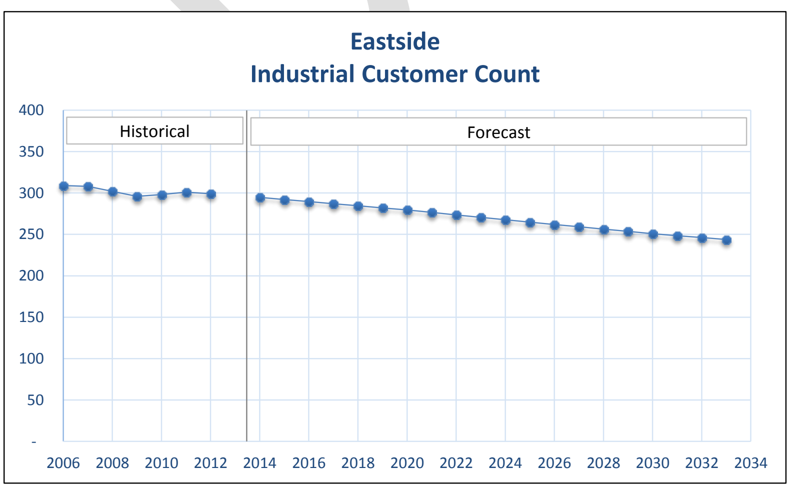



**Figure 6.14: Industrial Customer Count – Eastside**



### 6.3. End-Use Data, Including Demand-Side Response and Energy Efficiency

End-use data is evaluated in Integrated Resource Planning. The IRP is where a utility examines both Supply-Side and Demand-Side options with the objective of providing reliable and least-cost electric service to its customers while addressing applicable environmental, conservation and renewable energy requirements. Because energy efficiency is generally a low-cost resource, the IRP tends to incorporate energy efficiency as a utility system resource and reduce the need for additional Supply-Side resources.

Washington State's Renewable Portfolio Standard (RPS) law requires conservation potential be developed using Northwest Power & Conservation Council (NWPCC) methodology, and conservation targets are based on IRP with penalties for not achieving them. It requires PSE to meet specific percentages of its load with renewable resources or renewable energy credits (RECs) by specific dates.

The Energy Independence and Security Act (EISA, 2007) provides for minimum federal standards for lighting and other appliances beginning in 2012. It also sets standards for increasing the production of clean renewable fuels, increasing the efficiency of buildings and vehicles, and more.

PSE commissioned The Cadmus Group, Inc. (Cadmus) to conduct an independent study of Demand-Side Resources (DSR) in the PSE service territory as part of its biennial integrated resource planning (IRP) process. The study considered energy efficiency, fuel conversion, Demand Response, and distributed generation, totaling over four thousand measures. PSE also considered distribution efficiency. The achievable, technically feasibly Demand-Side measures were combined into bundles[21] based on levelized cost[22] for inclusion in the generation optimization analysis. The optimization model developed and tested different portfolios, combining Supply-Side Resources with Demand-Side bundles, to find the lowest cost combination of resources that: a) met capacity need; b) met renewable resources/RECs need; and c) included as much conservation as was cost effective. (Once the capacity and renewable resources/RECs needs are met, the decision to include additional conservation bundles is simply whether that next bundle of measures increases the cost or decreases it.) The final set of cost effective measures is identified as the "100% conservation" set. By 2033, the 100% conservation scenario is projected to reduce PSE's winter system peak by 1226 MW, 209 MW from the EISA programs and 1017 MW from all the other Demand-Side Resources. Only new opportunities are captured.

The table below breaks out the 100% conservation DSR at the King County and Eastside area level. The MW column shows the impact (reduction) to the demand forecast. For the Eastside area, 51 MW of peak DSR is projected by 2017, and 135 MW by 2031. These reductions are incorporated into the 100% Conservation forecast, which is what is being reviewed in this report.

[21] All the bundles are cost bundles, with the exception of a standards bundle (expected effects of codes and standards such as EISA) and a distribution efficiency bundle. An example bundle is the set of measures that cost between $28/MWh and $55/MWh.

[22] Levelized Cost - An economic assessment of the cost to build and operate a power-generating asset over its lifetime divided by the total power output of the asset over that lifetime. It is also used to compare different methods of electricity generation in cost terms on a comparable basis.

**Table 6.2: Cumulative DSR Impact (2013 IRP)**

| King County | | | Eastside Area | | |
|---|---|---|---|---|---|
| year | Annual DSR (MWh) | Peak DSR (MW) | year | Annual DSR (MWh) | Peak DSR (MW) |
| 2014 | 112,730 | 45 | 2014 | 94,667 | 21 |
| 2015 | 348,463 | 88 | 2015 | 152,559 | 31 |
| 2016 | 557,863 | 131 | 2016 | 207,980 | 41 |
| 2017 | 756,295 | 171 | 2017 | 262,563 | 51 |
| 2018 | 951,360 | 213 | 2018 | 317,493 | 61 |
| 2019 | 1,147,137 | 246 | 2019 | 386,767 | 74 |
| 2020 | 1,393,906 | 309 | 2020 | 464,427 | 86 |
| 2021 | 1,668,547 | 350 | 2021 | 529,013 | 96 |
| 2022 | 1,902,423 | 387 | 2022 | 585,484 | 107 |
| 2023 | 2,112,925 | 421 | 2023 | 629,201 | 110 |
| 2024 | 2,274,243 | 432 | 2024 | 650,086 | 113 |
| 2025 | 2,351,296 | 444 | 2025 | 672,152 | 116 |
| 2026 | 2,431,870 | 457 | 2026 | 693,168 | 120 |
| 2027 | 2,508,352 | 471 | 2027 | 715,397 | 123 |
| 2028 | 2,589,821 | 483 | 2028 | 734,411 | 127 |
| 2029 | 2,658,889 | 494 | 2029 | 754,139 | 130 |
| 2030 | 2,731,640 | 505 | 2030 | 771,869 | 134 |
| 2031 | 2,798,219 | 517 | 2031 | 793,300 | 135 |
| 2032 | 2,875,530 | 532 | | | |
| 2033 | 2,931,133 | 533 | | | |

Source: PSE

*Stakeholder Questions on Demand-Side Response:*

*Q2. What is the effect of the LED street light program on load?*

- A *The Eastside load is forecasted at 641 MW under normal conditions (Winter 15/16). The funded street light conversion program would reduce this load by 282 kW and the full conversion would reduce the load by 798 kW. On a percentage basis, the funded conversion would reduce Eastside load by 0.044% and the full conversion would reduce Eastside load by 0.12%. Though not evaluated in the 2013 IRP and thus not part of the 100% conservation measures, there will be limited impact to the overall load in any given year.*

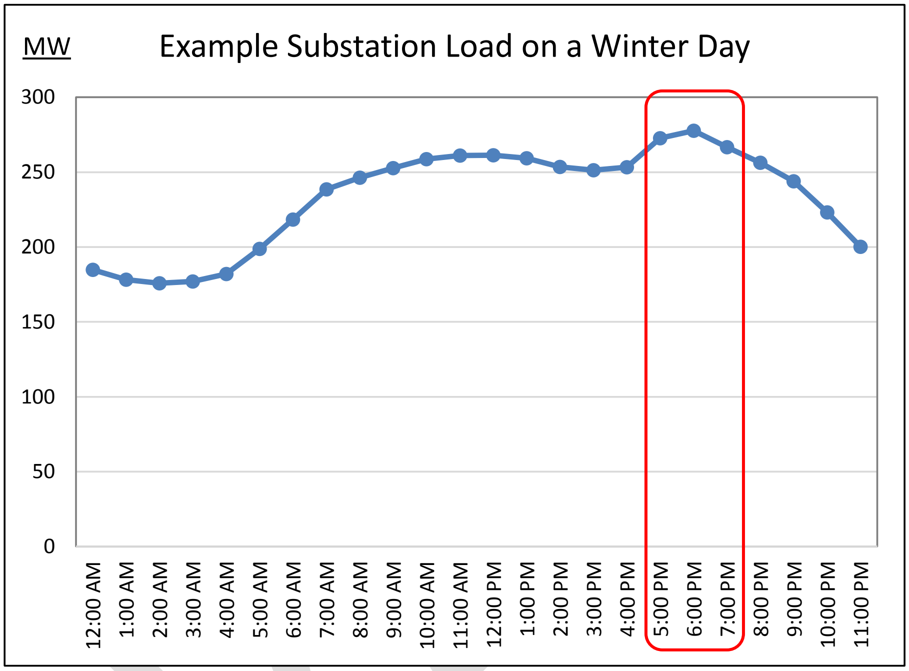
*Q3. Does the load forecast take into account local government actions, such as Bellevue's street light and traffic light initiatives?*

- A *The LED programs were not specifically identified in the 2013 IRP. The LED technology and availability is different today than it was when the 2013 IRP study began. PSE is planning on including LED lighting in the 2015 IRP.*

*Q4. What is the effect of the planned 289 kW of renewable generation (including Solarize Bellevue, the Bellevue College and the Bellevue Service Center), to the grid?*

- A *The Eastside load is forecasted at 641 MW under normal conditions (Winter 15/16). The planned 289 kW of renewable generation is nameplate rating, so actual output may be 80-85% of that on a sunny day. For a summer* *peak, the Eastside load could be reduced by 0.04%. For a winter peak, solar output would be significantly less or non-existent. PSE assumes that solar will not be available for the winter peak, since the winter peak usually occurs when it is dark out. The sample graph below reflects a mixed commercial/residential area, with the peak driven by the residential load. (A substation with the peak driven by commercial load could have a different load profile (different peaking curve).)*

**Figure 6.15: Sample Winter Load Profile**




*Q5. Is PSE using all the available Demand Response initiatives/opportunities?*

A *Available Demand Response initiatives/opportunities were evaluated as to whether they were achievable and technically feasible. Then PSE used a generation optimization tool to identify the lowest cost combination of resources that a) meet capacity need b) meet renewable resources/RECs need, and c) included as much conservation as was cost effective. (Once the capacity and renewable resources/RECs needs are met, the decision to include additional conservation bundles is simply whether that next bundle of measures increases the cost or decreases it. The IRP has the objective of providing reliable and least-cost electric service to its customers while addressing applicable environmental, conservation and renewable energy requirements. For example, Pacificorp states that the objective of the IRP is "…providing reliable and least-cost electric service to all of our customers while addressing the substantial risks and uncertainties inherent in the electric utility business." Energy Efficient West Virginia states that IRP is a process used by utility companies to determine the mix of resources that will meet electricity demand at the lowest cost.*

*Q6. How does efficiency affect energy usage?*

- *Energy efficiency elements were described above. The 2013 IRP identified 521 aMW*[23] *of market achievable, technically feasible electric energy-efficiency potential by the end of 2033. To gauge achievability, Cadmus relied on customer response to past PSE energy programs, the experience of other utilities offering similar programs, and the Northwest Power and Conservation Council's most recent energy efficiency potential assessment. For the 2013 IRP, PSE assumed achievable electric energy efficiency potentials of 85 percent in existing buildings and 65 percent in new construction. If this potential proves cost-effective and realizable, it would result in a 16% reduction in 2033 forecast retail sales. (Note: this is an energy usage question, not a demand (MW) question. That said, the forecast and need are based on incorporating all of the cost-effective conservation measures (100% Conservation).)*

*Q7. Provide details on cost-effective energy efficiency and Demand Response (DR) elements included in the forecast, and how "cost-effective" is determined.*

- *See Tables B-2-1, B-2-2, and B-2-3 (pages 156 – 265) of IRP Appendix N (2013) for a list of the thousands of electric measures studied. Table 13, page 20 provides a summary of the number of energy efficiency measures by customer class. The energy efficiency measures make up the majority of the DSR measures.*
- *Cost-effective: The short answer is that PSE has an optimization tool that ensures that the capacity needs are met, ensures that the renewable resources/RECs requirements are met, then minimizes total revenue requirements for both Supply-Side and Demand-Side. Those measures it selects are "cost effective". Longer answer: The measures are bundled into similar levelized costs and the optimization tool evaluates the measures in bundles rather than each individually, then the model determines which bundles are cost effective. See IRP Chapter 5 Figure 5-17 for the DSR bundles by cost group and Appendix N Figure 15 for the DSR supply curve. Out of an identified 1226 winter peak MW of achievable, technical potential in the PSE system (*1017 MW + 209 MW EISA), 1007 MW *were identified as cost effective.*

*Q8. Do the growth projections account for increased electrical efficiency? What assumptions are made, and do these represent the low, high, or average model outputs?*

- *Yes, the growth projections account for the cost effective efficiency measures.*
- *See answers to the preceding two questions.*
- *The forecast represents the base model.*

*Q9. Concern expressed with PSE's forecast when considering energy efficiency, renewables, and Demand Response incentives.*

- *Please see above discussion and answers.*

## *6.4. Major Loads*

PSE adjusts its forecast to incorporate major load additions, also called block load additions. The adjustment is a temporary adjustment, as they assume that within a few years the growth built into the load forecast will "catch up" and include the block load additions.

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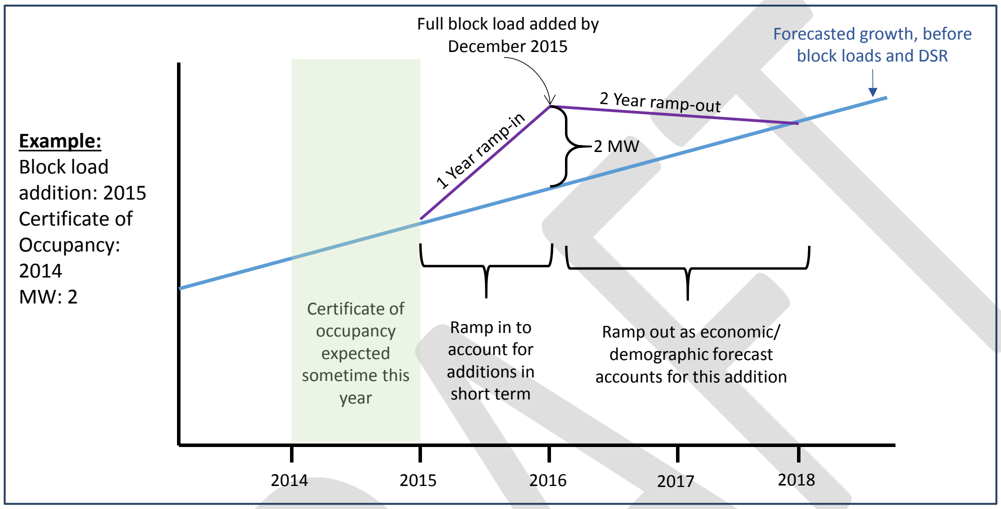
[23] aMW - The average number of megawatt-hours (MWh) over a specified time period; for example, 295,650 MWh generated over the course of one year equals 810 aMW (295,650/8,760 hours). (Source: PSE's 2013 IRP Definitions)

Example: A building has a certificate of occupancy in 2014, with an expected diversified load of 2 MW. PSE will assume it takes a year for the load to fully appear and will add it to the forecast using a one year ramp-in. PSE then ramps the adjustment out over two years, assuming that the growth built into the forecast will take two years to catch up to the block load addition. The block load additions are like bumps on the forecast; they don't change the overall trend, but do create short term changes. See the figure below.

**Figure 6.16: Block Load Addition Methodology (from PSE)**




PSE acquires data on major load additions from cities as well as directly from developers; some of this data is considered confidential and was not shared. PSE did provide a list of over fifty Eastside Block Load projects (unnamed) with estimated MW load and the expected year when the load would be fully realized. The table below provides a summary by year of this information. The square footage and number of units are reported where known. PSE's Planning group projects a probability of occurrence of 100% for loads anticipated through 2017, 50% for loads anticipated between 2018 and 2020, and 0% for projects after 2020. This probability is multiplied by the expected load before adding into the forecast. The probability factor is a way of addressing the increasing uncertainty of projects in future years.

Table 6.3 does include the City of Bellevue Projects (individually listed in Table 6.4). The Sound Transit East Link project is included in the forecast and accounts for a small portion of the load (approximately 3.5 MW) beginning in the year 2020. Although the East Link web site indicates a 2023 in-service date, PSE's initial expectation is that a small portion of the load will be needed in 2020 and as the project grows they anticipate that Sound Transit's impact on the peak demand will increase. This particular load may be forecasted in advance of need, but it would not impact the 2017/18 HW need for the Energize Eastside project.

### Table 6.3: Eastside Total Block Loads by Year

| Estimated Completion Year | Assigned Probability | # of Projects | Commercial Sq Footage | # of Multi-family units | MW fully energized this year | MW added to forecast |
|---|---|---|---|---|---|---|
| 2014 | 100% | 3 | 100,000 | 642 | 4.4 | 4.4 |
| 2015 | 100% | 9 | n/a | 1231 | 5.3 | 5.3 |
| 2016 | 100% | 6 | 263,000 | 493 | 7.0 | 7 |
| 2017 | 100% | 7 | 2,157,000 | 1566 | 25.0 | 25 |
| 2018 | 50% | 4 | 820,362 | n/a | 1.0 | 0.5 |
| 2019 | 50% | 6 | 1,989,340 | n/a | 21.5 | 10.75 |
| 2020 | 50% | 18 | 1,316,000 | 234 | 16.3 | 8.15 |
| 2021 | 0% | 4 | 2,010,000 | n/a | 14.8 | 0 |
| 2022 | 0% | 0 | 0 | 0 | 0.0 | 0 |
| 2023 | 0% | 0 | 0 | 0 | 0.0 | 0 |
| 2024 | 0% | 3 | 928,000 | n/a | 8.5 | 0 |
| 2025 and beyond | 0% | 9 | 602,000 | 150 | 17.8 | 0 |

* Square footage and number of units are reported where known.

Table 6.4 lists the thirty-nine major projects identified on the City of Bellevue's website, and is provided to show the significant growth expected in the City of Bellevue. Twelve of the Projects include data on the number of stories (building floors), and seven of these are planning fifteen stories or more.

### Table 6.4: City of Bellevue Major Projects (website)

| # | Name |
|---|---|
| Downtown - In Review | |
| 1 | Bellevue Square SE Corner Expansion |
| 2 | Washington Square Hilton garden Inn |
| 3 | Goldsmith Plaza 305 |
| 4 | Bellevue Center, Phase II |
| 5 | 415 Office Building |
| 6 | Rockefeller Bellevue Tower Phase I |
| 7 | Marriott AC Hotel |
| 8 | AMCUT |
| Downtown - Under Construction | |
| 1 | Alamo Manhattan Main Street |
| 2 | Main Street Gateway / Bellevue Gateway, LLC |
| 3 | Marriott Hotel |
| 4 | Bellevue at Main / SRM |
| 5 | Bellevue Apartments / LIHI |
| 6 | Alley 111 |
| 7 | Bellevue Office Tower |
| 8 | Bellevue Park II Apartments |
| 9 | Lincoln Square Expansion |
| 10 | SOMA Phase II |
| Downtown - Issued Land Use & Building | |
| 1 | The Summit Building C / Bentall |
| 2 | 103rd Avenue Apartments / HSL Properties |
| 3 | Bellevue Center, Phase I |
| 4 | Pacific Regent of Bellevue, Phase II |
| Downtown - In the Pipeline | |
| 1 | Evergreen Development Bellevue Tower |
| 2 | EROS Properties |
| 3 | Fana CBD Master Development Plan |
| 4 | Metro 112 Apartment, Phase II |
| 5 | 17-102nd Avenue NE |
| 6 | Eastlink Bellevue Transit Center Station |
| 7 | 10625 Main Street |
| 8 | 846 108th Avenue NE |
| 9 | Habib Properties |
| 10 | Bellevue Plaza |
| Bel-Red - In Review | |
| 1 | Spring District Residential (Land Use Approval) |
| 2 | Spring District Office, Bldgs. 16&24 (Building Permit) |
| 3 | East Link 130th Station |
| Bel-Red - Under Construction | |
| 1 | GRE Phase I and Phase II |
| Bel-Red - In the Pipeline | |
| 1 | Aegis at Overlake |
| 2 | Sherwood Center |
| 3 | East Link 120th Station |

Projects can shift, developers can change their schedule, but PSE's projected timing of the block loads falls within a realistic range based on current construction schedules and plans, with the possible exception of the East Link project in 2020. However, the East Link timing wouldn't affect the EE timing. PSE's 1-year ramp-in is based on having certificates of occupancy; as long as certificates of occupancy and visual confirmation of both construction and occupancy rates are utilized, the forecast can be updated each time with the best available information. In addition, some of the block load project information is still limited and doesn't provide a complete picture of the electric load requirements, so assumptions must be made. These situations are also typical and another reason for the need to regularly update block load information which is a typical industry practice. In summary, PSE's block load data appears to fall within a realistic range. Construction is happening. Developers have indicated interest in future projects. Also, PSE applies a probability factor to the estimated loads to try to address the uncertainty of projects with later in-service dates, and all the forecasted impacts of the block loads on the forecast are only temporary bumps, and are ramped out of the forecast so that they don't affect the overall growth trend.

*Stakeholder Questions on Major Projects*

*Q10. Is development like Bellevue's Spring District factored in? Are there numbers that account for the impact of individual projects in downtown Bellevue? What numbers are used to predict the load impact for these projects?*

- A *Yes. See Table 6.3 for the summary.*

*Q11. A scenario was posed that data centers were consolidating and moving out of the Eastside area, and a question was asked whether PSE had accounted for that in their forecast.*

- A *PSE does account for large loads leaving the system or moving from one substation to another, but is not aware of any major changes in data centers. Data centers can be relatively small or quite large. Per PSE, the large data centers generally locate outside the PSE service area, where it is cheaper. PSE's planners have seen no indication of large data center changes. A short, independent web search did not turn up any large data center moves out of the Eastside area.*

## 6.5. PSE's Forecast

Figures 6.17 – 6.21 depict energy and demand (MWh and MW) forecasts, and growth rates. The peak forecast is affected by conservation programs, and all the graphs assume 100% conservation and a normal winter. PSE's conservation programs are heavily weighted toward the first 10 years of the forecast (2014-2023), with less aggressive conservation occurring in the second 10 years of the forecast (2024-2033). This can result in a slower growth rate in the load forecast for the first 10 years.

PSE reached several key conclusions in comparing the new 2014 forecast (F14) with the prior 2012 forecast (F12), which affects some of the information that PSE had publicly shared showing demand and need for the project. PSE's F14 system forecast assumed a more gradual recovery of the US economy from recession than the prior F12 forecast. The F14 system forecast also used an updated US population growth forecast from the US Bureau of Census which is lower than what was used in F12.

In addition, customer growth and customer counts in the F14 system forecast are lower than in F12 because of slower housing recovery. Finally, peak load growth and peak load levels at the system and King County level are also projected to be lower in F14 versus F12.

The Eastside area is where the load projections increased. Eastside peak loads in the new forecast, based on PSRC's population and employment growth forecasts, are projected to grow by 2.4% per year[24] in the next 10 years driven by growth in commercial sector and high density residential sector.

Although the F14 forecasted Eastside growth rate increased over the 2012 forecast (F12), the resultant F14 forecast for Eastside reduced the projected 2017/18 normal winter loading by 11 MW. The new F14 forecast, based on census tract level demographic data for the Eastside area, had normalized actual peak loads for winter 2012/13 and 2013/14 which were less than the forecasted peak loads from the F12 forecast, which in turn resulted in lower forecasted peaks for winter 2017/18. Section 8 of the report discusses the impact on the Energize Eastside project need.

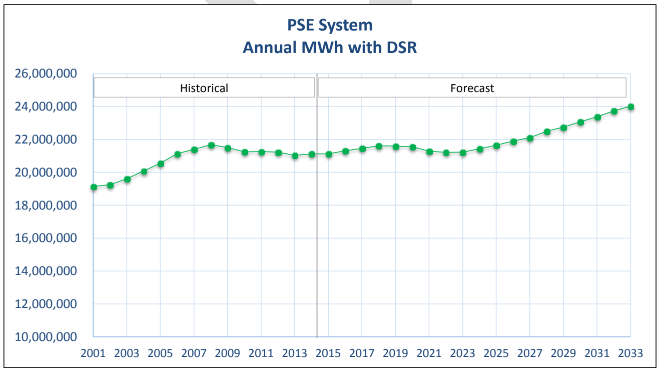
### Table 6.5: PSE's Eastside 2017/18 Forecast Comparison

| Forecast Development Year | 2017/18 Winter Peak |
|---|---|
| 2012 | 699 MW |
| 2014 | 688 MW |

Figures 6.17 – 6.20 show MWh and MW forecasts for the PSE system, King County, and the Eastside area. The EE project need is based on the MW graph for Eastside. The MWh forecasts do not drive the need, but are shown because of the number of Stakeholder questions received and the uncertainty and/or misconception of what MWh indicate. The MWh forecasts show *usage*, like the odometer, not *peak.* They reflect growth and conservation, but are not directly tied to the peak. The typical behavior or response of a household may be different on the one or two very cold days in a year, as one is getting ready in the morning or coming back from work to a cold house.

Figure 6.17 shows the energy forecast for the PSE system. The forecasted dip in energy is due in part to the aggressive conservation programs that are weighted toward the first 10 years of the forecast (2014-2023). In addition, the block loads are phased in and then phased out over time. Any block loads that come in after 2017 are only given half of the MWh since these projects are less certain to be completed. After 2020 no block loads would be phased in, with a few more years of earlier block loads phasing out.

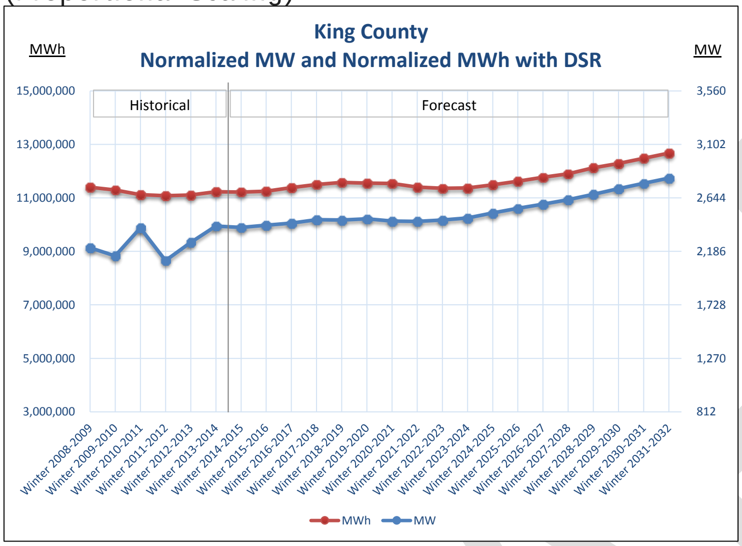
### Figure 6.17: PSE's Energy Forecast (MWh) – PSE System




[24] The growth rate is a peak load growth rate and is developed through a regression analysis.

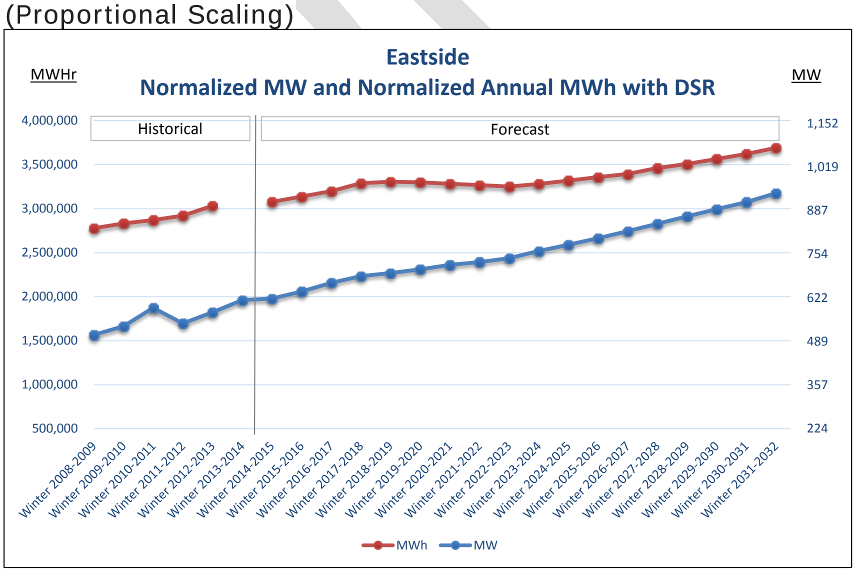
Figure 6.18 shows the energy forecast and demand forecast for King County. King County is forecasted to have a relatively flat energy and demand forecast until approximately winter 2023/2024, at which point both forecasts are increasing. The energy and demand forecasts track fairly closely in King County, but this doesn't mean the same response is expected in other areas.

**Figure 6.18: PSE's Energy (MWh) and Demand (MW) Forecasts - King County**
(Proportional Scaling)




In the Eastside area, the energy forecast appears to show a stronger impact from conservation compared to the demand forecast. As mentioned previously, the forecasted dip in energy is due in part to the aggressive conservation programs that are weighted toward the first 10 years of the forecast (2014-2023). It is also impacted by the block loads which are phased in and then phased out over time. After 2020 no block loads would be phased in, with a few more years of earlier block loads phasing out.

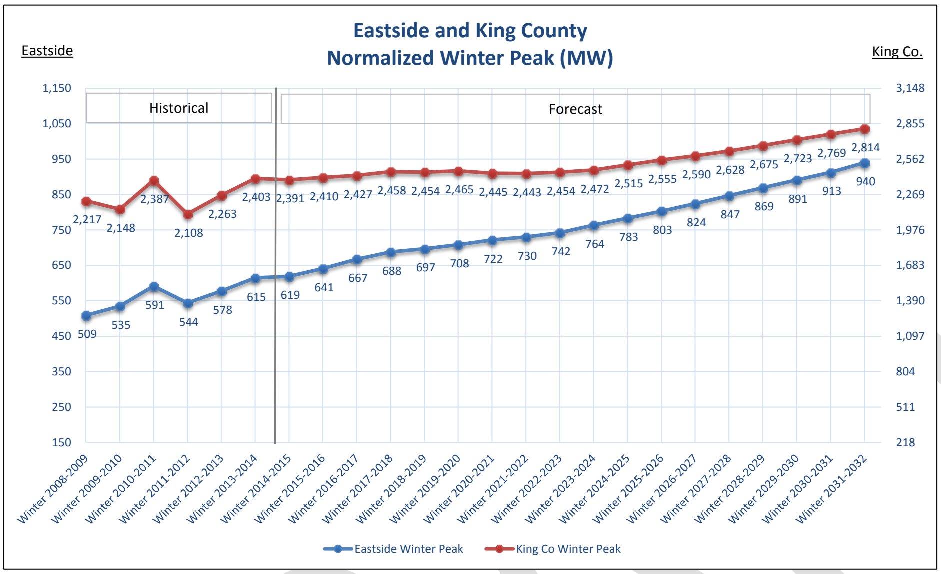
**Figure 6.19: PSE's Winter Energy (MWh) and Demand (MW) Forecasts – Eastside**
(Proportional Scaling)




The dip is due to a cold snap that lasted several days. Per PSE their weather adjustment does not fully account for the lag effects of longer cold snaps.

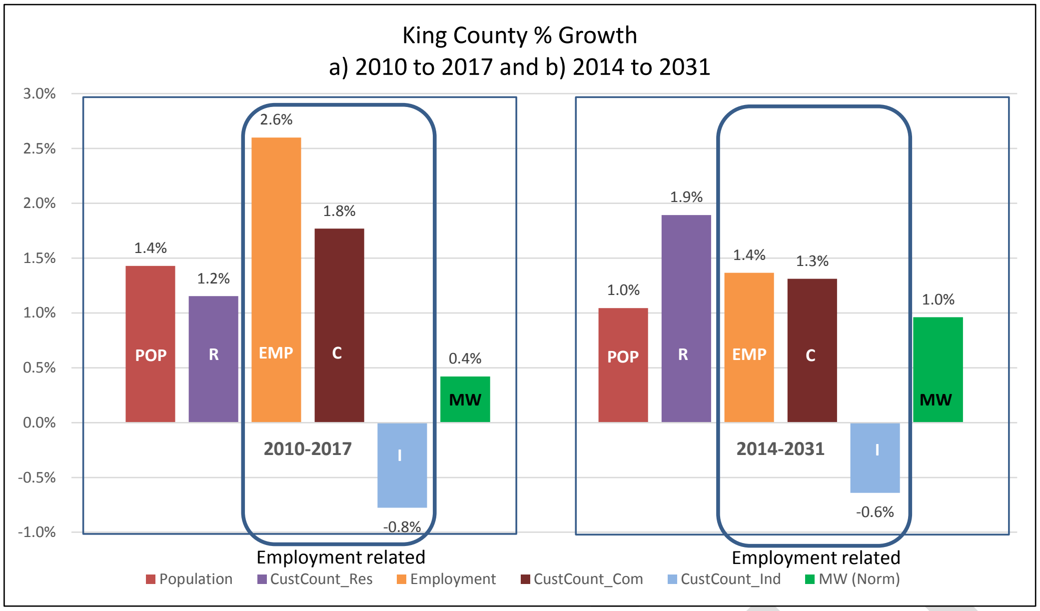
Figure 6.20 compares the Eastside and King County winter peak demand forecasts. The Eastside area is forecasted to grow at a faster rate than King County. This is in line with the Vision 2040 Regional Growth Strategy

**Figure 6.20: PSE's Winter Demand Forecasts – Eastside and King County, 100% Conservation**
(Proportional Scaling)



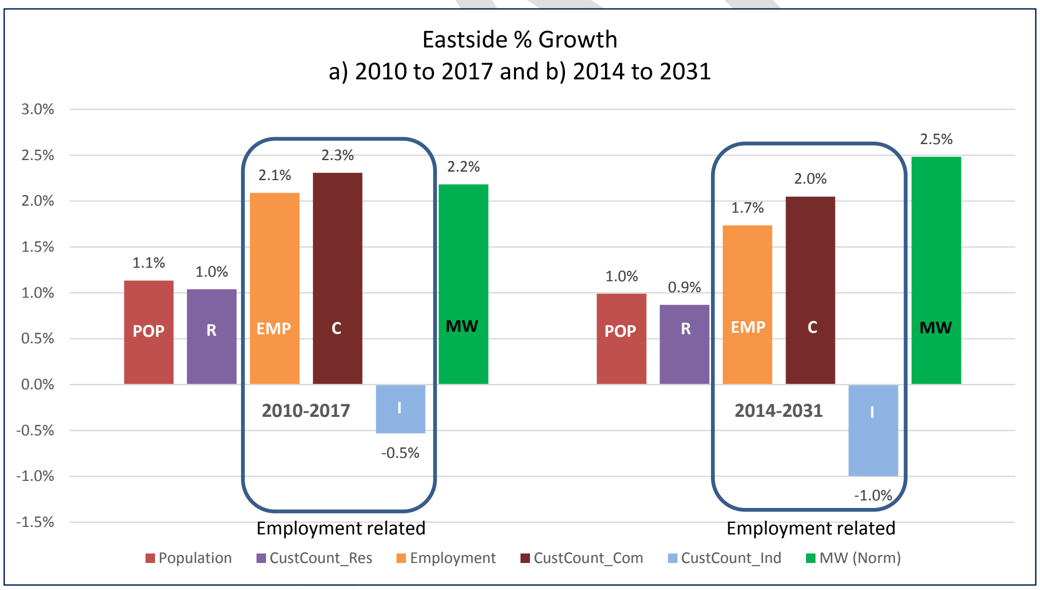

The 2014 forecast shows a 2.4% growth rate for the Eastside area from 2014-2024 and a 2.5% growth for Eastside between 2014 and 2031. In comparison, the forecast shows a 1% growth rate for King County between 2014 and 2031. The Eastside area is projected to grow significantly faster than King County as a whole, which is in line with the Vision 2040 Regional Growth Strategy report. Whether this growth will be sustained through 2031 is unknown. Note: if the growth rate is calculated from the 2010 actuals through 2017, the growth rate is 2.2% for Eastside and 0.4% for King County. See Figure 6.21 and Figure 6.22.

### Figure 6.21: Growth Rates – King County




See Table 6.1 for original data sources. Numbers provided by PSE.

### Figure 6.22: Growth Rates – Eastside Area




See Table 6.1 for original data sources. Numbers provided by PSE.

<u>Stakeholder Questions related to Actuals (Historical Data)</u>

*Q12. What are the ACTUAL numbers for 2012, 2013 and 2014?*

A *Actual numbers for employment, population and customer count are shown in Section 6.2. Actual numbers (normalized) for MWh and MW are shown in Section 6.5.*

*Q13. Please show historical loads.*

A *See preceding question.*

*Q14. What is the source of the actuals?*

- A *See Table 6.1*

*Q15. Would like graph showing load history (back to 2000) and forecast.*

- A *See Section 6.5*

*Q16. Please include 2014/15 winter peak data.*

- A *The data is not yet available for the 2014/15 winter peak. See Figure 6.2 and the paragraph above it.*

*Q17. Please provide the unadjusted and temperature adjusted historical peaks.*

- A *Temperature adjusted historical peaks are shown in Section 6.5. See the beginning of Section 5 and Section 5.1 for why unadjusted peaks are not used.*

*Q18. What have been the highest actual aggregate winter peak loads on Eastside feeders and distribution lines …? How would they relate to PSE's forecast of future loads?*

- A *The aggregate peaks for the Eastside area are captured in the historical data shown in Figure 6.19.*
- A *The historic loads are included in the regression analysis which results in the forecast of future loads.*

## *6.6. Summary Analysis of PSE's Forecasting*

PSE has followed industry practice in forecasting their demand load.

- PSE included the major components of a typical system forecast: weather normalizing, use of econometric data, incorporating end-use data (including conservation and DSR measures), and making adjustments for block (major) loads.
- The variables used in the weather normalizing process were typical based on industry practice.
- PSE used typical data set elements and multiple data sources for economic/demographic data as shown in Table 6.1, acquiring data at the county level, and for the Eastside area at the census track level, in order to differentiate growth rates within its service territory.
- PSE employed regression analysis at this step, an industry standard computer analysis technique, to determine the forecast before Demand Side Resources (DSR) and block load adjustments. (The computerized regression analysis was not analyzed as part of this study, but the technique is a computerize estimation of the best fit of the variables to the given data. The equations are considered proprietary by PSE.)
- PSE acquired/developed significant end-use data via their IRP process on over four thousand DSR measures, incorporated National and State requirements on conservation and RPS, and optimized the achievable, technical measures with a resultant 100% Conservation scenario which projects 135 MW of Eastside winter peak DSR by 2031.
- PSE gathered block load data (major projects) and utilized short-term forecast adjustments (1-year ramp in based on certificates of occupancy and 2-year ramp-out) to account for the impact. The block load impact was further adjusted by applying a probability factor based on the projected block load in-service date, with 100% through 2017, 50% from 2018 to 2020, and 0% after 2020. The in-service date accuracy and the ramp-in timing of one year is harder to evaluate. Projects can shift, developers can change their schedule, but PSE's projected timing of the block loads falls within a realistic range based

on current construction schedules and plans, with the possible exception of the East Link project in 2020 which wouldn't affect the EE timing. PSE's 1-year ramp-in is based on having certificates of occupancy; as long as certificates of occupancy and visual confirmation of both construction and occupancy rates are utilized, the forecast can be updated each time with the best available information. In addition, some of the block load project information is still limited and doesn't provide a complete picture of the electric load requirements, so assumptions must be made. This is also typical and another reason for the need to regularly update block load information which is a typical industry practice. In summary, PSE's block load data appears to fall within a realistic range. Construction is happening. Developers have indicated interest in future projects. Also, PSE applies a probability factor to the estimated loads to try to address the uncertainty of projects with later in-service dates, and all the forecasted impacts of the block loads on the forecast are only temporary bumps, and are ramped out such that they don't affect the overall growth trend.

No forecast is perfect, but by following industry practice, PSE used reasonable methods to develop the forecast. PSE's resultant forecast shows the Eastside area growing at a higher level than at the county and system level, and that is based on the data PSE received.

<u>Comments on weather adjustment:</u>

PSE is applying the Northwest US practice (as does SCL) of basing projects on a normal 50/50 forecast, which by definition should be exceeded half the time, and using a 95/5 (1-in-20) extreme weather scenario for reference (but not for developing projects). Although a regional industry standard, many other US utilities base projects on an adverse weather scenario, such as a 90/10 or 80/20. Basing projects on an adverse weather scenario is more conservative, but seeks to ensure that the lights stay on given the adverse weather event. These statistically less frequent assumptions would result in a higher load forecast, and if adopted as a policy on which to base projects, would require the system to be designed to withstand it.

Based on historical temperature data, one could suggest that PSE's forecast use a normal temperature of 24°F rather than 23°F for winter normalizing (see Figure 6.1), but: a) the 24°F average is based on a relatively short span of time, and b) the forecast used to propose projects is a normal 50/50 forecast and is expected to be exceeded given an adverse weather event. If PSE were to adopt an adverse weather policy on which to base projects, then it could make sense to re-evaluate the "normal" winter peak temperature; however, since the system demand is based on the less conservative 50/50 load forecast, using 23°F for the normal temperature is a reasonable assumption because it results in a slightly higher system demand than using 24°F.

<u>*Stakeholder* Questions related to Forecast Methodology</u>

*Q19. Questions on heat map. Request to create a more accurate map.*

A *USE attempted to make a replacement heat map. One can obtain usage (kWh) data at a detailed level, but that doesn't show the peak demand which drives the project need - analogy of the odometer and speedometer. USE created a map of substation peak demand, using spatial interpolation* *between the substations, but the accuracy wasn't sufficient for the granularity of detail that is desired. The substations aren't necessarily located right where the heaviest load is. USE didn't feel the result gave a sufficiently clear representation of the area load and so did not include it.*

*Q20. What are the industry standards for forecasting? Compare to PSE forecast.*

- A *See Sections 5 & 6 for standard industry practice.*

*Q21. There appear to be no industry wide standards for the development of utility load forecasts, but there do appear to be standards for Integrated Resource Plans. RCW 19.280 State IRP, WAC 480-100-238. Clarify term "conservation" and why it is used for customer load reductions.*

- A *Yes, the industry standards have concentrated on the IRP process, but within that are requirements relating to some of the forecast elements. There are typical industry practices.*
- A *100% Conservation is defined as the cost-effective, achievable, technical DSR measures. See the Section 5 introduction and Section 6.3.*

*Q22. Is PSE using population growth as a parameter? If so, at what granularity are the growth projections made? In other words, are growth projections used for individual cities, or is the Eastside treated as a whole, with one forecast governing the whole area?*

- A *Population is used as a parameter.*
- A *Forecasts were developed at the system level, at the county level, and for the Eastside area. The Eastside forecast was developed using census tract data.*

*Q23. We would like to understand economic projections as well. Is economic growth projected for each city, or only for the whole Eastside? What numbers were used?*

- A *Economic projections were made at the system level, at the county level, and for the Eastside area. Graphs were provided for some of the major elements (Section 6.2 and 6.5).*

*Q24. Does the load forecast anticipate changes in regional transmission flow, such as south-north transmissions to Canada?*

- A *The load forecast is based on load. Transmission flows are irrelevant to the forecast. The link between forecast and transmission flows comes from modeling the substation load data, which was correlated to the load forecast, into a powerflow case. The powerflow case is where regional flow scenarios can be modeled. (See Appendix B, Optional Technical Analysis for study results of this scenario. It showed that even with no power flowing to Canada on the Northern Intertie (which is an unrealistic hypothetical scenario but modeled to answer the local vs. regional question), there is still a project need.*

*Q25. What other factors governing the regional grid is the load forecast taking into account?*

- A *See preceding answer.*

*Q26. Is it possible that the industry-standard methodology which PSE uses to forecast load growth has not evolved to reflect the realities of the current electricity marketplace? Are there any newer methodologies, or modifications to existing methodologies, which better reflect the realities of the modern electricity marketplace?*

- A *This question is outside the scope of this study; however, the IRP process continues to get attention, and frequently includes input from stakeholders, which is where Demand-Side Resources are evaluated and feed into the forecast process.*

*Q27. Is PSE's load projection reasonable? Are they the needs of Eastside or the needs or BPA, etc.? Are the loads PSE is projecting based on a farfetched combination of circumstances that are unlikely to actually happen?*

- A *The load projections and need determination are based on a normal weather forecast with 100% conservation. The 2014 forecast methodology and inputs are reasonable. See Section 6.6. See Section 7 for discussion on standards.*

*Q28. Is PSE's forecast based on good data, independently verified?*

- A *Yes, PSE has followed industry practice in forecasting their demand load. See section 6.6.*

*Q29. Why is PSE projecting load growth when their public documents (e.g. 10k) show they are selling less electricity?*

- A *The referenced 10k report is based on energy, which like an odometer reading shows usage, not peak demand. As noted previously, average use behavior is not necessarily winter peak behavior; the trends don't have to match. In addition, the data in the report is not adjusted for weather. See figures in Section 6.5 for current forecasts.*

*Q30. Provide justification/rational/definition for the System Capacity line on PSE's "Customer Demand Forecast".*

- A *System Capacity: Occurs when the load (Eastside Area) just hits the rating limit of the critical contingency condition(s). The System Capacity line can shift depending on where load grows (if not homogenous). The contingency analysis is dictated by national standards. Using the same methodology as the 2013 report, a winter Eastside system capacity range of 688-708 MW has been identified based on the 2014 load forecast powerflow results (see Figure 8.1).*

*Q31. How does PSE justify an Eastside growth rate of 1.7% to 2%?*

- A *PSE used reasonable methods to develop the 2014 forecast by following industry practice (see Section 6.6). The forecast is built from the data inputs via regression analysis. The 2014 demand forecast shows a 2.4% growth rate for the Eastside area from 2014-2024 and a 2.5% growth for Eastside between 2014 and 2031. In comparison, the forecast shows a 1% growth rate for King County between 2014 and 2031. The Eastside area demand is projected to grow significantly faster than King County as a whole, which is in line with the land use* Vision 2040 Regional Growth Strategy *report. Whether the forecasted demand growth will be sustained through 2031 is unknown. Note: if the growth rate is calculated from the 2010 actuals through 2017, the growth rate is 2.2% for Eastside and 0.4% for King County. See Figure 6.18 and Figure 6.19.*
- A *Note: SCL's "demand" forecast growth of 0.5% noted in their latest IRP update is actually an energy forecast. SCL's actual demand forecast from December 2013 to December 2034 has an estimated compound annual growth rate (CAGR) of 1.2%, based on an estimated 1180 MW in December 2013 and using their IRP demand graph as reference. PSE has a CAGR of 2.4% from winter 2013/14 to winter 2031/32 based on an estimated 615 MW in winter 2013/14.*

*Q32. What is the magnitude and timing of the need for EE? An updated peak load forecast is needed to resolve serious questions about the load forecast used by PSE to justify the project as now proposed.*

- A *In early February, 2015, PSE completed their 2014 forecast which included historical data through 2014, and thus included the summer 2014 peak and the winter 2013/2014 peak. See the top of Section 6 for discussion on the new forecast methodology.*

*Q33. Please explain PSE's "Eastside Customer Demand Forecast" chart. A detailed quantitative analysis for the years is needed on this chart. There have been several credible articles stating electrical usage is not growing but is flat, even declining in the United States. This trend is apparent over several years and is due to conservation and technological changes in production, usage and storage. How does Energize Eastside explain this disparity? Also, solar energy has been increasing on the Eastside.*

- A *Please see discussions in Section 6.2 on the economic and demographic data sources, the Vision 2040 Regional Growth Strategy, and Section 6.4 on Major Loads. Please see Section 4 on Energy vs. Demand and Q4 on potential impact of solar on a winter peak.*

*Q34. PSE's energy use (MWh) trend and # of customer trend is similar to SCL, yet PSE's load forecast (MW) shows a significantly higher growth % than SCL. Explain. National electricity use is declining as is regional (Pacific Northwest Utilities Conference Committee (PNUCC)). Why is PSE's forecast increasing? Explain why electricity use in Bellevue is so different from other cities.*

- A *Please see Q31 and Q33 answers.*

*Q35. Please explain PSE's "Eastside Customer Demand Forecast" chart. Show peak demand for Bellevue. Show retail sales to customers, off-system sales and electricity delivered to transmission only customers. Concern over accuracy of trend.*

- A *See preceding answer. See Figures in Section 6.5.*
- A *There are no off-system sales within the Eastside area; this would not affect the Eastside forecast. There are transmission only customers in King County outside of the Eastside area, but since the off-system sales customers are not PSE's customers, they wouldn't affect that forecast either.*

*Q36. Is it true that PSE's "Eastside Customer Demand Forecast" graph is based on a hypothetical "grid-flow modeling scenario" … rare winter peak …*

- A *No. It is based on normal winter weather. The hypothetical outage scenarios are part of the industry mandated contingency analysis. Please see the weather normalizing discussion in Section 5 and see Section 7 on Standards, regarding the required contingency analysis.*

# 7. Electric Utility Reliability Standards

## 7.1. EPAct 2005

On August 14, 2003, large portions of the Midwest and Northeast United States and Ontario, Canada, experienced an electric power blackout. The outage affected an area with an estimated 50 million people and 61,800 megawatts (MW) of electric load in the states of Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey and the Canadian province of Ontario. The blackout began a few minutes after 4:00 pm Eastern Daylight Time (16:00 EDT), and power was not restored for 4 days in some parts of the United States. Parts of Ontario suffered rolling blackouts for more than a week before full power was restored. Estimates of total costs in the United States range between $4 billion and $10 billion (U.S. dollars). In Canada, gross domestic product was down 0.7% that August, there was a net loss of 18.9 million work hours, and manufacturing shipments in Ontario were down $2.3 billion (Canadian dollars).[25]

Partially in response to this blackout, Section 1211 was added to the Energy Policy Act of 2005 (EPAct 2005). EPAct 2005 became law on August 8, 2005. Section 1211 of the EPAct 2005 requires that the Federal Energy Regulatory Commission (FERC) certify an Electric Reliability Organization (ERO) to establish and enforce reliability standards for the bulk-power system[26], subject to FERC review. On July 20, 2006, FERC certified the North American Electric Reliability Corporation (NERC) as the ERO for the continental U.S. under the Federal Power Act Section 215.

From the NERC website (www.nerc.com):

> "NERC is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC’s area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization for North America, subject to oversight by the Federal Energy Regulatory Commission and governmental authorities in Canada. NERC’s jurisdiction includes users, owners, and operators of the bulk power system, which serves more than 334 million people."

Because of changes brought about by EPAct 2005, the NERC standards that were previously voluntary are now mandatory and all users of the Bulk Power System (BPS) must comply with these standards. There are currently 1426 requirements in 143 reliability standards either subject to enforcement or subject to future enforcement.

[25] http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf, pg. 1
[26] In this report, the terms Bulk Power System (BPS) and Bulk Electric System (BES) will be used interchangeably. While the definitions are slightly different, for the purposes of this report and for determining the need for the Energize Eastside Project, these two terms can be treated as the same.

## *7.2. Reliability Standards Applicable to Energize Eastside*[27]

NERC Reliability Standard TPL-001-4[28] (Transmission System Planning Performance Requirements) is the Reliability Standard most relevant to the need for the Energize Eastside Project. TPL-001-4 Requirement 1 and Requirement 7 are currently subject to enforcement. Requirements 2-6 and 8 are not currently subject to enforcement but will be subject to enforcement on January 1, 2016. The enforcement date for Requirements 2-6 and 8 is before the planned in-service date of the Energize Eastside Project. Therefore, the Energize Eastside Project will be subject to the newer requirements before the project goes into service. In addition, the newer requirements are in many cases more stringent than the existing requirements. For the above reasons, this report will limit its discussion to the newer TPL-00104 Requirements and will not discuss the currently enforceable requirements of TPL-001-0.1, TPL-002-0b, TPL-003-0b, and TPL-004-0a[29].

Another Reliability Standard that can have an impact on the need for the Energize Eastside Project is FAC-008-3[30] (Facility Ratings). TPL-001-4 and FAC-008-3 are discussed in more detail below.

TPL-001-4 requires that each Planning Coordinator and Transmission Planner[31] perform an annual transmission assessment of its portion of the Bulk Electric System[32] (BES). This assessment must model, among other things, system peak load, known commitments for Firm Transmission Service and Interchange, and the planning events (contingencies) listed in Table 1 of TPL-001-4[33].

TPL-001-4 requires the development of a Corrective Action Plan (CAP)[34] whenever the transmission assessment determines that the system cannot meet the performance requirements listed in Table 1. In other words, once a performance requirement specified in TPL-001-4 cannot be met (e.g., an overload is found), a need has been determined.

FAC-008-3 is applicable to both Transmission Owners and Generation Owners[35]. FAC-008-3 requires each Transmission Owner and Generation Owner to have a facility[36]

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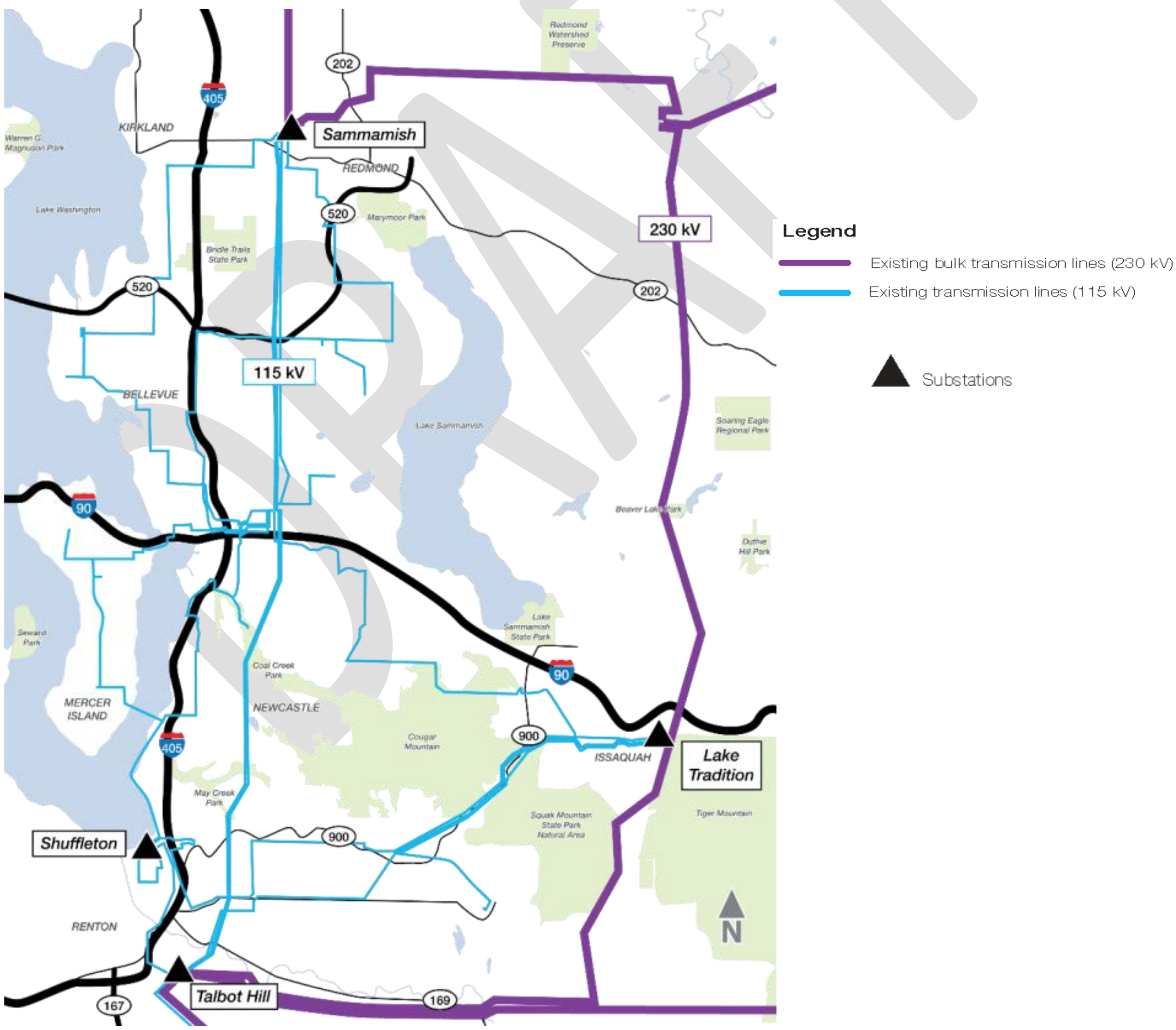
[27] capitalized terms in this section refer to terms that are defined in the NERC Glossary
[28] http://www.nerc.com/files/TPL-001-4.pdf
[29] Reliability Standards TPL-001-0.1, TPL-002-0b, TPL-003-0b, and TPL-004-0a are being replaced by TPL-001-4.
[30] http://www.nerc.com/files/FAC-008-3.pdf
[31] Puget Sound Energy is registered with NERC as both a Planning Coordinator and a Transmission Planner.
[32] The Bulk Electric System (BES) definition is fairly long and involved (see http://www.nerc.com/pa/RAPA/BES%20DL/BES%20Definition%20Approved%20by%20FERC%203-20-14.pdf), but for the purposes of this report, the BES can be considered to be all networked transmission elements with an operating voltage of 100 kV or higher. Radial facilities are generally not considered to be part of the BES even if they are operated at voltages of 100 kV or higher.
[33] Table 1 is provided in Appendix RPM-1 of this report.
[34] Corrective Action Plans as used in the TPL-001-4 Reliability Standard are not the same as the Corrective Action Plans described by PSE in the Eastside Needs Assessment Report (October 2013). In TPL-001-4, a Corrective Action Plan may include operational measures (such as switching existing facilities in or out) and/or the addition of new facilities. In the Eastside Needs Assessment Report, Corrective Action Plans only refer to operational measures.
[35] Puget Sound Energy is registered with NERC as both a Transmission Owner and a Generation Owner.
[36] A facility is a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

rating[37] methodology[38] that is consistent with manufacturer ratings, standards developed through an open process, or a practice that has been verified by testing, performance history, or engineering analysis. The intent of this Reliability Standard is to ensure that facility ratings are based upon sound engineering practices and are consistent across a utility's service area.

## *7.3. Critical Contingencies for the Energize Eastside Project*

Figure 7.1 below is a sketch of the Eastside area transmission network[39]. The area between Sammamish and Talbot Hill is the area of where a number of overloads have been seen in planning studies.

**Figure 7.1: Eastside Area Transmission Sketch**



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[37] A facility rating is the maximum or minimum voltage, current, frequency, or power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
[38] A facility rating methodology is a procedure that is used to establish the facility ratings for all of a utilities facilities.
[39] From the Energize Eastside website: energizeeastside.com

The specific contingencies that cause facility rating violations on specific elements of the power system are CEII[40] and cannot be disclosed in a public document. However, the general types of contingencies that cause overloads on various facilities can be disclosed. Below is a list of the general types of contingencies that are causing overloads on the PSE eastside transmission system.

- Overlapping outages of two transformers (N-1-1) (P6),
- Overlapping outages of two transmission lines (N-1-1) (P6),
- Overlapping outages of one transmission line and one transformer (N-1-1) (P6), and
- Simultaneous outage of two transmission lines (N-2) (P7).

As discussed above, the NERC TPL-001-4 Reliability Standard requires that a Corrective Action Plan (CAP) be developed whenever the system does not meet the performance requirements specified in the standard. A CAP can include: new facilities such as transmission lines; adjustments to operating procedures (such as opening a switch at the end of a transmission line); or a combination of both new facilities and operating procedures.

## 7.4. Normal vs. Emergency Ratings

A "*normal rating*" is the limit at which a transmission facility can operate indefinitely (i.e., 24/7/365 for the life of the project, which in some cases could be over 50 years). An "*emergency rating*" is only available for use for a short period of time and using an emergency rating usually involves a loss of usable life for the facility. This loss of usable life is caused by the increased temperatures that the facility is subject to when loaded to its emergency limit. The higher temperatures can cause insulation in transformer banks to degrade or overhead conductors to weaken and/or sag. In some cases an emergency rating may have a lifetime limit on the number of hours it can be used (e.g., 100 hours). Once that lifetime limit is reached, a facility will not be able to exceed its normal rating or it may need to be replaced. An emergency rating cannot be used for normal overloads that might occur due to load growth or a sudden increase in load due to extreme weather. Given a typical lifetime limit of 100 hours, an emergency rating would only be good for a little over 4 days under normal (non-contingency) conditions. Therefore, an emergency rating can only be used under contingency (outage/equipment failure) conditions.

In addition to the differences between normal and emergency ratings, there are typically different ratings for summer and winter conditions. Because equipment ratings are based in part on thermal limits of the equipment (as noted above) and the ambient temperatures expected during winter are less than the ambient temperatures seen during summer, normal and emergency winter ratings are almost always higher than the respective normal and emergency ratings for summer.

PSE utilizes different normal and emergency facility ratings for summer and winter conditions, consistent with industry practice.

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[40] CEII - Critical Energy Infrastructure Information CEII is protected information whose release could compromise the reliability of the BES. Each individual utility decides what information they deem to be CEII. The specific contingencies that cause overloads on the elements documented in the public Energize Eastside study reports are considered to be CEII by PSE. Other utilities also consider information such as this to be CEII.

## 7.5. *Transmission Reliability vs. Distribution Reliability*

Transmission outages currently cause about 5% of the customer outage duration on PSE's system in the Energize Eastside area. The remaining 95% of the customer outage duration are caused by distribution outages (see Table 7.1) below[41]. As can be seen from Table 7.1, the City of Bellevue's transmission related customer outage performance is much better than the rest of the Energize Eastside area (less than 1% of the customer outage minutes were due to transmission outages).

**Table 7.1: Transmission and Distribution Outage Data (from PSE)**

| 2014 Total Outages | | | | | |
|---|---|---|---|---|---|
| **Energize Eastside Area (includes City of Bellevue)** | | | | | |
| | # of Outages | # of Customers Impacted | Total Customer Minutes | Customers Impacted Per Outage | Outage Minutes Per Customer Per Outage |
| Transmission outages | 6 | 35,614 | 2,521,995 | 5936 | 11 |
| All other outages | 1182 | 120,074 | 47,481,181 | 102 | 0.33 |
| Total outages for EE | 1188 | 155,688 | 50,003,176 | | |
| Transmission outage percentage of total | 0.5% | 22.9% | 5.0% | | |
| **City of Bellevue** | | | | | |
| | # of Outages | # of Customers Impacted | Total Customer Minutes | Customers Impacted Per Outage | Outage Minutes Per Customer Per Outage |
| Transmission outages | 3 | 18,939 | 224,327 | 6313 | 4 |
| All other outages | 745 | 61,963 | 29,964,379 | 83 | 0.65 |
| Total outages for COB | 748 | 80,902 | 30,188,706 | | |
| Transmission outage percentage of total | 0.4% | 23.4% | 0.7% | | |

Table 7.1 also shows some additional pertinent information regarding the relative severity of transmission outages versus distribution outages. The number of customers affected by a transmission outage in this example is over 50 times greater than the number affected by a distribution outage. In addition, the outage duration per customer per outage is much longer for transmission outages than for distribution outages. This difference is one reason why transmission reliability is required to be so high. While the risk of an outage is low, the consequences of that outage can be quite large.

[41] This data from PSE indicates that the Energize Eastside area has fewer customer outage minutes due to transmission outages (as a fraction of the total outage minutes) than other utilities in the U.S.

The reason mentioned above is the same reason why the nuclear industry designs back-up systems for the reactor core cooling system with multiple layers of redundancy. Nuclear plants are typically designed with two sources of off-site (grid) power. If one source fails, the other can be used to supply the plant cooling load. In addition, just in case both off-site power sources are out, the plant has backup diesel generators that are capable of supplying the cooling system load. Just in case the primary diesel generators fail, there is a redundant set of diesel generators to step in if necessary. Then for additional protection, battery backup is provided in case the offsite grid power and both sets of diesel generators fail. The reason for this extreme level of redundancy is because even though the risk of a failure of four levels of cooling system power supply is incredibly small, the consequence of a failure is extremely large.

In addition to the Northeast blackout discussed above, two other major blackouts have occurred in the Western Interconnection in the last two decades. These two blackouts are discussed below.

On July 2, 1996 at 1424 MDT a disturbance occurred that ultimately resulted in the Western Systems Coordinating Council (WSCC) system (the Western Interconnection) separating into five unconnected load and generation subsystems. This disturbance resulted in the loss of 11,850 MW of load and affected 2 million people in the West. Customers were affected in Arizona, California, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming in the United States; Alberta and British Columbia in Canada; and Baja California Norte in Mexico. Outages lasted from a few minutes to several hours. Electric service was restored to most customers within 30 minutes, except on the Idaho Power Company (IPC) system, a portion of the Public Service Company of Colorado (PSC), and the Platte River Power Authority (PRPA) systems in Colorado, where some customers were out of service for up to six hours. On portions of the Sierra Pacific Power Company (SPP) system in northern Nevada, service restoration required up to three hours.

On August 10, 1996 a major disturbance occurred in the Western Interconnection (Western Systems Coordinating Council, WSCC) at 1548 PDT resulting in the Interconnection separating into four unconnected load and generation subsystems. Conditions prior to the disturbance were marked by high summer temperatures (near or above 100 degrees Fahrenheit) in most of the Region, by heavy exports (well within known limits) from the Pacific Northwest into California and from Canada into the Pacific Northwest, and by the loss of several 500 kV lines in Oregon. The California−Oregon Intertie (COI) (Pacific Northwest to California) north to south electricity flow was within parameters established by recent studies initiated as a result of the July 2-3, 1996 disturbance (see above). The flow on the AC system between the Pacific Northwest and California was about 4,350 MW and the flow on the Pacific DC Intertie (PDCI) (a DC system) was 2,848 MW. This disturbance resulted in the loss of over 28,000 MW of load and affected 7.5 million people in the West. Customers were affected in Arizona, California, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming in the United States; Alberta and British Columbia in Canada; and Baja California Norte in Mexico. Outages lasted from a few minutes to as long as nine hours.

Both of the above outages occurred prior to the implementation of mandatory Reliability Standards. The purpose of the mandatory Reliability Standards is to maintain the reliability of the BES and to help prevent major outages like these from happening again. As previously noted, even though the probability of outages like these is very small, the consequences of this type of outage are very large. Therefore, the Reliability Standards require the examination of contingencies that to a lay person seem to be highly unlikely.

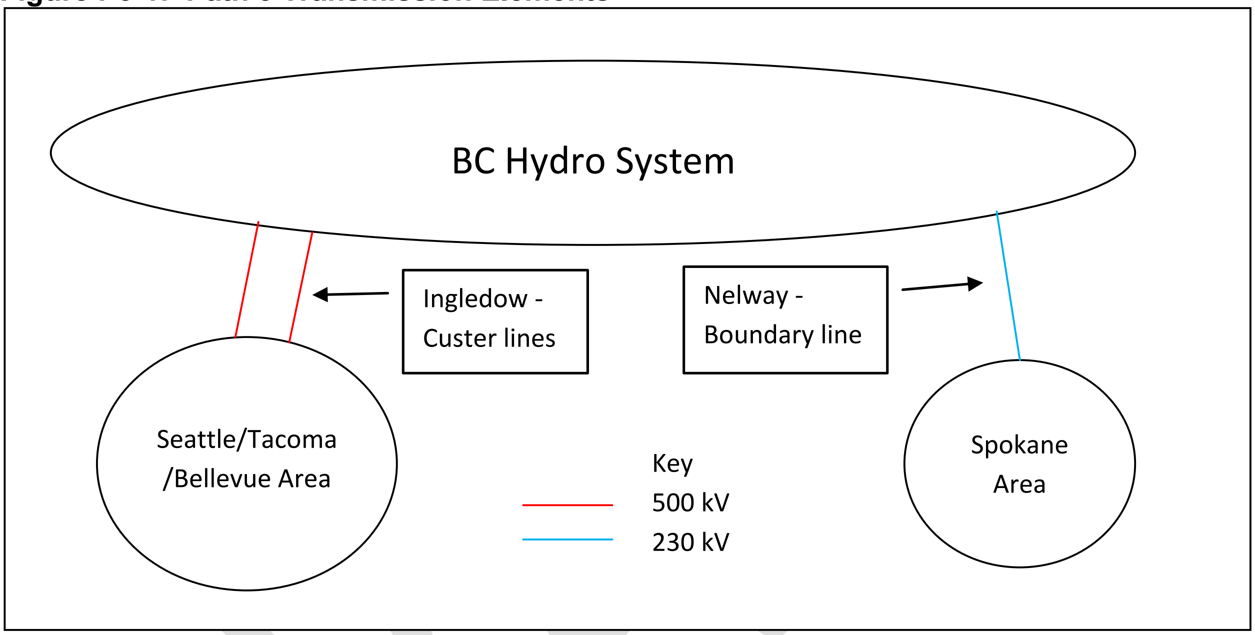
In general, the probability of a single contingency (N-1) is at least once every three years. The probability of multiple contingencies such as N-1-1 or N-2 is somewhere between once every three years and once every 30 years. (See Section 8 and Appendix B for analysis of this subject.)

### *7.6. Path 3 Issues*

Path 3 is the transmission interconnection between Washington and British Columbia. Path 3 consists of three transmission circuits (see Figure P3-1):

1. Ingledow - Custer 500 kV #1,
2. Ingledow - Custer 500 kV #2, and
3. Nelway - Boundary 230 kV #1.

**Figure P3-1: Path 3 Transmission Elements**




It should be noted when discussing Path 3 that sometimes the Nelway - Boundary 230 kV line is referred to as the Path 3 eastside intertie. This term should not be confused with eastside as it is used in the context of the Energize Eastside project. The Path 3 eastside intertie is located near Spokane, WA and is over 250 miles away from the area under consideration for the Energize Eastside project.

Path 3 has a non-simultaneous rating of 3150 MW north to south and 3000 MW south to north. Known commitments for Firm Transmission Service and Interchange on Path 3 are 2300 MW north to south and 1500 MW south to north.

The planning cases PSE used to study the need for the Energize Eastside project had Path 3 flow at 3150 MW north to south in the summer base cases and 1500 MW south to north in the winter base cases.

<u>Stakeholder Questions related to Standards and Reliability</u>

*Q37. 2013 Needs Assessment report, page 43. The "3d" sensitivity, modeling 2021-2022 extreme Weather with 100% conservation. Explain why this scenario, which had 845 MW predicted Eastside load, showed no overload for N-0 yet 845 MW is above PSE's "current system capacity" line in their 2013 report. Clarify what PSE's capacity line represents.*

- A *PSE's capacity line is the load level at which overloads will just begin to occur under contingency situations. Because the scenario being referred to in this question is "N-0" (or no contingency), there are no overloads. The reason for there being no overloads is that up to two additional pieces of equipment are in service to carry power to the load.*

*Q38. Too much transmission reliability?*

- A *The requirement for transmission reliability is discussed in the section on NERC Reliability Standards. Because the Reliability Standards are mandatory, meeting these standards provides just adequate reliability.*

*Q39. How are EE "need" and "reliability" related? How many outages in the next 10 years (2017-2027) are anticipated to be avoided by implementation of EE, due to transformer limitations or otherwise stressing system capacity due to local Eastside growth (excluding unpredictable weather events)?*

- A *EE need is related to reliability by the requirement that when overloads occur during a planning assessment under the contingencies that are required to be run (see the discussion of TPL-001-4 in the Independent Technical Analysis), there is by definition a need. This need is not necessarily EE, but something must be done to mitigate the overloads seen in the planning assessment. The question of how many outages may be avoided by implementation of EE is not relevant to the question of need. The Reliability Standards require that a defined set of contingencies be run on the system model. If overloads or other violations are found, then a Corrective Action Plan must be produced. The fact that a Corrective Action Plan is needed demonstrates that there is a need.*

*Q40. What is the probability of an N-1-1?*

- A *The probability of an N-1-1 is not a factor that is considered in determining if there is a need for a project. However, typically the probability of an N-1-1 is between 0.33 and 0.033 outages per year or once in 3 years to once in 30 years.*

*Q41. One of the rationales advanced by PSE for the new transmission lines was to increase the 'reliability' of PSE's transmission system and/or the reliability of PSE's "system" that supplies electricity to Bellevue and other east side communities.*

- A *Energize Eastside is a project designed to mitigate overloads found in planning studies that used projected future load growth. Therefore, a better way to look at EE is that it will maintain the current reliability that exists today and prevent it from getting worse.*

*Q42. Task 8 of USE's 'scope of services' states that USE will develop a formal, written evaluation of the need for PSE's Energize Eastside (EE) project, including an assessment of the " … impacts to electrical system reliability …" Please describe (or provide in the report) a schematic/line-diagram of the "electrical system" that USE evaluated to assess the "reliability" of the "electrical system"; and describe the quantitative reliability measures/metrics that were used in performing the evaluation of the impact of PSE's EE project on the "electrical system" reliability.*

- A *The electrical system modeled was the entire Western Interconnection that extends from the Pacific Ocean on the west east to Colorado and from British Columbia and Alberta in the north south to Arizona and a portion of northern Mexico. The studies concentrated on the Puget Sound area, but included all facilities in the entire Western Interconnection. USE did not assess the impacts of PSE's EE project on electric system reliability. Our work scope was limited to investigating the need for EE. Therefore, we investigated the accuracy of PSE's latest load forecast (2014) and ran studies using the system model without EE in it to see if problems occurred that would require a project like EE to solve. In performing this* *investigation, we addressed the impacts of PSE's assumptions regarding load growth and regional transfers on the system without EE to determine if there was a need for a project like EE. The Optional Technical Assessment (OTA) (Appendix B) looked at the sensitivity of modified assumptions regarding load growth, westside generation levels, and regional transfers on the need for a project like EE. Determining the preferred project to mitigate the problems found in the studies of the system without EE is one of the purposes of the EIS process, but this determination is beyond the scope of the ITA and the OTA.*

*Q43. Why is an N-1-1 outage scenario (rare) used to determine need?*

A *Because N-1-1 contingencies must be simulated in the planning assessments required by the mandatory NERC TPL-001-4 Reliability Standard.*

*Q44. Questions about reliability, outages, contingency analysis.*

A *As noted in responses to other questions, probability of an outage is not considered in determining need using the NERC TPL-001-4 Reliability Standard. When performing a planning assessment all outages need to be simulated and if there are any overloads or other violations, then a Corrective Action Plan must be developed. What is included in this Corrective Action Plan will vary depending on the type of outage and what sort of mitigation is allowed for that outage in the TPL-001-4 Reliability Standard. However, need is established as soon as a Corrective Action Plan needs to be developed.*

*Q45. We ask the consultant to forecast how many outages in the next five years (2016 – 2020) would be avoided by implementation of Energize Eastside.*

A *Please see the responses above.*

*Q46. Is it true that PSE's "Eastside Customer Demand Forecast" graph is based on a hypothetical "grid-flow modelling scenario" in which a rare winter peak electricity demand event occurs on the Eastside at exactly the same time that there are two major and simultaneous equipment outages on nearby transmission lines?*

A *The demand forecast is independent of any equipment outages. The current system capacity line is determined by studies of system performance under multiple contingency scenarios with models that incorporated forecasted peak load. These studies are required to be run in this manner by the Requirements in the NERC TPL-001-4 Reliability Standard.*

*Q47. Are PSE's conclusions reasonable?*

A *See the conclusions section of the Independent Technical Analysis and the Executive Summary of the OTA (Appendix B).*

# 8. Assessment of PSE's Identified Drivers for the Eastside Project (PSE's Results)

This section addresses PSE's findings based on their new 2014 normal winter forecast, with 100% conservation.

Table 8.1 shows the new forecasted loads for Eastside that were utilized in the powerflow cases; three normal winter and three normal summer cases were studied by PSE. The winter forecasts between 2017/18 and 2023/24 show Eastside growing, while King County otherwise declines. The ITA confirmed that the load values in Table 1 matched the new forecast and were modeled[42] in the cases.

**Table 8.1: PSE's King County and Eastside Forecasted Loads in Studied Years**

| Forecast Development Year | King County (excluding Eastside) | Eastside |
|---|---|---|
| Normal Winter | | |
| 2017/18 | 1881 | 688 |
| 2019/20 | 1867 | 708 |
| 2023/24 | 1817 | 764 |
| Normal Summer | | |
| 2018 | 1379 | 538 |
| 2020 | 1385 | 561 |
| 2024 | 1399 | 618 |

The ITA also confirmed the Northern Intertie (Path 3) transfers matched PSE's modeling plan (Table 8.2), and that PSE's winter generation dispatch scenario of "no PSE and SCL generation west of the Cascades" was modeled in the winter cases, as per Table 4.4 in the October 2013 Eastside Needs Assessment Report.

**Table 8.2: Northern Intertie Flows**

| Northern Intertie | Flow Direction |
|---|---|
| Normal Winter | |
| 3150 MW | South to North |
| Normal Summer | |
| 1500 MW | North to South |

Source: PSE. Verified by ITA.

Tables 8.3 and 8.4 list the overloaded elements that PSE identified based on the new 2014 forecast. The ITA confirmed these overloaded elements drive the need for an Eastside project by simulating the contingencies (outages) in the powerflow cases provided by PSE.

[42] The aggregate Eastside load matched the numbers in Table 8.1.

**Table 8.3: PSE Projected Normal Winter, 100% Conservation – Overloaded Elements**

| South to North Flow | Type of Contingency and Season | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2017/18 Winter (23°F) 100% Conservation | | | 2019/20 Winter (23°F) 100% Conservation | | | 2023/24 Winter (23°F) 100% Conservation | | |
| Transmission Line or Transformer | N-1 | N-1-1 | N-2 | N-1 | N-1-1 | N-2 | N-1 | N-1-1 | N-2 |
| Talbot Hill - Lakeside #1 115 kV line | | OL | | | OL | | | OL | |
| Talbot Hill - Lakeside #2 115 kV line | | OL | | | OL | | | OL | |
| Talbot Hill 230-115 kV transformer #1 | | OL | | | OL | | | OL | |
| Talbot Hill 230-115 kV transformer #2 | | OL | | | OL | | | OL | |
| Talbot Hill-Boeing Renton-Shuffleton 115 kV line | | OL | | | OL | | | OL | |

OL= Overload of Emergency Rating. Source: PSE Results. ITA verified overloaded elements driving project need.

**Table 8.4: PSE Projected Normal Summer, 100% Conservation - Overloaded Elements**

| North to South Flow | Type of Contingency and Season | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2018 Summer (86°F) 100% Conservation | | | 2020 Summer (86° F) 100% Conservation | | | 2024 Summer (86° F) 100% Conservation | | |
| Transmission Line or Transformer | N-1 | N-1-1 | N-2 | N-1 | N-1-1 | N-2 | N-1 | N-1-1 | N-2 |
| Sammamish 230/115 kV Xfmr[43] #1 | | OL | | | OL | | | OL | |
| Sammamish 230/115 kV Xfmr #2 | | OL | | | OL | | | OL | |
| Novelty Hill 230/115 kV Xfmr #2 | | OL | | | OL | | | OL | |
| BPA Monroe – Novelty Hill 230 kV | OL | | OL | OL | | OL | OL | | OL |
| Beverly Park - Cottage Brook 115 kV line | | OL | | | OL | | | OL | |
| Sammamish – BPA Maple Valley 230 kV line | | | | OL | | | OL | | |

OL= Overload of Emergency Rating. Source: PSE Results. ITA verified overloaded elements driving project need.

Figure 8.1 utilizes the 2014 load forecast and was supplied by PSE. Two system capacity lines for the Eastside area reflect where the powerflow results indicated violations of the mandatory performance requirements that put customer's reliability at risk. The powerflow results show a range of need for the Eastside area between <u>688 MW</u> in winter 2017/18 and <u>708 MW</u> in winter 2019/20. These levels were chosen by PSE because at 688 MW system elements are overloaded, and by 708 MW they are not only overloaded but 63,200 customers are at risk of losing power, which is a more severe situation. Further detail is noted below.

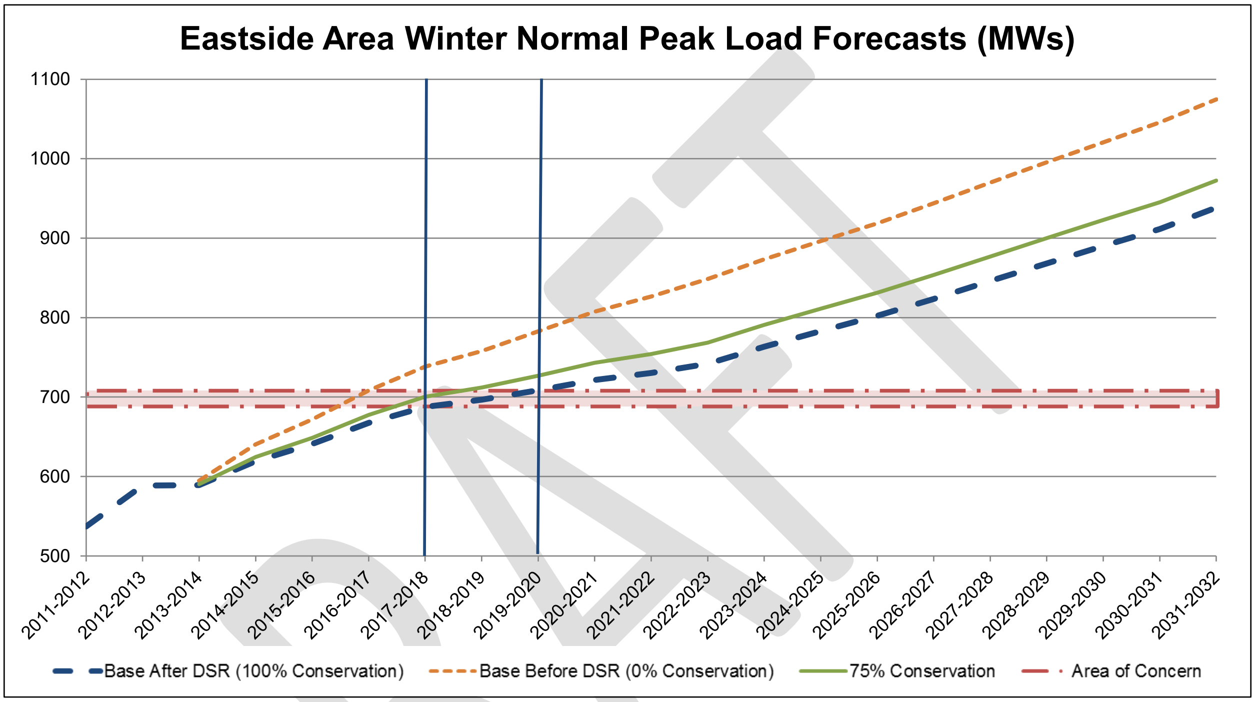
- In winter 2017/18 system elements would be overloaded requiring Corrective Action Plans (CAPs) for the Category C overloads. Zero customers are at risk of losing power by the CAPs[44].

[43] Xfmr = Transformer

[44] CAPs are implemented to protect system equipment from overload and resulting loss of equipment life or damage. CAPs can result in the forced reduction of load (intentionally causing customer outages) to bring

- By winter 2019/20, the CAPs radialize[45] existing loop service such that approximately 63,200 customers are at risk of losing power.
- By winter 2023/24, 16,800 customers are at risk from load shedding (intentional outage to customers to protect the system equipment), with another 52,000 customers at risk of losing power.

**Figure 8.1: PSE's Graph of System Capacity, 2014 Forecast, 100% Conservation**




In sum, PSE's need date for the Energize Eastside project remains as winter 2017/18. The following issues were identified by PSE and forecast levels and overloads were confirmed by the ITA:

- Transmission system elements will be over their capacity, and will require the use of CAPS to mitigate transmission overloads.
- Although the CAPS do not drop customer load in winter 2017/18, by winter 2019/20 approximately 63,200 customers are at risk of losing power. Intentionally dropping firm load for an N-1-1 or N-2 contingency to meet its federal planning requirements is not a practice that PSE endorses. This view is not unique amongst utilities. The CAISO Planning Standards states that "Increased reliance on load shedding … would run counter to historical and current practices, resulting in general deterioration of service levels."
- The forecast uses a 1 in 2 year weather forecast. Colder weather will result in higher load levels in winter 2017/18.
- 100% conservation may not be achieved which would result in a higher load level in winter 2017/18. Even if 100% conservation is achieved, it may not be in the appropriate locations and correct magnitudes.

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the equipment loading below the emergency rating. This would only be used as a stopgap measure until system reinforcements (new equipment, etc.) are completed. CAPs as used here is a subset of CAPs defined in the NERC Reliability Standards. See Section 7 on Standards.

[45] Radialize: Convert from loop service to radial service (only one source).

- By the summer of 2018, studies show that customers will be at risk of outages and load shedding using CAPS to mitigate transmission overloads.

# 9. Regional Issues related to EE

Note: All ColumbiaGrid regional documentation of Energize Eastside refers to the project by its terminals: Sammamish-Lakeside-Talbot. The following text refers to Energize Eastside as the Project.

Background

ColumbiaGrid is a regional transmission planning organization with a footprint encompassing Oregon, Washington, parts of Idaho and Montana. A planning team was formed with all Puget Sound area transmission owners and operators as planning participants within a year after the creation of ColumbiaGrid in 2007 to address the beginning curtailments of firm service in the Puget Sound area. Since 1997 and prior to the formation of this team, BPA had been planning to address these needs with a major 500kV line project from Monroe to Echo Lake, but construction had not started. The study team was able to identify a collection of projects to achieve the planning objectives with a cumulative scope less than the 500kV project.

The ColumbiaGrid Puget Sound Area transmission planning activity created 150 document postings on the team website that provide a detailed history of the work that led up to the regional plan. Of the 150 postings, three postings provide the information sufficient to describe the Project's role in regional objectives. The three postings are final reports and are all publicly available. These documents are:

- Transmission Expansion Plan for the Puget Sound Area (October 20,2010)
- Updated Recommended Transmission Expansion Plan for the Puget Sound Area to Support Winter South-to-North Transfers (October 28, 2011)
- Updated Transmission Expansion Plan for the Puget Sound Area to Support Summer North-to-South Transfers (February 21, 2013)

Project Specific Information

The following Project specific regional information was obtained from the above documentation.

1. Either the Project or reconductoring BPA's and SCL's Maple Valley-SnoKing 230kV lines is needed, but not both.
2. The Project or rebuilding SCL's Bothell-SnoKing 230kV lines is needed, but not both. The Bothell-SnoKing lines still need to be reconductored with the Project, but rebuilding is avoided.
3. If the Project voltage level is 115kV, the Project does not achieve the regional objectives. With that scenario, the regional objectives will be achieved by reconductoring the Maple Valley-SnoKing 230kV lines and the Bothell-SnoKing 230kV lines will need to be rebuilt.
4. The Project at 230kV is identified as the preferred alternative because of its dual purpose for regional objectives and local load service. If the Maple Valley-SnoKing 230kV lines had been reconductored prior to development of the Project, there would have been unnecessary redundancy developed in the transmission infrastructure, assuming that the Project voltage level needed to be 230kV.

ColumbiaGrid determined that the Energize Eastside project at 230 kV is the preferred alternative of all the options studied because of its dual purpose for regional objectives and local load service.

Stakeholder Questions related to Regional vs. Local Need

*Q49. What is the connection between the need for EE and Columbia Grid (CG) technical objectives?*

- A *The CG technical objective is to identify effects of multiple systems that prevent fulfillment of firm transmission commitments. Mitigating transmission effects that do not involve multiple systems is not within the CG mandate. After the effects are identified, the multiple system owners are convened as a team facilitated by CG to identify mitigating alternatives and select the preferred alternative. The proposed 230kV scope of EE is identified by the CG facilitated team as a preferred alternative to reconductoring SCL's Maple Valley-SnoKing 230kV lines. EE at 230kV also changes the SCL scope of rebuilding the Bothell-SnoKing 230kV lines to reconductoring these lines.*

*Q50. How are the technical needs of Columbia Grid prioritized and what criteria are used for evaluation and prioritization?*

- A *CG performs system assessments to determine forecasted transmission constraints to serving firm transmission commitments. A constraint that affects more than one member is the criteria for creating a study team, facilitated by CG, composed of the affected members. The study team mandate is to determine the mitigating alternatives and select the preferred alternative. Each study team determines their own evaluation and prioritization criteria. In the Puget Sound Area Study Team (PSAST), the criteria is a qualitative combination of cost and a planning metric (i.e. Transmission Curtailment Risk Measure or TCRM).*

*Q51. Who has regulatory oversight of Columbia Grid?*

- A *There is no government regulatory oversight of CG. The oversight is by CG members, who have their own government regulatory oversight at state and federal levels. CG has no construction authority. The only CG authority is determining cost allocation, but this authority is only used if members do not agree on the cost allocation for a project they agree to implement.*

*Q52. Is EE an "OPEN ACCESS" project?*

- A *No. An "Open Access" project provides new requested transmission service. This project provides service for existing firm obligations. (The longer answer is as follows: This answer assumes that "Open Access" refers to a transmission service request under a transmission provider's Open Access Transmission Tariff (OATT). These transmission service requests are for new transmission service that involve study requirements, facility addition determinations, and FERC pricing policies. Since EE is for load growth that falls under existing transmission service, it isn't "open access" because it is not new transmission service. .*

*Q53. How are the merits of each need evaluated independently and which need takes priority?*

- A *The CG PSAST team evaluated the regional, multi-system needs for bulk power transfers independent of local load service needs. The local load service need is evaluated by the single systems. If a single system project (e.g. EE at 230kV) affects multi-system power transfer needs, then it is included in the multi-system evaluation. Firm commitments, regardless of bulk power transfers or local load service, are equal priority to be addressed and issues mitigated.*

*Q54. Please describe how the need for EE and Power Wheeling are connected. What are PSE's power wheeling objectives for EE, and how much of the EE need is based on the ability to participate in additional power wheeling?*

- A *Wheeling is the transportation of electric power over transmission lines by an entity that does not own or directly use the power it is transmitting.*
- A *(from PSE's Energize Eastside website, based on 2012 forecast) "PSE makes no profit on wheeling power. All revenue obtained from wheeling contracts is passed directly back to our customers in the form of lower rates. PSE does have contracts to wheel power across the region; those contracts bring in revenue of roughly $28 million a year. One hundred percent of this revenue is returned to our customers in the form of a rate reduction. As we stated in our presentation, 92-97% of the power flows on the Energize Eastside line will deliver electricity to local Eastside customers. The power flow studies show that the power used for regional purposes on the Energize Eastside project is 3 to 8% - not 38% (as was incorrectly stated at the meeting). This is the natural consequence of connecting a transmission line into an interconnected system."* June, 2014 http://energizeeastside.com/Media/Default/CAG/Meeting3/2014_0609_CAGLetter_SCL.pdf

*Q55. Is any of the capacity of the planned EE 230 kV line, or the existing 115 kV lines between Sammamish and Talbot Hill, allocated for transmission contracts to BC Hydro or CA? If so, what %? What are PSE's power wheeling objectives for Energize Eastside? Does existing or planned/potential wheeling affect the Project capacity?*

- A *No/None. PSE makes no profit from wheeling contracts. See Q56.*
- A *Per PSE, Project capacity is not affected by existing or planned/potential wheeling.*

# 10. Conclusion

The independent technical analysis (ITA) determined that PSE used reasonable methods to develop the 2014 forecast by following industry practice (See section 6.6.). The ITA reviewed PSE's powerflow cases and verified PSE's modeling of the updated load forecast, the Northern Intertie transfers, and the identified winter generation dispatch.

The ITA verified the following key result:
*Although the new 2014 forecast resulted in an 11 MW decrease in the Eastside area's 2017/18 winter forecast, the reduced loading still resulted in overloaded transmission elements that drive the project need to address Eastside system reliability issues.*

Although the CAP required in the 2017/18 winter to avoid facility overload doesn't drop load, by winter 2019/20 approximately 63,200 customers are at risk of losing power. In addition, by summer 2018, studies show that customers will be at risk of outages and load shedding due to CAPs used to mitigate transmission overloads. One might argue to delay the Energize Eastside project six months until summer 2018 when PSE studies show that customers will be at risk of outages and load shedding. However, balancing a six month delay in a complex and multi-year EIS process, which can have its own delays, against the risk of an adverse winter or less realized conservation (which could increase 2017/18 winter loading to a point where customers are at risk of load shedding) suggests it is reasonable to maintain the schedule for the existing project in-service date.

# Appendix A – Glossary

| | |
|---|---|
| AC | Alternating Current |
| aMW | aMW - The average number of megawatt-hours (MWh) over a specified time period; for example, 295,650 MWh generated over the course of one year equals 810 aMW (295,650/8,760 hours). (Source: PSE's 2013 IRP Definitions) |
| Balancing Authority (BA) | Balancing Authority (BA) -- an entity that manages generation, transmission, and load; it maintains load-interchange-generation balance within a geographic or electrically interconnected Balancing Authority area, and it supports frequency in real time. The responsibility of the PSE Balancing Authority is to maintain frequency on its system and support frequency on the greater interconnection. To accomplish this, the PSE BA must balance load with generation on the system at all times. When load is greater than generation, a negative frequency error occurs. When generation is greater than load, a positive frequency error occurs. Small positive or negative frequency deviations are acceptable and occur commonly during the course of normal operations, but moderate to high deviations require corrective action by the BA. Large frequency deviations can severely damage electrical generating equipment and ultimately result in large-scale cascading power outages. Therefore, the primary responsibility of the BA is to do everything it can to maintain frequency so that load will be served reliably. (Source: PSE 2013 IRP) |
| BES | BES - Bulk Electric System - Unless modified by the inclusion and exclusion lists in the full definition that is available in the NERC Glossary of Terms (http://www.nerc.com/files/glossary_of_terms.pdf), all Transmission Elements operated at 100 kV or higher and resources connected at 100 kV or higher. The BES does not include facilities used in the local distribution of electric energy. (Source: NERC Glossary of Terms) |
| BPS | BPS - Bulk Power System - A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. (Source: NERC Glossary of Terms) |
| CAP | CAP - Corrective Action Plan - A list of actions and an associated timetable for implementation to remedy a specific problem. (Source: NERC Glossary of Terms) |
| COI | COI - California–Oregon Intertie - The three 500 kV AC electric transmission lines between southern Oregon and northern California. |
| CPI | Consumer Price Index (CPI) – A measure that examines the weighted average of prices of a basket of consumer goods and services, such as transportation, food and medical care. The CPI is calculated by taking price changes for each item in the predetermined basket of goods and averaging them; the goods are weighted according to their importance. (Source: Investopedia) |
| Critical Energy Infrastructure Information (CEII) | Critical Energy Infrastructure Information (CEII) Regulations –- Established by the Federal Energy Regulatory Commission (FERC). "CEII is specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure (physical or virtual) that: Relates details about the production, generation, transmission, or distribution of energy; Could be useful to a person planning an attack on critical infrastructure; Is |

| | |
|---|---|
| | exempt from mandatory disclosure under the Freedom of Information Act; and Gives strategic information beyond the location of the critical infrastructure." (Source: FERC) |
| DC | Direct Current |
| Demand (Utility) | Demand (Utility) – The level at which electricity or natural gas is delivered to users at a given point in time. Electric demand is expressed in kilowatts. (Source: CEC Glossary) |
| Demand-Side Resources (DSR) | Demand-Side Resources (DSR) - Resources that reduce the demand. (As opposed to Supply-Side Resources) |
| Demographic | Demographics - Studies of a population based on factors such as age, race, sex, economic status, level of education, income level and employment, among others. Demographics are used by governments, corporations and non-government organizations to learn more about a population's characteristics for many purposes, including policy development and economic market research. (Source: Investopedia.com) |
| Direct Control Load Management (DCLM) | Direct Control Load Management (DCLM) - Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand. (Source: NERC Glossary) |
| Distribution System | Distribution System - An electric power distribution system is the final stage in the delivery of electric power; it carries electricity from the transmission system to individual consumers. (Source: Wikipedia) |
| Econometric Data | Econometric Data – Data sets to which econometric analyses are applied. |
| Econometrics | Econometrics – The application of mathematics and statistical methods to economics. Econometrics tests hypotheses and forecasts future trends by applying statistical and mathematical theories to economics. It's concerned with setting up mathematical models and testing the validity of economic relationships to measure the strengths of various influences. |
| EPAct 2005 | EPAct 2005 – The federal Energy Policy Act of 2005 |
| ERO | ERO - Electric Reliability Organization |
| Firm Transmission Service | Firm Transmission Service – 1) Transmission service available at all times during a period covered by an agreement. 2) The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption. (Source: NERC) |
| GO | GO - Generator Owner |
| Interruptible Load or Interruptible Demand | Interruptible Load or Interruptible Demand - Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment. (Source: NERC Glossary) |
| IRP | Integrated Resource Plan - A comprehensive and long-range road map for meeting the utility's objective of providing reliable and least-cost electric service to its customers while addressing applicable environmental, conservation and renewable energy requirements. A process used by utility companies to determine the mix of Supply-Side Resources and Demand-Side Resources that will meet electricity demand at the lowest cost. The IRP is often developed with input from various stakeholder groups.<br><br>Also Integrated Resource Planning. |

| | |
|---|---|
| Levelized Cost | Levelized Cost - An economic assessment of the cost to build and operate a power-generating asset over its lifetime divided by the total power output of the asset over that lifetime. It is also used to compare different methods of electricity generation in cost terms on a comparable basis. |
| MW | MW - Megawatt - A unit of power equal to one million watts or one thousand kilowatts. |
| N-1 | N-1 - Loss of a single element such as a generator, a transmission line, or a transformer (P2) |
| N-2 | N-2 - Simultaneous loss of two elements due to a single event. For example, loss of two transmission lines on a common tower due to failure of the tower (P6) |
| N-1-1 | N-1-1 - Loss of a single element such as a generator, a transmission line, or a transformer followed by a system readjustment such as generation redispatch, then loss of a second element such as a generator, a transmission line, or a transformer (P7) |
| Native load | Native load – 1. The cumulative load (power requirement) of a utility's retail customer base. 2. The end-use customers that the Load-Serving Entity is obligated to serve. (NERC Glossary) http://www.energy.ca.gov/glossary/glossary-d.html |
| NAICS | NAICS - The North American Industry Classification System (NAICS) is the standard used by Federal statistical agencies in classifying business establishments for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. business economy (Source: Census.gov) |
| NERC | NERC - North American Electric Reliability Corporation |
| Northern Intertie | Northern Intertie - transmission interconnection between Washington and British Columbia (Also called Path 3.) |
| Off-system sales | Off-system sales – Sales by a utility to a customer outside of its current traditional market. |
| PC | PC - Planning Coordinator |
| PDCI | PDCI - Pacific Direct Current Intertie |
| PJM | PJM – PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. |
| Personal Consumption Expenditure Deflator (PCE Deflator) | Personal Consumption Expenditure Deflator (PCE Deflator) - Measures the average change over time in the price paid for all consumer purchases, thus measures changes in the cost of living. (Source: Investopedia) |
| Powerflow | Powerflow - a numerical analysis of the flow of electric power in an interconnected system. It can refer to the analysis program, or to a simulation |
| RE | RE - Regional Entity. |
| Regression Analysis | Regression analysis is a statistical process for estimating the relationships among variables. It seeks to determine the strength of the relationship between one dependent variable (usually denoted by Y) and a series of other changing variables (known as independent variables). It is also known also as curve fitting or line fitting because a regression analysis equation can be used in fitting a curve or line to data points. It includes many techniques for modeling and analyzing variables. |

| | |
|---|---|
| Renewable energy credits (RECs) | Renewable energy credits (RECs) - A REC represents the property rights to the non-power qualities of renewable electricity generation, such as environmental and social qualities. A REC, and its associated attributes and benefits, can be sold separately from the underlying physical electricity associated with a renewable-based generation source. At the point of generation, both product components can be sold together or separately, as a bundled or unbundled product. (Source: US EPA) |
| Renewable Portfolio Standard (RPS) | Renewable Portfolio Standard (RPS) – A regulatory mandate to increase production of energy from renewable sources such as wind, solar, biomass and other alternatives to fossil and nuclear electric generation. It's also known as a renewable electricity standard. (Source: National Renewable Energy Laboratory - NREL) |
| Substation | Substation – Substations transform voltage from high to low or from low to high. They also perform other functions, such as limiting outages, protecting equipment, et cetera. |
| Supply-Side Resources | Supply-Side Resources – Conventional generation plants, renewable generation, etc. (as opposed to Demand-Side Resources). |
| TO | TO - Transmission Owner |
| TP | TP - Transmission Planner |
| Weather Normalizing | Weather normalization is a process that adjusts actual energy or peak outcomes to what would have happened under normal weather conditions. Normal weather conditions are expected on a 50 percent probability basis, also known as a 50/50 forecast (i.e., there is a 50 percent probability that the actual peak realized will be either under or over the projected peak). |
| WECC | WECC - Western Electricity Coordinating Council. WECC has been approved by the Federal Energy Regulatory Commission (FERC) as the Regional Entity for the Western Interconnection. The North American Electric Reliability Corporation (NERC) delegated some of its authority to create, monitor, and enforce reliability standards to WECC through a Delegation Agreement. |
| Western Interconnection | Western Interconnection - North America is comprised of two major and three minor alternating current (AC) power grids, also called "interconnections." The Western Interconnection stretches from the Pacific Ocean eastward over the Rockies to the Great Plains, and from Baja California, Mexico in the South into Western Canada. (Source: Energy.gov) |
| Wheeling | Wheeling -- The transmission of electricity by an entity that does not own or directly use the power it is transmitting. Wholesale wheeling is used to indicate bulk transactions in the wholesale market, whereas retail wheeling allows power producers direct access to retail customers. This term is often used colloquially as meaning transmission. |
| WSCC | WSCC - Western Systems Coordinating Council. The predecessor to WECC. |

# Appendix B – Optional Technical Analysis

## *Executive Summary*

Utility System Efficiencies, Inc. (USE) was engaged by the City of Bellevue in February, 2014 to conduct an Optional Technical Analysis (OTA) of the purpose, need, and timing of the Energize Eastside project. Energize Eastside (EE) is Puget Sound Energy's (PSE's) proposed project to build a new electric substation and new higher–capacity (230 kilovolt) electric transmission lines in the East King County area, which encompasses Bellevue, Clyde Hill, Medina, Mercer Island, Newcastle, the towns of Yarrow Point, Hunts Point, and Beaux Arts, and portions of Kirkland, Redmond, and Renton (the Eastside). The transmission lines would extend from an existing substation in Redmond to one in Renton (See Figure 3.1).

The scope of the OTA was to perform an analysis on PSE's study cases to determine the impact of potential forecast variability on the timing of improvements, and was later expanded to evaluate whether regional requirements rather than local requirements might be driving the project need. The OTA examined several hypothetical scenarios by conducting analysis on PSE's study cases. It looked at the effect of a) reducing load growth in the *Eastside* area to 1.5%, b) reducing load growth in *PSE's portion of King County* to 0.25% while keeping the Eastside growth the same, c) increasing power output of existing Puget Sound area generation, and d) reducing the Northern Intertie[46] flow to zero (no transfers to Canada). Although d) is not actually possible due to extant treaties, it was modeled to examine if regional requirements might be driving the need. In the winter cases, the OTA also combined scenarios c) and d). Finally, the OTA looked at the impact of an Extreme Winter forecast.

If the load growth rate was reduced, would the project still be needed? Yes

The OTA results showed that reducing the Eastside average load growth from an average of 2.4%/year to an average of 1.5%/year from winter 2013/14 to winter 2017/18 did not eliminate any overloaded elements; there is still project need. Similarly, reducing PSE's *King County growth rate* (less Eastside) from an average of 0.5 %/year to an average of 0.25%/year from winter 2013/14 to winter 2017/18 did not eliminate any overloaded elements; there is still project need.

If generation was increased in the Puget Sound area, would the project still be needed? Yes

Results showed that increasing the power output of existing Puget Sound area generation to the levels specified in ColumbiaGrid's July 2010 "Puget Sound Area Generation Modeling Guideline" eliminated one of five overloads in the 2017/18 normal winter, but did not eliminate project need. (This study increased the amount of PSE and SCL generation west of the Cascades from zero to the level identified in the above document. Since the document is confidential (CEII) the generation output is not provided in this report.)



[46] Northern Intertie - transmission interconnection between Washington and British Columbia (Also called Path 3.)

IS THERE A NEED FOR THE PROJECT TO ADDRESS REGIONAL FLOWS, WITH IMPORTS/EXPORTS TO CANADA (COLUMBIAGRID[47])? Modeling zero flow to Canada, the project is still necessary to address local need.

The Optional Technical Analysis examined this issue by analyzing a reduction in the Northern Intertie flow to zero (no transfers to Canada). Although this scenario is not actually possible due to extant treaties, it was modeled to provide data on the drivers for the EE project, to examine if regional requirements might be driving the need. The results showed that in winter 2017/18, even with the Northern Intertie adjusted to zero flow, the Talbot Hill 230/115 kV transformer #2 is still overloaded by several contingencies. This indicates there is a project need at the local level.

The OTA results showed that all studied scenarios resulted in at least one equipment overload in normal winter 2017/18 with 100% conservation, indicating project need.

## *Analysis and Findings*

The OTA studied five normal winter scenarios and three extreme winter scenarios for winter 2017/18 and winter 2019/20. The OTA also studied five normal summer scenarios for 2018 and 2020. The scenarios were modeled in the powerflow cases. Details on the modeling are not provided due to Critical Energy Infrastructure Information (CEII) restrictions.

Table B.1 lists the overloaded elements for winter 2017/18 for each studied scenario. The scenarios are listed in the second blue row in Table B.1 (the vertically oriented text). The normal winter scenarios are numbered 1-6 (with #1 representing the original PSE case). The extreme weather scenarios are numbered E1-E3.

Normal winter results showed:

- Reducing the Eastside average load growth to 1.5% did not eliminate any overloaded elements; there is still project need.
- Reducing PSE's King County growth rate (less Eastside) to 0.25% did not eliminate any overloaded elements; there is still project need.
- Increasing the power output of existing Puget Sound area generation to the levels specified in ColumbiaGrid's July 2010 "Puget Sound Area Generation Modeling Guideline"[48] eliminated one of five overloads, but did not eliminate project need.
- Reducing the Northern Intertie flow to zero (no transfers to Canada) eliminated all but one overload; there is still local project need.
- Reducing the Northern Intertie flow to zero (no transfers to Canada) AND Increasing the Puget Sound area generation to ColumbiaGrid's July 2010 "Puget Sound Area Generation Modeling Guideline" eliminated all but one overload; there is still project need.

Extreme winter results increased the overload levels and/or caused overloads on additional elements. Although the normal winter results showed only one overload when the Northern Intertie flow was reduced to zero, the extreme winter case showed four overloads.

[47] ColumbiaGrid (single word) is a regional transmission planning organization with a footprint encompassing Oregon, Washington, parts of Idaho and Montana.
[48] Confidential (CEII) document that provides modeling values (MW levels of generation) for applicable generators.

**Table B.1: Winter 2017/18, 100% Conservation - Overloaded Elements**

| Northern Intertie: South to North<br><br>Overloaded Element (Transmission Line or Transformer) | 2017/18 Normal Winter 100% Conservation | | | | | | 2017/18 Extreme Winter, 100% Cons. | | |
|---|---|---|---|---|---|---|---|---|---|
| | 1) Original PSE Case | 2) Reduce Eastside load growth to 1.5% | 3) Reduce PSE's King County growth to 0.25%[49] | 4) Increase Puget Sound area generation | 5) Set Load transfers to Canada = 0 (North. Intertie = 0) | 6) Combination of Scenario 4 and & 5 | E1) Original PSE Case adjusted for extreme weather | E2) Set Load transfers to Canada = 0 (North. Intertie = 0) | E3) Scenario E2 + Increase Puget Sound area generation |
| Talbot Hill - Lakeside #1 115 kV line | OL | OL | OL | OL | | | OL | | |
| Talbot Hill - Lakeside #2 115 kV line | OL | OL | OL | OL | | | OL | | |
| Talbot Hill 230-115 kV transformer #1 | OL | OL | OL | OL | | | OL | OL | OL |
| Talbot Hill 230-115 kV transformer #2 | OL | OL | OL | OL | OL | OL | OL | OL | OL |
| Talbot Hill-Boeing Renton-Shuffleton 115 kV line | OL | OL | OL | | | | OL | | |
| Sammamish 230/115 kV transformer #1 | | | | | | | | OL | OL |
| Sammamish 230/115 kV transformer #2 | | | | | | | | OL | OL |

OL = Overload of Emergency Rating. Source: OTA Results

Table B.2 lists the overloaded elements for winter 2019/20 for each studied scenario. The scenarios are listed in the second blue row (the vertically oriented text).

The 2019/20 winter results showed the same overloaded elements as 2017/18. The overloads in the base cases and in the load reduction cases were more severe in 2019/20. The overload levels in the generation dispatch and Northern Intertie=0 scenarios were mixed; some overloads were more severe in 2019/20, but some were slightly less. Nevertheless, project need was shown in all cases. Extreme winter results increased the overload levels over normal winter and/or caused overloads on additional elements.

**Table B.2: Winter 2019/20, 100% Conservation - Overloaded Elements**

| Northern Intertie: South to North<br><br>Overloaded Element (Transmission Line or Transformer) | 2019/20 Normal Winter 100% Conservation | | | | | | 2019/20 Extreme Winter, 100% Cons. | | |
|---|---|---|---|---|---|---|---|---|---|
| | 1) Original PSE Case | 2) Reduce Eastside load growth to 1.5% | 3) Reduce PSE's King County growth to 0.25%[50] | 4) Increase Puget Sound area generation | 5) Set Load transfers to Canada = 0 (North. Intertie = 0) | 6) Combination of Scenario 4 and & 5 | E1) Original PSE Case adjusted for extreme weather | E2) Set Load transfers to Canada = 0 (North. Intertie = 0) | E3) Scenario E2 + Increase Puget Sound area generation |
| Talbot Hill - Lakeside #1 115 kV line | OL | OL | OL | OL | | | OL | | |
| Talbot Hill - Lakeside #2 115 kV line | OL | OL | OL | OL | | | OL | | |
| Talbot Hill 230-115 kV transformer #1 | OL | OL | OL | | | | OL | OL | OL |
| Talbot Hill 230-115 kV transformer #2 | OL | OL | OL | OL | OL | OL | OL | OL | OL |
| Talbot Hill-Boeing Renton-Shuffleton 115 kV line | OL | OL | OL | | | | OL | | |
| Sammamish 230/115 kV transformer #1 | | | | | | | | | OL |
| Sammamish 230/115 kV transformer #2 | | | | | | | | OL | OL |

OL = Overload of Emergency Rating. Source: OTA Results

[49] Excluding Eastside load
[50] Excluding Eastside load

Table B.3 lists the overloaded elements for summer 2018 for each studied scenario. The scenarios are listed in the second green row. The normal summer scenarios are numbered 1-5 (with #1 representing the original PSE case). There is no extreme weather summer forecast.

The 2018 normal summer results showed:

- Reducing the Eastside average load growth did not eliminate any overloaded elements; there is still project need.
- Reducing PSE's King County growth rate (less Eastside) did not eliminate any overloaded elements; there is still project need.
- Increasing the Puget Sound area generation to ColumbiaGrid's July 2010 "Puget Sound Area Generation Modeling Guideline" eliminated one of six overloads, but did not eliminate project need.
- Reducing the Northern Intertie flow to zero (no transfers to Canada) eliminated all the summer overloads; however, there is still a winter overload which means there is still local project need.

**Table B.3: Summer 2018, 100% Conservation - Overloaded Elements**

| Northern Intertie: North to South | 2018 Summer (86°F) 100% Conservation | | | | |
|---|---|---|---|---|---|
| Overloaded Element (Transmission Line or Transformer) | 1) Original PSE Case | 2) Reduce Eastside load growth | 3) Reduce PSE's King County growth | 4) Increase Puget Sound area generation | 5) Set Load transfers to Canada = 0 (Northern Intertie = 0) |
| Sammamish 230/115 kV Xfmr #1 | OL | OL | OL | OL | |
| Sammamish 230/115 kV Xfmr #2 | OL | OL | OL | OL | |
| Novelty Hill 230/115 kV Xfmr #2 | OL | OL | OL | | |
| BPA Monroe – Novelty Hill 230 kV | OL | OL | OL | OL | |
| Beverly Park - Cottage Brook 115 kV line | OL | OL | OL | OL | |
| Sammamish – BPA Maple Valley 230 kV line | OL | OL | OL | OL | |

OL = Overload of Emergency Rating. Source: OTA Results

The 2020 summer results (Table B.4) showed the same overloaded elements as 2018. The overloads were more severe in 2020, with the exception of the Beverly Park – Cottage Brook 115 kV line which was either unchanged or reduced by less than 0.1%.

**Table B.4: Summer 2020, 100% Conservation - Overloaded Elements**

| Northern Intertie: North to South<br><br>Overloaded Element<br>(Transmission Line or Transformer) | 2020 Summer (86°F)<br>100% Conservation | | | | |
|---|---|---|---|---|---|
| | 1) Original PSE Case | 2) Reduce Eastside load growth | 3) Reduce PSE's King County growth | 4) Increase Puget Sound area generation | 5) Set Load transfers to Canada = 0 (Northern Intertie = 0) |
| Sammamish 230/115 kV Xfmr #1 | OL | OL | OL | OL | |
| Sammamish 230/115 kV Xfmr #2 | OL | OL | OL | OL | |
| Novelty Hill 230/115 kV Xfmr #2 | OL | OL | OL | | |
| BPA Monroe – Novelty Hill 230 kV | OL | OL | OL | OL | |
| Beverly Park - Cottage Brook 115 kV line | OL | OL | OL | OL | |
| Sammamish – BPA Maple Valley 230 kV line | OL | OL | OL | OL | |

OL = Overload of Emergency Rating. Source: OTA Results



Stakeholder Questions related to the OTA

*Q56. The study must as clearly, but non-technically as possible, define will happens regarding power flow to and from Canada.*

A *See the OTA in Appendix B. Sensitivities were performed where power flow to and from Canada were reduced to zero. These cases still showed overloads so there is clearly a local need. Some overloads were eliminated when flows were reduced to zero, which indicates that flows to and from Canada also have an impact on the need.*

*Q57. Clarify Eastside vs. regional needs. What load is causing the problem? Local or regional?*

A *Local. The Optional Technical Analysis results showed that in winter 2017/18, even with the Northern Intertie adjusted to zero flow, the Talbot Hill 230/115 kV transformer #2 is still overloaded by several contingencies. This indicates there is a project need at the local level. See the full Appendix B for further detail.*

*Q58. I am concerned that the need is not just for Bellevue and the Eastside but more for Bonneville Power, Snohomish Power, Seattle City Light -- the Columbia Grid. I would ask the consultants to provide a simple quantitative and pie chart breakout of the need that each stakeholder has in "Energize Eastside".*

A *See Q56.*

*Q59. Provide a quantitative analysis and pie charts (both historical and futuristic) showing a breakout of the need (demand and reliability) for each of the members of the Columbia Grid.*

A *The Optional Technical Analysis results showed that in winter 2017/18, even with the Northern Intertie adjusted to zero flow, the Talbot Hill 230/115 kV transformer #2 is still overloaded by several contingencies. These results indicate there is a project need at the local level.*

*Q60. Given the scenario and contingency driving the EE project, how much regional load will flow through the line?*

A *See Q61 below.*

*Q61. What percentage of North-South flow-through load (to Canada/California) will be carried on EE during an N-1-1 event (failure of BPA bulk main PLUS a second transmission line failure?*

A *The OTA studied a scenario with flows to Canada at 1500 MW and a scenario with flows to Canada set to 0 MW. Under the worst contingency condition (N-1-1), the reduction in flow on the Talbot Hill - Lakeside lines was 22.5%. Under the worst contingency condition (again N-1-1), the reduction in flow on the Talbot Hill 230/115 kV transformer was 2.6%. These results are before EE and reflect the effects on the current transmission system serving the EE area. As you can see from these results, the impact of flows to Canada on the Talbot Hill 230/115 kV transformer (the main driver of the need for EE) is almost insignificant.*

*Q62. Was the system studied with generation on the west side?*

A *Yes, the OTA studied a scenario with generation on the west side.*

*Q63. Is EE a "BLENDED PROJECT" to satisfy the needs of Columbia Grid, BPA grid reinforcement (Monroe-Echo Lake bottleneck), Columbia River treaty "Canadian Entitlement" curtailments, Seattle City Light load needs, as well as PSE load growth?*

A *The term "Blended Project" is not clear. However, the OTA results do show that there is a need for a project to satisfy local needs. A review of ColumbiaGrid documentation indicates that EE will also help satisfy a regional need which is why EE was included in the recommended transmission solution from ColumbiaGrid Puget Sound Area transmission planning activity.*

# Appendix C – End-Use Data and IRP

End-use data is evaluated in Integrated Resource Planning, where a utility examines both Supply-Side and Demand-Side options with the objective of providing reliable and least-cost electric service to its customers while addressing applicable environmental, conservation and renewable energy requirements. Because energy efficiency is generally a low-cost resource, the IRP tends to incorporate energy efficiency as a utility system resource and reduce the need for additional Supply-Side resources.

PSE commissioned The Cadmus Group, Inc. (Cadmus) to conduct an independent study of Demand-Side Resources (DSR) in the PSE service territory as part of its biennial integrated resource planning (IRP) process. The study considered energy efficiency, fuel conversion, Demand Response, and distributed generation. PSE also considered distribution efficiency.

Energy efficiency looked at naturally occurring conservation, which occurs due to normal market forces such as technological change, energy prices, improved energy codes and standards, and efforts to change or transform the market. This includes gradual efficiency increases due to replacing or retiring old equipment in existing buildings and replacing it with units that meet minimum standards at that time. It also includes new construction which reflects current state specific building codes, and improvements to equipment efficiency standards that are pending and will take effect during the planning horizon.

Fuel Conversion considered opportunities to substitute natural gas for electricity through replacements of space heating systems, water heating equipment, and appliances.

Demand Response options seek to reduce peak demand during system emergencies or conditions of extreme market prices. It may also be used to improve system reliability and could potentially help to balance variable-load resources such as wind energy.

Washington State's Renewable Portfolio Standard (RPS) law requires conservation potential be developed using Northwest Power & Conservation Council (NWPCC) methodology, and conservation targets are based on IRP with penalties for not achieving them. It requires PSE to meet specific percentages of its load with renewable resources or renewable energy credits (RECs) by specific dates.

The Energy Independence and Security Act (EISA, 2007) provides for minimum federal standards for lighting and other appliances beginning in 2012. It also sets standards for increasing the production of clean renewable fuels, increasing the efficiency of buildings and vehicles, and more.

Cadmus compiled technical, economic, and market data from the following sources:

- PSE Internal Data: Historical and projected sales and customers, historic and projected DSR accomplishments, and hourly load profiles
- 2010 Residential Characteristic Survey (PSE Service Territory)
- 2008 Fuel Conversion Survey (PSE Service Territory)

- 2007 Puget Sound-Area Regional Compact Fluorescent Light (CFL) Saturation Study
- NEEA's 2009 Commercial Building Stock Assessment (CBSA)
- Building Simulations for the residential sector, employing separate models for customer segments and construction vintage
- Pacific Northwest Sources. Technical information included on hourly end-use load shapes (to supplement building simulations), commercial building and energy characteristics. Information on measure savings, costs, and lives
    - The Northwest Power and Conservation Council (Council)
    - The Regional Technical Forum (RTF)
    - The Northwest Energy Efficiency Alliance (NEEA)
- Sources to characterize measures, assess baseline conditions, and benchmark results against other utilities' experiences
    - The California Energy Commission's Database of Energy Efficiency Resources (DEER)
    - ENERGY STAR
    - The Energy Information Administration
    - Annual and evaluation reports on energy-efficiency and Demand Response programs from various utilities

Only new opportunities for conservation are captured in the DSR value and thousands of measures were evaluated. Conservation programs included Energy Efficiency, Fuel Conversion, Distributed Generation, Demand Response and Distribution Efficiency (voltage reduction and phase balancing[51]). Lighting savings in the 2013 IRP assume the availability of a technology meeting the minimum requirements of EISA, and that savings from Compact Fluorescent Lamp (CFL) installations will remain available[52]. (Cadmus estimated that 33% of sockets have CFLs before the 2013 IRP measures are selected.) EISA accounts for 31% of residential DSR and 26% of commercial DSR. DSR targets are reviewed by the Conservation Resource Advisory Group and the Integrated Resource Plan Advisory Group.

The 2013 IRP identified market achievable, technically feasible Demand-Side measures. These measures (over four thousand) were combined into bundles[53] based on levelized cost[54] for inclusion in the generation optimization analysis. The effect of the bundles is to reduce load, so the costs to achieve the savings must be added to the cost of the electric portfolios.

The optimization analysis identifies the economic potential (cost-effective level) of DSR bundles that would work well in planning for generation requirements. (For example, solar energy has a different impact on the summer peak than on a winter peak.) The optimization model developed and tested different portfolios, combining Supply-Side Resources with Demand-Side bundles, to find the lowest cost combination of resources that a) met capacity need b) met renewable resources/RECs need, and c) included as much conservation as was cost effective. (Once the capacity and renewable resources/RECs needs are met, the decision to include additional

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[51] Phase balancing: Balancing the single-phase load among the three phases so that unbalanced load isn't driving the peak load value.
[52] LED lighting: The LED programs were not specifically identified in the 2013 IRP. The LED technology and availability is different today than it was when the 2013 IRP study began. PSE is planning on including LED lighting in the 2015 IRP.
[53] An example bundle is the set of measures that cost between $28/MWh and $55/MWh.
[54] Levelized Cost - An economic assessment of the cost to build and operate a power-generating asset over its lifetime divided by the total power output of the asset over that lifetime. It is also used to compare different methods of electricity generation in cost terms on a comparable basis.

conservation bundles is simply whether that next bundle of measures increases the cost or decreases it.)

The optimization analysis results in the final set of cost effective measures, which are identified as the "100% conservation" set.

# Appendix D – Ask the Consultant

A key purpose of the ITA and the OTA was to provide an increased level of understanding of the purpose, need and timing of the EE project to the City Council and to community stakeholders. Over the course of the project, dozens of questions were received from various stakeholders. The City engaged such comments through an online outreach feature called 'Ask the Consultant.' In addition to this outreach the City initiated separate interviews with key stakeholders and USE staff. City staff filtered all Ask the Consultant stakeholder comment through the various Tasks in the Scope of Services and submitted the need-related comments to USE for report inclusion. Other comments were directed as appropriate to other comment venues including for example to the scoping process for the Environmental Impact Statement (EIS) the Integrated Resource Plan (IRP) process. That filtering is documented in the chart below.

A Q&A discussion is documented at the end of each section of the ITA.

See Attached Table 1.

| Date | Name | Question or Comment | Directed to: |
|---|---|---|---|
| 1/27 | Plummer | Industry standards, IRP, average yearly loads | Extensive reference to lack of industry wide standards; paragraph 4 and 5 to ITA |
| 1/22 | Marsh | Questions for ITA consultant: Overview, Real need, distribution of peak use, Eastside vs regional needs, reliability | Skype session |
| 1/28 | Marsh | Questions for ITA consultant: extreme winter study case, other adjustments modeled, System Cap. | Role of Case Study Assumption, clarify reference to Needs Assessment Section 6, connection between CSA and CDF to ITA |
| 1/30 | Sweet | Data center consolidation comment | ITA |
| 2/6 | Plummer | Quantitative reliability metrics | ITA |
| 2/9 | Lander | Choice of USE and communications | Communications response |
| 1/15 | Osterberg/ Laughlin | E3 and Cadmus Study, declining revenue, blended project | EIS |
| 2/3 | Borgmann | 12 questions: forecast, growth rates, Columbia Grid role, used and useful comparison, alternatives | 1, 2, 7, 8, 12 to ITA<br>3 ? to ITA, comments to EIS<br>5 ? to ITA, comments to EIS<br>6 ? to ITA, comments to EIS<br>7- 2nd set? to EIS<br>4, 9, 10, 11 to EIS |
| 2/9 | Kim | 2 comments on tech study and CDF chart; 2 questions on growth forecast disparity, show project stakeholder pie chart | 1 and 2 to EIS<br>3 and 4 to ITA |

| | | | |
|---|---|---|---|
| 2/10 | McCray | 4 questions: Load projection, options, trend down, Chang proposal | 1 and 3 to ITA<br>2 and 4 (Chang) to EIS |
| 2/10 | Marsh | Circumstances of all-time peak usage occurrence | EIS |
| 2/10 | Marsh | PSE and SCL electricity trends | EIS |
| 2/11 | Alford | comment on tech study and CDF chart; questions on growth forecast disparity, show project stakeholder pie chart | See Kim comment |
| 2/11 | Mozer | Magnitude and timing of EE, alternatives, Canada powerflow | ITA (1) and EIS (2) |
| 2/12 | Andersen | 4 questions: SCL capacity, Peak load information, use of temperature in modelling, distributed generation, use of peaking turbine generation | New Q1 to EIS<br>Add 1 Q4 not in ITA scope<br>Add 2 Q7 not in ITA scope<br>Add 3 Q15 DSR and DG in ITA modelling, cost info not in scope<br>Add 4 Q19 to EIS |
| 2/12 | Merrill | 7 questions: Reasonableness of PSE conclusions, rational look, Eastside Customer demand, use of actual data, replacement, outages | 1, 3, 5, 6 to ITA<br>2, 4, 7 to EIS |
| 2/12 | Hansen | Bridle Trails Subarea infrastructure reliability | EIS or ERS implementation |
| 2/12 | Halvorson | Customer Demand Forecast and Columbia Grid need pie chart | ITA |
| 2/12 | Marsh | 7 questions: Top assumptions and parameters of the load forecast, economic projections, Spring District, increased efficiency, local government actions, regional transmission flow, regional grid | ITA |

# Appendix E – Transmission Planning Standards TPL-001-4

See attached Table 1.

# Appendix F – Utility System Efficiency, Inc. (USE) Qualifications

**R. Peter Mackin, P.E.**
Vice President of Analytical Services

**ACADEMIC BACKGROUND**
M.S., Electrical Engineering, Montana State University, 1982
B.S., Civil Engineering, Montana State University, 1981

**PROFESSIONAL EXPERIENCE**
Peter Mackin has over 33 years of power system planning and computer application development experience and has been involved in WSCC/WECC planning and operating activities since 1985. In April of 2006, Mr. Mackin joined Utility System Efficiencies, Inc. (USE) as Vice President of Analytical Services. At USE, among other duties, Mr. Mackin has directed and performed system studies to meet the requirements of the WECC Project Rating Review Process, assisted developer clients with interconnection applications, and supervised a wind integration study for FERC.

While employed at Navigant Consulting, Inc., Mr. Mackin performed several transmission and resource integration studies for the Alberta Electric System Operator (AESO) as well as generation interconnection studies and transmission feasibility analyses for other clients. Mr. Mackin was a member of the NERC Version 0 and Phase III/IV Standards drafting teams. In addition, Mr. Mackin provided expert witness testimony at FERC in Docket No. ER01-1639-006.

While employed by the California Independent System Operator (CAISO), Mr. Mackin performed or reviewed system planning studies for Reliability Must Run generation requirements, new generator interconnection studies, as well as Participating Transmission Owner annual Transmission Assessments. In addition, Mr. Mackin helped develop the CAISO's New Facility Interconnection Policy and Long-Term Grid Planning Policy. Mr. Mackin provided expert witness testimony regarding six new generation projects before the California Energy Commission.

While employed by Pacific Gas and Electric Company (PG&E), Mr. Mackin was the lead transmission planning engineer performing transient stability simulations for the 500 kV California – Oregon Transmission Project. In addition, Mr. Mackin performed, supervised or reviewed studies to determine simultaneous import capabilities into California from the Pacific Northwest and the Desert Southwest. For two years, he served as chairman of the work group that undertook these studies. This work group was comprised of utilities from California, the Northwest, and the Desert Southwest.

**Jennifer Geer, P.E.**
Principal Power Systems Engineer

## ACADEMIC BACKGROUND

B.S., Electrical Engineering, University of New Mexico, 1985

## PROFESSIONAL EXPERIENCE

Ms. Geer has over 25 years of electric utility industry experience and has extensive background in the transmission and distribution areas, including transmission planning and generation interconnection studies, distribution planning and forecast development and approval, outage analysis, reliability analysis, project development, and project management. Ms. Geer has also provided training in many of these areas. Ms. Geer joined Utility System Efficiencies, Inc. (USE) in 2009. At USE, Ms. Geer's focus has been on generation interconnection studies, transmission planning and project development.

Prior to joining USE, Ms. Geer was a member of San Diego Gas and Electric's Transmission Planning Department. Though part of their generation interconnection team, she was also involved in studies to determine the need and benefit of new transmission projects on the existing system, examining different route and voltage options.

While running Geer and Geer Engineering, Ms. Geer developed a procedure to determine if a new substation was needed; part of this procedure involved developing long term forecasts for the relevant areas. She also led teams to optimize substation site selection based on both engineering and non-engineering issues, and provided project management for a long term transmission study that was used to determine client company strategy. In addition, Ms. Geer developed or reviewed many distribution projects, trained engineers and leads on distribution planning, developed a training manual, conducted process mapping of distribution functions, and analyzed visibility and accuracy of distribution accounting.

While employed by San Diego Gas & Electric (SDG&E), Ms. Geer forecasted distribution loads, identified issues and alternatives, and developed circuit and substation projects. Ms. Geer also conducted distribution reliability studies to improve performance indices and developed training documents on multiple topics. She reviewed the entire set of distribution circuit forecasts and proposed distribution capital projects for San Diego Gas & Electric in later years, and provided feedback and/or modification as needed. Ms. Geer also developed checklists and forms to assist in forecasting, project development and new business engineering review, and trained engineering personnel on distribution planning procedures.

City of Bellevue

DATE: 07/31/2015

TO: Energize Eastside EIS File – 14-139122-LE

FROM: David Pyle, Senior Environmental Planner – 425-452-2973

SUBJECT: Energize Eastside EIS Team Review of Project Need

PSE has represented that there is a need to construct a new 230 kV bulk electrical transmission corridor and associated electrical substations on the eastside of Lake Washington to supply future electrical capacity and improve eastside electrical grid reliability. Preliminary discussion between potentially affected jurisdictions and PSE indicated that the proposal is likely to have probable significant adverse environmental impacts, and issuance of a Washington State Environmental Policy Act (State Environmental Policy Act (SEPA) Threshold Determination of Significance was deemed appropriate as outlined in Chapter 197-11-360 WAC.

Following PSE's identification of this essential electrical infrastructure link, and to address the potential for significant environmental impacts, the utility submitted application for processing of an Environmental Impact Statement (EIS) with the City of Bellevue, who assumed the role of lead agency. Subsequent to this initiating action, several steps have been taken to begin processing the required EIS. The EIS is now underway and the EIS project team has been in review of information provided by PSE and collected during the process.

To better understand PSE's project proposal, the EIS project team has obtained clearance to access un-redacted sensitive (protected in accordance with industry security protocol) utility planning and operations information used by PSE in developing the Energize Eastside project proposal. The EIS project team, represented by Stantec (electrical system planning and engineering sub-consultant working in support of the Energize Eastside EIS effort), has reviewed this background information and studied the process used by PSE to establish a need for the proposed Energize Eastside project. A report from Stantec summarizing the findings is attached.

Although validation of the need for the proposed Energize Eastside project is not considered as a component of the EIS process under the requirements of SEPA, review of the need for the project is important in developing a thorough understanding of the project objectives and technical requirements to accurately identify feasible and reasonable project alternatives[1]. The EIS process is not to be used to reject or validate the need for a proposal. Rather, the EIS process is intended to identify and disclose potential significant adverse environmental impacts associated with a specific proposal.

[1] WAC 197-11-786 - Reasonable alternative.
"Reasonable alternative" means an action that could feasibly attain or approximate a proposal's objectives, but at a lower environmental cost or decreased level of environmental degradation. Reasonable alternatives may be those over which an agency with jurisdiction has authority to control impacts, either directly, or indirectly through requirement of mitigation measures.

Stantec

# Memo

| | | | |
|---|---|---|---|
| To: | Mark Johnson<br>Program Manager<br>ESA \| NW Community Development Director | From: | Keith DeClerck<br>Tucson, ArizonaTucson, Arizona |
| File: | Energize Eastside | Date: | July 31, 2015 |

**Reference: Energize Eastside Project**

The purpose of this memorandum is to summarize my findings regarding Puget Sound Energy's (PSE) electrical system needs that support the purpose and need for PSE's proposed Energize Eastside project. It memorializes the issues we have discussed in depth with the principal jurisdictions reviewing the project (the Cities) as we examined PSE's project criteria and possible alternatives to the 230 kV transmission system improvements that PSE has proposed for consideration in the Phase 1 Draft Environmental Impact Statement (EIS). I have prepared this memo at ESA's request to support a plain-language description of the purpose and need for the Energize Eastside project that can be used in the EIS that ESA is preparing. I understand that ESA and the Cities also want to understand the purpose and need for the project and the constraints PSE is working with so that you can make informed choices about what alternatives to evaluate in the EIS.

<u>My Background</u>
As an electrical engineer with more than 25 years of experience in both Industrial and utility environments, I understand the concerns on both sides of the meter. Specific to this project I have over 14 years of experience in transmission and distribution power flow simulations and have conducted and published extensive power flow studies in several of the states included in the Western Electricity Coordinating Council (WECC) region. I have critical infrastructure security clearance for viewing FERC data, and have experience reviewing such data. In addition, I have conducted transmission adequacy studies and renewable generation interconnection studies in several other North American Electric Reliability Corporation (NERC) regions across the United States. My experience in load forecasting and transmission planning, coupled with the fact that I have never worked for or have been under contract to PSE, allows me to provide a knowledgeable, independent view of the project purpose and need.

<u>Documents Reviewed</u>
In preparing this memo, I reviewed the unredacted versions of the following documents prepared by PSE and Quanta Technology (Quanta):

- *Eastside Needs Assessment Report, Transmission System, King County,* dated October 2013;
- *Supplemental Eastside Needs Assessment Report, Transmission System, King County,* dated April 2015;
- *Eastside Transmission Solutions Report, King County Area,* dated October 2013; and
- *Supplemental Eastside Transmission Solutions Report, King County Area,* dated April 2015.

I also reviewed the *Independent Technical Analysis of Energize Eastside for the City of Bellevue, WA (Version 1.3)* dated April 28, 2015 by Utility System Efficiencies, Inc. (USE). Although PSE's findings are the focus of this assessment, I found the USE report to be helpful in exploring other facets of the proposed need and verifying my own conclusions.

In the process of reviewing these documents I also referred to many other documents prepared by federal and regional agencies and by PSE.

Findings

Based on my expertise, I found that the PSE needs assessment was overall very thorough and applied methods considered to be the industry standard for planning of this nature. Based on the information that the needs assessment contains, I concur with the conclusion that there is a transmission capacity deficiency in PSE's system on the Eastside that requires attention in the near future. For purposes of this memo, "Eastside" refers to the central portion of King County roughly located between the cities of Redmond to the north and Renton to the south.

The transmission capacity deficiency is complex. It arises from growing population and employment, changing consumption patterns, and a changing regulatory structure that requires a higher level of reliability than what was required in the past. PSE has concluded that the only effective and cost-efficient solution is to site a new 230 kV transformer in the center of the Eastside, fed by new 230 kV transmission lines from the north and south. While that conclusion seems simple and straightforward, it is the product of an analysis that considered dozens of options and thousands of potential scenarios that the power system could encounter.

The population of the Eastside is expected to grow at a rate of approximately 1.2% annually over the next decade, and employment is expected to grow at an annual rate of approximately 2.1%. Because of the nature of expected development, PSE projects that electrical demand will grow at a rate of 2.4% annually. Without adding at least 74 MW of transmission capacity or local peak period generation to the Eastside, a deficiency could develop as early as winter of 2017 - 2018 or summer of 2018, putting customers at risk of load shedding (power outages). It is impossible to place a single number on the projected deficiency because it varies by season (winter vs. summer) and by other assumptions that are made in the planning process. However, as the load continues to grow, the risk and extent of the load shedding required increases.

Four components must be understood in order to have a basic understanding of the nature of this expected capacity deficiency:

- Study Parameters
- Load Forecast
- Corrective Action Plans
- Regional Compliance

Study Parameters

PSE started with the WECC database model for load forecasting, distribution, and transmission. The model encompasses all utilities in the western United States, western Canada, and northern Mexico. This model is updated yearly by all entities in the WECC region and reflects the overall system configuration and load forecasts for each utility. This overall model does not always reflect the specific details of a utility's transmission and distribution system. Therefore, PSE added specific details about its system configuration on the Eastside to enhance the accuracy of the results. This includes PSE's 115 kV substations and transmission lines, and other equipment operating at lower voltage. In the model, forecasted electrical load is distributed by substation, based on historical load data for those locations. This model was used for most of the study results.

In addition, system sensitivity cases (i.e. scenarios) were conducted using various levels of energy conservation, extreme weather temperatures, power generation patterns, and expected "intertie" flows between PSE and its interconnected neighbors. These scenarios were used to evaluate stresses on the system that can reasonably be expected. The scenarios generally involve trying to operate the system during these extreme weather periods with one or two system components taken offline either because of planned maintenance, or because of an emergency such as damage caused by a storm or vandalism. Scenarios provide insight as to the strengths and weaknesses of the system. Because weaknesses represent vulnerable aspects of the system, specific information about them is not released to the general public.

This procedure is a typical method of study and consistent with standard accepted practice for the industry. Extreme weather conditions examined are relatively high likelihood events, that is, conditions expected in one out of every two years.

Results from both summer and winter conditions were reported. This is because although the Eastside has historically had its highest electrical demand during the winter, recent trends show that summer usage is growing rapidly and will eventually lead to similar or even greater levels of demand as peak winter days. This is discussed further under Load Forecast.

Load Forecast

The load forecast is central to determining the need for the project. The primary contributing factors to the growth in load are as follows:

- Local residential consumption due to population growth; and
- Local growth in commercial and industrial electrical consumption due to both the quantity and types of local businesses that are growing.

PSE prepared a Needs Assessment in 2013 and a Supplemental Needs Assessment in 2015. The methodology used in the Supplemental Needs Assessment increased the accuracy of the results by breaking down the systemwide forecast into county-by-county forecasts and a sub-county area forecast for the Eastside. Both the 2013 and the 2015 reports show that Eastside growth is expected to be relatively strong, with peak loads projected to grow by approximately 2.4% per year over the next 10 years (2014 - 2024) driven mainly by new development in the commercial and high-density residential sectors.

Table 2-2 in the Supplemental Needs Assessment compares the load growth forecast from the 2013 assessment and the 2015 assessment. The 2015 supplemental forecast showed a slight reduction in PSE's overall peak load projections for winter 2017 - 2018 of 46 MW (0.9% of total) as compared to the 2013 projections, which is due to a slower than expected recovery in the housing sector. Similarly, Eastside load projections for winter 2017 - 2018 decreased by 11 MW (1.6% of total) as compared to the previous forecast. Although the new forecast slightly extends the time before system components on the Eastside will have reached capacity, the conclusion regarding the need in the long run has not changed.

PSE has traditionally been a winter-peaking utility, meaning that the highest demand periods typically have occurred in winter when cold weather drives the demand for heating. Both Needs Assessment reports indicate that, in addition to growing winter peak load demand, summer loads on the Eastside are growing even more rapidly, to a point where they also pose transmission capacity deficiency issues.

In the 2015 Supplemental Needs Assessment report, the 2018 summer load projections for the Eastside were 12 MW (2.2% of total) lower than the previous forecast. However, by 2018 the supplemental assessment shows that approximately 74 MW of customer load is at risk of load shedding (shutting off or limiting power to customers) in order to maintain a reliable and secure transmission system. Ultimately, the result of having both a winter and summer peak deficiency leads to more hours of the year when the system is vulnerable to excess loading.

As with the previous forecast, PSE's supplemental forecast was based on historical data that were modified for such variables as energy conservation programs, economic data, population growth trends, and population and employment growth forecasts from the Puget Sound Regional Council (PSRC). Also included into the final shape of the forecast were any expected community development increases in load that have been identified by PSE customer relations and/or PSE local area distribution planning staff as being of significant size. These would be considered block loads and their addition is a typical practice in utility forecasting. In the model, block loads were added to the forecast for the substation that would serve those loads at 100% for the first three years, 50% for the next three years, and 0% after six years. Even though there are no standards for adding block loads of this type, this staged approach allows the forecast to capture any immediate sizable increases while tapering off and allowing the data available on employment and population provided by the other forecasting agencies to shape the outer years. This approach is a reasonable way to capture any significant near-term load increases without skewing the entire forecast.

In my opinion, the one area where PSE used an approach to load growth that was not typical of most utilities was in looking at the effect of its conservation programs. PSE used a conservation level of 100% in its load forecast, which assumes PSE will be able to achieve all of its planned conservation goals. Although PSE has a highly successful conservation program at present, this is more optimistic than most utilities are when making load forecasts, since conservation programs are typically voluntary. Using this as an expectation, anything short of that level of conservation would increase load levels and accelerate the timeframe for the deficiency to develop. The demand-side reduction program is described in PSE's *Integrated Resource Plan* (2013) including the methods used in determining the achievable levels of conservation. My review did not include a review of the methodology or results used in that analysis, although it appears to consider a wide range of factors that should be considered when establishing conservation goals.

In summary, PSE's load forecasting analysis applied methods and assumptions that are standard practice for the utility industry. My only concern is that the approach taken on conservation could result in understating the potential capacity deficiency if PSE were to fall short of its conservation goals.

<u>Corrective Action Plans (CAPs)</u>

An unwanted side effect from transforming power or transmitting power across power lines is the effect of thermal heating. Similar to water encountering friction in a hose, electrons face resistance in the conductor or transformer. Many individuals have felt this phenomenon when attempting to change a light bulb after it has been on for a period of time. Electrical transformation and delivery can cause extreme heat. As electrical system components heat up due to these thermal stresses, they reach a point where physical damage can occur if the temperatures are too high.

System operators monitor the load, which is in direct correlation to the heating of equipment. If the load gets too high, operators must reduce (shed) load, either automatically or manually, from the equipment. This reduces the loading and allows the destructive temperatures to decrease to a safe level. This heating can occur in any system component (transformers, conductors, generators etc.). If the operator does not shed load the equipment will eventually fail due to the excess heat, and no load will be able to be served by that system component until it is replaced. For some components this could take weeks or months to accomplish due to equipment availability, shipment requirements and the time it takes to install and test the component.

Corrective action plans (CAPs) are instructions to PSE transmission operators to take particular actions during certain events to prevent destruction of system components and maintain appropriate voltage levels to all customers. Equipment overheating mainly triggers those actions. Overheating is typically due to high "steady state" load levels during peak load times (i.e., running the system near full capacity for several hours or days, such as during a cold snap or hot spell), or increases in load on a particular piece of equipment due to an outage of another transmission system component. Outages can occur due to unforeseen events such as storms, or during routine maintenance, when pieces of equipment need to be isolated from the system for personnel safety. CAPs are used by all electrical utilities as temporary fixes that can be implemented for short periods in lieu of increasing the capacity of the system.

The electrical transmission system is basically a link between generation (supply of electrical power) and load (demand for electricity). Unless the load is turned off or generation is unavailable, the transmission system will continue to try to deliver electricity to the load even if certain parts of the system are overheating. Operators must be constantly aware of system loading parameters to prevent components of the system from being destroyed by overheating. Once destroyed, the component may be out of service for weeks or months while being repaired, and customers may be adversely affected for the duration. CAPs are sometimes administered manually by the operator, or automatically by control systems in more critical cases where immediate action is deemed appropriate.

CAPs limit the adverse effects to equipment, but during the period that a CAP is being implemented, the electrical supply system is left in a more vulnerable state with fewer components to carry the load. Regardless of whether a CAP has been initiated by normal load levels, an unexpected outage, or a maintenance outage, there is a higher probability during a CAP that any further system upset could leave large areas of the Eastside and thousands of customers without power. As the load for the Eastside increases, and as the problem becomes not only a winter but summer peak issue, the number of hours per year when CAPs must be implemented will increase, meaning the length of time that the system is vulnerable also increases. Therefore, from a functional standpoint the system becomes less reliable in regard to normal load and unexpected system outages. From a maintenance standpoint the system becomes harder to operate and maintain its components in good condition. For example, PSE currently uses CAPs at the Talbot Hill substation to avoid load shedding in winter months.

PSE considered CAPs in its Needs Assessment for the Energize Eastside project, recognizing that with growing demand CAPs alone would not be a sustainable solution. CAPs allow PSE transmission operators to temporarily mitigate system problems on the Eastside in order to keep the system operational during certain outages and maintenance procedures. However, each CAP increases the exposure to more widespread customer power outages if any further system upset occurs while the CAP is implemented. As load increases over time, more CAPs are needed for more hours of the year and system reliability decreases. Therefore, CAPs should not be regarded as a long-term solution.

Regional Compliance

Like all major electrical utilities, PSE's electrical supply system does not operate independently of other power providers in the region. The interconnected power system, or bulk electric system (BES) as it is commonly referred to, is intended to be cost and resource effective by allowing excess power generation in one part of the region to supply load in another. In addition, because of the characteristics of electricity, increased system reliability, voltage stability, and performance are achieved by employing an interconnected system.

Several regional agencies in the Northwest oversee the operation of the BES to ensure that it is capable of delivering electricity. These regional agencies are ultimately responsible on a national level to the Federal Energy Regulatory Commission (FERC) and NERC. Among other duties, these regional entities identify additions to the transmission system needed to ensure service to load and meet firm transmission service commitments into the future, while complying with national reliability standards. In order to participate in the benefits of the regional grid, PSE must adhere to these transmission reliability standards.

These standards have become more stringent in recent years, after lessons learned in the cascading blackout that struck the northeastern portion of North America in 2003. Particularly relevant to planning for the Energize Eastside project, the current standards require that the system must be capable of operating safely and reliably with two components being disabled (referred to as N-2 and N-1-1 scenarios), whereas past standards only required that the system operate reliably with one component disabled (referred to as N-1 scenarios).

The Eastside Needs Assessment Report and the Supplemental Eastside Needs Assessment Report mention several other reports prepared by regional agencies, or that PSE prepared in order to comply with these agencies' standards. Each of these reports investigated a range of solutions to meet a particular regional electric system need. Being regional, these studies often encompass several utilities in order to address a particular issue or range of issues.

The Energize Eastside project was discussed as one of the possible solutions in some reports, and it was found to help address regional transmission issues. This should not lead to the conclusion that Energize Eastside was conceived as a means to address these regional needs. It only means that PSE's proposed Energize Eastside 230 kV transmission line would benefit the reliability of the regional grid in addition to addressing the local capacity deficiency on the Eastside. Conversely, other regional solutions these reports investigated would address the regional issue but would not be effective for solving the local transmission capacity deficiency on the Eastside. This is because they were designed only to address the regional issue. Providing support for the electrical needs of the region should not be equated with support for the need identified for the Energize Eastside project.

For instance, in the past PSE has utilized various CAPs as mentioned above to meet some of its regional compliance issues for reliability. Yet, as was also indicated above, the enforcement of a CAP is a temporary solution that puts large numbers of Eastside customers at higher risk of a power failure, and the hours of exposure per year continue to increase.

Regional compliance is part of operating an electric utility. There is a tension between what is best for the region and what is best for the local utility.

Summary

Due to increasing load demand, the Eastside is quickly approaching a transmission capacity deficiency. If and when this deficiency develops, PSE's electrical supply system will reach a point where it cannot ensure the level of reliability that it is mandated to provide. Assuming projected growth occurs, the Supplemental Needs Assessment indicates this capacity will be reached as early as winter 2017 - 2018. This is not a prediction that weather conditions and load demand will converge in this time period and require load shedding. Rather, it is a projection that load demand will increase to a point where, if adverse weather conditions occur and one or more components of the system is not operating for any reason, load shedding would be required. Once the threshold is crossed, the physical limitations of the system are such that even the slightest overload will produce overheating that can damage equipment, and larger overloads will produce overheating more quickly. Once equipment is in an overload condition, the options are to let it fail or take it out of service. Both conditions leave the Eastside in a vulnerable state where the system is incapable of reliably serving customer load. At that point further actions may be needed such as load shedding in order to keep the system intact. By the end of the 10-year forecast period, a large number of customers would be at risk, and the load shedding requirement could be as high as 133 MW.

The deficiency is caused by load growth, which is a byproduct of economic growth and population increases in the Eastside area. Addressing the deficiency is difficult because the needed generation to supply this load growth is outside the service area and the available existing pathways to bring that power to the load have reached capacity. The load area in question is situated between two sources: Sammamish substation on the north end (Redmond/Kirkland area) and Talbot Hill substation on the south end (Renton area). These are the only two sites that effectively support this geographical area. Increases or decreases in load that are not directly supplied by these two substations, or power flow to other parts of the system outside the service area, have minimal effect on the ability of these substations to supply load. Only a direct interruption of supply power to or power fed from these two substations will affect the Eastside area. Once the higher voltage (230 kV) is transformed down to a lower voltage (115 kV) at these two substations, the system is limited by the physical capacity of the conductors and transformers that connect those two sources to the load and feed the area.

A simple analogy for the transmission problem on the Eastside would be the water pressure at a residence with a vegetable garden located at the back of the property. In the summer months the vegetable garden needs more water but there isn't enough pressure to deliver an adequate supply. Even if the homeowner increases the size of the hoses or adds more sprinklers, the pressure is divided among them and the flow at each sprinkler reduces to a trickle. To solve the problem the homeowner must either increase the pressure at the main, or develop another water source (such as a well) near the garden.

For the Eastside the highest load densities are north of I-90 and west of Lake Sammamish. In electrical systems, voltage is the pressure. As with the hoses and sprinklers, the physical limitations of the transformers and conductors dictate that the transformation sites closest to the load center will have best performance. Bringing a higher voltage source into the area and making the transformation to a lower voltage closer to the load increases the pressure at the source (comparable to the analogy of bringing a larger water main with plenty of pressure) and adequate power can flow to all parts of the area. The other solution is to produce a new source of power close to the load center. This would be some type of electrical generation (similar to adding a new well in the garden hose analogy). Other solutions would be less effective.

Energy conservation, technological advancements, and system operational improvements can and will slow the need for these infrastructure improvements. In its planning for Energize Eastside, PSE has assumed that a relatively high level of voluntary energy efficiency measures will be adopted within the Eastside over the coming decade, approximately 110 MW by 2024. The analysis PSE provided shows that even with these measures, the economic and population growth expected by planning agencies and businesses on the Eastside equates to the need for either more energy infrastructure, or at least 163 MW of additional conservation, over and above conservation already planned for the Eastside.

Energy conservation is one way of reducing load. But when increasing load has eclipsed increases in energy conservation and the electrical system is reaching capacity, the only other method is to open transmission lines. That is the purpose of CAPs: to reduce load, and therefore heating, by opening transmission lines. CAPs are temporary measures to help the system supply load. However, CAPs do not solve the long-term capacity issue, and when implemented they leave the system vulnerable to increased outages.

To understand this, the garden example can again be used. The homeowner has two sources of water to the garden, one from a faucet on the north side and one from the south much as Sammamish and Talbot Hill substations feed the Eastside load. It is a particularly hot mid-summer day, and the garden needs extra water. The homeowner connects more hoses to each faucet but realizes that even with the additional hoses and the faucets wide open, there is not enough water pressure to effectively water the garden. The only option is to disconnect a hose or two so that the others will have enough pressure to operate the sprinklers. Only now some of the garden is going without water (similar to load shedding in an electrical system). Also, depending on what is disconnected, large portions of the garden would be vulnerable to losing their water supply if the remaining hoses were damaged. In a garden, it may be possible to keep plants alive by rotating areas where the water is turned off, but in an electrical system, instead of plants it is people who will not have the electricity they need for a period of the day.

This is a simple analogy, but the situation with the Eastside power system is similar, except that instead of sprinklers that won't operate, an overloaded electrical system overheats. During peak load periods, operators use CAPs to turn off (referred to as opening) lines from either Sammamish or Talbot Hill substation to reduce heating on certain system transformers and lines so that they will not be destroyed. They may be able to keep the Eastside area supplied with electricity, but in doing so large areas of the Eastside may only be fed from one source. If something happens to that source, such as a tree falling into a line, or a car accidentally taking out a pole, or a piece of equipment fails due to fatigue, at that moment the last viable connection to a power source is gone and the lights go out. Even worse, as load continues to grow, or the area hits the coldest winter or hottest summer on record, the operator will be left with a decision: who will have power and who will not. Until the peak period is over, in order to reduce overloads to an acceptable level, large portions of the Eastside area could be left without power. A further possible consequence would be that hospitals, nursing homes, fire departments, police stations and other critical support services must run on emergency power or are without power. In this situation the event has become not just an inconvenience but a hazard.

There are a lot of questions surrounding the probability of these events occurring on the Eastside. Most people are likely unaware of how many times an outage is imminent or narrowly avoided. Attempting to specifically predict these events is nearly impossible because of the number of potential scenarios and permutations. Is it an extreme peak? Are 100% conservation levels being met? Is there a system component out for repair? Has an accident removed a piece of equipment from service? Has a natural or man-made disaster occurred that no one thought would ever happen? Was the forecast wrong and loads grew faster than expected? The permutations are endless.

Regional electrical reliability is important to local communities. Without a reliable regional backbone, energy generated by a wide variety of sources could not be efficiently delivered to the population areas that need it. All the utilities in the Northwest bear some responsibility to keep the transmission system in working order. However, a local utility's main role is its customers and each has a legal duty to provide electricity to customers in its service area.

The local utility has two roles to play. On the community level, it needs to provide an adequate infrastructure of facilities and equipment that can reliably deliver energy to its local customers. As a regional player, the utility provides its customers access to the larger interconnected system while making sure its system is as reliable as its regional neighbors' systems and not a detriment to the whole.

The Energize Eastside project is designed to bring the needed infrastructure to supply the local need. Any regional benefits that it provides would be added benefits of a stronger regional source, but these are not the primary reasons why the project has been proposed. The transmission capacity deficiency is driven primarily by local rather than regional growth. If the entire region surrounding the Eastside was eliminated or disconnected from Sammamish and Talbot Hill substations, and replaced with an independent 230 kV source of power at both ends, the result would be the same. The Eastside 230 -115 kV system as it exists cannot supply the projected load under all circumstances, with the required levels of reliability that the community and neighboring utilities expect.

**STANTEC CONSULTING SERVICES INC.****STANTEC CONSULTING SERVICES INC.**

**Reference: Energize Eastside Project**

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# Eastside System Energy Storage Alternatives Screening Study

STRATEGEN
STRATEGIES FOR CLEAN ENERGY

**Prepared for:**

PSE PUGET SOUND ENERGY

MARCH, 2015

# Eastside System Energy Storage Alternatives Screening Study

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Puget Sound Energy

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Electric Power Research Institute (EPRI)

Strategen Consulting, LLC developed this report based on information received from Puget Sound Energy, who is solely responsible for this application of Energy Valuation Tool (ESVT) Version 4, with all reliance thereon to be at evaluator's sole risk without any endorsement by the Electric Power Research Institute, Inc.

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# 2 Executive Summary

## 2.1 Background

Puget Sound Energy (PSE) is evaluating several possible solutions to meet reliability needs identified in PSE's Eastside transmission system located in Central King County (the Eastside) as part of PSE's annual comprehensive reliability assessment.

PSE commissioned Strategen Consulting, LLC (Strategen) to assess one of those prospective solutions: the feasibility of using energy storage – combined with other previously identified cost-effective non-wires alternatives – to meet the reliability need.

This assessment includes the following:

1) An overview of the current state of energy storage;

2) An assessment of the feasibility of energy storage paired with previously identified non-wires options to meet the Eastside's reliability need through 2021 in a manner comparable to that of a transmission solution;

3) A screening-level assessment to determine whether an energy storage system, when paired with other non-wires solutions, would be able to come online by 2017-2018 to meet the identified winter peak reduction system need and PSE planning guidelines;

4) A detailed evaluation of cost-effectiveness of whether an Eastside energy storage configuration would be cost effective as a grid resource within PSE's system.

### 2.1.1 *Description of the Identified Eastside System Reliability Need*

PSE's 2013 Integrated Resource Plan demonstrated that PSE service territory is experiencing sustained economic growth resulting in increased electricity demand. Existing infrastructure on the eastside of King County is already strained and requires the use of corrective action plans (CAPs) to mitigate thermal violations.


Figure 1. Eastside System

In 2013 PSE commissioned the Eastside Needs Assessment Report (the "Eastside Assessment)[1] to better understand and quantify the issue. The report identified a deficiency in transmission capacity that will cause North American Electric Reliability Corporation (NERC) criteria violations and overloads in certain contingencies leading to loss of customer load at the 230 kV supply injections between Talbot Hill and Sammamish Substations.

The Eastside Assessment found that overloading of the Talbot Hill Substation 230-115 kV transformers and 115 kV transmission lines, primarily experienced during winter, will worsen as demand increases. Sammamish Substation summer overload issues will increase as well, with significant overloading projected in summer 2018. Beyond the 2017-2018 timeframe, overloads and NERC reliability violations are projected to occur and worsen at both substations even if 100% of conservation targets identified in PSE's Integrated Resource Plan (IRP) are met. The use of CAPs will have to increase as well to continue being effective, putting even more PSE customers at risk for outages.

Importantly, if not all conservation targets (identified during the IRP process) are met and/or during extreme weather events, overloads may occur before the 2017-2018 timeframe, and could be more significant in the latter years of the planning period than indicated by the IRP base case forecast.

Further detail about the Eastside situation is found in Appendix B: Description of the Eastside System Reliability Need.

### 2.1.2 *Summary of Proposed Transmission Solution*

Following the Eastside Assessment findings, PSE commissioned the Eastside Transmission Solutions Study[2] to rigorously evaluate potential solutions to the identified transmission needs. To be viable, a possible solution must solve the transmission issues identified in the Eastside Assessment, comply with environmental requirements, and satisfy constructability and longevity requirements. A variety of solution types were considered: distributed generation, transformer addition with minimal system reinforcements, demand side reduction, and transmission lines plus transformers.

Various solutions were evaluated based on their effectiveness at resolving the capacity deficiency, operational flexibility, potential to eliminate reliance on CAPs, and effects on adjacent grid infrastructure. After screening for feasibility and performing power flow analysis on each solution type, the addition of new transformers combined with new/upgraded transmission lines emerged as the most viable solution.

Further description of the identified transmission solution is found in Appendix C: Proposed Eastside Solutions.

[1] Quanta (2013)
[2] Quanta (2014)

### 2.1.3 *Non-Wires Alternatives Assessment*

To supplement PSE's work on transmission options, Energy + Environmental Economics (E3) was retained by PSE to conduct a screening analysis of "non-wires" solutions (hereafter referred to as the "Non-wires Report").[3]

The Non-wires Report evaluated the feasibility and cost-effectiveness of demand side reduction ("DSR"), including energy efficiency, demand response, and distributed generation, to defer PSE's identified need date for the Eastside transmission upgrades by maintaining peak load levels below amounts that would produce potential overloads under contingencies greater than those shown in 2017-18 in the Eastside Assessment and create the need for the upgrades.

PSE transmission planners determined that a *minimum* of 70 MW of incremental load reduction would be required for a four year deferral (2017-2021) while maintaining system reliability at 2017-2018 levels[4], assuming normal weather conditions and 100% of PSE's IRP-identified conservation measures were also successful. As much as 160 MW of incremental load reduction would be required under a higher load growth / 75% conservation scenario.

The Non-wires Report found that only 56 MW of potential non-wires alternatives in the Eastside would be cost-effective (in addition to the conservation measures identified by PSE in the IRP), and concluded that DSR alone is insufficient to address the local transmission capacity deficiency.

Additional details from the Non-wires Report are found in Appendix C: Proposed Eastside Solutions.

Because the overload reduction provided by the combined cost-effective non-wires alternatives identified in PSE's IRP and the Non-wires Report do not sufficiently meet the deferral requirement, PSE commissioned Strategen to evaluate the feasibility of energy storage to accommodate the gap between the capacity provided by the non-wires alternatives and the expected overloading.

## 2.2 **Evaluation Summary and Results**

### 2.2.1 *System Sizing*

PSE provided Strategen with its planning and operating requirements used to determine the power and energy rating and physical configuration of an energy storage system that both a) meets the Eastside system's reliability needs in a manner comparable to that of a transmission solution and b) is technically viable and can be built and sited when and where needed. These requirements are as follows:

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[3] E3 (2014)

[4] True capacity deficits could be larger if any of the following occurred: Extreme cold weather conditions (models and forecasts are based on 23° F average), faster load growth than expected (based on prevailing economic conditions), or IRP conservation targets were implemented slower than expected.

1. The system must mitigate all Eastside line and transformer overloads to below 100% of their emergency limits in the 2021-2022 winter case and in the 2018 summer case for all required contingencies;

2. The system must reduce the duration of all line and transformer overloads in excess of 100% of their normal operating limits to no more than 8 consecutive hours; and

3. The system must be able to come online by in time to address the winter 2017-2018 peak.

PSE annual hourly data was used to determine the maximum emergency power flows on the Talbot Hill and Sammamish substations during Category C NERC contingencies (N-1-1). Using the normal and emergency line ratings for those substations, Strategen determined that in all years, Talbot Hill was the substation with the most significant normal and emergency overloads, thus Talbot Hill was the element that determined the overall need.

Strategen evaluated the power and energy requirements for an energy storage system to accomplish the above objectives.

The maximum Eastside mitigation needs required in 2021 to prevent the overloads from occurring are summarized in Table 1 and represented graphically in Figure 6 and Figure 11 on pages 70 and 79.

**Table 1. Eastside Mitigation Needs**

| Scenario | 2021 Deferral | |
|---|---|---|
| | Power (MWp) | Energy (MWh) |
| Baseline<br>Normal Overload Reduction | 76.8 | 491.0 |
| Alternate #1<br>Emergency Overload Elimination | 34.1 | 82.3 |
| Alternate #2<br>Normal Overload Elimination | 120.1 | 1,253.6 |

An energy storage configuration would have to fully address the *Normal Overload Reduction* requirement shown above in order to meet PSE's planning and operating requirements. Note that the third criterion, *Normal Overload Elimination*, was evaluated as a potential longer term solution for the Eastside, beyond the 2021 timeframe. A system sized to meet this criterion would have *eliminated* all line and transformer overloads in excess of 100% of their normal operating limits.

After accounting for an approximately 21% effectiveness factor,[5] updated NERC and PSE planning standards,[6] and assumed procurement of previously-identified, cost-effective non-wires alternatives, Strategen calculated net injection requirements for the baseline energy storage system ("ESS") meeting the first two criteria, which is summarized in Table 2.

*Effectiveness Factor*

The amount of power required is significantly more than just the localized load exceeding the Eastside transmission equipment's rating.

That is due to many factors, such as: 1) the number of transformers serving the area, (2) system impedance, and 3) use of the Eastside facilities for energy transfer not related to local demand.

As a result, to address one MW of actual excess localized demand, almost five MW of storage power is required; hence the important concept of effectiveness factor. For details see Chapter 6.1.

[5] See Chapter 6.1 for further description of the effectiveness factor
[6] See Chapter 6.2 for further description of updated planning standards

**Table 2. Baseline Energy Storage System Net Injection Requirements**

| | 2021 Deferral[7] | | |
|---|---|---|---|
| | Power (MWp) | Energy (MWh) | Duration (hours) |
| Normal Overload Reduction | 328.0 | 2,338.0 | 7.1 |

Strategen notes that the key factor driving higher net injection requirements than the Non-wires Report was the additional requirement that the ESS also eliminate the need to use Corrective Action Plans, improving reliability to more comprehensively comply with PSE planning standards through 2021.

Two alternate energy storage system configurations were also evaluated and are summarized in Table 3. The first configuration, *Emergency Overload Elimination*, would *only* meet the first criteria established by PSE, elimination of the emergency overload. This configuration is not a comparable solution to new transmission/transformer infrastructure, and would not restore reliability to the levels required by PSE's planning and operating standards. The second configuration, *Normal Overload Elimination*, would present a longer term solution than a 2021 transmission line deferral because it would completely eliminate the 2021 normal overload.

[7] Accounts for a 2% per year cell degradation rate

**Table 3. Energy Storage Alternate Configurations Net injection Requirements**

| Scenario | 2021 Deferral[8] | | |
|---|---|---|---|
| | Power (MWp) | Energy (MWh) | Duration (hours) |
| Alternate #1<br>Emergency Overload Elimination | 121.0 | 225.6 | 1.9 |
| Alternate #2<br>Normal Overload Elimination | 544.4 | 5,770.9 | 10.6 |

### 2.2.2 *Technological Readiness and Suitability*

Although the scale of bulk storage technologies (i.e. pumped hydro and compressed air) is frequently characterized by large power and energy ratings, siting limitations in the Eastside area caused Strategen and PSE to omit bulk storage options from this analysis (See Chapter 5.4 for a more detailed explanation). Chemical (battery) storage was determined to be the most appropriate and commercially-viable technology for this location and application.

Chemical storage technology is rapidly advancing (See Chapter 5.1.1), but the only system of comparable size to what PSE requires is a 100 MW/400 MWh lithium-ion ESS recently procured by Southern California Edison ("SCE"), which is not expected to be operational until 2021. The largest currently deployed and commissioned chemical storage project (by power rating) in the United States is SCE's Tehachapi Wind Energy Storage ESS, an 8 MW/32 MWh lithium ion battery.

Confidential interviews with various vendors indicate that the technology and capability exists for batteries to be deployed for this application at this magnitude. However, since no similarly-sized system has ever actually been built or commissioned, it is difficult to estimate the time necessary for development, procurement, construction and deployment. Procurement of battery cells in particular may result in long lead times, especially for the two larger systems contemplated would constitute a significant portion of the global market for batteries.[9]

### 2.2.3 *Siting Feasibility, Permitting, and Interconnection*

After an ESS is deemed technically feasible, to be considered an appropriate solution, it must also be permitted and sited somewhere that is acceptable to the local community. The Eastside is a dense urban area and an ESS of this scale would be very large, so this analysis focuses specifically on a substation-sited solution that minimizes both cost and potential negative community impacts.

[8] Accounts for a 2% per year cell degradation rate

[9] Tesla's "Gigafactory", for instance, is expected to produce 35 GWh/yr of lithium ion cells by 2020, approximately equal to the total estimated global lithium ion production in 2013. Assuming 2016/2017 capacity is roughly double the 2013 global capacity estimate, the largest system contemplated would require cells equal to roughly 8% of annual global production.

PSE supplied estimated acreages for ESS interconnection facilities and parking, and satellite imagery and vendor interviews provided size estimates for the enclosures to house ESS batteries and power conversion systems. ESS sizing estimates for each scenario are as follows: 5.8 acres to eliminate emergency overload, 19.6 acres to reduce normal overload, and 45.7 acres to eliminate normal overload. For frame of reference, a football field including end zones covers approximately 1.32 acres.

Acquisition of large plots of land within already developed urban areas presents economic and social challenges. Since the ESS would be sited adjacent to an existing substation, potential locations for land acquisition are severely constrained. After reviewing footprint and siting requirements,[10] PSE determined that several substation configurations would be equally effective, so Strategen assumed for the purposes of sizing the system that all storage would be located at Lakeside substation. Slightly more land would be required if the system were to be broken up between multiple substations.

The interconnection study process takes approximately 1-2 years, at which point an interconnection agreement is signed and work can begin on any necessary upgrades, which often take 6+ months to complete. The lengthy interconnection study process likely presents a barrier for an ESS beginning development in early 2015 to meet a winter 2017/2018 online date, as generally speaking, equipment procurement does not commence until a signed interconnection agreement is achieved.

Permitting also generally involves a long lead time. When evaluating locations to site a larger scale battery facility, it was assumed that the site would be within the City of Bellevue. Since large scale battery facilities are an emerging technology, they are not addressed in the City's land use regulations.  It was therefore assumed that a battery facility would be categorized as something similar to a transmission switching or substation.  According to the City of Bellevue, as of March 2015, Administrative CUPs averaged around 25 weeks, with Major Clear and Grade permits averaging around 65 weeks.  If Design Review is triggered, those approvals averaged 90 weeks.  Permits for Major Commercial Projects average around 59 weeks.  PSE estimated that it would take at least two years to permit, and up to three to four years if the project triggered a comprehensive review process.

PSE indicated that it does not take the risk of contracting for major equipment before permits are in hand. PSE expects that, once permitting is complete and interconnection agreements are in hand, the project would require one-and-a-half years for major equipment lead-time, and a half-year for construction. Private developers, on the other hand, are often willing to take that risk and can accelerate the development timeframe by about one year, according to PSE.

Based on the timelines provided by PSE for permitting, interconnection, procurement and construction, we conclude that it would take approximately four years for PSE to permit, interconnect, procure equipment and build an energy storage system. Assuming the process began in 2015, it would be complete in 2019, which would not meet PSE's objective for the project to come online in time to meet the winter 2017-2018 reliability need.

[10] PSE transmission planners reviewed siting either spread evenly between Sammamish, Talbot Hill, and Lakeside substations, spread with half at Lakeside and ¼ each at Sammamish and Talbot Hill, or all at Lakeside. The 3 alternatives were found to be about equally effective.

See Chapter 6.4 through 6.7 for a more detailed explanation of siting feasibility, permitting and interconnection.

### 2.2.4 *Technical Feasibility*

The critical technical challenge identified for an energy storage system configured to meet the Eastside system need is the existing transmission system's available capacity to support charging of the storage system.

Strategen determined that the existing Eastside transmission system does not have sufficient capacity to charge an energy storage system configured to reduce normal overloads to a level sufficient to meet the system requirements provided by PSE (the Baseline Configuration). Specifically, 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.

See Chapter 6.3.1 and 6.3.2 for detailed analysis on the transmission system's ability to support charging of various energy storage configurations.

### 2.2.5 *Cost-Effectiveness*

In addition to looking at the commercial readiness and technical feasibility of energy storage as a transmission deferral resource for the Eastside need, Strategen evaluated the cost effectiveness of a non-wires deferral solution that included energy storage.

Chapter 7.2 addresses the full range of benefits considered and evaluated for the cost effectiveness assessment. The most significant sources of value identified for the storage resource include: system capacity and system flexibility (which includes a broad category of functions including energy time shifting, and provision of ancillary services).

Importantly for the evaluation of the financial merits of adding *energy storage* to the overall non-wires deferral solution, the entire deferral benefit is assumed to accrue to the previously identified portfolio of cost-effective non-storage alternatives identified. That is, the total cost for the cost-effective alternatives identified was commensurate with the deferral benefit. It is also important to note that the non-storage alternatives' value for deferring the transmission solution was established based on an expectation that they would fully meet the deferral need. However, the amount of non-storage alternatives is not "effective" enough to actually allow for the deferral without the addition of energy storage. Therefore, *additional* energy storage as part of the non-wires solution was necessary to meet the deferral requirements, but was not assigned additional *value* specific to the deferral, because such benefits would have resulted in a double-counting of the value of deferral.

Therefore, benefits associated with storage that were quantified for the evaluation are not specifically related to the deferral. Rather, benefits associated with storage are for what are often referred to as "system" benefits that are related to the PSE electric supply and transmission system as a whole. While not directly related to the deferral, these benefit types are addressed quantitatively in the study and provide the sources of additional value to PSE's customers that drive the cost effectiveness results.

As Strategen determined that the baseline energy storage / non-wires solution sized to satisfy PSE's planning and operating requirements would not be technically feasible, Strategen conducted a cost effectiveness assessment on an alternate configuration, a smaller system configured to meet PSE's emergency overload planning requirements only through 2021. This configuration does seem to be cost effective to address PSE's broader system capacity and flexibility needs, with a benefit-cost ratio of approximately 1.13. Strategen did not evaluate the relative cost effectiveness of energy storage versus other types of system resources, as this would require a more robust analysis that is best suited for PSE's Integrated Resource Planning process.

## 2.3 Key Conclusions

Based upon the results of the study, Strategen provides the following conclusions for PSE's consideration.

- The existing Eastside transmission system does not have sufficient capacity to charge the Baseline Configuration to a level sufficient to meet PSE's operating standards. Specifically, 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.
- An energy storage system with power and energy storage ratings comparable to the Baseline Configuration (large enough to reduce normal overloads) has not yet been installed anywhere in the world. Projects comparable to the more modest Alternate Configuration #1 have been contracted by other utilities.

  Based on the interconnection, permitting, procurement and construction timelines provided by PSE, project development for any configuration would take approximately four years, resulting in a mid-2019 online date. Private developers able to take on more project risk might be able to accelerate this cycle by approximately one year. However, neither approach appears capable of meeting PSE's target online date of 2017-2018.
- Strategen estimates that the Baseline Configuration to defer the Eastside transmission system upgrade through 2021 would cost ratepayers approximately $1.44 billion (in NPV terms, based on PSE's revenue requirement). Alternate Configuration #1 would cost ratepayers approximately $264 million (in NPV terms, based on PSE's revenue requirement). See Table 4 below for capital cost estimates.
- Cost-effectiveness was only evaluated for Alternate Configuration #1 because the Baseline Configuration is not technically feasible. Value was derived primarily from the system capacity, flexibility and oversupply reduction benefits for PSE's customers. GHG reduction is another benefit of energy storage, but is currently non-monetizable. Alternate Configuration #1 does not meet the reliability requirements identified by PSE, but does appear to be cost effective, with a benefit-cost ratio of approximately 1.13.
- The following Table summarizes the configurations studied:

**Table 4. Energy Storage Configuration Summary**

| Configuration | Power (MWp) | Energy (MWh) | Duration (hours) | Est. Cost ($MM) | Includes Non-Wires Alternatives[11] | Technically Feasible | Meets Requirements |
|---|---|---|---|---|---|---|---|
| Baseline Normal Overload Reduction | 328 | 2,338 | 7.1 | **$1,030** | ✓ | × | ✓ |
| Alternate #1 Emergency Overload Elimination* | 121 | 226 | 1.9 | **$184** | ✓ | ✓ | × |
| Alternate #2 Normal Overload Elimination | 545 | 5,771 | 10.6 | **$2,367** | ✓ | × | ✓ |

## 2.4 Scope Limitations

- Strategen relied on inputs from PSE provided between September 2014 and February 2015 to develop the contents of this report. Many assumptions were made as to the system costs, benefits, feasibility, and timeline that would need to be studied in a more detailed manner prior to any final determination of project feasibility. Subsequent developments, such as PSE's recent decision to join the California ISO's Energy Imbalance Market, were not studied as part of this analysis.
- The benefit analysis presumes that PSE would own and operate the energy storage assets. This scope does not assess the viability of alternative financial offerings and ownership models.
- The scope of Strategen's evaluation does not include consideration of any regulatory challenges PSE might face in adding distributed energy storage deployed as a transmission reliability asset to PSE's rate base.
- The cost effectiveness modeling evaluates the absolute cost effectiveness of energy storage in terms of system benefits versus revenue requirements. It does not evaluate the relative cost effectiveness of energy storage versus other system resources.

[11] E3 (2014)

# 3 Introduction and Background

Puget Sound Energy ("PSE") is developing a solution to meet reliability needs identified in PSE's Eastside transmission system located in Central King County (the "Eastside") as part of PSE's annual comprehensive reliability assessment. The goal of the solution is to avoid the risk of NERC reliability criteria violations or losses of customer load in the area.

PSE identified a number of transmission options to reinforce the Eastside system, and recently retained Energy + Environmental Economics ("E3") to conduct a non-wires alternatives screening analysis to supplement PSE's work on transmission options. This report was published in February 2014 (the "Non-wires Report"), but did not evaluate the feasibility of energy storage to cost-effectively meet a similar transmission deferral target.

PSE believes that such supplemental analysis is warranted, and hired Strategen to answer several key questions:

1) What is the current state of technology for energy storage?

    a. What energy storage technologies are currently commercially ready to provide grid services and meet utility standards to reliably meet system needs?

    b. What is the estimated cost of an energy storage solution designed to meet the Eastside's needs?

2) What are the applications for grid- connected energy storage systems? What services can energy storage provide for the bulk power system? Services of particular interest to PSE include power system stability and renewable resource integration.

3) What is the potential for energy storage systems to defer the need for new transmission in PSE's Eastside grid, either on a standalone basis, or combined with other non-wires alternatives?

4) If energy storage theoretically can meet the need to defer transmission upgrades to the Eastside grid, can it do so cost effectively (assuming all system benefits of energy storage are accounted for)?

## 3.1 Summary of Analysis Methodology

Strategen approached this analysis by drawing upon recent and historic publicly available research, methodologies, and cost projections, and applying that information to PSE's unique system and transmission planning requirements. The results of the analysis - particularly with respect to Sections 6 (Energy Storage Configurations and Feasibility) and 7 (Cost-Effectiveness Evaluation) - were developed based on inputs received from PSE. The results of these analyses are premised on the accuracy of the inputs provided by PSE.

### 3.1.1 *Overview of Analysis Objective*

The goal of this analysis is to provide information for PSE to help it determine whether energy storage is a commercially ready, technically feasible, and cost-effective as a solution to defer the need for new transmission in PSE's Eastside region. Strategen worked closely with the PSE team to determine a scope of work and objective for the assessment that were consistent with the need identified and assumptions used in PSE's transmission planning process.

### 3.1.2 *Literature Review*

A preliminary step in the analysis was to review relevant literature to determine the commercial viability of energy storage for the primary use case needed in PSE's Eastside system.

The list of literature reviewed is provided in Chapter 9.

### 3.1.3 *Overview of Energy Storage Technologies*

Based on the literature review, Strategen prepared an overview of energy storage technologies. The goal of the overview is to provide insight into which technologies are technically and commercially feasible for the primary use case. Strategen also contacted third parties to determine a more accurate and use-case relevant set of cost data for the selected configurations.

### 3.1.4 *Data Collection*

PSE provided a variety of data for the analysis. Specifically, this data included:

- Full hourly substation and line load duration data for Talbot Hill and Sammamish substations in the year 2012.
- Line rating and loading information at multiple substation locations
- Locational effectiveness factors for centralized energy storage systems at multiple substations and for distributed (customer-sited) energy storage.
- Flexibility values, capacity values, overgeneration reduction values, and energy cost forecasts for the relevant years customized to the system configured to mitigate emergency overloads, as well as values for systems with smaller power ratings (2 MW and 20 MW) to test the sensitivity of system sizing to system benefits.
- The underlying costs and year-by-year incremental load reduction capability of other non-wires alternatives reported in the Non-wires Report.
- Information on PSE planning and operating standards.
- Interconnection cost, land value, and permitting cost assumptions for the three studied energy storage configurations.
- Footprint assumptions for interconnection equipment associated with the three studied storage configurations.

- Assumptions needed to calculate PSE's revenue requirements for a utility-owned energy storage system.

### 3.1.5 *Need Identification*

In order to inform the required need for energy storage as a transmission deferral alternative, Strategen started by assuming that all cost-effective non-wires alternatives other than energy storage would be implemented according to the timeline identified in the Non-wires Report. Other non-wires alternatives include incremental energy efficiency, distributed generation, and demand response.

The remaining need was identified by running hourly power flow assessments assuming:

1. PSE is meeting 100% of its conservation and efficiency goals described in its Integrated Resource Plan;

2. Normal (1 in 2) weather conditions would set the demand forecasts

Four sets of hourly overload data were then generated based on the power flow assessment:

- Talbot Hill overloads in excess of the emergency equipment ratings

- Talbot Hill overloads in excess of the normal equipment ratings

- Sammamish overloads in excess of the emergency equipment ratings

- Sammamish overloads in excess of the normal equipment ratings

In order to completely resolve the need, the energy storage device would need to (a) eliminate the need for CAPs, improving Eastside system reliability to meet PSE planning standards, (b) eliminate all overloads in excess of the substation equipment's emergency ratings, and (c) reduce the duration of any overloads exceeding the substation equipment's normal ratings to less than or equal to 8 hours. All incrementally cost-effective non-wires alternatives identified in the prior Non-wires Report would be assumed to be implemented and contributing to PSE's necessary load reductions to help address the system need, prior to identification of the amount of incremental energy storage needed to fully resolve the above overloads.

### 3.1.6 *Scenario Modeling*

Strategen then developed a baseline configuration for assessment along with two alternate configurations, in consultation with PSE, to evaluate the feasibility of addressing Eastside System reliability requirements:

- The baseline configuration – "Normal Overload Reduction" - was developed to reduce the duration of all line and transformer overloads in excess of 100% of their normal operating limits to no more than 8 consecutive hours, as well as to eliminate all overloads exceeding emergency limits in the 2021-2022 winter case and in the 2018 summer case for all FERC/NERC required contingencies;

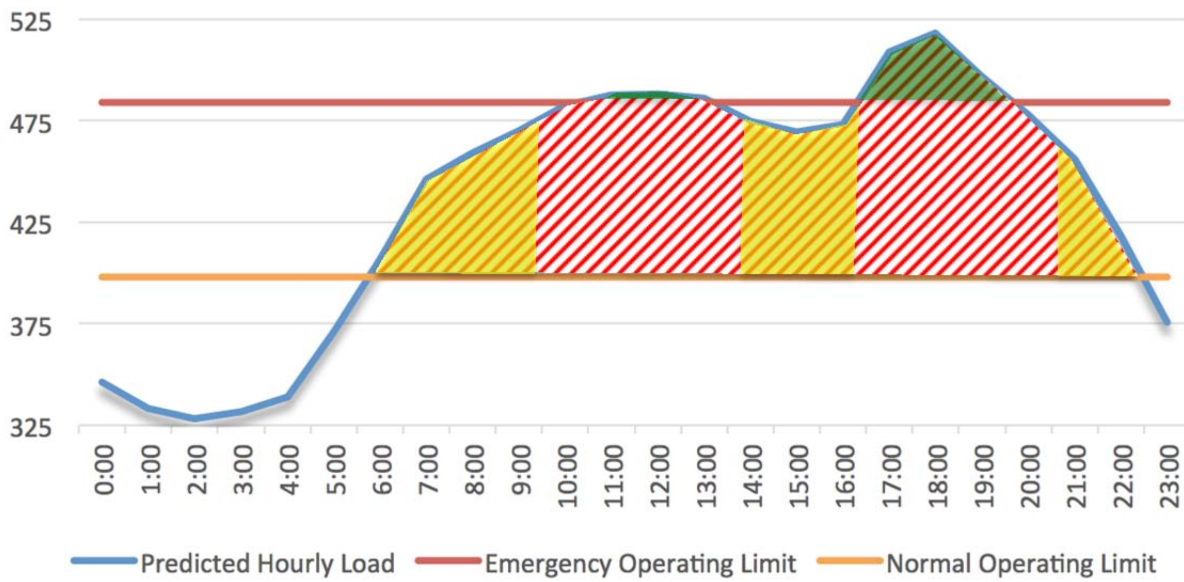
- The first alternate configuration – "Emergency Overload Elimination" - was developed to mitigate only line and transformer overloads to below 100% of their emergency limits in the 2021-2022 winter case and in the 2018 summer case for all FERC/NERC required contingencies;[12] and

- The second alternate configuration – "Normal Overload Elimination" - was developed to eliminate all line and transformer overloads in excess of 100% of their normal operating limits.

Figure 2 is a representative example of how the energy storage system would discharge under each scenario and affect a daily load profile.

[12] Configuration #1 would meet PSE planning requirements, but would not meet PSE operating requirements. This configuration was selected for the cost effectiveness modeling due to the determination that the other two configurations were not technically feasible.

**Figure 2. Graphical Representation of Eastside Overload Scenarios (in MW)***



***Shading represents ESS net injection requirements to meet overload scenarios: Green -** *Emergency Overload Elimination*; **Yellow -** *Normal Overload Reduction*; **and Red -** *Normal Overload Elimination*

After accounting for an approximately 21% effectiveness factor,[13] updated NERC and PSE planning standards,[14] cell degradation, and assumed procurement of previously-identified, cost-effective non-wires alternatives, Strategen calculated net injection requirements for the ESS configurations.

Strategen evaluated customer-sited storage as a potential alternate method to meet the configuration requirements. However, the effectiveness factor of a customer-sited solution was determined by PSE to be lower than that of a substation-sited solution. In addition, the high complexity of evaluating the feasibility of contracting, permitting, and deploying customer-sited units at the scale and timeframe necessary to categorically meet PSE's 2017-2018 transmission deficiency resulted in a focus of this analysis on a centralized, substation-sited solution. Chapter 6.4.1 reviews customer-sited energy storage issues in greater depth.

### 3.1.7 *Cost Effectiveness Evaluation*

In addition to looking at the commercial readiness and technical feasibility of energy storage as a transmission deferral resource for the Eastside need, Strategen developed a custom spreadsheet-based model to evaluate the cost effectiveness of the modeled configuration. Because the baseline *Normal Overload Reduction* configuration was determined not to be technically feasible, Strategen modeled the smaller, alternate *Emergency Overload Elimination* configuration.

Chapter 7.2 addresses the full range of benefits studied for the cost effectiveness assessment. As energy storage devices are able to perform multiple services for the system, benefits were generally "stacked" to the extent they did not conflict. However, during the deferral period of 2017-2021, Strategen assumed that the system would not be providing system flexibility services during January or August, due to the need for it to be reserved for use as a transmission reliability resource.

Strategen did not evaluate the relative cost effectiveness of energy storage versus other types of system resources, as this would require a more robust analysis that is best suited for PSE's Integrated Resource Planning ("IRP") process.

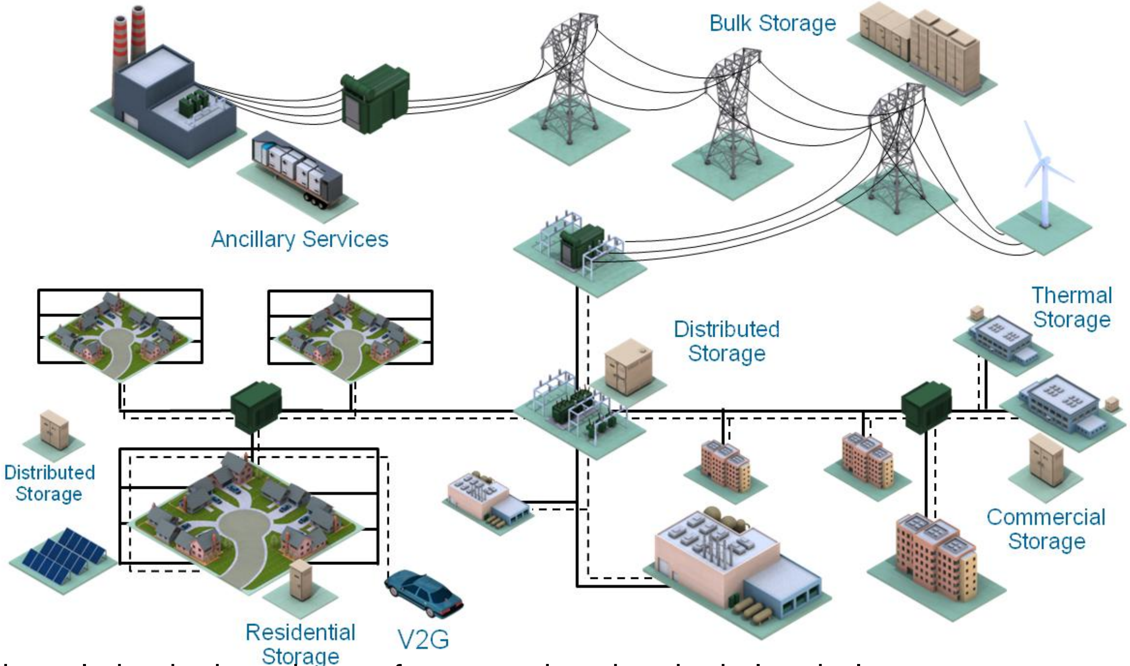
[13] See Chapter 6.1 for further description of the effectiveness factor
[14] See Chapter 6.2 for further description of PSE's planning and operating standards

# 4 Intro to Energy Storage, Grid Benefits & Use Cases

Energy storage is a uniquely flexible type of asset in terms of the diverse range of benefits it can provide, locations where it may be sited, and the large number of potential technologies which may be suited to provide value to the grid. Fundamentally, energy storage shifts energy from one time period to another time period. However, the value of energy stored by a resource varies highly based on its ability to control and dispatch that energy. Because the electric system operates on "just-in-time" delivery, generation and load must always be perfectly balanced to ensure high power quality and reliability to end customers. With large amounts of variable and uncertain wind and solar generation currently being deployed, guaranteeing this perfect balance is becoming an increasingly challenging issue. At very high penetrations of variable wind and solar generation, energy storage may be effective for absorbing excess energy at certain times and moving it to other times, enhancing reliability and providing economic benefits.

Figure 3 illustrates the many roles that energy storage can fill within the electric grid. Energy storage can provide large amounts of power and energy to the electric grid, as has been historically demonstrated by pumped hydropower facilities that can provide hundreds of megawatts or gigawatts of power for many hours. On the other end of the spectrum, off-grid battery systems have long been used to support electric service for small remote, residential buildings. The future may contain a spectrum of technologies, locations, and grid services, ranging from very large to very small energy storage systems capable of enhancing the reliability, economics, and environmental performance of the electric grid.

**Figure 3. Overview of Energy Storage Roles on the Electric Grid**[15]




In this analysis, the investigators focus on substation-sited electrical energy storage systems with a primary use case of transmission upgrade deferral (i.e. meeting identified transmission system reliability needs through a non-wires solution). Secondary use cases are also evaluated as inputs into the overall cost-effectiveness assessment, as further described below. Terminology and definitions for the grid services that energy storage could provide is not entirely uniform across the country, but the DOE/EPRI Energy Storage Handbook of 2013 provides the following list of energy storage grid services.

[15] Source: DOE-EPRI Energy Storage Handbook (2013)

Figure 4. Grid Services of Energy Storage

| Bulk Energy Services |
|---|
| Electric Energy Time-Shift (Arbitrage) |
| Electric Supply Capacity |
| **Ancillary Services** |
| Regulation |
| Spinning, Non-Spinning and Supplemental Reserves |
| Voltage Support |
| Black Start |
| Other Related Uses |

| Transmission Infrastructure Services |
|---|
| Transmission Upgrade Deferral |
| Transmission Congestion Relief |
| **Distribution Infrastructure Services** |
| Distribution Upgrade Deferral |
| Voltage Support |
| **Customer Energy Management Services** |
| Power Quality |
| Power Reliability |
| Retail Electric Energy Time-Shift |
| Demand Charge Management |

The following paragraphs will provide a summary of the grid services that energy storage resources may be capable of providing.

## 4.1 Bulk Energy Services

"**Bulk Energy Services**" refers to the potential of energy storage to avoid costs associated with generation of electricity.

*Electric Energy Time-Shift (Arbitrage)* refers to the ability of energy storage to store energy (charge) when the cost of electricity is low, and release energy (discharge) when the cost of electricity is high. For example, in the summer, electricity costs are typically low when demand is low at night and low marginal cost energy sources (such as hydro or wind energy) can supply a substantial portion of the load. Conversely, summer electricity costs are typically high in the late afternoon on hot days when the system's highest marginal cost resources (such as less efficient gas turbines) must be called upon to meet peak load conditions.

*Electric Supply Capacity (or System Capacity)* refers to a similar usage of energy storage as energy time-shift, but it refers to a different economic value. Where the arbitrage value comes from time-shifting the variable cost of electricity generation, the capacity value is an avoided fixed cost of generation. Historically, the decision to add new generation capacity (i.e. build power plants) has not been an economic one. Based on customer load growth forecasts, utilities create an integrated resource plan which determines where and when new generators are needed. This new capacity need is defined by the peak load conditions. If energy storage can reliably provide capacity during peak system load conditions, it has the potential to avoid the fixed costs of new power plants, which are typically passed through to utilities and, by extension, customers as a fixed monthly or annual payment.

## 4.2 Ancillary Services

**"Ancillary Services"** are defined as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."[16] In other words, these services are all services to the high voltage transmission system that support the reliable delivery of power and energy.

*Regulation (or Frequency Regulation)* is an ancillary service that ensures the balance of electricity supply and demand at all times, particularly over time frames from seconds to minutes. When supply exceeds demand the electric grid frequency increases; when demand exceeds supply, grid frequency decreases. Sensitive equipment in the United States relies on grid frequency of 60 Hertz (60 cycles / second), with very low tolerance. Because energy storage can both charge and discharge power, it has the potential to play a valuable role in managing grid frequency. Furthermore, many energy storage technologies have been demonstrated to be faster and more accurate than other grid alternatives at correcting these frequency deviations. FERC Order 755 has stipulated that independent system operators (ISOs)

[16] FERC (1995)

implement mechanisms to pay resources based upon their responsiveness to control signals. Under the new rules, energy storage resources with high speed ramping capabilities will receive greater regulation compensation than slower storage or conventional resources.

*Spinning Reserves, Non-spinning Reserves, and Supplemental Reserves* comprise another class of ancillary service referring to reserved excess generation capacity that is available to the electric system in the case of the worst contingency events. Spinning reserves are the fastest available reserve capacity, because the generators providing them are already "spinning", but not fully loaded. Therefore, spinning reserves can begin responding immediately to a contingency event. Non-spinning reserves typically have minutes to respond to a contingency, and supplemental reserves are intended to replace spinning and non-spinning reserves after an hour. Because many energy storage technologies can be synchronized to grid frequency through their power electronics, energy storage could provide a service equivalent to spinning reserve while idle. Furthermore, an energy storage system that is charging energy may be capable to provide a magnitude of spinning reserve equivalent to the sum of its charging and discharging power. In other words, a storage system rated at 1 megawatt capacity could provide 2 megawatts of spinning reserve, because it has the capability to move from a state of 1 megawatt charging to 1 megawatt discharging. Energy storage would be equally capable of providing non-spinning or supplemental reserves, but these services are typically lower value than spinning reserve because they are easier for traditional generators to accomplish and have lower opportunity cost.

*Voltage support* is an ancillary service that is used to maintain transmission voltage within an acceptable range. With alternating current (ac) power, voltage and current are transmitted as sinusoidal waves. Maximum power is transmitted when voltage and current waveforms are synchronized. Certain electric loads, particularly inductive motors, have a tendency to cause voltage to move out of sync with current by consuming reactive, or imaginary, power (aka "VARs). Due to advanced power electronics capabilities, energy storage has the capability to inject VARs and correct transmission voltages that are suboptimal or outside of acceptable bounds. Because a number of other devices are capable of providing voltage support at low cost, the value of this service for energy storage is typically considered to be low and has not received a deep level of attention.

*Black start* is a service typically provided by designated generators to restore the electric grid following a blackout. While this is conceptually a service that could be provided by energy storage, the exact specifications of a limited energy resource have not been well-defined. Black start is typically considered to be a low value, incremental source of value for energy storage.

## 4.3 Transmission Infrastructure Services

**"Transmission Infrastructure Services"** refer to the services, related to reliability and economics, to enable the electric transmission system to operate more optimally.

*Transmission investment deferral* is a service whereby a capital investment in the transmission is avoided for a period of time. For example, if power transmitted from point A to point B exceeds the power rating of a transmission transformer or power line, it may require an upgrade to a higher rated piece of equipment. However, this upgrade could be triggered by peak loads which occur relatively infrequently, perhaps only a few hours per day and a few days per year. In such cases, a sufficient quantity of energy storage may be capable to charge during low load periods and discharge during high loads periods on the load side of the overloaded piece(s) of transmission equipment and therefore to offset power flows and reduce loading experienced on that equipment. By doing so, energy storage has the ability to defer an upgrade investment for a period of time, creating economic value equal to the *time value of money* for the size of the planned transmission upgrade investment for the deferral period.

*Transmission congestion relief* is a similar service to transmission investment deferral. However, the economic value associated with congestion relief does not necessarily tie directly to a planned transmission upgrade. In some regions, the wholesale price of energy is defined at different geographic locations, where the congestion associated with high loads results in a higher hourly energy price. This geographically-specific energy price is called a *locational marginal price (LMP)*. In practice, energy storage would behave very similarly to how it would perform energy time-shift (arbitrage) or transmission investment deferral (i.e. charging during low load periods and discharging during high load periods), but it would optimize its charge/discharge behavior based on an hourly price signal that is jointly defined by the wholesale market price of energy and the amount of location-specific congestion specific to its geographic location in the electric system.

## 4.4 Distribution Infrastructure Services

**"Distribution Infrastructure Services"** refer to services which support the physical infrastructure of the low voltage distribution system from the substation to the customer meter. These services support delivery of electric power with high reliability and lowest cost to the electric utility customer. The costs of the electric distribution system are typically regulated by a public utility commission (PUC) or similar entity which approves electric utility spending plans and offers them a regulated return on investment for managing the reliability of the system.

*Distribution investment deferral* is a service similar to the aforementioned transmission investment deferral, but specific to the low voltage distribution system. To relieve overloaded distribution lines or transformers, particularly high cost substation transformers, energy storage can charge during low load period and "peak shave" the highest load periods to avoid a high cost upgrade investment for a period of time. Once again, the economic value associated with an upgrade deferral would be the time value of money for the cost of the upgrade for the achieved timeframe of deferral. The storage may only be required to perform for a relatively small number of days and hours associated with local maximum load events, which are overloading the asset in question.

*Distribution voltage support* refers to a service which maintains the power voltage within acceptable bounds, defined by ANSI standards (typically +/- 5% of nominal). For sensitive consumer appliances and electronics, it is important that voltage is supplied within these limits. Typically, the service voltage drops as power moves to the end of the line as customer computer and motor loads are consuming VARs (explained in the "voltage support" service description above). As a result, utilities typically install capacitor banks or voltage regulators, which boost voltage at the end of the line. However, voltage support is becoming more complicated in certain load pockets due to the increase in installed distributed solar photovoltaic (PV) systems. In areas with high distributed generation penetration rates, these systems can reverse power flow altogether at certain times, and create significant variability in local operational requirements.[17] Energy storage, with power electronics capable of injecting and absorbing both real and reactive power at different rates, conceptually provides a balance for rooftop PV installations. However, the state of research is still nascent in this area, so it is unclear how much value this service has and what the technical requirements are for energy storage to provide this service effectively.

## 4.5 Customer Energy Management Services

**"Customer Energy Management Services"** refer to the services that benefit an electric utility customer that result in lower utility bills or higher quality of electric service.

*Power Quality* describes a comprehensive service delivered to electric utility customers. Some elements of power quality include consistent service voltage, low harmonics, and no disruptions in service. Some customers have very high requirements for power quality, due to sensitive equipment or electronics. A well-known example is data centers. Data centers regularly use energy storage in the form of an uninterruptible power supply (UPS), which converts grid electricity from ac-to-dc-to-ac and provide acceptably high power quality for the equipment. The value of this service is highly variable, depending on the consequences and alternatives available to the customer for solving specific power quality issues. However, the ubiquity of UPS systems in data centers and critical loads is evidence of the importance of power quality for certain customers.

*Reliability* refers to the "uptime" of the electric grid, which is the measure of time that the grid is in operation. Outages can be caused by a number of different factors, including weather events and other unexpected contingencies, as well as unanticipated equipment failures. Because energy storage provides an inventory for electric energy, it may be able to help grid operators avoid some outages, or otherwise provide customers with backup power to ride through outages when they happen. Depending on the type of customer, their economic losses associated with outages, and the utility reliability characteristics at the customer location, economic value may be provided by an energy storage system to provide backup power. An energy storage system would need to have the appropriate capability to "island" its operation and serve the entire customer load, or a specified portion of the customer load.

*Retail energy time-shift* refers to charging an energy storage device during periods when the retail price of electricity is low and discharging that energy when the retail price of electricity is high. This situation is present when customers have a utility tariff with time-of-use (TOU) metering. This type of tariff is enabled by the deployment of automated metering infrastructure (AMI). The existence of TOU tariffs has existed for a long time in the commercial and industrial electricity sector, but its emergence in the residential sector is relatively new. Residential customers often opt-in for these tariffs when they purchase rooftop solar PV or electric vehicles to increase bill savings.

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[17] For example, Hawaiian Electric Company cited increasing penetration rates of distributed solar as contributing to voltage stability issues on its grid that led to an April 2013 blackout for 79,000 customers on the island of O'ahu. See p. 4 in the "Hawaiian Electric State of the System" report dated April 23, 2014: http://www.hawaiianelectric.com/vcmcontent/StaticFiles/pdf/ESS_Attachment_G_Hawaiian_Electric_State_of_the_System.pdf

*Retail demand charge management* refers to a service offered by energy storage, or other measures, to reduce the "demand charge" portion of a customer electric bill. A demand charge is a charge levied proportional to the peak customer instantaneous (15 minute average) demand each month. Without careful control, a customer could add a significant component to their electric bill as a result of a "peaky" load shape that causes them to pay a high monthly charge, with relatively lower average consumption. Energy storage can store energy during periods when the customer demand is low and discharge to shave off peak customer load periods, which in some cases could be infrequent and short duration. Typically the value of reducing demand charges exceeds the value of energy time-shifting, under current national tariff structures.

## 4.6 Summary of Grid Services for Energy Storage

The preceding section described widely accepted categories of energy storage services to the electric grid. These services span the entire scope of electric service from generation to end customer. However, it should be noted that not all of these services have been demonstrated in commercial or utility settings. Moreover, the ability to provide multiple grid services in an operational setting can be challenging, particularly when such services have the potential to be mutually exclusive. For example, an energy storage device providing a transmission reliability service must reserve its capacity during operational periods when such a reliability service is potentially needed. Providing other services during that period may not be possible.

## 4.7 Societal Benefits

It should be noted that energy storage may provide benefits to society in addition to its value for grid services. These benefits may include:

*Greenhouse Gas and/or Pollution Reductions* – Certain types of energy storage dispatch may result in reduced system-wide emissions. Cases where storage may reduce emissions include:

- **Offsetting regulation services provided by non-renewable sources** - Energy storage that provides frequency regulation service to the grid may offset heat rate (efficiency) penalties incurred by ramping traditional generators, thereby allowing the existing generator fleet to operate at a lower, overall heat rate. Large quantities of grid storage may also reduce the number of cold starts for fossil generators, allowing for more efficient grid operations.

- **Increased capture of renewable over-generation -** In cases of high renewable penetration, energy storage may charge from excess renewable generation that would otherwise be spilled or curtailed and discharge that energy at times that offset the need for traditional generation.

*Job creation and/or technology leadership –* Energy storage, as a rapidly developing industry, has the potential to create local jobs or establish technology leadership in the region. The complex calculation required to determine long term benefits was not part of the scope of this study.

## 4.8 Energy Storage Use Cases

Due to the variety of operational modes and potential locations where energy storage can be sited, energy storage has the potential to provide many different combinations of the aforementioned services. The ability of a single energy storage system to provide these services can be assessed across multiple parameters, including 1) minimum required energy storage power (capacity) and energy (duration), 2) location requirements, 3) availability requirements, both frequency and duration, and 4) flexibility and penalties of non-performance.

An energy storage use case describes a specific scenario for a single energy storage asset sited at a specific location and operated in a particular way to deliver a specific combination of grid services and benefits. The value of these services and benefits may be quantifiable to varying degrees through modeling and analysis, but not all will receive commensurate compensation under current policies.

Unlike the preceding list of individual energy storage services, which is fairly consistent and converging across the energy storage and electric industries, a comprehensive list of energy storage use cases has not yet been widely agreed upon. Due to the emerging nature of the energy storage industry, new use cases are being identified. These new use cases are often targeted to the specific needs of a utility, customer, or new wholesale electricity market opportunities.

This paper will not attempt to cover the full universe of use cases, as most use cases are not relevant to the primary service requirement of the system, which is to provide transmission investment deferral. Rather, this paper will focus on the use case of transmission-connected, utility substation-sited energy storage providing transmission infrastructure services as a primary function, with secondary functions of providing bulk energy services, ancillary services, and additional societal benefits such as greenhouse gas reduction. Neither distribution infrastructure services nor customer energy management services are relevant to this assessment due the required configuration of the system based on the need primary service requirement of the system.

Table 5 summarizes use cases for projects sited on the transmission side of the power grid.

**Table 5. Use Cases for Transmission Sited Energy Storage Projects**

| Connection | Category | Use Case |
|---|---|---|
| **Transmission Sited** | Standalone | Rate Based (Transmission Deferral & NERC Reliability) |
| | | Rate Based (Economic - Congestion Management, Avoiding costs of lost customer service) |
| | | Rate Based (Policy - Renewables Integration) |
| | | Dual Use (Partial Rate Based, Partial Market Participant) |
| | | Market Participant - Bulk Peaker *(Energy & AS)* |
| | | Market Participant - AS Only |
| | Generator Paired | Variable Energy Resource 1 (wind/solar) |
| | | Variable Energy Resource 2 (CSP molten salt) |
| | | Thermal + Turbine Inlet Chilling or CAES |
| | | Hybrid Thermal + Fast Response Storage |
| | | Thermal + Oxygen Chilling |

# 5 Energy Storage Technology & Commercial Overview

This chapter provides a high-level overview of energy storage technologies, including their commercial viability and currently deployed utility-scale projects.

## 5.1 Energy Storage Technology Classes

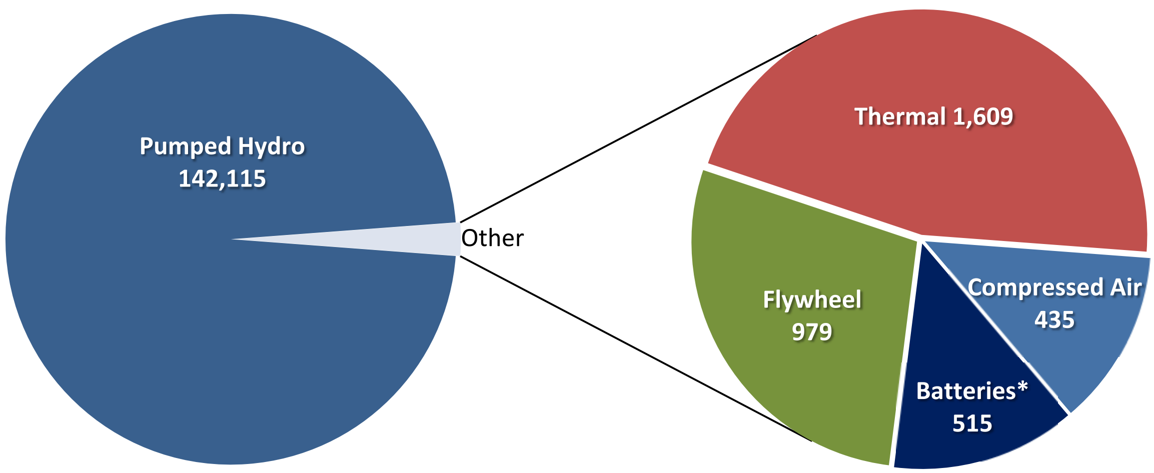
Energy storage encompasses a wide range of technologies and resource capabilities, with differing tradeoffs in cycle life, system life, efficiency, size, and other parameters.

**Table 6. Energy Storage Technology Classes**

| Technology Class | Examples |
|---|---|
| **Electrochemical Storage** | Batteries, Supercapacitors |
| **Mechanical Storage** | Flywheels, Compressed Air |
| **Thermal Storage** | Ice, Molten Salt, Chilled Water |
| **Bulk Gravitational Storage** | Pumped Hydropower, Gravel |

The vast majority of energy storage currently deployed in the market is pumped hydropower, as Figure 5 shows.

**Figure 5. Installed Grid-Connected Energy Storage in MW, by Technology, as of 10/2014[18]**




*Batteries include Flow, Lithium Ion, Sodium Sulfur, Nickel Cadmium, Lead Acid, Electrochemical Capacitors, and Ultra Batteries

Note that while much of the focus within the industry and in the press has been on advanced energy storage technologies, particularly battery technology, pumped hydro still comprises the substantial majority of grid connected energy storage (97.6%), with the remaining categories combined comprising 2.4% of installed capacity.

### 5.1.1 *Electro-chemical Storage (Batteries)*

This class of energy storage includes the following chemistries: advanced lead acid, lithium ion, sodium based, nickel based, flow batteries, and electrochemical capacitors. Technologies are further classified into sub-categories based on the specific chemical composition of the main components (anode, cathode, separator, electrolyte, etc.). As Table 7 summarizes, each class and sub-category is at a different stage of commercial maturity and has unique power and energy characteristics that make it more or less appropriate for specific grid support applications.

[18] DOE GESDB (October 2014)

### Table 7. Characteristics of Common Chemical Energy Storage Technologies[19]

| Technology Class | Advanced Lead Acid | Lithium Ion | Sodium | | Nickel based | Flow Batteries | |
|---|---|---|---|---|---|---|---|
| Technology Sub-Category | | | Sodium sulfur | Sodium nickel chloride | | Vanadium redox | Zinc bromine |
| Roundtrip Efficiency (%)[20] | 75-90 | 85-98 | 70-90 | 85-90 | 60-80 | 60-85 | 60-75 |
| Self-Discharge (%energy/day) | 0.5-1 | 0.1-0.3 | 0.05-20 | 15 | 0.3-1 | 0.2 | 0.24 |
| Cycle Lifetimes (cycles) | 300-2.5k | 1k-10k | 2.5-4.5k | 2.5k-4.5k | 800-3.5k | 12k-14k | 2k-10k |
| Expected Lifetime (years) | 6-15 | 5-15 | 5-15 | 10-15 | 5-20 | 5-15 | 5-15 |
| Specific Power (W/kg) | 75-300 | 230-1.5k | 150-230 | 150-200 | 150-300 | 16-33 | 30-60 |
| Specific Energy (Wh/kg) | 30-50 | 125-250 | 150-240 | 100-200 | 50-75 | 15-50 | 75-85 |
| Power Density (W/l) | 90-700 | 1.3k-10k | 120-160 | 250-270 | 75-3k | 0.5-2 | 1-25 |
| Energy Density (Wh/l) | 30-80 | 250-630 | 150-300 | 150-200 | 200-350 | 20-70 | 65 |
| Commercial Maturity[21] | Dem. | Dem. | Comm. | Dem. | Dem. | Pre-Comm. | Dem. |

## Advanced Lead Acid

Invented in the 19th century, lead acid are the most developed and commercially mature type of rechargeable battery. They are widely used in both mobile (cars, boats) and stationary consumer applications (UPS, off-grid PV), but several issues including short cycle life, slow charging rates, and high maintenance requirements have prevented widespread adoption for utility-scale grid applications.[22] A screen of the Department of Energy's Energy Storage Database identified nine currently operational projects with a power rating greater than 1 MW. These perform a wide variety of services including peak shaving, on site power, ancillary services, load following/ramping, and renewables capacity firming.

[19] Antonucci (2012), SBC Energy Institute (2013), IEA-ETSAP/IRENA (2012), IEC (2011)
[20] Cell roundtrip efficiency only; additional losses due to the system's power electronics must be accounted for as well (see Chapter 5.2)
[21] Dem. = Demonstration; Comm. = Commercial; Pre-Comm. = Pre-Commercial
[22] Navigant (2012)

### *Technical Details*

Lead acid batteries rely on a positive, lead dioxide electrode reacting with a negative, metallic lead electrode through a sulfuric acid electrolyte. Ongoing research and development has produced several proprietary technologies falling within two categories: advanced lead acid and lead acid carbon. While technologically distinct, lead acid carbon is considered a type of advanced lead acid battery.[23]

Advanced lead acid batteries incorporate a variety of technological enhancements depending on the manufacturer. Companies such as GS Yuasa and Hitachi are developing units that improve system response times by incremental technology enhancements such as valve-regulation, solid state electrolyte-electrode configurations, and anode electrodes that include capacitors.[24]

Lead acid carbon batteries add carbon to one or both electrodes. This addresses two major historic barriers to the adoption of lead acid technology: 1) a tendency for sulfate to accumulate on the negative electrode surface which led to large decreases in capacity and cycle life and 2) slow charge/discharge rates. The addition of carbon reduces sulfate accumulation and allows faster charge and discharge with no apparent detrimental effects.[25] Research and development by Xtreme Power (now Younicos), Axion Power, and Ecoult/East Penn has led to several utility-scale deployments ranging from 1 MW to 36 MW.[26] Improvements in maintenance requirements, cycle life, and charging rates are allowing lead acid carbon systems to perform a variety of grid services that were not economically justifiable with standard lead acid.

Downsides to lead acid technology include its low power and energy density compared to other batteries, limited life ranges of approximately (6-15 years), and lead electrodes and sulfur electrolyte that are toxic and require appropriate handling and recycling.[27]

### *Deployments*

Operational deployments total 68 MW/67 MWh in 25 projects. These have capacities ranging from 100 kW/226 kWh (2 hr 15 min duration) to 36 MW/24 MWh (40 min duration). Table 8 lists details of the five largest installations.

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[23] DOE-EPRI Energy Storage Handbook (2013)
[24] *Ibid.*
[25] *Ibid.*
[26] "Carbon-Enhanced Lead-Acid Batteries." Sandia (2012)
[27] IEC (2011)

**Table 8. Five Largest Operational Lead Acid Energy Storage Projects**

| Owner / Project | Nominal Power / Energy (Duration) | Technology | Location | Primary Function |
|---|---|---|---|---|
| **Duke Energy / Notrees** | 36 MW / 24 MWh (40 min) | Advanced lead acid | Goldsmith, TX | Renewables capacity firming |
| **Kuroshio Power / Shiura Wind Park** | 4.5 MW / 10.5 MWh (2.3 hour) | Valve regulated lead acid | Aomori, Japan | Renewables capacity firming |
| **Shonai Wind Power Generation Co. / Yuza Wind Farm Battery** | 4.5 MW / 10.5 MWh (2.3 hour) | Valve regulated lead acid | Yamagata, Japan | Renewables capacity firming |
| **First Wind LLC / Kaheawa Wind Project II** | 10 MW / 7.5 MWh (45 min) | Advanced lead acid | Maalaea, HI | Renewables capacity firming |
| **East Penn Manufacturing Co. / UltraBattery Demo** | 3 MW / 2.2 MWh (42 min) | UltraBattery® | Lyon Station, PA | Frequency regulation |

In 1994, Puerto Rican Utility PREPA commissioned a 20 MW/14 MWh (40 min duration) lead acid system designed to support grid stability with frequency regulation and voltage support. The system operated for five years before being replaced by a similarly sized system that was later destroyed by fire. Metlakatla Power and Light and GNB (now Exide) installed a 1 MW/1.4 MWh (1 h 24 min duration) lead acid battery system in 1996 that successfully performed voltage regulation and frequency regulation for 12 years. It was replaced in 2008 with an identical system and is still operational.

Hitachi currently has two 4.5 MW/10.5 MWh (2 h 20 min duration) advanced lead acid field trials operating in conjunction with wind farms in Japan. The systems are performing renewables capacity firming, frequency regulation, and load following.

Recently, lead acid carbon has seen more utility deployments that other lead acid technologies. The Duke Notrees 36 MW/24 MWh (40 min duration) located in Texas has the highest power rating of any battery in the world[28]. Commissioned in 2012 with the help of a $22 million DOE grant, the system is used to firm wind energy and perform peak shifting and frequency regulation. Another Xtreme Power project adjoined to a wind farm, the Kaheawa II Project in Hawai'i features a 10 MW/7.5 MWh (45 min duration) battery. In addition to storing wind generation that would otherwise be curtailed, the unit provides ramp control, frequency regulation, and automatic generation control for Maui Electric Company.

Several smaller utility demonstration systems from different vendors are also in operation. For instance, a 500 kW/2 MWh (4 hour duration) Public Service Company of New Mexico pilot combines and coordinates two batteries of different ratings for renewable smoothing and peak shifting, while Xcel's SolarTAC project in Colorado is using a 1.5MW/1MWh (40 min

[28] Although several sodium sulfur batteries are larger when rated by *energy capacity*.

duration) for ramp control, frequency response, voltage support, and solar generation firming.

7MW/11MWh of lead acid deployments are currently either planned or under construction, 5MW of which are from three projects.[29]

### Lithium Ion

First commercialized in 1991, lithium ion batteries have experienced tremendous R&D and publicity in the last few years due to their high energy density, voltage ratings, cycle life, and efficiency ratios. They have been the preferred energy storage technology for portable electronic devices, and now are being scaled up and deployed for grid services at utility scale. There are approximately 70 systems with power ratings greater than 1 MW currently operational globally. Lithium ion's adaptability to a range of power and energy ratings allows it to perform a wide variety of services. Grid scale application units range from small 1 MW/0.5 MWh (30 min duration) frequency regulation pilot projects, to large 8 MW/32 MWh (4 hour duration) and 32 MW/8 MWh (15 min duration) systems performing ramp control and shifting wind and solar generation.[30]

#### *Technical Details*

Lithium ion is a broad technology class that encompasses multiple sub-technology types based on differing chemistries, each with unique characteristics. Subtype classifications generally refer to the cathode material.[31] Some common chemistries are compared in Table 9.

Technologies are again divided by cell shape: cylindrical, prismatic, or laminate. Cylindrical cells have high potential capacity, lower cost, and good structural strength. Prismatic cells have a smaller footprint, so they are used when space is limited (i.e. mobile phones). Laminate cells are flexible and safer than the other shapes.[32]

Lithium ion batteries have several key advantages over other battery chemistries, including high energy density, high power, high efficiency, low self-discharge, lack of cell "memory", and fast response time. However, lithium ion chemistries also present a number of challenges including short life cycle, high cost, heat management issues, flammability, and narrow operating temperatures.[33]

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[29] DOE GESDB (2014)
[30] *Ibid.*
[31] Yoshio et al. (2009)
[32] Citi (2012)
[33] PNNL (2012)

**Table 9. Relative Comparison of Lithium Ion Chemistries[34]**

| Chemistry (Shorthand) | Safety | Energy | Power | Life | Cost/ kWh | Summary |
|---|---|---|---|---|---|---|
| | Scale 1-5 with 5 Best | | | | | |
| Lithium Manganese Oxide (LMO) | 3 | 4 | 3 | 3 | 4 | Versatile technology with good overall performance & cost |
| Lithium Iron Phosphate (LFP) | 3 | 3 | 4 | 4 | 3 | Similar to LMO, but slightly more power & less energy |
| Lithium Nickel Cobalt Aluminum (NCA) | 1 | 3 | 4 | 4 | 2 | Good for power applications; poor safety & high cost/kWh |
| Lithium Titanate (LTO) | 5 | 2 | 5 | 5 | 2 | Excellent power & cycle life; high cost/kWh |
| Lithium Nickel Manganese Cobalt (NMC) | 3 | 4 | 4 | 4 | 4 | Versatile technology with good overall performance & cost |

### *Deployments*

Approximately 235 MW/294 MWh of lithium ion projects are currently operational and approximately 65 projects have a power rating of 1 MW or larger. These utility scale systems can generally be separated into two categories: high power, short duration projects performing frequency regulation (i.e. AES Laurel Mountain 32 MW/8 MWh) and high energy projects helping to integrate intermittent renewable generation (See Table 10).

In June 2014, Southern California Edison commissioned the largest lithium ion system (by energy rating) in the United States. The 8 MW/32 MWh (4 hour duration) project is connected to the Tehachapi Pass Wind Farm and was installed to test 13 different service/use cases. The overall goal is to improve grid performance and integrate renewables.

The three largest lithium ion projects in terms of rated power (MW) were installed by AES to provide frequency regulation services. These include the 32 MW Laurel Mountain, 20 MW Angamos, and 12 MW Los Andes projects all having between 15-20 minute duration. Laurel Mountain is adjacent to a wind farm and participates in PJM's wholesale market, while Los Andes and Angamos act to support large mining operations in Chile.

[34] Hardin (2014)

**Table 10. Five Largest Operational Lithium Ion Energy Storage Projects, by energy rating**

| Owner / Project | Nominal Power / Energy (Duration) | Technology | Location | Primary Function |
|---|---|---|---|---|
| **State Grid Corporation of China / Zhangbei National Wind and Solar Energy Storage and Transmission Project** | 6 MW / 36 MWh (6 hour) | Lithium-iron-phosphate | Hebei, China | Renewable generation shifting |
| **Southern California Edison / Tehachapi Wind Energy Storage Project** | 8 MW / 32 MWh (4 hour) | Lithium ion | Tehachapi, CA | Renewable generation shifting |
| **State Grid Corporation of China / Zhangbei National Wind and Solar Energy Storage and Transmission Project** | 4 MW / 16 MWh (4 hour) | Lithium-iron-phosphate | Hebei, China | Renewable generation shifting |
| **China Southern Power Grid / Baoqing Plant Phase-1** | 3 MW / 12 MWh (4 hour) | Lithium-iron-phosphate | Guangdong, China | Electric energy time shift |
| **State Grid Corporation of China / Qingdao XueJiadao Battery Pilot Project** | 7 MW / 10.5 MWh (1.5 hour) | Lithium-iron-phosphate | Qingdao, China | Transportati on services |

There are more than 40 lithium ion projects with anticipated power ratings greater than 1 MW either planned or under construction, totaling 287 MW.[35]

### Sodium Sulfur

Sodium sulfur (NaS) battery technology was invented by Ford Motors in the 1960's, but research, development, and deployment from Japanese companies like NGK Insulators and Tokyo Electric Power Company over the past 25 years established NaS as a commercially viable technology for fixed, grid-connected applications. Sodium sulfur batteries are able to provide numerous high energy grid support applications with commercially deployed systems in the 400 kW to 34 MW power rating range and system duration of roughly 6 hours.[36]

#### *Technical Details*

The battery utilizes a positive electrode of molten sulfur, a negative electrode of molten sodium, and a solid beta alumina ceramic electrolyte that separates the electrodes. Batteries require charge/discharge operating temperatures between 300-350°C, so each unit has a built in heating element. Due to high operating temperatures and hazardous materials, the systems contains various safety features including fused electrical isolation, hermetically-sealed cells,

[35] DOE GESDB (2014)
[36] DOE-EPRI Energy Storage Handbook (2013)

sand surrounding cells to mitigate fire, and a battery management system that monitors cell block voltages and temperatures.

Typical units are composed of 50 kW NaS modules and available in multiples of 1 MW/~6 MWh (generally, an approximate 6 hour duration). Units are combined in parallel to create large scale systems, typically between 2-10 MW.[37]

The advantages of sodium sulfur are its high power and long duration, good energy density (150-300 Wh/l), extensive deployment history and commercial maturity. Downsides include risk of fire, round trip efficiencies of 70-90%, and potentially high self-discharge/parasitic load values of 0.05-20% due to the internal heating element using the battery's own electricity.[38] NaS is also much less efficient for low cycle applications due to the continual energy consumption of the internal heating element.

### *Deployments*

To date about 306 MW/1896 MWh of sodium sulfur has been deployed in approximately 220 sites globally, with systems ranging in size from 400 kW to 34 MW. Installations are predominately in Japan, but in the last ten years, eleven systems have been commissioned in the US. Peak shifting is the most frequent application, but renewables capacity firming, T&D upgrade deferral, frequency regulation and electric supply reserve capacity specified services.

The largest operational sodium sulfur battery was installed in 2008 at Rokkasho Village Wind Farm, Japan. The 34 MW/238 MWh (7 hour duration) unit is interconnected to the transmission system and stabilizes wind output, shifting it to times of peak demand.[39]

Since 2002 American Electric Power (AEP) has deployed 11 MW in 5 different locations. In 2008 a 4 MW/32 MWh (8 hour duration) unit in Texas was part of a transmission upgrade that included a new 69 kV line and autotransformer. That system is used to support aging transmission lines, supply back up power to minimize outages and provide voltage support.[40] Additionally, AEP installed three 2 MW/12 MWh (6 hour duration) units in different locations for load leveling, to alleviate transformer loading during summer peaks, capital upgrade deferral, and emergency electric supply. These units provide AEP time to make long-term decisions, and can be relocated for an estimated $115,000 if utility needs or goals change in the future.

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[37] DOE-EPRI Energy Storage Handbook (2013)
[38] SBC Energy Institute (2013)
[39] DOE GESDB (2014)
[40] IEA (2014)

**Table 11. Five Largest Operational Sodium Sulfur Energy Storage Projects**

| Owner / Project | Nominal Power / Energy (Duration) | Technology | Location | Primary Function |
|---|---|---|---|---|
| **Japan Wind Development / Rokkasho Village Wind Farm** | 34 MW / 238 MWh (7 hour) | Sodium sulfur | Rokkasho Village, Japan | Renewable generation shifting |
| **Tokyo Metropolitan Government / Morigasaki Water Reclamation Center** | 8 MW / 58 MWh (7.25 hour) | Sodium sulfur | Tokyo, Japan | Load leveling |
| **Hitachi / Automotive Plant ESS** | 9.6 MW / 57.6 MWh (6 hour) | Sodium sulfur | Ibaraki, Japan | Load leveling |
| **Abu Dhabi Water & Electricity Authority / BESS** | 8 MW / 48 MWh (6 hour) | Sodium sulfur | Abu Dhabi, United Arab Emirates | Load leveling |
| **American Electric Power / Presidio ESS** | 4 MW / 32 MWh (8 hour) | Sodium sulfur | Presidio, TX | Ancillary services |

In the last 3 years, Pacific Gas and Electric (PG&E) commissioned two demonstration systems of 4 MW/28 MWh (7 hour duration) and 2 MW/14 MWh (7 hour duration). PG&E is testing the units under a number of conditions and applications to better understand energy storage technologies.[41]

The DOE Global Energy Storage Database lists three deployments that are planned or under construction. All three are for Italian utility TERNA and total 35 MW/278 MWh.

## Sodium Nickel Chloride

Sodium nickel chloride batteries ($NaNiCl_2$), also referred to as ZEBRA (Zero Emissions Battery Research), are similar to sodium sulfur in their operating characteristics but are still in a demonstration and limited deployment stage. General Electric and FIAMM have about 15 current operational deployments with power ratings ranging from 20 kW/70 kWh (3.5 hour duration) to 1 MW/2 MWh (2 hour duration). Systems are primarily integrating renewable generation and providing utility grid services through voltage support, load following and frequency regulation.

### *Technical Details*

Sodium nickel chloride batteries are similar to sodium sulfur, but the cathode is composed of nickel-chloride rather than sulfur. They require operating temperatures between 260°C and 350°C and therefore feature internal thermal management components. Able to withstand limited overcharging, they are potentially safer than sodium sulfur while also having a higher

[41] DOE GESDB (2014)

cell voltage. Typical cells are 20 kWh, so system power and energy ratings are more customizable to a given application than sodium sulfur.[42]

Compared to other chemical storage technologies, advantages of sodium nickel chloride include scalability, ability to operate in a wide temperature range (-40°C to 60°C)[43], high power density (250-270 W/l), long cycle life (2k+ cycles @ 80% DOD), and easy recycling of battery materials.[44] Disadvantages include lack of commercial deployments and maturity, high cost, and thermal management.[45]

### *Deployments*

In total, approximately 2.7 MW/5.2 MWh of sodium nickel chloride installations are operational globally.[46] Deployments include a 1 MW/2 MWh (2 hour duration) unit performing wind energy integration at the Wind Institute of Canada, a 400 kw/280 kWh (42 min duration) unit providing frequency regulation and voltage support at a Duke substation in North Carolina, and a 200 kW/140 kWh (42 min duration) unit supplementing electric supply and peak shaving in Korea.

The number of sodium nickel chloride projects, as well as the power ratings of those deployments, is far less than sodium sulfur installations. The largest current installation is a 1 MW/2 MWh (2 hour duration) unit at the Wind Energy Institute of Canada. The system was commissioned in January 2014 and primarily integrates intermittent wind generation.

The only other system with rated energy greater than 1 MW is transmission interconnected on a wind farm in Texas. Another GE Durathon unit, it also primarily performs renewable smoothing and integration.

A half dozen multi-megawatt (2-6 MW) deployments are scheduled or under construction in Italy, Japan and Africa.[47]

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[42] IEC (2011)
[43] GE Website (2014): http://geenergystorage.com/technology
[44] EUROBAT Website (2014): http://www.eurobat.org
[45] Antonucci (2012)
[46] DOE GESDB (2014)
[47] DOE GESDB (2014)

**Table 12. Five Largest Operational Sodium Nickel Chloride Energy Storage Projects**

| Owner / Project | Nominal Power / Energy (Duration) | Technology | Location | Primary Function |
|---|---|---|---|---|
| **Wind Energy Institute of Canada / Durathon Battery** | 1 MW / 2 MWh (2 hour) | Sodium nickel chloride | Prince Edward Island, Canada | Renewable generation shifting |
| **General Electric / Wind Durathon Battery Project** | 0.3 MW / 1.2 MWh (4 hour) | Sodium nickel chloride | Tehachapi, TX | Renewable generation shifting |
| **Western Power Distribution / Falcon Project** | 0.25 MW / 0.5 MWh (2 hour) | Sodium nickel chloride | Milton Keynes, United Kingdom | T&D upgrade deferral |
| **Duke Energy / Rankin Substation ESS** | 0.4 MW / .3 MWh (42 min) | Sodium nickel chloride | Mount Holly, NC | Renewables capacity firming |
| **State Grid Shanghai / FIAMM Battery Project** | 0.1 MW / 0.2 MWh (1.7 hour) | Sodium nickel chloride | Shanghai, China | Renewable generation shifting |

## Nickel-Based

The two main sub-technologies in the nickel-based family are nickel cadmium (NiCad), which has been in commercial use since 1915, and nickel metal hydride (NiMH), which became available around 1995. Nickel-based batteries are primarily used in portable electronics and electric vehicles do to their high power density, cycle life and roundtrip efficiency. There are only two operational projects with rated energy greater than 1 MWh, one of which provides electric supply reserve capacity in Alaska and the other performs renewable capacity firming on Bonaire Island. Although Sandia states that "Nickel-cadmium and nickel metal hydride batteries are mature and suitable for niche applications,"[48] the fact that so few grid scale operational deployments exist suggests that nickel-based technology is not currently competitive with other battery types.

### *Technical Details*

All nickel batteries employ a cathode of nickel hydroxide. The anode composition is used to classify the sub-categories: nickel cadmium, nickel iron, nickel zinc, nickel hydrogen, and nickel metal hydride. The three former sub-categories utilize a metallic anode while the latter two use one that stores hydrogen.

Nickel cadmium chemistry is a low cost, mature technology with high energy density, but the toxicity of cadmium necessitated the search for alternatives. Nickel metal hydride was developed in response. The metal hydride chemistry is safer and has a higher specific energy than nickel cadmium, but it charges slower and does not withstand very low operating

[48] DOE-EPRI Energy Storage Handbook (2013); p. 109.

temperatures.[49] The safety of nickel metal hydride made it the battery of choice for electric and hybrid vehicles, but lithium ion is currently challenging this status.

Other nickel chemistries are in the research and development phase.

In general, the nickel family is characterized by high power density (up to 3000 W/l), a slightly greater energy density than lead acid (200-350 Wh/l), operating well at low temperatures (-20°C to -40°C) and good cycle life (800-3,500 cycles).[50]

### *Deployments*

Total operational deployments of nickel based batteries total 31.4 MW/8.9 MWh, of which 27 MW/6.8 MWh is installed in one project. Table 13 shows the three largest nickel based projects on the DOE Global Energy Storage Database that are not systems of private citizens.

[49] Linden (2001)
[50] See Table 7

**Table 13. Three Largest Nickel-Based Energy Storage Projects**

| Owner / Project | Nominal Power / Energy (Duration) | Technology | Location | Primary Function |
|---|---|---|---|---|
| **Golden Valley Electric Association / Battery Energy Storage System** | 27 MW / 6.75 MWh (15 min) | Nickel cadmium | Fairbanks, AK | Electric Supply Reserve - Spinning |
| **EcoPower Bonaire BV / Bonaire Wind-Diesel Hybrid** | 3 MW / 0.25 MWh (5 min) | Nickel cadmium | Bonaire, Netherlands | Renewables capacity firming |
| **Okinawa Electric Power Company / Minami Daito Island** | 0.3 MW / 0.08 MWh (15 min) | Nickel metal hydride | Okinawa, Japan | Frequency regulation |

The Golden Valley Electric Association Battery Energy Storage System is by far the largest nickel-based battery in the world. Rated at 27 MW/6.75 MWh (15 min duration), the nickel cadmium system can potentially operate at 46 MW for as long as five minutes if needed. The unit is primarily used to provide emergency reserves to give the grid operator time to ramp local generation resources should an outage occur.

According to the DOE Global Energy Storage Database, there are no megawatt scale nickel-based projects currently planned or under construction.

## Flow Batteries

Flow batteries are fundamentally different than other types of electrochemical storage because the power and energy of a system are independent of one another. This feature allows systems to be tailored to specific applications and constraints. A number of megawatt-scale demonstration projects are testing the deep discharge ability, long cycle life, and easy scalability that characterize flow batteries. Some chemistries have been more extensively developed and deployed than others, and technological maturity ranges from development stage (iron-chromium, zinc-bromine) to pre-commercial (vanadium). Operational projects ranging from 5 MW/10 MWh (2 hour duration) to 250 kW/2 MWh (8 hour duration) are focused on integrating renewables, but several smaller pilots are testing different chemistries for peak shaving and ancillary services as well.[51]

### *Technical Details*

Flow batteries have one or both of their active materials in solution in the electrolyte at any given time. In traditional flow batteries, the solution is stored in external containers and pumped to the cell stack and electrodes where an oxidation-reduction reaction occurs. This allows for independent sizing of the electrolyte tanks (energy) and cell stack (power), which in turn allows systems to be tailored to many applications.[52]

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[51] DOE-EPRI Energy Storage Handbook (2013)
[52] Gyuk/ESTAP (2014)

Several chemistries have proven technologically feasible including vanadium-vanadium ($V^{n+}$), iron-chromium (Fe-Cr), and zinc-bromine ($ZnBr_2$). Iron-chromium's advantages are a very safe electrolyte and high abundance and low cost of materials.[53] Vanadium utilizes ions of the same metal on both sides of the reaction, thus preventing the typical crossover degradation that occurs in other flow batteries as ions try to cross the cell membrane.[54] Zinc-bromine combines features of a conventional battery and flow battery: One electrolyte is stored in an external tank and the other is stored internally in the electrochemical cell. The zinc-bromine chemistry allows higher power and energy densities than other flow batteries (See Table 7), but bromine is extremely corrosive and can lead to component degradation and failure.[55]

### *Deployments*

As demonstrated in Table 14, Vanadium flow batteries are the most mature and commercially deployed systems. Of the approximately 18 MW/42 MWh of flow battery capacity installed globally, 17 MW/40 MWh are vanadium redox batteries.

Commissioned in 2013, the GuoDian Wind Farm is the largest flow battery by power and energy in the world. Installed by Rongke Power, it integrates wind generation, provides voltage support, and serves as reserve electric supply capacity.

The Tomamae Wind Farm was commissioned in 2005 by Sumitomo Electric Industries. It has sometimes performed over 50 charge-discharge cycles an hour while smoothing the wind output. China's Zhangbei Project was commissioned in 2011 by Prudent Energy. It firms renewable output while providing frequency regulation and load following/ramping as well.

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[53] Horne/ESTAP (2014)
[54] IEC (2011)
[55] DOE-EPRI Energy Storage Handbook (2013)

**Table 14. Five Largest Operational Flow Battery Energy Storage Projects**

| Owner / Project | Nominal Power / Energy (Duration) | Technology | Location | Primary Function |
|---|---|---|---|---|
| **GuoDian LongYuan (Shenyang) Wind Power Co. / GuoDian LongYuan Wind Farm VFB** | 5 MW / 10 MWh (2 hour) | Vanadium redox | Liaoning, China | Renewable generation shifting |
| **State Grid Corporation of China / Zhangbei National Wind and Solar Energy Storage and Transmission Project** | 2 MW / 8 MWh (4 hour) | Vanadium redox | Hebei, China | Renewable generation shifting |
| **J-Power / Tomamae Wind Farm** | 4 MW / 6 MWh (1.5 hour) | Vanadium redox | Hokkaido, Japan | Renewables capacity firming |
| **Sumitomo Electric Industries / Yokohama Works VRB** | 1 MW / 5 MWh (5 hour) | Vanadium redox | Kanagawa, Japan | Renewable generation shifting |
| **Prudent Energy / Gills Onions VRB** | 0.6 MW / 3.6 MWh (6 hour) | Vanadium redox | Oxnard, CA | Grid-Connected Commercial (Reliability & Quality) |

Operational US deployments range from a 600 kW/3.6 MWh Prudent Energy vanadium unit providing power quality at a factory to a 25 kW/50 kWh ZBB zinc bromine system acting as a UPS for a data center. Non-vanadium projects are becoming more common: Enervault commissioned a 250 kW/1 MW (4 hour duration) iron chromium system adjacent to a California solar array in 2014, and Primus Power is currently constructing several identically sized zinc-bromine units.

Approximately 29 MW/110 MWh of deployments are planned or under construction globally.[56]

### Supercapacitors

Also called electrochemical double-layer capacitors and ultracapacitors, this technology class bridges the gap between batteries and traditional capacitors and stores energy electrostatically. Supercapacitors are characterized by low internal resistance which allows rapid charging and discharging, very high power density (but low energy density), and high cycle life.[57] Current deployments are primarily used in voltage support, load following/ramping and regenerative braking in transportation applications and have sizes between 300 kW/3 kWh and 1 MW/17 kWh. The technology is still considered to be in demonstration phase.[58]

[56] DOE GESDB (2014)
[57] IEA-ETSAP/IRENA (2012)
[58] SBC Energy Institute (2013), DOE-EPRI Energy Storage Handbook (2013)

### *Technical Details*

Supercapacitors use carbon electrodes with very high surface area to create a solid-liquid interface that allows electricity to be stored by the separation of charge, rather than through chemical transformation like traditional batteries.[59]

Advantages of supercapacitors include high power density (40-120 kW/l), very fast response time (<1 sec), high efficiency (80-98%), and high cycle life (10k-100k).[60] While disadvantages include low specific energy (30 Wh/kg) and corresponding high cost per kWh.

### *Deployments*

There are 13 operational deployments listed on the DOE Global Energy Storage Database, of which 11 are 1 MW or greater. Total installed capacity is approximately 21.4 MW/0.1 MWh and the largest projects are summarized in Table 15.

[59] Badwal et al. (2014)
[60] SBC Energy Institute (2013)

**Table 15. Five Largest Operational Supercapacitor Energy Storage Projects**

| Owner / Project | Nominal Power / Energy (Duration) | Location | Primary Function |
|---|---|---|---|
| **Electrical Power worX / LIRR Malverne WESS: Ioxus** | 1 MW / 16 kWh (1 min) | Malverne, NY | Transportation Services |
| **Electrical Power worX / LIRR Malverne WESS: Maxwell** | 1 MW / 16 kWh (1 min) | Malverne, NY | Transportation Services |
| **Incheon Transit Corporation / Incheon Line 1 - Technopark Station** | 2.3 MW / 13 kWh (20 sec) | Incheon, South Korea | Transportation Services |
| **Seoul Metro / Seoul Line 2 - Seocho Station** | 2.3 MW / 13 kWh (20 sec) | Seoul, South Korea | Transportation Services |
| **Seoul Metro / Seoul Line 4 - Ssangmun Station** | 2.3 MW / 13 kWh (20 sec) | Seoul, South Korea | Transportation Services |

Installations of supercapacitors as standalone energy storage systems are almost exclusively focused on providing near-instantaneous voltage ramping and regenerative braking for trains.

In the last two years, Maxwell Technologies and Woojin Industrial Systems have deployed nine systems that provide over 15 MW/83 kWh in support of Korean Metro operations. In New York a pilot testing two 1 MW/16 kWh units side by side was recently commissioned by Electrical Power WorX.

Supercapacitors are also being deployed in conjunction with traditional batteries. Southern Pennsylvania Transportation Authority and ABB are commissioning two hybrid units that combine lithium ion batteries with supercapacitors to provide voltage support for trains while simultaneously capturing braking energy that is sold into the frequency regulation market. Deka/EastPenn's Ultrabattery, currently in frequency regulation pilot demonstrations (See Table 8), is a packaged unit that combines a lead acid battery with a supercapacitor.

At least 11 MW/88 kWh of additional deployments are planned or under construction.[61]

### 5.1.2 *Mechanical Storage*

The mechanical storage technology class consists of compressed air energy storage and flywheels.

*Compressed air energy storage* generally makes use of off peak power to compress air and store it in a reservoir, typically either an underground cavern, or aboveground storage pipes or tanks. Compressed air energy storage is a commercially available technology for long duration storage requirements.

Underground compressed air storage facilities are generally considered less expensive than aboveground; however, siting an underground compressed air storage facility requires

[61] DOE GESDB (2014)

identification of a geologically suitable underground cavern.[62] Underground compressed air storage facilities are generally most cost effective as very long duration resources, on the scale of 8 to 26 hours.

Above ground compressed air storage facilities are more modular and less location-specific with respect to siting. The US Department of Energy states that the typical above ground compressed air storage facility is in the 3-50 MW power range, with durations of two to six hours.[63] However the incremental additional cost for above ground compressed air storage is significant, with DOE citing a cost of between $4,900-5,000/MW for a 50 MW/5 hour above ground system, and a levelized cost of slightly more than $200/MWh, or between about $380-390/kW-yr.[64]

Table 16 shows operational compressed air storage facilities.

[62] DOE-EPRI Energy Storage Handbook (2013); p. 38.
[63] *Ibid.*; p. 38.
[64] *Ibid.*; p. 39-40.

**Table 16. Five Largest Operational Compressed Air Storage Facilities**

| Owner / Project | Nominal Power / Energy (Duration) | Technology | Location | Primary Function |
|---|---|---|---|---|
| **E. ON / Kraftwerk Huntorf** | 321 MW / 642 MWh (2 hours) | In-ground Natural Gas Combustion | Elsfleth, Germany | Electric Energy Time Shift |
| **PowerSouth Utility Cooperative / McIntosh CAES Plant** | 110 MW / 2,860 MWh (26 hours) | In-ground Natural Gas Combustion | McIntosh, AL | Electric Energy Time Shift |
| **General Compression, Inc. / Texas Dispatchable Wind** | 2 MW / 500 MWh (250 hours) | In-ground Iso-thermal | Seminole, TX | Renewable Generation Shifting |
| **SustainX Inc. / Isothermal Compressed Air Energy Storage** | 1.5 MW / 1.5 MWh (1 hour) | Modular Iso-thermal | Seabrook, NH | Renewable Generation Shifting |
| **Highview Power Storage / Pilot Plant** | .35 MW / 2.45 MWh (7 hours) | Modular | Slough, United Kingdom | Renewable Generation Shifting |

*Flywheels* are the other mechanical energy storage technology sub-class. Flywheels are modular and can range from 22 kW in size (Stornetic's EnWheel) to 160 kW (Beacon Power). In essence, a flywheel works by accelerating a rotor (flywheel) to a very high speed in a very low-friction environment. The spinning mass stores potential energy to be discharged as necessary.

**Table 17. Five Largest Operational Flywheel Facilities**

| Owner / Project | Nominal Power / Energy (Duration) | Location | Primary Function |
|---|---|---|---|
| **European Fusion Development Agreement / EFDA JET Fusion Flywheel** | 400 MW / 3.3 MWh (30 sec) | Abingdon, United Kingdom | Onsite power |
| **Max Planck Institute, EURATOM Association / ASDEX-Upgrade Pulsed Power Supply System** | 387 MW / 0.54 MWh (5 sec) | Bavaria, Germany | Onsite power |
| **Spindle Grid Regulation, LLC / Beacon Power 20 MW Flywheel Plant** | 20 MW / 5 MWh (15 min) | Stephentown, NY | Frequency Regulation |
| **Spindle Grid Regulation, LLC / Beacon Power 20 MW Flywheel Plant** | 20 MW / 5 MWh (15 min) | Hazle Township, PA | Frequency Regulation |
| **NRStor Inc. / Minto Flywheel Energy Storage Project** | 2 MW / 0.5 MWh (15 min) | Ontario, Canada | Frequency Regulation |

Flywheels are best for short-duration, high power, and high-cycle applications. Generally, they have a much longer cycle life than other storage alternatives. Primary competitors are supercapacitors or ultracapacitors. They are less heat sensitive than batteries and are often guaranteed for 20 years of performance (batteries are often less than 10 years). Primary use cases for flywheels on the power grid are for Voltage/VAR Support, Regulation Energy Management (REM), and improved flexible capacity.

### 5.1.3 *Thermal Storage*

Thermal storage comes in many forms, although perhaps the most well-known bulk thermal storage solution is molten salt. Molten salt thermal storage is paired with solar thermal generation plants and is used to improve the dispatchability of concentrated solar power (CSP) facilities through the storage of thermal energy to power steam turbines for electric generation after the solar day had ended. Molten salt is not further considered in this assessment; its need to be paired with thermal generation is incompatible with the Eastside's reliability requirements.

**Table 18. Five Largest Operational Bulk Thermal Storage Facilities**

| Owner / Project | Nominal Power / Energy (Duration) | Technology | Location | Primary Function |
|---|---|---|---|---|
| **Abengoa Solar / Solana Solar Generating Plant** | 280 MW / 1,680 MWh (6 hours) | Molten Salt | Gila Bend, AZ | Renewable Generation Shifting |
| **Confidential / TAS Texas Cooperative** | 90 MW / 1,080 MWh (12 hours) | Chilled Water | Joplin, TX | Electric Supply Capacity |
| **Acciona Energía / Nevada Solar One Plant** | 72 MW / 36 Mwh (30 min) | Thermal | Boulder City, NV | Renewables Capacity Firming |
| **ACS - Cobra Group / Manchasol 2 Solar Plant** | 50 MW / 375 MWh (7.5 hours) | Molten Salt | Alcazar de San Juan, Spain | Renewable Generation Shifting |
| **Ortiz - TSK -Magtel / La Africana Solar Plant** | 50 MW / 375 MWh (7.5 hours) | Molten Salt | Posadas, Spain | Renewable Generation Shifting |

Other forms of thermal storage are typically of a distributed nature, and primarily interact with heating and cooling requirements to provide demand-side services such as demand response. Examples include ice storage technologies, which primarily shift air conditioner load, and water heater direct load control, which helps manage water heater load. Some of these technologies have already achieved widespread deployment in electrical and heating networks within certain markets. However, the mild weather in the Pacific Northwest generally limits the days that demand savings can be achieved by the customer for ice storage, and the lack of time of use pricing in PSE service territory has limited customer benefits for both ice storage and water heater direct load control in the area. Water heater direct load control was previously evaluated for its load management potential in PSE's 2013 IRP, and the Non-wires Report evaluated the potential incremental benefits of cost effective direct load control of residential room heating and water heating. Therefore, this report does not further evaluate these technologies. Furthermore, given the limited benefits to customers combined with the likely incompatibility of ice storage in addressing winter peak needs in particular, ice storage was not further evaluated.

### 5.1.4 *Bulk Gravitational Storage*

Bulk gravitational storage includes technologies such as pumped hydro and gravel in railcars. Pumped hydro is a mature technology that is currently used throughout North America and the world. Pumped hydro is suitable for bulk energy shifting, and the concept behind pumped hydro is that off-peak power is used to pump water from a reservoir up to a higher reservoir, where it can be released to generate electricity during peak periods.

As pumped hydro facilities generally require above ground reservoirs, the required footprint can be quite significant, is location-specific, and generally is unable to be placed near urban load centers. In addition, due to the large environmental impact, permitting of pumped hydro facilities can take many years with uncertain outcomes.

**Table 19. Operational Pumped Hydro Storage Facility in Washington State**

| Owner / Project | Nominal Power / Energy (Duration) | Location | Primary Function |
|---|---|---|---|
| **Bonneville Power Administration / John W. Keys III Pump-Generating Plant** | 314 MW / 25,120 MWh (80 hours) | Grand Coulee, WA | Electric Supply Capacity |

The gravel/railcar storage method operates in a similar manner to pumped hydro. Typically, off peak power is used to move rail cars filled with gravel or another heavy material up a slope. When power is needed, the railcar moves down the slope, converting gravitational energy into electricity as it moves down.

An advantage of railcar/gravel energy storage over pumped hydro is that it does not require reservoirs to function. Rather, it requires a long slope of existing or new railroad track. This makes it somewhat easier to site than pumped hydro, although still not suitable for urban areas, nor is it generally suitable for segments of railroad that have existing rail traffic.

**Table 20. Planned Railcar Energy Storage Facility**

| Owner / Project | Nominal Power / Energy (Duration) | Location | Primary Function | Status |
|---|---|---|---|---|
| **ARES North America / Advanced Rail Energy Storage Nevada** | 50 MW / 12.5 MWh (15 min) | Pahrump, NV | Load Following, Voltage Support | Announced |

For these reasons, bulk gravitational storage is not an appropriate technology class for the Eastside reliability requirements and has therefore not been further considered in this assessment.

## 5.2 Roundtrip Efficiency

Roundtrip efficiency (RTE) of energy storage technologies varies substantially based on many factors. Differences amongst technology classes can be significant, but differences due to operational profiles and the environment can be even more significant.

An interview with one vendor offering a lithium ion solution indicated, for example, that the discharge rate as a ratio of the overall energy capacity of the battery cells (the "C Rate) can have a drastic impact on RTE. Systems that slowly discharge (C rate of 0.01, or discharging 1% of capacity per hour) can operate as efficiently as 98%, while efficiency rapidly declines as discharge rate increases.

Ambient temperature can also impact RTE, particularly for chemical energy storage systems. Low temperatures can cause lithium ion, for example, to have a lower RTE, although generally power electronics have higher efficiencies at lower temperatures. Sodium sulfur systems need to be maintained at a high temperature as well in order to operate correctly. Factors such as altitude and humidity can also have a significant RTE impact.

Inverter-based technologies, such as chemical storage, also must factor in additional instantaneous and overall RTE losses that vary substantially based on inverter manufacturer, inverter size, and the device operating profile.[65] Typically efficiency is lower at lower power output as a ratio of the inverter rated maximum power output, and increases as power output increases. This is only true up to a point, however, as inverters flatten or decrease somewhat in efficiency as output nears 100%.

The State of California maintains a database of inverters that have received UL 1741 safety certification and that have developed and submitted efficiency data tested by a Nationally Recognized Testing Laboratory.[66] With 2,249 inverters currently listed, this database is perceived to be a comprehensive source of commercially available inverter power ratings and weighted operational efficiency because it is used to determine eligibility for California state

[65] Inverter capabilities also vary substantially. Certain modern "smart inverters", for example, also have the capability to actively enhance system reliability beyond simply injecting power into the grid. While these capabilities are beyond the scope of this report, such capabilities should be explored as part of PSE's future technical assessments of energy storage or other inverter-based technologies' ability to meet system needs.

[66] http://www.gosolarcalifornia.ca.gov/equipment/inverters.php

incentives. The benefits of this database are that efficiency is determined using a common and generally accepted protocol, which removes the uncertainty of relying on manufacturers' spec sheets. Per this database, modern inverters have weighted operational efficiencies in the 84.5-98.5% range, with median weighted unidirectional efficiency rated at 96%. As efficiencies are rated in a single direction, the values must be multiplied to determine approximate ac-ac RTE (e.g. if an inverter is 96% efficient, the RTE would be approximately 0.96 * 0.96 or 92.16%).

Based on this assessment, we believe that an energy storage power electronics system should be assumed to contribute to at least an additional 8-10% to overall RTE losses versus the standalone cell RTE.

## 5.3 Technologies Modeled

Chemical (battery) storage is the technology class the investigators determined would be most suited for further evaluation to meet the Eastside reliability needs.[67]

Strategen conducted a search of the United States Department of Energy Global Energy Storage Database[68] to assess the technical readiness of the above battery chemistries for deployment on the bulk system to provide a transmission investment deferral function.

No battery technology has yet been utilized to provide transmission or distribution reliability services at the power rating required and evaluated in this assessment, although the Rokkasho Village Wind Farm is comparable in terms of energy rating. The top 5 largest currently operational electrochemical storage projects in the world are shown in Table 21 below:

[67] Distributed thermal storage may also be suitable to meet some or all of the need. However, it was not further evaluated in this assessment as it was previously studied as a demand response resource in PSE's Integrated Resource Plan. See Chapter 5.1.3 for a complete explanation.
[68] DOE GESDB (2014)

**Table 21. Largest Operational Electrochemical Storage Projects, by Power Rating**

| Owner / Project | Nominal Power / Energy (Duration) | Technology | Location | Primary Function |
|---|---|---|---|---|
| **Duke Energy / Notrees** | 54 MW / 36 MWh (40 min) | Advanced Lead acid | Goldsmith, TX | Renewables capacity firming |
| **Japan Wind Development / Rokkasho Village Wind Farm** | 34 MW / 238 MWh (7 hour) | Sodium sulfur | Rokkasho Village, Japan | Renewables capacity firming |
| **AES / Laurel Mountain** | 32 MW / 8 MWh (15 min) | Lithium ion | Elkins, WV | Ancillary Services |
| **GVEA / Battery Energy Storage System** | 27 MW / 6.75 MWh (15 min) | Nickel cadmium | Fairbanks, AK | Backup power |
| **AES / Angamos** | 20 MW / 6.6 MWh (20 min) | Lithium ion | Mejillones, Chile | Backup power |

Other notable utility-owned projects to come online recently include two substation-sited projects in California; specifically, PG&E's Yerba Buena Battery Energy Storage System Pilot Project, a 4 MW/28 MWh (7 hour duration) sodium sulfur battery system, and SCE's Techachapi Wind Energy Storage Project, an 8 MW/32 MWh (4 hour duration) lithium ion battery system. These two systems have been used in this assessment to evaluate visual impact and footprint requirements for the configuration studied herein.

It should also be noted that SCE recently announced the most significant procurement of energy storage to date (summarized in Table 22), amounting to 261 MW. While the AES project cited below has not yet been built, the facility is an in front of the meter installation (rated at 100 MW/400 MWh) and is considered by Strategen to be a comparable benchmark for this study.

**Table 22. Summary of Southern California Edison's Energy Storage LCR Procurement**

| Seller | Resource Type | Nominal Power (MW) | Technology |
|---|---|---|---|
| Ice Energy Holdings, Inc. | Behind-the-Meter | 25.6 | Thermal |
| Advanced Microgrid Solutions | Behind-the-Meter | 50 | Battery |
| Stem | Behind-the-Meter | 85 | Battery |
| AES | In-Front-of-Meter | 100 | Battery |
| NRG Energy, Inc. | In-Front-of-Meter | 0.5 | Battery |
| TOTAL | | **261.1** | |

### 5.3.1 *Operational Energy Storage Systems for T&D Deferral*

A variety of energy storage technologies have been commercially deployed to the grid, providing substantial dispatchable generation and ancillary services resources to bulk energy systems around the world. However, using energy storage to provide a transmission or distribution reliability function *capable of deferring construction of new transmission equipment* as a primary use case is a less common use case at this point in time (with the potential exception of pumped hydro). The largest projects serving a *transmission or distribution deferral function*, per the DOE Global Energy Storage Database are shown in Table 23 below. Note that we include both operational projects and those under construction due to the limited number of projects meeting this criteria.

**Table 23. Largest Projects Serving Transmission or Distribution Deferral Functions, By Power Rating**

| Owner / Project | Power / Energy (Duration) | Technology | Location | Status |
|---|---|---|---|---|
| **UK Power Networks / Smarter Network Storage Project** | 6 MW / 10 MWh (1.67 hour) | Lithium ion | Bedfordshire, United Kingdom | Under construction |
| **Northern Powergrid / CLNR EES1** | 2.5 MW / 5 MWh (2 hour) | Lithium ion | Darlington, United Kingdom | Operational |
| **Bosch / Braderup Energy Storage Facility** | 2 MW / 2 MWh (1 hour) | Lithium ion | Braderup, Germany | Operational |
| **SDG&E / Julian GRC Energy Storage Program** | 1 MW / 3 MWh (3 hour) | Lithium ion | Julian, California | Under construction |
| **SDG&E / Borrego SES** | 1 MW / 3 MWh (3 hour) | Lithium ion | Borrego, California | Under construction |

## 5.4 Technologies Not Further Evaluated

As discussed above, certain technology classes were not further considered in this assessment. Such technology classes and sub-classes include:

- Advanced battery technologies that do not currently have commercial deployments at grid scale, such as flow batteries, were not further considered because they may not be appropriate for a near term, large scale deployment to meet a system reliability need.

- Mechanical storage – this category, which includes flywheels and modular compressed air, was not further considered. Flywheels are optimized to provide short duration storage, typically 15 minutes or less. The primary use case under evaluation in this paper is therefore suboptimal due to the longer duration requirement. The potential use cases of modular compressed air includes the type of load shifting necessary to defer the Eastside reliability need; however, the technology is in pre-commercial demonstration phase and thus may not be appropriate for a near term, large scale deployment to meet a system reliability need.

- Bulk mechanical storage – this category was not further considered due to the unique geological requirements it has for deployment that are incompatible with siting a project in the Eastside area.

- Thermal storage – this technology was not further evaluated due to its typical application of being paired with thermal solar in the case of molten salt and hot water, in the case of direct load management of water and room heating, because it already is studied through PSE's Integrated Resource Planning process, and in the case of ice storage, because it provides benefits that are relatively unaligned with the winter peak need.

- Bulk gravitational storage – this technology class, which includes pumped hydro and rail cars, was not further considered due to the typical space requirements, which are generally more suited to be sited in rural locations, and therefore make this class unsuitable for siting a project in the Eastside area.

## 5.5 Commercial Models of Contracting Bulk Energy Storage

### 5.5.1 *Contracting Models*

Different energy storage contracting models are being utilized to address a wide range of necessary grid support applications. Contracting models include turnkey systems, power purchase tolling agreements, and demand response agreements. Each offers unique financial liabilities and operating characteristics.

#### Turnkey

In the turnkey model, developers are responsible for engineering, procurement, construction, testing, commissioning, start-up and performance verification. Projects could be built on either on utility or private land, and the utility agrees to acquire the system after commissioning. These utility owned systems can then be flexibly operated to deliver whatever kind of grid support the utility desires, without the operational complexity of third party involvement in the system operation. Typically, turnkey solutions come with warranties commensurate with other utility infrastructure purchases.

Examples of recent turnkey energy storage solicitations include HECO's May 2014 Request for Proposal (RFP) for 60-200 MW of energy storage (RFP# 072114-01), which requested only turn key projects. PG&E and San Diego Gas and Electric's (SDG&E) December 2014 Request for Offers (RFO) for energy storage solicited both turnkey and tolling agreements.

#### Energy Storage Tolling Agreements

Southern California Edison (SCE) recently developed a new style of agreement, the "Energy Storage Agreement" (ESA) for its recent solicitation to meet Southern California's Local Capacity Requirements (2013 LCR RFO). According to Les Sherman of Orrick, "SCE's pro-forma ESA will likely evolve, but is expected to become the basis for other SCE storage solicitations, as well as an example for other IOUs, and even potentially utilities in other jurisdictions."[69] This agreement was created based on SCE's standard power purchase tolling agreements (PPTA), which are "contracts to purchase power wherein the utility pays the seller a periodic payment for capacity for the length of the contract."[70] PPTAs apply to third-party owned systems and are a typical contractual arrangement for system capacity resources that have been extended to energy storage procurement where typical utility dispatch of the storage system is unknown.

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[69] Sherman (2014)

[70] California Office of Ratepayer Advocate: http://www.ora.ca.gov/ppta.aspx

The commercial terms are generally structured such that the developer is fully responsible and at risk for all project development, as well as for the full operation, maintenance, and repair of the project. The buyer (utility) is typically the scheduling coordinator, and as such responsible for scheduling of all energy deliveries and dispatches, and is also responsible for all costs associated with charging, and receives all revenues from discharging. The seller's compensation is generally structured as a fixed payment for capacity, and a variable payment for operations and maintenance.

#### Demand Response Agreement

Utilities seeking to manage/reduce peak demand may opt for demand response agreements (DRAs). DRAs apply to distributed, customer-sited energy storage systems. A utility agrees to receive and purchase a specified amount of power and energy which the system owner agrees to deliver and sell during specific time periods.

For example, SCE solicited DRA as part of its 2013 LCR RFO.[71]

### 5.5.2 *Warranties & Performance Guarantees*

Performance guarantees and warranties are a critical component of energy storage procurement. Buyer protections typically include a variety of performance guarantees, damages for failure to hit pre-commercial operation milestones, testing and operations requirements that are custom to the project and technology, default provisions, capacity payment reduction mechanisms, project financing requirements, and others.[72]

Warranty terms are generally negotiated on a case-by-case basis. HECO's energy storage RFP, for example, contemplated an 18 month "performance verification" period that is mandatory for all bids, with sellers to offer warranty terms beyond the 18-month period as part of the solicitation response. HECO indicated that it preferred a single warranty wrap from the EPC contractor for the project, and expected bidders to design the system to maintain "full nameplate performance" at the end of the system's expected 15-year lifespan. [73]

PG&E's 2014 Energy Storage RFO contemplates a variety of performance guarantees. For its distribution deferral turnkey component of the RFO, PG&E's performance guarantees included guarantees on the following: Cmax (maximum charge rating), charging duration, daily efficiency, standby energy consumption, Dmax (maximum discharge rating), discharge duration, site-specific duty cycle, and emissions limits.[74]

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[71] The SCE agreement can be downloaded here: https://www.sce.com/wps/wcm/connect/aac24575-6a82-439b-8da0-893638296a99/2013_LCRRFO_DR_ES_ProForma_03262014.docx?MOD=AJPERES

[72] Sherman (2014)

[73] Hawaiian Electric Company RFP (RFP# 072114-01) for 60 to 200 MW of Energy Storage for Oahu, Q&A Log: http://www.hawaiianelectric.com/vcmcontent/StaticFiles/pdf/ESS_Master_Question_and_Answer_Log_071614.pdf

[74] Exhibit F of PG&E's Energy Storage RFO protocol: http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/RFO/ES_RFO2014/index.page

# 6 Energy Storage Configurations and Feasibility

This white paper focuses on addressing the feasibility of using energy storage combined with other cost-effective non-wires solutions to address PSE's Eastside System Reliability Needs. As such, the location and configuration of the energy storage system combined with lower cost non-wires alternatives, must be capable of meeting or exceeding the Eastside system reliability need. Importantly, it must do so with a sufficient degree of margin as to provide confidence that the system would remain reliable under system conditions that exceed the stress of PSE's more aggressive planning scenarios. This section of the report discusses the factors used as inputs to develop the configurations studied, and evaluates the feasibility of each configuration.

## 6.1 Effectiveness Factor

Energy storage (or any non-wires alternative) cannot offset transmission line overloads at a 1:1 ratio. Because energy flows over the power system based on the relative resistances of various lines, less than 100% of the power rating of an energy storage system will flow on the lines in the direction needed to offset load in an appropriate manner. If 1 MW of energy discharge offset 1 MW of system need, the effectiveness factor would be 100%. If 1 MW of energy discharge offsets only 0.25 MW of system need, the effectiveness factor would be 25%.

In the case of the Eastside system, PSE transmission planners modeled the impact of the load reduction via energy storage or other non-wires alternatives and determined that such load reduction would have an effectiveness factor of approximately 20-21%.[75]

## 6.2 Planning and Operating Standards

The Non-wires Report sought to address a 2017 transmission capacity deficiency of between 70 MW and 160 MW. That study concluded that 56 MW of non-wires (DSR) alternatives were cost-effective, and thus the overall deficiency would hypothetically be reduced but not eliminated. The Non-wires Report, though, did not reduce the need for PSE to rely on CAPs to mitigate overloads at Sammamish and Talbot substations. Discussions with PSE's transmission planners and a re-evaluation of planning criteria concluded that energy storage, if selected, must fully meet planning and operating standards in order provide a level of reliability comparable to a transmission solution.

### *Steady State Requirements*

There were three levels of mitigation requirements to be met:

- Near Term Planning Requirements: In order to solve the transmission system capacity deficiencies indicated in the 2013 Eastside Transmission Needs Assessment, it was

[75] Based on power flow studies run by PSE, its transmission planners determined that a 29.44 MW peak overload under N-1-1 conditions in 2017 at Talbot Hill transformer #1 was offset by 135 MW of non-wires resources including storage (20.0% effectiveness). That peak overload grows to 34.07 MW by 2021, which required 170 MW of resources to offset the need (20.6%), which is within a very close margin of error when compared to the 2017 calculations.

necessary to bring loading on all lines and transformers below 100% of the emergency rating in the 2021-22 winter case and in the 2018 summer case for all FERC required contingencies.

- Long Term Solution: To be equivalent to the Bellevue 230-115 kV transformer connected to PSE's 230 kV transmission system, the battery solution would need to keep overloads below 100% in the longer term, as modeled in the 2021-22 normal winter case with 75% conservation for all FERC required contingencies.

- Operating Requirements: Day to day operations are required to keep all line and transformer loading below 100% of the emergency rating. Operations must also keep transformer loading between the normal and the emergency limit for no more than 8 consecutive hours. These limits are applicable to all cases for all FERC required contingencies. These values were provided to Strategen for reference but not required as a solution by 2021. If PSE Operations is faced with limiting 230-115 kV transformer loading above the normal limits for no more than eight hours, it may be necessary to dispatch generation, sectionalize transmission lines, or shed load, or combinations of all three.

FERC requires that PSE meet the NERC Transmission Planning Standards (TPL) for all elements in service (N-0), loss of one element (N-1), loss of a double or multiple-element site (N-2) or loss of one element followed by an adjustment then loss of a second element (N-1-1). During all of these contingencies, no elements may overload nor experience voltages out of compliance. These are included in NERC Reliability Standards TPL-001-4. PSE is not allowed to create an adverse impact on neighboring utilities during any of these contingencies.

Due to the operating characteristics of batteries, which are rated for a peak demand as well as watt-hour duration, it was necessary to consider the operating requirements as well as the planning requirements for this study. Once the battery discharges, it requires a charging period sufficient to restore its full charge prior to the next discharge cycle. Therefore the hourly load profile forecast into the future was provided to Strategen.

## 6.3 Defining the Size

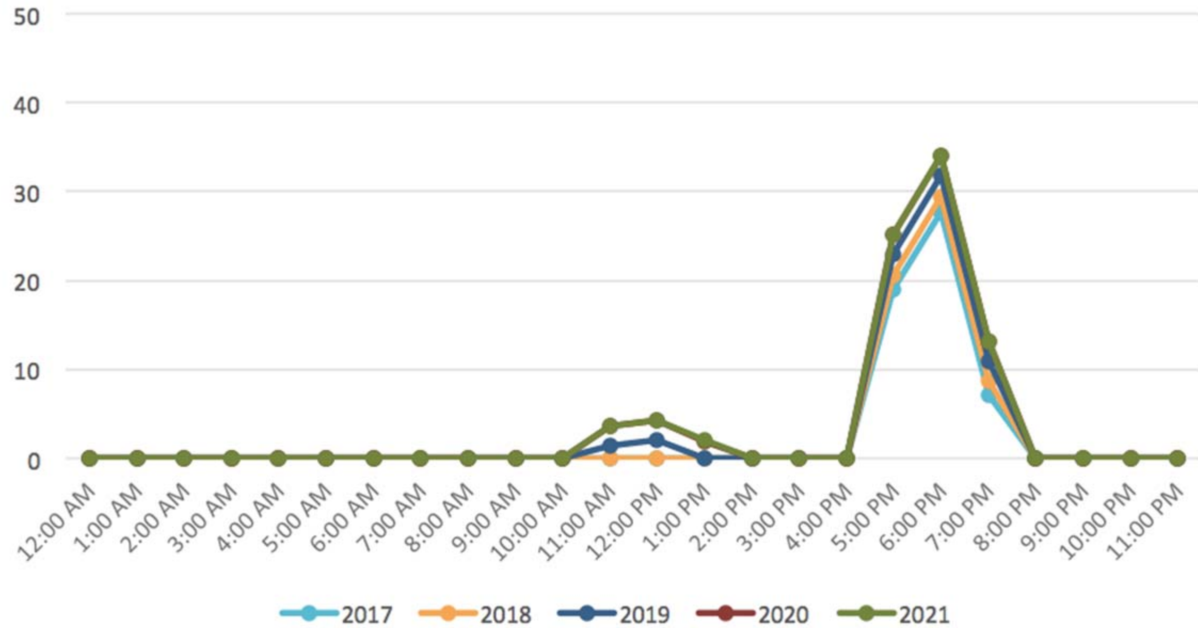
Strategen started its evaluation by looking at the maximum emergency power flows on the Talbot Hill and Sammamish substations during Category C NERC contingencies (N-1-1). This data was provided as hourly (8760 per year) data by Puget Sound Energy's transmission planning team. PSE also provided the normal and emergency line ratings for Talbot Hill and Sammamish substations. The analysis determined that in all years, Talbot Hill was the substation with the most significant normal and emergency winter overloads, thus Talbot Hill was the element that determined the overall need.

### 6.3.1 *Talbot Hill Emergency Overloads*

#### 6.3.1.1 *Talbot Hill Emergency Overload Profile*

Based on the data provided by PSE, Talbot Hill's emergency rating could be exceeded on the peak day in 2017 for 3 hours, peaking at approximately 28 MW exceedance. By 2021, this increases to an overload that runs for 6 non-contiguous hours on the peak day, with a peak of 34 MW.

**Figure 6. Maximum Eastside Emergency Overload Profile, from 2017 to 2021 (in MW)**




The hourly overload distribution in any given year is likely to be slightly different than any other year, and could vary significantly from what was studied due to a variety of factors that include:

a) actual load growth the region will see between now and 2021 could deviate from load growth forecasts;

b) the amount of energy efficiency, distributed generation, and demand response that PSE assumes will develop in its integrated resource plan may not materialize as planned; and

c) Actual future weather conditions could drive higher or lower peak load on the system during any given year versus typical[76] winter and summer conditions.

Any of the above factors may not occur as planned. The eventual system requirements may be higher than the load reduction need identified based on the data provided by PSE.

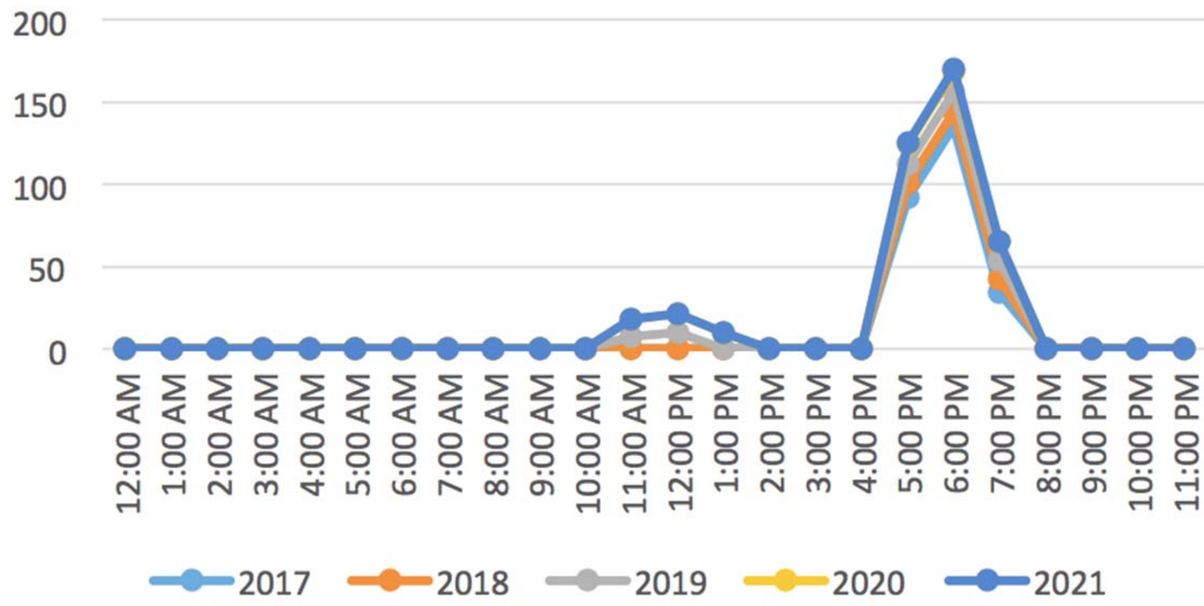
#### 6.3.1.2 *Gross Talbot Hill Emergency Load Reduction Need*

Notwithstanding the potential for variability in actual overloads, the above data was used to determine the cumulative amount of non-wires + storage alternatives needed to address the Eastside need. As indicated in Chapter 6.1, PSE transmission planners modeled the impact of the load reduction (in the form of energy storage or other non-wires alternatives) on the overload and determined that discharged energy from the configuration would have an effectiveness factor of approximately 20-21%. In order to determine the power rating of the

[76] Typical conditions are conditions that are likely to occur in one out of every two years.

energy storage needed to meet the emergency overload need, the above overloads were multiplied by the effectiveness factor of non-wires alternatives (including energy storage) to determine the following duration and shape of load reduction requirements to offset the emergency overload on Talbot Hill:

**Figure 7. Duration and Shape of Gross Non-Wires + Storage Resource Requirement by Year for Emergency Overload Elimination (in MW)**




As shown on the above chart, the resulting peak need is approximately 135 MW in 2017, increasing to a peak need of 170 MW in 2021.

#### 6.3.1.3 *Reduction in Gross Need due to Non-Wires Alternatives*

Other non-wires alternatives that were determined to be cost effective in meeting the deferral need[77] were then used to offset a portion of the identified reliability need. Figure 18, taken from the Non-wires Report[78], graphically depicts the amount of cost effective non-wires alternatives available is anticipated to increase from 2017 to 2021. The underlying data shows available non-wires resources growing from 17.7 MW in 2017 to 55.6 MW in 2021. Non-wires alternatives deemed to be cost effective include all energy efficiency, demand response, and distributed generation programs included in the Non-wires Report[79] that were not previously selected in PSE's Integrated Resource Plan. Demand Response programs deemed cost effective by PSE were already included in its integrated resource plan. The increase in other non-wires alternatives closely tracks projected growth in Talbot Hill's emergency overload, resulting in the following energy storage net injection requirements from 2017-2021:

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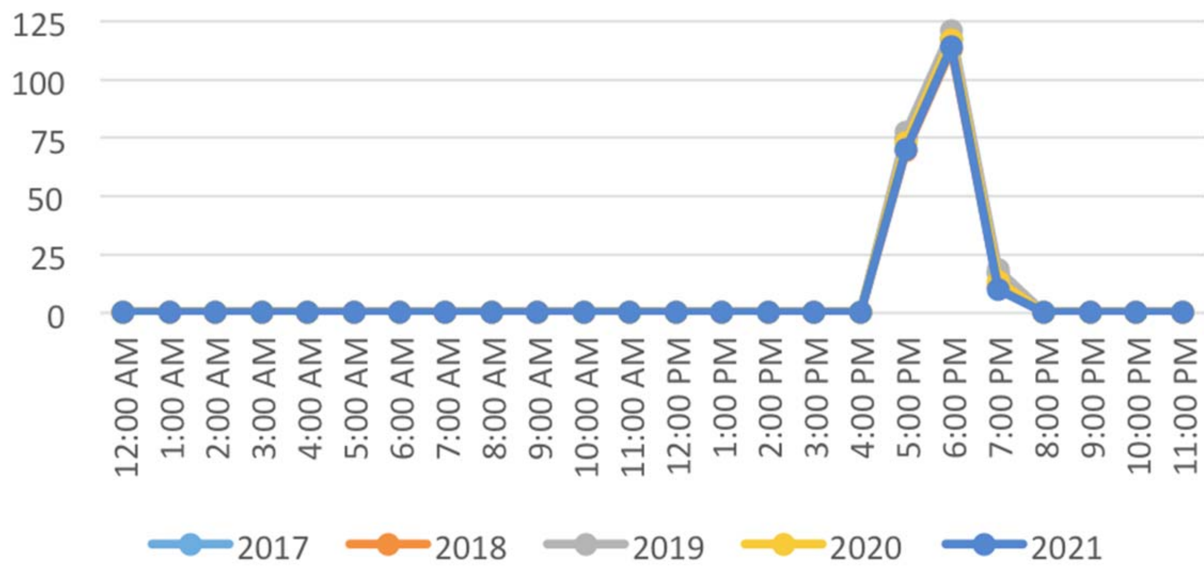
[77] E3 (2014)
[78] *Ibid.*
[79] *Ibid.*

**Figure 8. Energy Storage Net Injection Requirement by Year for Emergency Overload Elimination (in MW)**




Note that the non-wires resources were effective at eliminating the overload during the first three hour peak, and reducing the emergency overload during the second peak. As the above chart shows, the peak power requirement of the energy storage system to address an emergency overload only was determined to be as follows:

2017: 117 MW

2019: 121 MW

2021: 114 MW[80]

Thus, to meet the 2021 deferral need based on the emergency rating, the system would have to be capable of having a power rating of 121 MW (to meet the 2019 peak need).

The above analysis identifies not just the power requirements of the energy storage system (i.e. MW), but also informs the *total* energy (i.e. MWh) required of the energy storage system. This was accomplished by evaluating the *duration* and *shape* of the incremental need during times when the peak capabilities of existing transmission lines are being exceeded.

Take, as an example, flow modeling that shows that over a 3-hour period, peak load exceeds line rating by 20 MW in the first hour, 30 MW in the second hour, and 10 MW in the third hour. In this case, an energy storage system would need to provide peak output of 30 MW and an energy rating of 20 MWh in the first hour, 30 MWh in the second hour, and 10 MWh in the third

[80] Note that the results show a slight drop in the 2021 power requirement versus 2019. This is driven by the projected availability of new cost effective non-wires resources in the 2019-2021 timeframe exceeding growth in line loading.

hour. This would result in an energy storage system sized to provide peak output of 30 MW and an energy rating of 60 MWh to meet the need. Depending on the chemistry of the battery used, an additional buffer may also need to be included in order to prevent the battery from completely discharging, which can have negative impacts on the life expectancy of certain batteries.

For the PSE Winter Peak Scenario, load flow analysis identified the following energy requirements:

2017: 209 MWh

2019: 216 MWh

2021: 194 MWh[81]

#### 6.3.1.4 *Energy Storage Sizing to Meet Emergency Overload*

The investigators used the Eastside hourly overload data above as the basis to develop power and energy requirements for energy storage systems meeting the emergency overload. Chemical energy storage systems also exhibit a tendency to degrade over time as the device is charged and discharged (this is called cycling). The investigators modeled the operation of the configurations studied in a manner that conforms to a standard system degradation rate of approximately 2% per year. As such, the system meeting a 2021 deferral needs to be slightly upsized in order to account for degradation from 2017-2021. This results in a slightly greater energy requirement for the energy storage system than the 2021 injection requirement.

[81] Similar to what was noted above, the results show a slight drop in the 2021 energy requirement versus 2019.

**Table 24. Emergency Overload Elimination Net Injection Requirements by Year***

| | 2017 Sizing for deferral through calendar year | |
|---|---|---|
| | **2017** | **2021** |
| **Power (MW)** | 117.3 | 121.0 |
| **Energy (MWh)** | 208.8 | 225.6 |
| **Duration (hours)** | 1.8 | 1.9 |

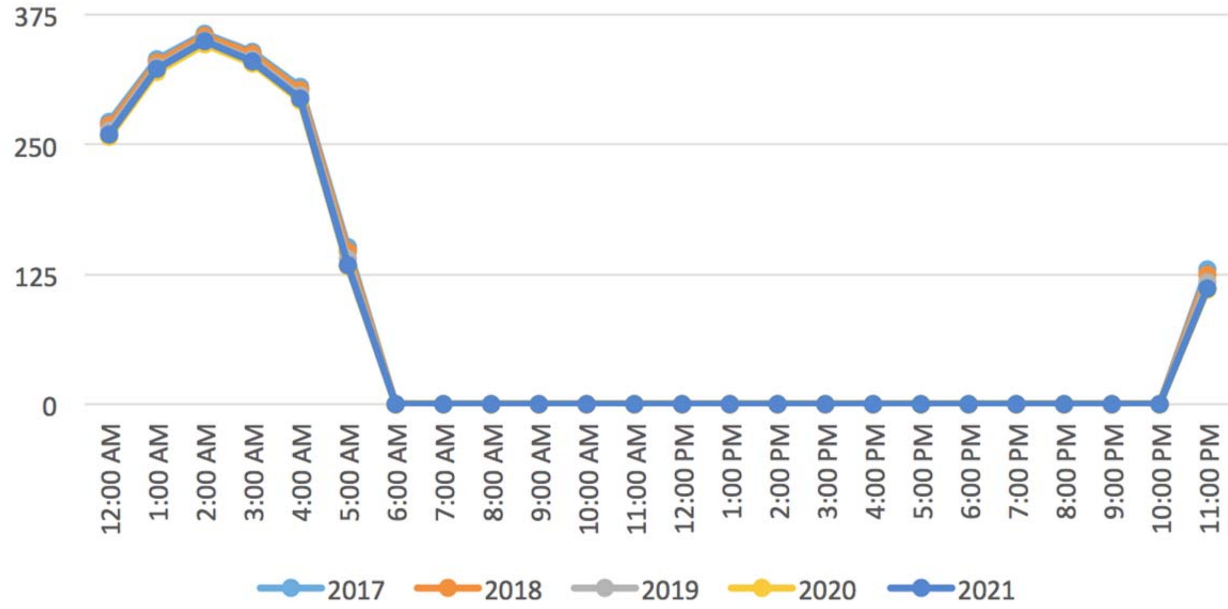
***Accounts for a 2%/year battery cell degradation**

#### 6.3.1.5 *Charging Requirement versus Available Grid Capacity*

Available capacity on the Eastside system must also be sufficient to fully charge an energy storage device between discharge cycles without overloading equipment.

After accounting for the effectiveness factor of the energy storage and the benefits of other non-wires alternatives in alleviating the overloads, the maximum charging capacity as constrained by Talbot Hill was determined to be as follows:

**Figure 9. Available Hourly Grid Capacity for ES Charging by Year (in MW)***




*Accounts for non-wires alternatives

In order to determine whether the available grid capacity is sufficient to fully charge the energy storage over the course of a day to prepare for the system's duty cycle, the charge requirement is compared against the available grid capacity. The charge requirement is determined by dividing the system's energy requirement (for discharging to the grid) by the assumed ac-to-ac roundtrip efficiency of the energy storage system. We assume an average 85% roundtrip efficiency for the studied system, which results in the following.

**Figure 10. Net Energy Storage Charge Requirement vs Available Grid Capacity (in MWh)**

| | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| **Discharge Requirement** | **208.8** | **194.1** | **216.8** | **203.4** | **194.2** |
| **Charge Requirement** | **245.6** | **228.3** | **255.1** | **239.3** | **228.5** |
| **Capability to Charge (ex NW)*** | **1886.0** | **1863.2** | **1825.9** | **1788.1** | **1802.0** |
| **Capability to Charge (inc NW)*** | **2009.6** | **2088.4** | **2074.9** | **2158.4** | **2204.2** |
| ✓ | OK | OK | OK | OK | OK |

* “ex NW” = Not accounting for Non-wires alternatives, and “inc NW” = After Accounting for Non-wires alternatives”

As shown above, the Eastside system does have sufficient capacity to charge the storage system in order to meet the emergency overload discharge requirement.

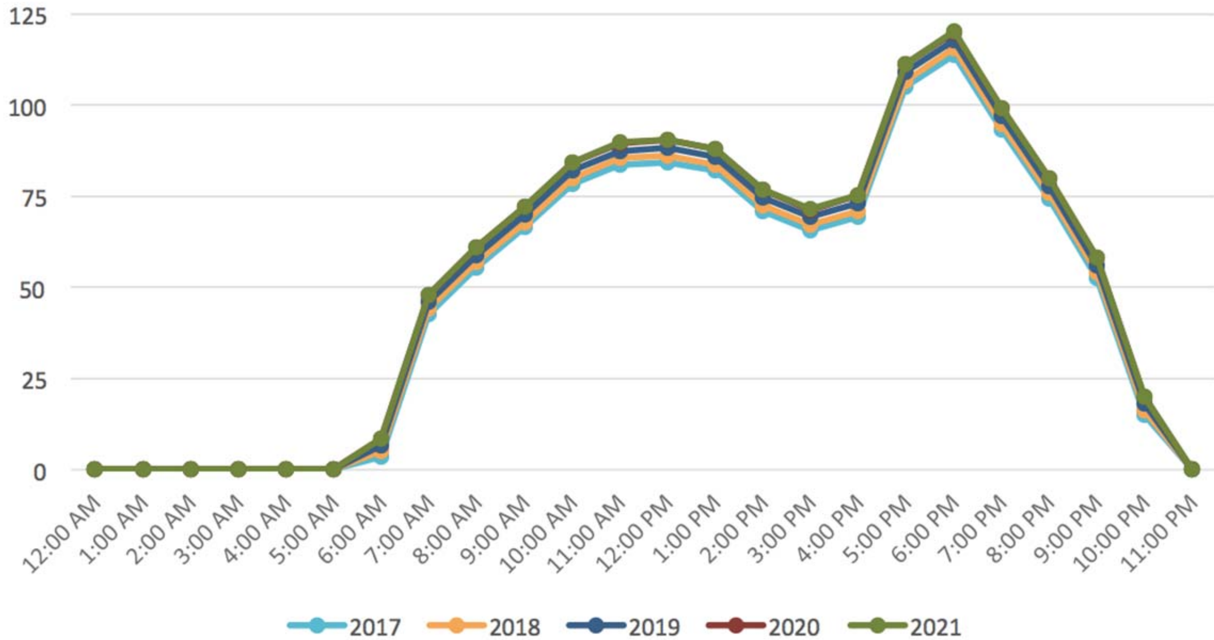
## 6.3.2 *Talbot Hill Normal Overloads*

### 6.3.2.1 *Talbot Hill Normal Overload Profile*

Based on the data provided by PSE, Talbot Hill’s normal rating could be exceeded in 2017 for 17 consecutive hours. As PSE’s operating standards do not allow for normal overloads to be exceeded for more than eight contiguous hours, Talbot Hill’s normal overload constitutes a violation of PSE planning criteria and thus must be reduced to less than or equal to eight hours.

Talbot Hill’s normal overload peaks in 2017 at approximately 114 MW exceedance. By 2021, this increases to an overload running for 17 consecutive hours with a peak of 120 MW.

**Figure 11. Eastside System Maximum Normal Overload by Year (in MW)**

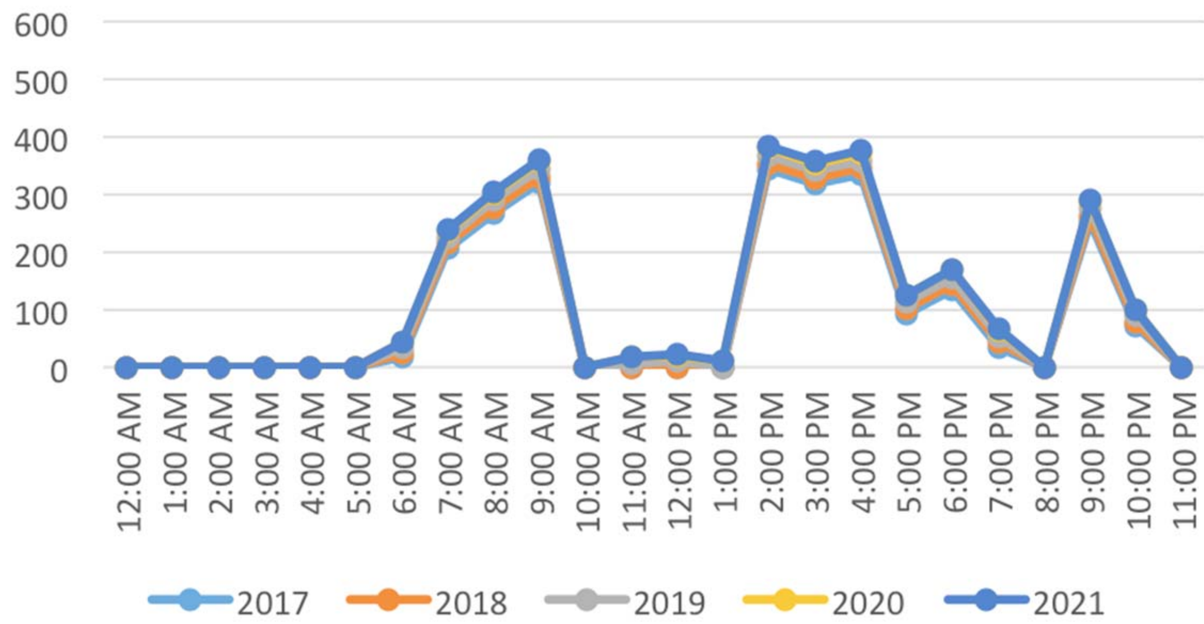



#### 6.3.2.2 *Gross Talbot Hill Normal Load Reduction Need*

PSE data was used to determine the cumulative amount of non-wires + storage alternatives needed to address the Eastside normal overload. In order to meet PSE's planning and operating requirements, the system must both reduce the normal overload to less than or equal to eight contiguous hours, and mitigate the emergency overload during hours when the energy storage device is not also being used to address the normal overload. Due to the two-peak nature of the Eastside winter load profile, the investigators assumed that from 10:00 am – 2:00 pm and from 5:00 pm – 9:00 pm, the non-wires and energy storage solution would only be used to mitigate the emergency need; the normal overload would remain unmitigated.

The effectiveness factor of approximately 20-21% was used to determine the amount of non-wires alternatives (including energy storage) necessary to offset the normal + emergency overload on Talbot Hill. The assumed shape of the non-wires and energy storage requirement appears as such:

**Figure 12. Duration and Shape of Gross Non-Wires + Storage Requirement by Year (in MW)**



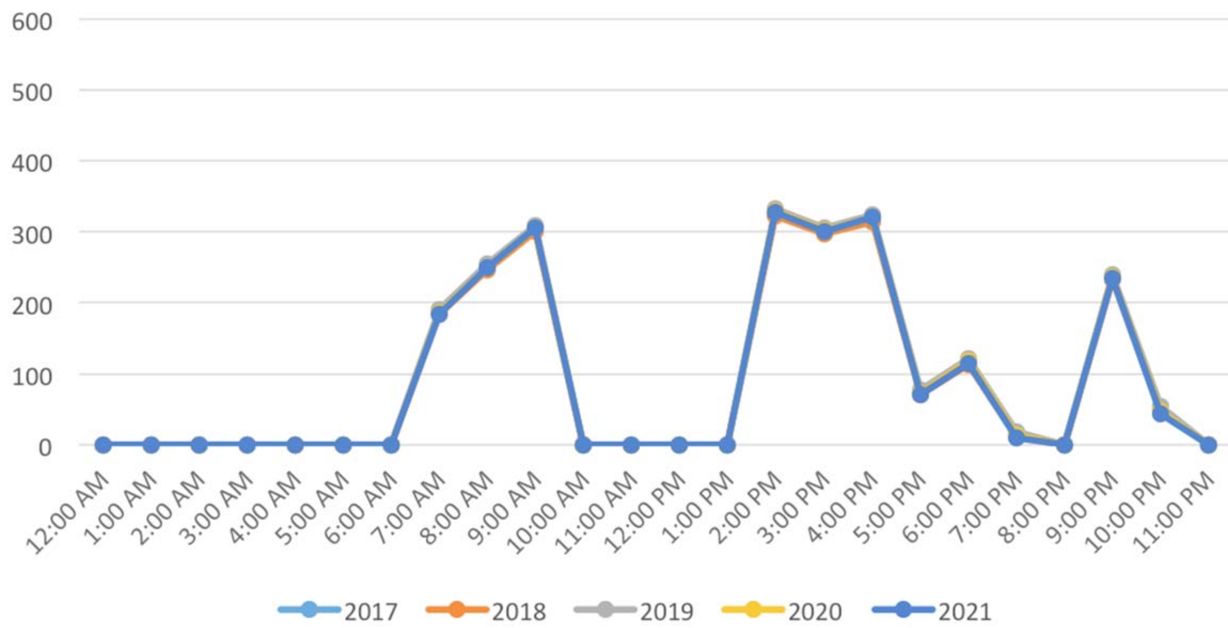

As shown on the above chart, the resulting peak need is approximately 343 MW in 2017, increasing to a peak need of 384 MW in 2021.

#### 6.3.2.3 *Reduction in Gross Need due to Non-Wires Alternatives*

Other non-wires alternatives such as demand response, energy efficiency and distributed generation that were determined to be cost effective in meeting the deferral need[82] were then used to offset a portion of the identified reliability need, resulting in the following energy storage net injection requirements from 2017-2021:

[82] E3 (2014)

**Figure 13. Duration and Shape of Energy Storage Net Injection Requirement by Year (in MW)**




The above chart shows the peak power requirement of the energy storage system was determined to be as follows:

2017: 326 MW

2019: 332 MW

2021: 328 MW

Thus, to meet the 2021 deferral need in a manner that meets PSE's planning and operating requirements, the system would have to be capable of having a power rating of 332 MW (to meet the 2019 peak need). Energy requirements were identified as such:

2017: 2,184 MWh

2019: 2,224 MWh

2021: 2,160 MWh

#### 6.3.2.4 *Energy Storage Sizing to Meet PSE Planning and Operating Requirements*

The investigators used the Eastside hourly overload data above as the basis to develop power and energy requirements for energy storage systems meeting the deferral need. Chemical energy storage systems also exhibit a tendency to degrade over time as the device is charged and discharged (this is called cycling). The investigators modeled the operation of the configurations studied in a manner that conforms to a standard system degradation rate of approximately 2% per year. As such, the system meeting a 2021 deferral needs to be slightly upsized in order to account for degradation from 2017-2021. This results in a slightly greater energy requirement for the energy storage system than the 2021 injection requirement. Note that the 2019 requirement, while higher, ends up resulting in a slightly smaller system than the 2021 requirement once degradation is accounted for. Therefore, the 2021 energy requirement with degradation is used.

**Table 25. Normal Overload Reduction Net Injection Requirements by Year***

| | 2017 Sizing for deferral through CY | |
|---|---|---|
| | **2017** | **2021** |
| **Power (MW)** | 326 | 328 |
| **Energy (MWh)** | 2,184 | 2,338 |
| **Duration (hours)** | 6.7 | 7.1 |

***Accounts for a 2%/year battery cell degradation**

#### 6.3.2.5 *Charging Requirement versus Available Grid Capacity*

As discussed above, available capacity on the Eastside system must also be sufficient to fully charge an energy storage device between discharge cycles without overloading equipment.

The investigators assume an average 85% roundtrip efficiency for the studied system, which results in the following.

**Figure 14: Net Energy Storage Charge Requirement versus Available Grid Capacity (in MWh)**

| | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| Discharge Requirement | 2184.3 | 2136.7 | 2224.4 | 2179.8 | 2160.0 |
| Charge Requirement | 2569.8 | 2513.7 | 2616.9 | 2564.4 | 2541.1 |
| Capability to Charge (ex NW) | 1886.0 | 1863.2 | 1825.9 | 1788.1 | 1802.0 |
| Capability to Charge (inc NW) | 2009.6 | 2088.4 | 2074.9 | 2158.4 | 2204.2 |
| ✓ | FAIL | FAIL | FAIL | FAIL | FAIL |

* "ex NW" = Not accounting for Non-wires alternatives, and "inc NW" = After Accounting for Non-wires alternatives"

As shown above, the Eastside system does not have sufficient capacity to charge the storage system in order to meet the normal overload discharge requirement. **Therefore, we have determined that it is electrically impossible for energy storage, even when paired with other non-wires alternatives, to fully mitigate the normal overload at Talbot Hill in a manner sufficient to meet Puget Sound Energy's required planning and operating standards.**

### 6.3.3 *Sammamish Emergency and Normal Overloads*

Strategen also evaluated the maximum emergency and normal overloads occurring at Sammamish substation. These overloads generally occurred during the summer, rather than winter, peak. However, in all circumstances, the maximum overloads were substantially less than those occurring at Talbot Hill. Thus, energy storage sized to meet the Talbot Hill overloads and sited in an appropriate location was assumed to be sufficient to meet the Sammamish overload. No further analysis was conducted on the Sammamish overloads as part of this assessment. However, further validation of this assumption would be required prior to making a definitive conclusion that both Talbot Hill and Sammamish overloads could be addressed with the studied configurations.

## 6.4 **Ownership Model and Location**

In theory, serving PSE's transmission deferral objective could be achieved independent of energy storage facility ownership model. Additionally, it could occur independent of a predetermined configuration, provided that configuration and location meets certain parameters.

For example, the need could be met by placing utility-owned energy storage devices at substations, or the utility could use a power purchase or tolling agreement with a third party for bulk system storage. The utility could develop a program wherein customer-sited energy storage systems could be used as demand response resources called upon to meet reliability needs during winter or summer peak conditions.

The analysis focused on substation-sited energy storage to address the Eastside needs. An analysis of the practical considerations of both customer-sited and substation-sited configurations are below.

### 6.4.1 *Customer-Sited Energy Storage*

Customer-sited energy storage is generally physically located at the customer site, but it does not necessarily require being on the customer-side of the meter. It can also include siting of energy storage at campus-level microgrids or small-scale residential-level microgrids. As such, these use cases may provide services to the customer, the utility, or both.

A conceptual advantage of a fleet of customer-sited storage is that, from a technical perspective, it provides flexibility to provide the maximum number of grid services, which are very location-specific. Additionally, energy delivered at the end-customer has the ability to avoid the line and transformer losses that occur with energy generated, transmitted, and distributed by a remote power plant. Moreover, the effectiveness factor may be higher for customer-sited storage closely aligned with load on individual circuits than for transmission level energy storage located at a substation. Power delivered from customer-sited energy storage during a system peak can simultaneously off-load T&D assets and generators, with the potential to provide multiple value streams to the owner with a simple operational objective. Additionally, due to the proximity to the customer, energy storage located at the customer site is best positioned to provide enhanced reliability and backup power during power outages. Another benefit of customer-sited systems is that a large number of distributed systems can provide redundancy and potentially leverage economies of scale in manufacturing compared to larger, more customized units.

There are, however, some potential drawbacks to customer-sited storage for this application. First is the cost associated with the small scale of the individual storage resources, should they be fully committed to transmission deferral. The fixed costs associated with installation and management of customer energy storage systems are typically higher over multiple small to mid-size energy storage resources, especially as compared to megawatt-scale systems. However, given the Eastside system deferral need is of limited frequency and duration, we do not believe this to necessarily be a constraint, as a customer-sited program in this case could potentially be cost-effectively be deployed with secondary uses benefitting retail customers.

Perhaps the more substantive issue is that transmission deferral requires a threshold minimum deployment of energy storage to achieve the needed effect depending on the load characteristics and expected growth rate. In this case, in order to address the 2017 normal need sufficiently to meet PSE planning standards, a customer-sited program would require deploying more than 4,300 commercial/industrial sized energy storage systems rated at an average of 500 kWh each between 2015 and 2017. All of these systems would need to be located appropriately in the Eastside region to provide support to the substation in need of upgrade, and the storage systems' operation would need to be managed and aggregated through secure communication and control. While not technically impossible, the development of a customer-sited storage program at this scale to meet near-term grid reliability needs is likely to be challenging given the myriad site-specific challenges that could derail or delay any individual site being developed within the fixed timeframe needed to address the reliability need. Location-specific issues such as environmental impact, community involvement in siting, electrical interconnection challenges, logistics, third party contracting or other legal challenges, would all need to be successfully resolved for enough individual customer sites in order for the reliability need to successfully be met. Locating energy storage next to a customer also requires heightened sensitivity toward safety, as compared to remotely located energy storage systems in a secure, utility-controlled area.

PSE is also obligated to meet certain reliability standards under state and federal regulations. If PSE were to proceed with a customer-sited program today and the program failed to develop enough resources to address the need, PSE would be past the 'point of no return' to move forward with a wires-based solution in time to prevent the reliability issues. Given the binary nature of this challenge, (e.g. anything less than complete success would not address the reliability need), we did not further evaluate the cost-effectiveness of customer-sited energy storage to address the Eastside reliability issues in this assessment.

While Strategen and PSE concluded that the specifically large scope of the Eastside need was not conducive for further evaluation as part of this assessment, we note that there are many circumstances where customer-sited energy storage can be a cost effective way to manage system or local peak power requirements. Strategen recommends that PSE more thoroughly evaluate the cost-effectiveness of customer-sited energy storage programs to meet long term planning objectives as part of PSE's integrated resource planning process.

### 6.4.2 *Substation-Sited Energy Storage*

Substation-sited energy storage is a relatively straightforward concept. Energy storage equipment would generally be sited at or near a utility substation, and would be directly connected to the substation. The device would be directly controlled by the utility as a utility asset. Such a device could be utility-owned, but it could also be owned by a third party and contracted for use by a utility under a "Power Purchase Agreement" or "Tolling Agreement" model, similar to how independently-owned power plants frequently contract with utilities.

Key advantages of substation-sited energy storage in the context of meeting the Eastside system reliability needs are as follows:

- Development of the systems would have a higher degree of certainty due to utility control over the process – comparable to that of a utility-developed transmission line,

- Significant economies of scale exist in large scale system resource development. This will result in enough purchasing power to lower battery cell cost, as well as significantly lower balance of system cost, which is defined as all of the electric infrastructure needed to interconnect the battery to the grid, convert the power from DC to AC, control the equipment, and to communicate with the grid operator, and

- PSE will have greater control over when battery cell procurement occurs, which is the component of energy storage systems that is most likely to see large cost declines during the specified timeframe. For example, the balance of system could be built to meet the full deferral need, but batteries added in a modular fashion over the 2017-2021 timeframe as costs come down and the reliability need increases.

Disadvantages include:

- Due to the changing transmission system flow patterns between winter and summer, the effectiveness of specific substation-sited storage configurations may vary between winter and summer. For example, a specified configuration may be relatively effective at meeting the winter need, but less so at meeting the summer need, because the power that the storage system injects into the transmission system is flowing on the transmission system differently.

Due to the greater certainty that substation-sited energy storage can be developed and operational in time to meet a time-sensitive reliability need, we recommended that this report focus on substation-sited configurations.

## 6.5 Physical Footprint of Substation-Sited Storage

After deciding to proceed with a substation sited storage solution, evaluation was made of system acreage requirements and which substation would be most appropriate for siting.

PSE supplied acreage estimates for land related to interconnection facilities and parking, while vendor interviews and satellite imagery analysis provided sizing estimates for the battery, balance of system (including power electronics and related equipment) and the building. Table 26 summarizes acreage requirements for the three modeled scenarios.

**Table 26. ESS Acreage Requirement Estimates for 2021 Deferral (in acres)**

| Component | Baseline<br>Normal Overload Reduction | Alternate #1<br>Emergency Overload Elimination | Alternate #2<br>Normal Overload Elimination |
|---|---|---|---|
| Battery, BOS, Building | 9.6 | 1.3 | 22.7 |
| Interconnection Facilities and Parking | 10 | 4.5 | 23 |
| **TOTAL** | 19.6 | 5.8 | 45.7 |

Batteries were modeled at a combination of three centralized transmission substation locations. Battery models are not available in WECC for transmission-level interconnection, therefore batteries were modeled as a negative load at the substation bus. Negative loads were modeled as either evenly distributed between Sammamish, Lakeside and Talbot Hill, or half at Lakeside with the remainder split between the other two substations, or all at Lakeside. See Table 27 for battery distribution.

**Table 27. Centralized Battery Locations Modeled**

| Scenario | PowerWorld Case | Amount of Storage (MW) | Locations | Split |
|---|---|---|---|---|
| 1a | 2017-18 HW SN NG | 70 | Sammamish, Lakeside, Talbot Hill | 1/3, 1/3, 1/3 |
| 1b | 2017-18 HW SN NG | 70 | Sammamish, Lakeside, Talbot Hill | .25, .50, .25 |
| 1c | 2017-18 HW SN NG | 70 | Lakeside | 100% |
| 2a | 2018 HS SN FG | 70 | Sammamish, Lakeside, Talbot Hill | 1/3, 1/3, 1/3 |
| 3a | 2017-18 HW SN NG | 160 | Sammamish, Lakeside, Talbot Hill | 1/3, 1/3, 1/3 |
| 3b | 2017-18 HW SN NG | 160 | Sammamish, Lakeside, Talbot Hill | .25, .50, .25 |
| 3c | 2017-18 HW SN NG | 160 | Lakeside | 100% |
| 4a | 2017-18 HW 75% Cons SN NG | 160 | Sammamish, Lakeside, Talbot Hill | 1/3, 1/3, 1/3 |
| 4b | 2017-18 HW 75% Cons SN NG | 160 | Sammamish, Lakeside, Talbot Hill | .25, .50, .25 |
| 4c | 2017-18 HW 75% Cons SN NG | 160 | Lakeside | 100% |

There is little indication that any of the three options is more effective at reducing overloads; the results were roughly the same for all three scenarios studied. Therefore, for simplicity, the land use, cost, and interconnection assessments assume the system would be sited entirely at Lakeside 115kV substation.

## 6.6 Permitting Timeline

When evaluating locations to site a utility scale energy storage facility, it was assumed that the site would be within the City of Bellevue. Since utility scale battery storage facilities are an emerging technology, they are not addressed in the City's land use regulations. PSE therefore assumed that the facility would be categorized as something similar to a transmission switching or substation. These types of facilities are defined as Electrical Utility Facilities (§20.50.018) in Bellevue. Alternatively, PSE indicated that such a facility could be classified as a Regional Utility System (§20.50.044). If a battery facility is determined to be a Regional Utility System it would be allowed in all zoning districts, but would require a Conditional Use Permit (CUP).

Although permitted in all zoning districts, Electrical Utility Facilities are subject to additional review under Bellevue Land Use Code (§20.50.255). Approval of a battery facility as an Electrical Utility Facility could be approved through an Administrative Conditional Use Permit

(ACUP) or a CUP. Map UT-5a provided in the City's Comprehensive Plan is used to determine which permit is required. If a site is shown on the map as "sensitive," then an alternative siting analysis and CUP would be required. If the site is shown as "non-sensitive," then an ACUP would be required and alternative siting analysis would not be required. The existing Northup (0.96 ac), North Bellevue (1.11 ac), Midlakes (1.04 ac), Center (1.18 ac), Lakeside (7.82), Phantom Lake (0.92 ac), South Bellevue (1.08 ac), College (0.97 ac), Factoria (2.90 ac), and Somerset (3.15 ac) substations are designated as sites that could be expanded and are not considered sensitive. Sensitive substations sites include Clyde Hill (0.42 ac, existing), Vernell (2.87 ac), Westminster (6.15 ac), Bel-Red, Lochleven (0.75 ac, existing), Larsen, Newport, Ivy, and Lakemont.

Alternative Configuration #1 would require approximately 4.5 acres, so only the Lakeside and Westminster site are large enough to accommodate the facility. Alternative sites could be used; however, all would require alternative siting analysis and a CUP. None of the existing or future substation sites are large enough to accommodate the Baseline Configuration or Alternative Configuration #2, so additional property would need to be acquired. PSE does not own currently own property for the Bel-Red, Larson, Newport, Ivy, and Lakemont substations; therefore, an assessment to their size appropriateness cannot be made.

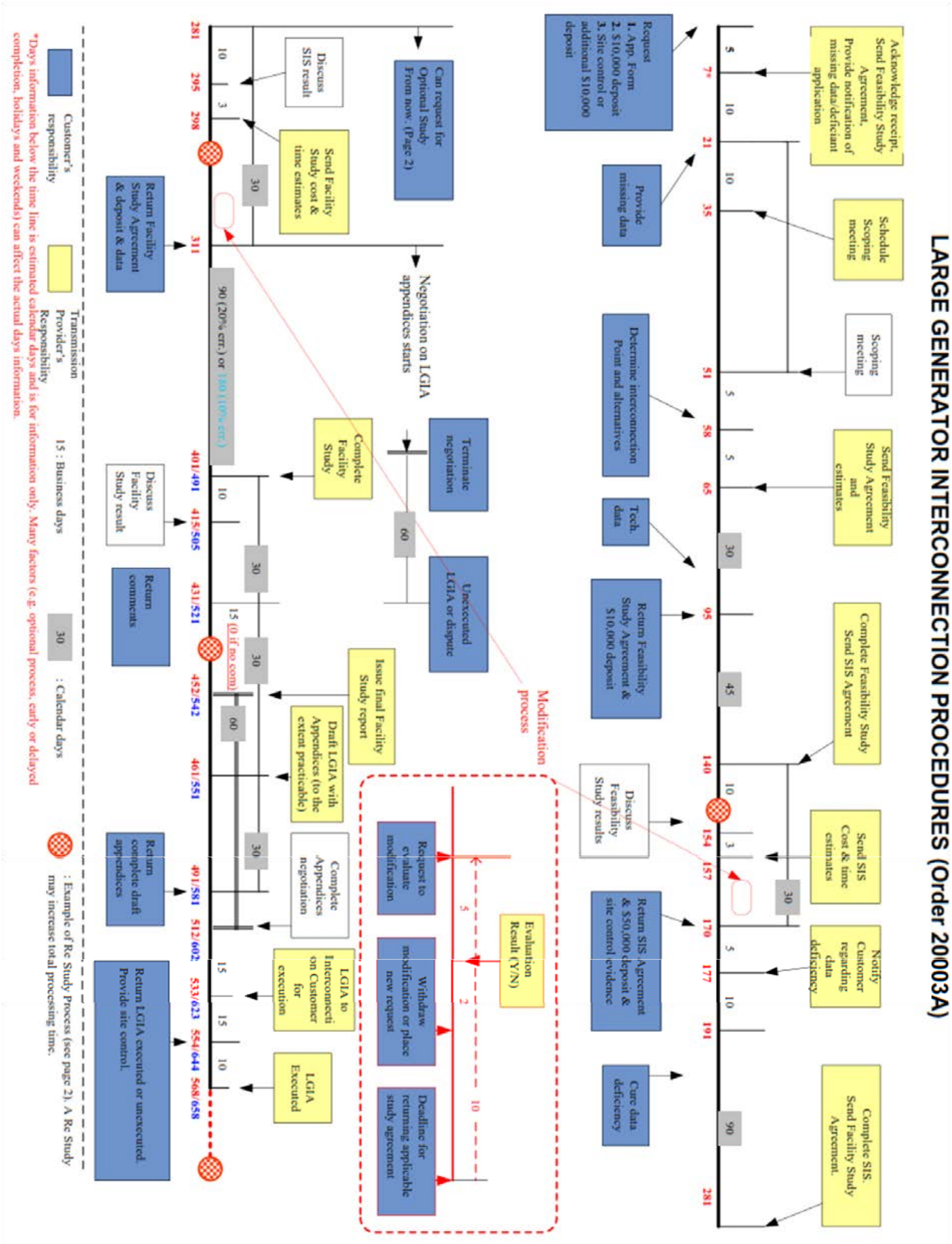
In addition to a CUP, compliance with the State Environmental Policy Act (SEPA) would be required. It is assumed that Alternative Configuration #1 would be issued a SEPA Mitigated Determination of Non-Significance (MDNS) and that the Baseline Configuration or Alternative Configuration #2 would likely receive a Determination of Significance (DS) and therefore required an Environmental Impact Statement (EIS), adding a year or more to the permitting process. Grading and building permits will also be required and if Critical Areas, such as wetlands are impacted, then additional approvals would be necessary.

According to the City of Bellevue, as of March 2015, ACUPs averaged around 25 weeks, with Major Clear and Grade permits averaging around 65 weeks. If Design Review is triggered, those approvals averaged 90 weeks. Permits for Major Commercial Projects average around 59 weeks. No data were provided for CUPs. It would be expected that Alternative Configuration #1 would take at least two years to permit with three to four years required for the Baseline Configuration or Alternative Configuration #2.

## 6.7 Interconnection Timeline

The interconnection process for large scale grid resource can be complicated and very time consuming. Puget Sound Energy's large generator interconnection process would be required for energy storage system interconnections with a nameplate power rating greater than 20 MW. This process is regulated by the Federal Energy Regulatory Commission and subject to open access provisions that require process standardization and transparency. PSE's process, detailed below, is fairly standard versus other utility processes.

## Figure 15. Puget Sound Energy's Large Generator Interconnection Procedures



As Figure 15 above shows, the interconnection study process generally takes 1-2 years (the process has a statutory maximum of 658 days), at which point an interconnection agreement is signed and work can begin on any necessary upgrades. Interconnection facilities such as substation upgrades generally take a minimum of 6 months and (depending on equipment lead times, permitting requirements, and system clearance requirements) can take upwards of several years from the time an interconnection agreement is signed before a project can interconnect to the grid.

## 6.8 Land Acquisition, Procurement and Construction Timeline

PSE indicated that it expects the land acquisition, procurement and construction timeline of a utility scale energy storage system to likely be comparable with that of a simple-cycle combustion turbine project. PSE discusses this timeline in its 2013 IRP:

> *"Greenfield development requires approximately four years: two years for development and permitting, one-and-a-half years for major equipment lead-time, and a half-year for construction. PSE does not take the risk of contracting for major equipment before permits are in hand. Private developers, on the other hand, are often willing to take that risk and can accelerate the development timeframe by about one year."*[83]

Assuming the permitting and interconnection processes are started in mid-2015 and completed in parallel, we estimate that land acquisition, equipment procurement and construction could begin in mid-2017. Based on PSE's assumptions, land acquisition, procurement and construction would take approximately two years, leading to a mid-2019 online date. A third-party developed asset willing to take land acquisition and procurement risk might be able to accelerate the online date to mid-2018. However, neither alternative would meet PSE's requirement that the asset come online in time for the winter 2017-2018 reliability need.

[83] Puget Sound Energy (PSE) (30 May 2013). P. D-35

# 7 Cost-Effectiveness Evaluation

This chapter summarizes the scope, approach and assumptions used for the cost-effectiveness evaluation as well as the results.

## 7.1 Configuration Evaluated for Cost-Effectiveness

One baseline configuration and two alternate configurations were developed as described in Chapter 6.3 of this report. As discussed, in order to fully meet both PSE's planning and operating standards, energy storage would need to reduce overloading so that it does not exceed the equipment's emergency rating, and so that it does not exceed the equipment's normal rating for more than eight consecutive hours.

Given that Strategen has determined that the baseline configuration is not technically feasible (See Chapter 0), Strategen did not study cost effectiveness of the baseline configuration. Rather, Strategen focused the cost-effectiveness evaluation on the more modest Alternate Configuration #1: *Emergency Overload Elimination*, even though this configuration fails to comply with PSE's planning and operating standards.

**Table 28. Energy Storage Configuration Summary**

| Configuration | Power (MWp) | Energy (MWh) | Duration (hours) | Est. Cost ($MM) | Includes Non-Wires Alternatives[84] | Technically Feasible | Meets Requirements |
|---|---|---|---|---|---|---|---|
| Baseline Normal Overload Reduction | 328 | 2,338 | 7.1 | **$1,030** | ✓ | × | ✓ |
| Alternate #1 Emergency Overload Elimination* | 121 | 226 | 1.9 | **$184** | ✓ | ✓ | × |
| Alternate #2 Normal Overload Elimination | 545 | 5,771 | 10.6 | **$2,367** | ✓ | × | ✓ |

[84] E3 (2014)

***Alternate Configuration #1 was evaluated for cost-effectiveness.**

## 7.2 Cost Assumptions

The cost of utility-scale energy storage systems is not well-established, and estimating cost is challenging because utility-owned storage other than pumped hydro is a fairly new concept. Large systems are custom built, designed and tailored for very specific, customer-identified applications and sites, so costs vary significantly.

To determine appropriate estimates for modelling system costs, Strategen reviewed publicly available cost data on utility energy storage projects, as well as research reports identifying cost trends over time, and cost estimates for projects recently contracted in California and Hawaii. Extrapolations from multiple sources were assembled to provide a realistic picture of the breakdown between battery cell costs and balance-of-system costs, while adding project-specific cost estimates for interconnection facilities, land, permitting, and operations and maintenance. Strategen also interviewed selected technology vendors to validate the accuracy of cost estimates.

After thorough review of available cost information, a generic fast-responding multi-hour lithium ion battery solution was ultimately chosen for the cost-effectiveness modeling[85]. The rationale for choosing lithium ion is that such cost estimates are the most readily available in research reports, and data is available on a spectrum of system configurations and sizes, including the relatively comparable system sizing and timing of systems announced in SCE's LCR procurement.[86]

### 7.2.1 *Cost Benchmarks of Utility Pilot Projects*

There are few examples of completed and planned grid scale systems for which all-in system costs can be accurately estimated.

SCE commissioned the Tehachapi Wind Energy Storage Project, an 8 MW/32 MWh lithium ion system in June 2014 with the help of a US Department of Energy grant. When the project was approved for the American Recovery and Reinvestment Act Smart Grid Demonstration Program Funding in 2010, total project cost was estimated at $50,000,000, and while actual incurred costs are unknown, it still provides a useful cost data point of $6,250/kW and $1,562/kWh. This includes batteries, BOS, interconnection, and every other component, and was probably a very conservative cost estimate that reflected 2010 component costs.

In December 2014 PSE and RES Americas announced an agreement to develop a 2 MW/4.4 MWh lithium ion project in Whatcom County to provide grid support, peak shaving, and emergency back-up power. The $9,800,000 cost equates to $4,900/kW and $2,227/kWh. Note

[85] While lithium ion solutions have the most readily available cost estimates, flow battery technologies designed for long duration applications might present a cost-competitive alternative should PSE determine that further evaluation is warranted.

[86] In particular, Southern California Edison's procurement of a 100 MW/400 MWh lithium ion energy storage system from AES: http://www.aesenergystorage.com/2014/11/05/aes-help-sce-meet-local-power-reliability-20-year-power-purchase-agreement-energy-storage-california-new-facility-will-provide-100-mw-interconnected-storage-equivalent-200-mw/

that economies of scale are important for battery ($/kWh) costs, hence the greater cost per kilowatt-hour for PSE's system versus the SCE Tehachapi system.

In both of the above pilot projects, significant one-time integration costs occurred that likely made these projects more costly than future energy storage deployments. As a result, Strategen does not believe these are suitable as direct comparisons to what a larger scale energy storage system deployment might cost in the near future. However, they are instructive, as they show a ceiling of what currently deployed energy storage systems have cost to develop.

### 7.2.2 *Battery Cell Costs*

The majority of publicly-available, energy storage price research focuses on battery cell costs, especially lithium ion, due to high growth and transparency in the electric vehicle market. Brattle Group, Bloomberg New Energy Finance, Morgan Stanley, CITI Research, and Navigant Research all project lithium ion prices will decrease significantly over the next few years.[87] Price estimates for 2014 ranged from $350 to $700/kWh.

Combining and averaging these sources into one analysis, IBM Research - Australia estimated the current price (as of 2014) to be approximately $600/kWh,[88] which is further supported by a December 2014 UBS report.[89,90]

IBM Research examined future cost projections in the 2015-2020 timeframe, which vary from $200/kWh to $354/kWh. Many of the studies averaged were from 2011 and 2012, and do not reflect the steeper cost reductions actually experienced in the last few years. Since the UBS report is the most recent study, incorporates the newest 100 MW SCE/AES data point, and is well within the range of other projections, this analysis uses the UBS future projection of $250/kWh as the battery cell cost. On the one hand, this might be viewed as an aggressive estimate, because the UBS report sets this as a baseline cost in 2020 and the Eastside system would need to be operational in winter 2017-2018. However, given that Tesla estimates its current (2014) battery cell costs in the $200-300/kWh range,[91] increasingly aggressive analyst cost projections, the economies of scale that can be obtained with the size of the Eastside system, as well as a potential to incrementally add storage capacity from 2017-2021 to meet increasing system needs over that time period, Strategen believes the $250/kWh cost estimate for cells to be achievable.

### 7.2.3 *Balance-of-System Costs*

Batteries for grid support have a myriad of other components and costs than just batteries. Known as balance-of-system ("BOS"), these components include power electronics, control module, battery enclosure, thermal management equipment, installation labor, interconnection, permitting, land, and contingencies. The Rocky Mountain Institute estimates

[87] Brattle/Oncor (2014); PG&E/BNEF (2013); Morgan Stanley (2014); CITI Research (2012); Sam Jaffe, Navigant Research (2014)
[88] A. Vishwanath and S. Kalyanaraman (2014)
[89] UBS Global Research (2014)
[90] Sam Jaffe, Navigant Research, highlights that cost vary significantly between different types of lithium ion batteries - $600/kWh is a generic price for the lithium ion family.
[91] UBS (2014)

that 63% of the total installed cost for a 200 kW/200 kWh commercial energy storage system is BOS, with residential system BOS costs accounting for 74% of installed cost.[92]

Some vendors include enclosures in the battery purchase price, while others do not.[93] For this analysis, we assume the enclosure price is included in the battery cost.

#### 7.2.3.1 *Power Electronics and Building Facilities*

The largest BOS costs are associated with power electronics, which includes the inverter/power conditioning system ("PCS") and control module/battery management system. UBS estimates BOS costs to be in the $400-$500/kWh range.[94] Confidential discussions with vendors suggest that BOS is better evaluated on a cost per kW basis, as power electronics tend to be based on power ratings rather than energy, and other balance of system costs tend to be relatively fixed. However, Strategen's findings correspond well to the UBS estimates for BOS costs, but on a dollars per kW basis (rather than per kWh).

Strategen views the 100 MW/400 MWh AES system recently procured by SCE as a reasonably good cost comp to the Eastside energy storage configurations. UBS estimates this project to cost roughly $1,500 per kW ($375/kWh), of which the majority of the total system cost estimates being attributable to batteries and BOS.[95] An assumed $250/kWh battery cost multiplied by a 4 hour duration gives $1,000/kW for batteries. Because the AES project is to be co-located near existing infrastructure designed to accommodate generation, we assume that land, permitting, and interconnection costs constitute a relatively small portion of remaining costs. Therefore, we assume the bulk of the remaining $500/kW as Power Electronics and Building Facilities cost, which is in line with BOS cost methodology and estimates previously identified. While using the overall project costs as a direct comp might be viewed as aggressive because the AES plant won't come online until 2021, this is counterbalanced by the fact that this analysis separately accounts for interconnection, land and permitting costs, and there is likely some (relatively small) interconnection and permitting costs blended in UBS' overall system cost estimates. Due to this counterbalancing impact, Strategen is therefore comfortable using $500/kW as the Power Electronics and Building Facilities cost in this analysis.

#### 7.2.3.2 *Interconnection, Permitting, and Land Costs*

The costs of many system components, such as interconnection, 115 kV step-up transformers, transformer installation, land to house the equipment, and permitting, are utility and site specific.

Table 29 shows PSE-supplied cost estimates for interconnection and permitting for the three configurations.

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92 RMI (2014)
93 DOE-EPRI Energy Storage Handbook (2013)
94 UBS Global Research (2014)
95 *Ibid.*

**Table 29. Interconnection and Permitting Cost Estimates**

| | Baseline<br>Normal Overload Reduction | Alternate #1<br>Emergency Overload Elimination | Alternate #2<br>Normal Overload Elimination |
|---|---|---|---|
| Interconnection Facilities | $73,020,000 | $28,140,000 | $167,946,000 |
| Permitting | $1,000,000 | $250,000 | $1,000,000 |

PSE supplied cost estimates for land related to interconnection facilities and parking, while vendor interviews and satellite imagery analysis provided sizing estimates for the battery and BOS which is further discussed in Chapter 6.5. Table 30 summarizes the land cost estimates for the three configurations.

**Table 30. Land Cost Estimates**

| | Baseline<br>Normal Overload Reduction | Alternate #1<br>Emergency Overload Elimination | Alternate #2<br>Normal Overload Elimination |
|---|---|---|---|
| Land Cost | $55,000,000 | $15,000,000 | $144,000,000 |

### 7.2.4 *Annual Operations and Maintenance Costs*

Systems operations and maintenance (O&M) activities and costs are divided into two categories: fixed and variable. These are usually site specific, dependent on local labor and tax rates, and vary by energy storage system specifications and specific contractual terms.

*Fixed O&M* refers to activities and costs that are incurred annually, unrelated to system energy requirement, and include staff to operate and maintain the building and site, property tax, insurance, routine inspections, remote monitoring/telecommunications, spare parts, and other foreseeable expenses for both the batteries and PCS.

*Variable O&M* refers to activities and costs that are proportional to the system's energy throughput (both charging and discharging). These costs frequently include system troubleshooting (diagnosing problems, testing components and corrective maintenance) and periodic replacement of degraded cells. However, contractual arrangements frequently wrap these costs into fixed warranty costs (thus they are already covered in Fixed O&M).[96,97]

Discussions with vendors revealed that O&M contracts are negotiable and highly sensitive. A literature review showed that cost estimates for both fixed and variable O&M vary by technology type. Fixed O&M costs ranged from approximately $2.50 to $25.20 per kilowatt-year ($/kw-year), and variable O&M costs ranged from $5 to $59 per MWh.[98,99,100] Based on discussions with utility scale developers, and given the assumption that normal system performance degradation would not be supplemented with new cell capacity, Strategen believes that fixed warranty costs will negate the need to have a separate line item for variable O&M.

Strategen assumes fixed O&M of $5.00/kW-year and no additional variable O&M costs for this analysis. Our rationale is that an ESS of this size will benefit from economies of scale for fixed costs, keeping them on the low end of the range, and that variable O&M will be wrapped under a warranty with the equipment vendor or developer. This is particularly likely given that ESS cells are not assumed to be replaced during the system life.

An annual escalator of 2.5% is applied to fixed O&M costs for the cost-effectiveness analysis.

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[96] PacificCorp (2011)
[97] PNNL (2010)
[98] *Ibid.*
[99] E. Cutter et al. (2014)
[100] Black & Veatch (2012)

### 7.2.5 *Contingency*

Contingency is a standard assumption in large scale development assets to cover unanticipated costs during construction. Unanticipated costs could include anything from geotechnical issues, cultural resources mitigation, environmental mitigation, or any number of other issues. Strategen assumed a contingency value of 20% of the cells and power electronics + building facilities cost.

## 7.3 Storage System Configuration Cost Estimates

Based on the specified cost projections, Table 31 shows the total estimated capital costs for the three energy storage configurations evaluated.

**Table 31. Summary of the Three Energy Storage System Configurations' Costs**

| Component | Per Unit Cost Projection | Baseline<br>Normal Overload Reduction through 2021 (≤8 hours) | | Alternate #1<br>Emergency Overload Elimination through 2021 | | Alternate #2<br>Normal Overload Elimination through 2021 | |
|---|---|---|---|---|---|---|---|
| | | Power (MW) | Energy (MWh) | Power (MW) | Energy (MWh) | Power (MW) | Energy (MWh) |
| | | 332 | 2,338 | 121 | 226 | 545 | 5,771 |
| **Cells** | $250/kWh | $584,500,000 | | $56,500,000 | | $1,442,750,000 | |
| **Power Elect. & Building** | $500/kW | $166,000,000 | | $60,500,000 | | $272,500,000 | |
| **Interconn. Facilities** | Na | $73,020,000 | | $28,140,000 | | $167,946,000 | |
| **Land** | Na | $55,000,000 | | $15,000,000 | | $140,000,000 | |
| **Permitting** | Na | $1,000,000 | | $250,000 | | $1,000,000 | |
| **Contingency**[101] | 20% of Cells + BOS | $150,100,000 | | $23,400,000 | | $343,050,000 | |
| **TOTAL** | | **$1,029,620,000** | | **$183,790,000** | | **$2,367,246,000** | |
| **NPV of Revenue Req'ments**[102] | | **$1,441,200,000** | | **$264,732,000** | | **$3,301,708,000** | |

## 7.4 Benefits

This subchapter includes a characterization of the quantifiable benefits that were included in the cost-effectiveness evaluation for the *Emergency Overload Elimination* configuration (as described in Section Configuration Evaluated for Cost-Effectiveness7.1). It also includes an overview of other notable storage benefits that were not quantified or included in the cost effectiveness evaluation.

### 7.4.1 *Transmission & Distribution Deferral*

This analysis assumes that all cost-effective non-wires alternatives identified in the Non-wires Report are deployed. Furthermore, given the approach used in the Non-wires Report, the benefit for the amount of incremental cost-effective non-wires alternatives is assumed to

[101] Contingency is a standard assumption in large scale development assets to cover unanticipated costs during construction

[102] Fixed O&M costs ($5/kW-yr), taxes, depreciation, insurance, and required rate of return are added to the above over the 20 year life of the asset, discounted at 7.77% to determine the NPV of the configurations' revenue requirements (See Chapter 7.5.2 for further description of the financial assumptions).

absorb the entire deferral benefit.[103] Therefore, no additional financial value associated with the deferral was assigned to the energy storage system for the storage cost-effectiveness evaluation.

## 7.4.2 *Non-deferral Benefits Quantified*

Four non-deferral benefit types/categories are addressed quantitatively for the cost-effectiveness evaluation: 1) system capacity, 2) system flexibility, 3) oversupply reduction, and 4) greenhouse gas reduction.[104]

### 7.4.2.1 *System Capacity Benefit*

#### *Introduction*

The system capacity benefit provided by an energy storage system refers to the ability of the ESS to discharge during system-wide peak demand periods such that it behaves like a small-scale generator or demand response resource, thus reducing the amount of peaking generation and/or transmission capacity needed. Of particular significance is the reduced need for simple-cycle combustion turbines ("SCCTs"). System capacity is comprised of this "energy supply capacity," as well as capacity that exceeds the need for new energy supply, which is called "surplus transmission capacity" herein.

The system capacity benefit is *not* location-specific: it accrues irrespective of where the system is located.

Unlike a) generation capacity supplied by a fuel system/network, b) transmission equipment and c) demand response (that , *technically* speaking, can be called on at any time to reduce capacity requirements); *storage* is sometimes referred to as a "limited energy resource" because once all *energy* has been discharged the storage system cannot provide *power*. As such, it may not be as useful for peaking service and/or contingency events, when extended generation output is needed.

Given that major difference between storage and conventional peaking resources, the PSE Resource Planning team performed an Incremental Capacity Equivalent ("ICE") analysis to better understand the potential capacity contribution from these resources. Analysis on a storage system with two hours of sustained discharge suggested that the ICE to be 100 percent.

**Correlation with Eastside Peaks**

Given that the primary function of the storage configuration is to reduce peak load to address the Eastside transmission constraint, the capacity value must be de-rated to the extent that the system peaks are not correlated to the Eastside peaks.

For this study it is assumed that there is a strong correlation between local (Eastside) and system peak demand.

[103] The non-wires alternatives' cost-effectiveness was predicated upon the value of transmission and distribution deferral benefits when the evaluation was undertaken.
[104] Greenhouse gas ("GHG") reduction benefits do not currently reflect a direct monetary benefit to PSE's customers. However, a range is provided in order to assign value to potential future scenarios where carbon reduction has direct monetary value in Washington State.

### *Default Peaking Capacity Resource: Simple Cycle Combustion Turbine*

PSE's 2013 IRP concluded that simple-cycle combustion turbines were the least-cost resource to meet peak hour capacity needs. More specifically, the F-Class ("frame" or industrial) simple-cycle combustion turbine with a peak winter capacity of 221 MW is considered the default resource. The revenue requirement (and the net present value thereof) and levelized cost of this resource was calculated based on the following assumptions derived from PSE's 2013 IRP (see also Table 32):

- The capital cost of the SCCT is estimated to be $202.2 million or $915/kW in 2012$. This value was inflated to $228.8 million for the 2017-2018 estimated completion.[105]

- Fixed O&M costs on the SCCT are estimated to be $20/kW-yr and the book life of the asset is 35 years.

- PSE assumed that the ESS will enable it to avoid 6.55% in T&D $I^2R$ energy losses[106,107] when compared to centralized generation. This is the assumption for avoided line losses from conservation measures at commercial and industrial customers. The effect is to increase the energy supply capacity value by that same 6.55%.

- The net present value (NPV) revenue requirement for the SCCT totaled $1,742/kW in 2017$ with a levelized cost of $146/kW-yr (also in 2017).

- The total NPV of avoided cost in 2017 is $1,829/kW and the annual (levelized) value is $153/kW-year as of 2017 (i.e., for the period 2017 to 2051).

- This year-specific annual/levelized value is escalated by 2.5% per annum to account for inflation.

[105] PSE (2013); p. 80, Figure 4-9.

[106] As energy is transmitted from a centralized generation facility to a customer, a portion of this energy is lost to resistance in the lines. When an energy supply capacity resource injects power close to load (or reduces load in the case of efficiency measures), as would be the case with this project, PSE would avoid slightly more than one unit of peak supply capacity by avoiding the line losses experienced while delivering peak capacity. To account for line losses an avoided loss factor of a loss factor of 6.55% was applied which is consistent with the loss factor used in PSE's energy efficiency cost effectiveness calculations for commercial and industrial programs. PSE recognizes that these losses may slightly overstate the benefits attributable to the storage resource, however PSE believes these effects are minor.

[107] The abbreviation $I^2R$ indicates that the energy losses are a function of the square of the amount of electric current flowing (the symbol for current is I) through electrical equipment times the electrical resistance (whose symbol is R) of the equipment, hence the term pronounced I squared R.

### Table 32. Energy Supply Capacity Revenue Requirement and Avoided Cost

| REVENUE REQUIREMENT FOR SCCT | | | | | |
|---|---|---|---|---|---|
| **Peaker Type** | **Units** | **Frame SCCT** | | | |
| Capacity | MW (winter) | 221 | | | |
| Capex (overnight cost) | $/kW, 2012 | $ 915 | | | |
| Capex | $, 2012 | $ 202,215,000 | | | |
| Fixed O&M | $/kW-yr, 2012 | $ 20 | | | |
| Year Peaker Needed | | 2017 | | | |
| NPV Revenue Req ($2017) | $/kW, 2017 | $ 1,742 | | | |
| Avoided Line Losses | | 6.55% | | | |
| Grossed-Up Avoided Cost | $/kW, 2017 | $ 1,856 | | | |
| Incremental Capacity Equivalent | | 100% | | | |
| NPV of Revenue Requirement ($/kW) | $/kW, 2017 | $ 1,856 | | | |
| Useful Life of SCCT | years | 35 | | | |
| **Levelized Avoided Revenue Requirement** | **$/kW-yr, 2017** | **$155.52** | | | |
| Annual Escalation Factor | 2.50% | | | | |
| Year | 2017 | 20.18 | 2019 | 2020 | 2021 |
| Levelized Avoided Revenue Requirement | $ 155.52 | $ 159.41 | $ 163.39 | $ 167.48 | $ 171.67 |

PSE advised Strategen to assume that energy supply system and local (transmission) peaks are highly correlated such that storage provides full energy supply capacity value if it is dispatched to address the local peak. Furthermore, PSE's methodology to evaluate the capacity value of resources is based on the two hour continual discharge rating of the resource. In this case, the energy storage system rated at 226 MWh would have a 2-hour continual discharge rating of 113 MW for the purpose of calculating its capacity value.

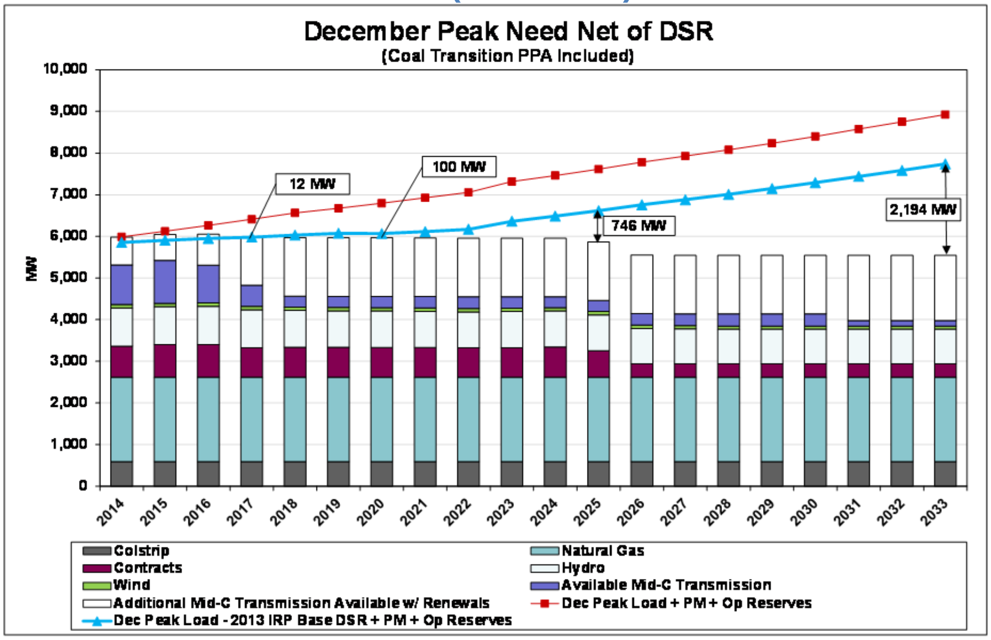
### *Energy Supply Capacity Needs*

The Base Scenario in PSE's most recent IRP (2013) projects a system-wide peak energy supply capacity deficit of 12 MW in 2017, growing to 100 MW in 2020.

**Table 33. 2013 IRP Forecast Energy Supply Capacity Deficit 2017 to 2021**

| Year | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| Capacity Deficit (MW) | 12 | 61 | 105 | 100 | 149 |

**Figure 16. December Peak Need Forecast (Source: PSE)**




### *Reduced Transmission Capacity Needs*

During the first several years of storage deployment, the need for energy supply capacity is less than the storage system's power rating. During those years, the storage capacity that is not needed for energy supply capacity is assumed to enable PSE to reduce transmission capacity needs as follows: Because the storage can serve a portion of end-user demand, real-time, the amount of energy that must be delivered via the transmission system is also reduced. That frees up transmission capacity so that it can be to be used for other purposes. PSE determined that Strategen could assume the transmission capacity that is freed up (as a result of the storage operation) could be resold to provide additional revenue.[108]

The estimated value for re-sale of transmission contracts in 2014 was approximately $17.00/kW-yr. This value is escalated by 2.5% per annum to account for inflation, grossed-up for line-losses, federal income taxes, and state revenue taxes to yield the total annual value, as shown below:

[108] PSE currently relies on approximately 1,500 MW of transmission to acquire energy and capacity from the market and holds a multitude of Mid-C transmission contracts with various termination dates. These contracts only need to be renewed for 5-year terms to preserve PSE's unilateral roll-over rights in the future. In any given year, PSE has the option to renew a portion of Mid-C capacity and reevaluate the Mid-C transmission need.

**Table 34. Mid-C Transmission Resale Values (Source: PSE)**

| | $/kW-yr | | | | |
|---|---|---|---|---|---|
| Year | Mid-C Tx Value | Line Loss Gross up | ICE De-Rate | Gross-up for FIT * | Gross Up for State Rev Tax |
| 2014 | 17.00 | 18.19 | 18.19 | 27.99 | 29.11 |
| 2015 | 17.43 | 18.65 | 18.65 | 28.69 | 29.84 |
| 2016 | 17.86 | 19.11 | 19.11 | 29.40 | 30.59 |
| 2017 | 18.31 | 19.59 | 19.59 | 30.14 | 31.35 |
| 2018 | 18.76 | 20.08 | 20.08 | 30.89 | 32.14 |
| 2019 | 19.23 | 20.58 | 20.58 | 31.66 | 32.94 |
| 2020 | 19.71 | 21.10 | 21.10 | 32.46 | 33.76 |
| 2021 | 20.21 | 21.62 | 21.62 | 33.27 | 34.61 |

* Federal Income Tax

### *Benefit Estimation Methodology*

The system capacity benefit is estimated based on the avoided cost for energy supply capacity plus additional revenue accruing from re-sale of transmission capacity.

To the extent that PSE needs incremental new peaking energy supply capacity, the energy supply capacity contribution from the ESS is valued at the avoided cost of the default resource (F-Class SCCT) using cost and performance data from the 2013 IRP.[109]

A key premise for the evaluation of the capacity benefit is that a peaking resource must discharge for at least two hours. However, the storage system whose power rating is 121 MW is designed to discharge for 1.86 hours. Therefore, as shown in Table 32, the storage system is assumed to be able to provide 112.8 MW of energy supply capacity in 2017. The benefit estimation for energy supply capacity must account for the diminishing energy output capability of the storage system throughout its life (assumed to be 2% per year).

And, to the extent that the energy storage system provides surplus capacity in a given year beyond the energy supply capacity deficit projected in the 2013 IRP, an additional benefit is estimated for the value of the revenues associated with re-sale of surplus transmission capacity to the Mid-C based on historical bilateral transactions.

[109] To estimate the financial benefit (avoided cost) for energy supply capacity a portfolio optimization analysis, such as that done as part of the IRP process, is the most appropriate method. That is not feasible given the scope, budget and timeframe for this study. So, the estimated avoided cost for simple cycle CT was used.

**Table 35. Storage System Capacity Assumptions**

| Year | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| Energy Supply Capacity Deficit (MW) | 12 | 61 | 105 | 100 | 149 |
| Value at Avoided Peaker Rate (MW) | 12 | 61 | 105 | 100 | 104.2 |
| Value at Trans. Resale Rate (MW) | 100.8 | 49.6 | 3.4 | 6.3 | 0 |
| **Total ESS Capacity (MWh/2)** | **112.8** | **110.6** | **108.4** | **106.3** | **104.2** |

#### 7.4.2.2 *System Flexibility Benefit*

*Introduction*

For this evaluation PSE defines "system flexibility" as an amalgamation of four ancillary services: 1) regulation and frequency response, 2) contingency reserve obligations, 3) intra-hour energy balancing and 4) load following/ramping[110]. To the extent that storage reduces the need for those services from other resources, there is a benefit (i.e. an avoided or reduced cost).

*Storage Power and System Benefits*

Notably, some benefits associated with a specific amount of storage power may be limited because there may be more storage capacity than needed to provide the respective service.

Consider an example: PSE's Contingency Reserve Obligation will soon be 3% of load plus 3% of generation. During periods when load is low and levels of market purchases are relatively high, PSE may only need to carry as little as 100 MW of reserves. During other times the requirement may be significantly higher.

There are similar considerations with regard to the need for balancing and load following/ramping resources. And, usually there are operational conflicts between the various ancillary services (and with the other benefits) meaning that at any given time only one service can be

Load fluctuations, Balancing Authority obligations to integrate scheduled interchanges, and unexpected events like forced outages all place demands on generators to provide "system flexibility." So does the need to maintain contingency reserves to assist other Balancing Authorities that may have sudden needs for help balancing loads. All generation resources provide some measure of flexibility; however, the ability of a resource to supply flexibility is constrained by unit-specific characteristics including availability, operational or environmental limitations, range, and ramp rate. These characteristics, coupled with economic dispatch generation set points, affect PSE's total supply of system flexibility.

PSE often faces challenges related to system flexibility during the second quarter of the year. During this period, spring runoff often leads to high river flows which limit the operating range of hydro generators on the Columbia River (these generators are referred to collectively as the Mid-Columbia or "Mid-C"). For example, during much of the year PSE has an operating range of roughly 50 – 650 MW on its share of the Mid-C. During Q2, this range may decline to less than 100 MW. The Mid-C generators are typically used to provide frequency regulation and spinning reserves, but during periods of constrained operations, PSE often uses simple-cycle combustion turbines for spinning reserve, which incur start charges, fuel costs, and O&M costs. Year-to-year there can be high variability in hydro conditions and other factors that

[110] Source: DOE-EPRI Energy Storage Handbook (2013)

drive the costs and challenges of providing adequate flexibility. For more information on system flexibility and PSE modeling methodology, see PSE's 2013 IRP, Appendix G.

Due to their especially fast response and ramp rates, and ability to provide spinning reserve at virtually zero variable cost, battery storage systems can provide flexibility services quite well. Given that, recent FERC regulatory changes have increased compensation paid to fast-acting regulation resources such as those involving batteries and flywheel energy storage.

Indeed, many large battery storage systems deployed in the grid today are for frequency regulation services. Flexibility is a system-wide benefit and can be realized anywhere the battery is placed on the system so long as the necessary controls and communication infrastructure exist.

### *Benefit Estimation Methodology*

The Pacific Northwest does not have a market for ancillary services such as spinning reserves and frequency regulation. Therefore, the valuation of the flexibility benefit provided by PSE involves two model-based evaluations of PSE's cost to provide system flexibility: 1) a baseline evaluation of the supply resource configuration *without* the storage system and 2) another evaluation that includes the storage system as part of PSE's electric supply resources. The flexibility benefit for storage is defined as the difference between the results from those two evaluations.

The model is consistent with modeling in the 2013 IRP, which assesses how PSE will meet its balancing obligations in the year 2018. The model uses a mixed-integer linear program in SAS-OR to simulate procuring sufficient flexible capacity from PSE generators prior to each operating hour, and then dispatching that capacity during the hour to manage load and resource variations.

The model output is a record of unit deployment for PSE's dispatchable generation that quantifies how each unit contributes to system balancing, pinpoints periods of stress, and identifies periods when the model could not balance the system.[111]

The Resource Integration Team modeled a generic battery system of 117 MW/208.8 MWh (a configuration of similar size to Alternate Configuration #1) using a subset of the 250 Aurora simulations used in the 2013 IRP, limited to the year 2018. The team has intended to use the exact size contemplated in the final report, but due to a minor sizing adjustment in the final configuration to accommodate system degradation, the former size was modeled. We do not believe this is a problem because previous modeling for smaller sizes (2MW, 18MW) yielded a similar overall value in the $100/kW-yr range. Given that the 117MW and 121MW configurations are so similar, we believe this slight inconsistency will have an insignificant impact on the overall results. For this evaluation the levelized system flexibility benefit is estimated to be $99.52/kW-yr.

[111] PSE's model prioritizes which constraints to solve (e.g., the "total energy=total demand" constraint has the highest priority), and sets an artificial price for marginal flexibility of $1,000/MW during periods when the model is unable to balance the system's flexibility needs while still solving for higher priority constraints. This may result in an artificial values being applied for system flexibility during certain periods, rather than actual market-clearing prices, which do not exist in the Pacific Northwest.

Notably, a significant portion of the flexibility benefits accrue during Q2 as that is the time of year when the significant amount of hydroelectric generation used by PSE generally is the least flexible. So, storage provides a significant portion of the total annual flexibility benefit during Q2.

Year-specific values are de-escalated or escalated at 2.5% per year throughout the study period.

The storage system is assumed to be reserved for providing the transmission reliability function (managing local transmission level winter peak demand) in January and summer peak demand during August. While the storage resource can theoretically provide multiple services such as reducing load on the transmission system and providing system flexibility, there is potential conflict during certain times when it is reserved for serving a transmission reliability function. For example, if the storage system is fully discharged in response to a transmission system overload, it can no longer be relied on for spinning reserve until recharged to a certain threshold. In these cases, other generation resources would have to be used to provide system flexibility. The data used in the system flexibility modeling is not structured in such a way to easily determine the probability that the storage system would be needed for transmission system overload relief and system flexibility concurrently.

During the transmission deferral period (2017 to 2021), PSE and Strategen agreed that the value of system flexibility should not be included for the months of January and August as a modeling assumption when the transmission overload is most likely to occur. During this period, storage receives 84.5% of the annual benefit, as 15.5% of the annual system flexibility benefit occurs in January and August. After the transmission deferral period, storage receives the entire annual benefit. This is a simplification that may result in an underestimation of the value of system flexibility provided by the storage resource, nonetheless it is a reasonable assumption for this case study.

PSE's flexibility analysis also assumes that the Eastside transmission system is capable of supporting unconstrained dispatch of the system. This may result in a possible overestimation of the flexibility benefits the storage could provide. For example, the transmission system is close to an overload situation, PSE might not be able to use the resource in full charge mode if the system needs down-balancing resources, as that might overload the transmission system. Fully resolving this issue would be complex, requiring either a study of the transmission upgrades that would be required to support unconstrained dispatch, or a study of whether current transmission constraints might limit dispatch. Such a study is beyond the scope of this assessment.

The annual values are shown in Table 36 below.

**Table 36. PSE Projected Annual Flexibility Benefit**

| | |
|---|---|
| ***Flexibility Value for Entire Year (Post Deferral)*** | |
| *Value in 2018* | Total ($/kW-year) |
| $/Month | $11,774,364 |
| $/kW-mo | $ 97.31 |
| *Value in 2017* | Total ($/kW-year) |
| $/Month | $11,487,184 |
| $/kW-mo | $ 94.94 |
| ***Flexibility Value During Deferral Period*** | |
| | Include |
| *Value in 2018* | Total ($/kW-year) |
| $/Month | $ 9,946,467 |
| $/kW-mo | $ 82.20 |
| *Value in 2017* | Total ($/kW-year) |
| $/Month | $ 9,703,870 |
| $/kW-mo | $ 80.20 |
| Levelized Value | Total |
| Constant Dollars ($000) | $ 220,827 |
| Current Dollars ($000) | $ 284,063 |
| Present Worth* ($000) | $ 140,662 |
| $/kW** | $ 1,162.50 |
| $/kW-year levelized*** | $ 116.37 |
| With Energy Output Degradation | |
| **Present Worth* ($000)** | **$ 120,296** |
| **$/kW**** | **$ 994.18** |
| **$/kW-year levelized***** | **$ 99.52** |
| *Based on escalation rate of 2.50%. | |
| *Based on discount rate of 7.77%. | |
| **Based on WACC of 7.77%. | |

### 7.4.2.3 *Oversupply Reduction Benefit*

Storage can prevent “over-generation” and curtailment of generation resources (especially wind generation) in several ways including time-shifting and reduced variability served by dispatchable/thermal generation. Though modest, that benefit will be increasingly important; so Strategen included it as part of the overall value proposition for the Eastside ESS.

The estimated annual value, calculated based on data provided by PSE, is shown in **Error! Reference source not found.** below.

**Table 37. Estimated Annual Oversupply Reduction Benefit, 2017**

| | | |
|---|---|---|
| With Energy Output Degradation | | |
| **Present Worth ($000)* **** | **$** | **1,687** |
| **$/kW** | **$** | **13.94** |
| **$/kW-year levelized***** | **$** | **1.40** |
| | | |
| *Escalation Rate 2.50% | | |
| **Discount Rate 7.77% | | |
| ***Life: 20 years, WACC (Discount Rate) = 7.77% | | |

### 7.4.3 *Other Benefits*

In order to provide a common frame of reference, it is worth noting that there are a variety of storage-related benefits that are frequently characterized differently than was done in this report. These benefits either were included as a subset of the benefit calculations above but were not studied separately, or would not accrue to storage deployed for the Eastside situation. They are summarized below and described in more detail in Appendix D: Unquantified and Partially Quantified Benefits.

#### Reduced GHG Emissions

Depending on the mix of fuels involved, storage can reduce overall GHG emissions in several ways, including reduced stops/starts and load following from conventional generation resources, dynamic operating benefits, more and more effective renewables integration, reduced use of the generation fleet's most inefficient peaking resources (via energy shifting) and by allowing for better and increased use of demand response and electric vehicles.

The benefit of GHG avoidance is not currently monetized, but President Obama and the United States Environmental Protection Agency's Clean Power Plan[112] announced in 2014 proposes "state-specific rate-based goals for carbon dioxide emissions". Therefore, Strategen believes that it is reasonable to assume that there will be at least some actual financial benefit associated with GHG reduction.

Ascribing a cost to these avoided GHG emissions is contentious and challenging, but estimates of the social cost of carbon ("SCC") were published by a US Government Interagency Working Group in 2010[113] and then updated in 2013.[114] PSE used a range of price estimates, including some from that analysis, for modeling different scenarios in the 2013 IRP.[115] In the 2013 IRP, PSE assumed the following:

[112] See http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule
[113] Interagency Working Group on the Social Cost of Carbon (2010)
[114] Interagency Working Group on the Social Cost of Carbon (2013)
[115] PSE (2013); Section 4-8.

**Table 38. PSE's 2013 IRP GHG Cost Assumptions**

| $CO_2$ Cost | $ per ton, 2014 | $ per ton, 2033 | Implied Escalation Rate |
|---|---|---|---|
| **Base** | $0 | $0 | -- |
| **Low** | $6 | $20 | 6.54% |
| **High** | $25 | $80 | 6.31% |
| **Very High** | $75 | $179 | 4.53% |

While the amount of carbon dioxide ("$CO_2$") emissions that would be avoided by PSE utility-owned generation annually if the Eastside storage facility is deployed has the potential to be quite significant, calculating the regional GHG reduction impact, inclusive of all benefits and in the context of the Northwest's regional generation mix, is a very complex analysis that was out of scope for this report. In particular, the analysis would need to evaluate both the impact on PSE utility-owned generation, as well as regional changes in the market-dispatch of generation in the Pacific Northwest. The latter is likely to react to less PSE-owned generation being dispatched. This may result in imports of more market resources, the mix of which is unknown and could be comprised of renewables or conventional generation resources. Thus a broader regional analysis of GHG impacts of storage is recommended before assigning specific value to the GHG reduction benefits of storage for PSE's customers. PSE plans to conduct such an analysis as part of its 2015 Integrated Resource Plan.

### Energy Time-Shifting

In essence the energy time-shift benefit is related generation/purchase of low priced/low cost electric energy when demand is low, for use or sale when demand and price are high (i.e., buy low – sell high). For the Eastside evaluation the energy time-shift benefit was included in the system flexibility benefit calculation.

### Ancillary Services

Storage can be used for the full spectrum of ancillary services. Storage is especially well-suited to provide these services given how responsive most storage types are when compared to the generation resources used most often to provide these services. For the Eastside evaluation, the ancillary service benefits of frequency response, balancing and load following/ramping was included in the system flexibility benefit calculation.

### Generation Dynamic Operating Benefits

Storage provides (generation fleet) dynamic operating benefits by enabling a more optimized (i.e. efficient and less variable) operation of the generation fleet by reducing the need to commit, start, ramp and operate generation at part load, which reduces fuel use and emissions (per kWh) and reduces plant wear and variable maintenance costs while extending equipment life. These benefits are captured for the Eastside evaluation in the system flexibility benefit calculation.

### Reduced Need for Flexible Generation Capacity

In addition to the assessment of flexibility benefits for the *existing* electric supply resource configuration, storage could also reduce the need for *additional* "flexible capacity" (especially combustion turbines) beyond that needed to address load growth and equipment retirement. However, that benefit is likely to be limited for PSE because hydroelectric generation provides most flexibility during most of the year. These benefits are captured for the Eastside evaluation in the system flexibility benefit calculation.

### Transmission Support and Voltage Control

Depending on where it is located, storage can enhance the "electrical" performance of transmission and even distribution equipment. It does that by reducing overloading and problematic current flows, offsetting/ameliorating voltage and other power quality challenges caused by renewables whose output varies, especially wind and PV, and by managing other electrical phenomena that reduce the overall effectiveness of T&D facilities such as voltage sags, excess reactance and sub-synchronous resonance and by providing means for effective Volt/VAR control and possibly even conservation voltage reduction.

### Reduced T&D $I^2R$ Energy Losses

As mentioned in the characterization of the system capacity benefits above, storage reduces real-time T&D $I^2R$ energy losses which reduces the need for energy supply capacity (to offset the energy losses). By reducing T&D $I^2R$ energy losses, storage also reduces the total amount of energy needed (and fuel used and GHG emissions produced) to serve PSE's end-users.

### Renewables Integration

Storage can be an important enabler of increased use of renewables whose output varies, especially wind and solar generation. Storage can also enable use of additional energy from hydroelectric generation, especially during years when precipitation is significant and/or times of the year when significant amounts of hydroelectric generated electricity is produced and demand is relatively low.

Storage does that, in part, by providing means for system operators to compensate quickly and effectively for renewables output variation and to address changes and opportunities related to reduced "oversupply" that occurs when a) the amount of generation output exceeds demand and b) most or all generation operating is not "dispatachable" (i.e., output cannot be varied without significant cost implications). Storage can also enable more deployment of distributed renewables, especially PV, by offsetting unhelpful electrical effects and by managing excess energy produced within a distribution system.

### Electric Service Reliability

Beyond the "reliability-related" considerations described above (related to NERC Standards), storage can be used to improve electric service reliability in several ways such as a) improving local power quality, b) improving the overall "electrical performance" and throughput of T&D systems, c) providing "back-up" power for end-users and d) managing localized peak demand and T&D overloading.

## 7.5 Other Assumptions and Inputs

This subchapter provides a summary of the assumptions used for the cost-effectiveness evaluation.

### 7.5.1 *Evaluation Period*

The evaluation is undertaken for storage deployed in 2017-2018, to enable the deferral of the upgrade through 2021 (deferral for four years). The storage is assumed to have a service life of 20 years (through 2036).

Storage operation during the evaluation period:

- During years 2017 to 2021, the Eastside transmission-related needs- to enable the deferral- is the priority use case of the energy storage device, while the storage is assumed to be used for other system benefits during other times of the year.

- During years 2022 to 2036, transmission reliability is no longer prioritized over other applications for the energy storage device, because additional transmission is assumed to be in place to relieve the Eastside system needs.

### 7.5.2 *Financial and Economic*

The ultimate criterion of merit regarding cost-effectiveness is the net present value (NPV) of alternatives being assessed. The alternative with the net cost (e.g. revenue requirements minus benefits) that results in the lowest NPV is assumed to be the “best” alternative, assuming that the alternatives provide equal utility.

For the evaluation (to calculate NPV), all costs are assumed to escalate at the nominal rate of 2.5% per year.

The financial assumptions used for the evaluation are shown in Table 39. Of particular note is the pre-tax discount rate of 7.77%, which is PSE’s pre-tax weighted average cost of capital and is used in Strategen’s calculations for NPV calculations when discounting pre-tax revenue requirements.

**Table 39. PSE Financial Assumptions**

| | |
|---|---|
| **State Revenue Tax** | 3.8712% |
| **Federal Income Tax** | 35.00% |
| **Property Tax** | 0.4800% |

| PSE Capital Structure | Ratio | Cost (Pre-tax) | Weighted (Pre-Tax) | Weighted (After-Tax) |
|---|---|---|---|---|
| LT Debt | 48.00% | 6.16% | 2.96% | 1.92% |
| ST Debt | 4.00% | 2.68% | 0.11% | 0.07% |
| Preferred | 0.00% | 0.00% | 0.00% | 0.00% |
| Equity | 48.00% | 9.80% | 4.70% | 4.70% |
| **TOTAL** | **100.00%** | | **7.77%** | **6.69%** |

### 7.5.3 *Energy Storage*

The following is a summary of key storage-related assumptions.

#### Configuration

The storage configuration selected for evaluation is a centralized storage system located at Lakeside substation with a power rating (capacity) of 121 MW and discharge duration of approximately 1.9 hours (e.g. 226 MWh of energy can be stored).

#### Performance

The storage system specified is assumed to have an AC-to-AC round trip efficiency of 85%. It is also assumed that the amount of energy that can be stored degrades at a rate of 2%/year (so, at the end of the 20-year life of the system, it is able to store about 68% of its rated capacity when first deployed). Note that the system sizing when deployed was adjusted slightly upwards to account for degradation during the deferral period.[116]

No battery replacements or other significant servicing/maintenance was assumed during the 20 year evaluation period so O&M costs were assumed to fixed (under contract with the vendor) to maintain system functionality only but not to replace or add cells when overall system degradation in line with projections occurs.

#### Storage Cost

The PSE-specific levelized and lifecycle cost for the storage plant was calculated. Please see Appendix F: for details about the lifecycle cost estimation for storage, and Chapter 7.6 for the cost and revenue requirement assumptions used in developing the pro forma.

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[116] Specifically, the need driving the 226 MW energy requirement is a 217 MW requirement in 2019. In order to meet this need, the system must be upsized to 226 MW to account for anticipated system degradation between 2017-2019.

## 7.6 Cost-effectiveness Evaluation Results

What follows is a detailed summary of the results of the cost effectiveness assessment of the Alternate Configuration #1: *Emergency Overload Elimination* configuration (as described in Chapter 7.1), including storage system cost, benefit values, net present value and benefit-to-cost ratio for the project.

As shown in in Table 40, the estimated NPV of storage cost is $264.2 Million and $2,183.6/kW installed, for a 20 year levelized cost of $218.6/kW-year.

### Table 40. NPV of Storage Cost

| Revenue Requirement ($Million) | | |
|---|---|---|
| | $Current ($000) | 414,783 |
| | $/kW | 3,428 |
| | | |
| | **$NPV ($000)** | **264,217** |
| | **$/kW** | **$ 2,183.61** |
| | **$/kW-year Levelized**** | **$ 218.58** |
| | | |
| | *Discount Rate 7.77% | |
| | ** Life: 20, WACC (Discount Rate): 7.77% | |

The NPV of the energy supply capacity benefit is based on the avoided cost for the SCCT described in the characterization of the Default Peaking Capacity Resource: Simple Cycle Combustion Turbine in Chapter 7.4.2. It also reflects PSE's projected capacity needs and the diminishing energy output from storage as it ages and is used.

Shown in Table 41 below are the annual capacity needs for the first five years of storage operation, and the resulting energy supply capacity benefit from storage reflecting the 2.5%/year escalation for that benefit and the diminishing storage power available for supply capacity reflects a 2%/year decline of energy output from the storage. The resulting NPV is about $171.2 Million or $1,518/kW of storage installed, for annual levelized benefit of $152/kW-year.

**Table 41. Estimated NPV of Energy Supply Capacity Benefit**

| | | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|
| Storage Power (MW) | | 112.8 | 110.6 | 108.4 | 106.3 | 104.2 |
| Supply Capacity Needs | | 12.0 | 61.0 | 105.0 | 100.0 | 149.0 |
| **Storage Power for Supply Capacity Credit (MW)** | | 12.0 | 61.0 | 105.0 | 100.0 | 104.2 |
| **Supply Capacity Value ($/kW-year, Capacity)** | | $ 156 | $ 156 | $ 156 | $ 156 | $ 156 |
| **Supply Capacity Benefit ($000 $2017)** | **$ 267,687** | $ 1,866 | $ 9,487 | $16,330 | $15,552 | $16,207 |
| **Supply Capacity Benefit ($000 $Current)*** | **$ 342,490** | $ 1,866 | $ 9,724 | $17,156 | $16,748 | $17,889 |
| **Supply Capacity Benefit ($000 $PW)**** | **$ 171,274** | $ 1,866 | $ 9,023 | $14,772 | $13,381 | $13,263 |
| **$/kW$_{\text{storage system}}$** | **$ 1,518.39** | | | | | |
| **$/kW-year levelized***** | **$ 151.99** | | | | | |

*Based on escalation rate of 2.50%.
**Based on discount rate of 7.77%.
***Based on WACC of 7.77%.

The NPV of the transmission capacity benefit is based on the revenue from re-sale of unused transmission capacity, as described in the System Flexibility Benefit in Chapter 7.4.2.1.

Shown in Table 42 below are the annual values for storage power that adds to PSE's energy supply capacity surplus (and, therefore, is allows PSE to re-sell transmission in the market), starting at about 108 MW in 2017 and declining through 2020 to 6.3 MW. Those results also show the effects of 2.5%/year escalation of the benefit and the diminishing storage power available for capacity due to degradation (at a rate of 2%/year). The result is an NPV of $4.9 Million or $43.5/kW of storage installed, for an annual levelized benefit of $4.53/kW-year.

### Table 42. Estimated NPV of Transmission Capacity Benefit

| | | | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| **Storage Power for T Capacity Credit (MW)** | | | 100.8 | 49.6 | 3.4 | 6.3 |
| **Transmission Capacity Value ($/kW-year$_{storage}$)** | | | $ 31.35 | $ 32.14 | $ 32.94 | $ 33.76 |
| | | | | +2.5% | +2.5% | +2.5% |
| **T Capacity Benefit ($000 $2017)** | **$** | **5,079** | $ 3,160 | $ 1,594 | $ 113 | $ 212 |
| **T Capacity Benefit ($000 $Current)*** | **$** | **5,079** | $ 3,160 | $ 1,594 | $ 113 | $ 212 |
| **T Capacity Benefit ($000 $PW)**** | **$** | **4,906** | $ 3,160 | $ 1,479 | $ 97 | $ 170 |
| **$/kW$_{storage\ system}$** | **$** | **43.49** | | | | |
| **$/kW-year levelized***** | **$** | **4.35** | | | | |

*Based on escalation rate of 2.50%.
**Based on discount rate of 7.77%.
***Based on WACC of 7.77%.

Shown in Table 43 is the NPV of the flexibility benefits for all 20 years of storage operation. The results reflect a benefit escalation of 2.5%/year and diminishing storage power due to the declining storage energy output (declining at a rate of 2%/year). The result is a NPV of $120.3 Million or $994/kW of storage installed, for an annual levelized benefit of $99.52/kW-year.

### Table 43. Estimated Annual Flexibility Benefit, 2017

| | Total |
|---|---|
| Constant Dollars ($000) | $220,827 |
| Current Dollars ($000) | $284,063 |
| Present Worth* ($000) | $140,662 |
| $/kW** | $1,162.50 |
| $/kW-year levelized*** | $116.37 |
| With Energy Output Degradation | |
| **Present Worth* ($000)** | **$120,296** |
| **$/kW**** | **$994.18** |
| **$/kW-year levelized***** | **$99.52** |

*Based on escalation rate of 2.50%.
*Based on discount rate of 7.77%.
**Based on WACC of 7.77%.

Shown in Table 44, the estimated NPV for the oversupply reduction during the 20 years of storage operation, assuming that the benefits escalate at a rate of 2.5%/year and that the benefit declines due to the declining storage energy output at a rate of 2%/year. The NPV of those two benefits is approximately $1.7 Million or about $14/kW installed and $1.40/kW-year levelized.

### Table 44. Estimated Annual Oversupply Reduction Benefit, 2017

| With Energy Output Degradation | |
|---|---|
| **Present Worth ($000)* **** | **$ 1,687** |
| **$/kW** | **$ 13.94** |
| **$/kW-year levelized***** | **$ 1.40** |
| | |
| *Escalation Rate 2.50% | |
| **Discount Rate 7.77% | |
| ***Life: 20 years, WACC (Discount Rate) = 7.77% | |

Although not included in the final benefit/cost calculus, GHG reduction benefits could also potentially be significant. The results of the cost-effectiveness evaluations are summarized in Table 45, which shows storage cost, benefits and the benefit cost ratio. The total NPV of the storage (revenue requirements) is $264.2 Million and the NPV of all benefits estimated is $298.2 Million for a net NPV of $34.0 Million and a benefit cost ratio of 1.13.

### Table 45. Net Present Value Summary and Benefit Cost Ratio

| | | | | |
|---|---|---|---|---|
| *Storage Cost* | **Total Cost** | **$264.22** | **$2,183.61** | **$218.58** |
| *Benefits* | | $ Million* | $/kW* | $/kW-year** |
| | Transmission Deferral*** | $- | $- | $- |
| | Energy Supply Capacity | $171.27 | $1,518.39 | $151.99 |
| | Transmission Capacity | $4.91 | $43.49 | $4.35 |
| | Flexibility | $120.30 | $994.18 | $99.52 |
| | Oversupply | $1.69 | $13.94 | $1.40 |
| | **Total Monetizable Benefits** | **$298.16** | **$2,570.00** | **$257.26** |
| *Benefit/Cost Ratio* | | | | 1.13 |

*Values are discounted using 7.77% and are expressed in $2017.
**Based on WACC of 7.77%.
*** Assumes other non-wires alternatives fully absorb this $155/kW-year benefit

# 8 Conclusions and Recommendations

This chapter highlights the major conclusions and recommendations. In summary, Strategen was unable to find a solution that was both technically feasible and also meets PSE's requirements for addressing the Eastside need. Further, the timeline for interconnection and land use permitting appear render infeasible an online date in time to meet PSE's winter 2017-2018 need, and the cost of energy storage to meet the Eastside need appears prohibitive. We therefore conclude that energy storage is not a viable transmission deferral option for the Eastside need. However, we did find that energy storage in general shows promise as a potentially cost effective solution to meet other system needs, and recommend further evaluation in PSE's upcoming Integrated Resource Plan.

## 8.1 System Sizing

Strategen evaluated the power and energy requirements for an energy storage system to accomplish the PSE's objectives as identified in previous chapters.

Strategen calculated net injection requirements of 328.0 MW/2,338.0 MWh for an energy storage system to fully meet PSE's objectives. Alternate configurations were developed to address emergency overloads only (Alternate #1), and to create a more robust solution that would result in a longer deferral, through the elimination of all normal overloads during system contingencies (Alternate #2). A summary of key findings is contained in Table 46 below.

**Table 46. Energy Storage Configuration Summary**

| Configuration | Power (MWp) | Energy (MWh) | Acreage | Est. Cost ($MM) | Includes Non-Wires Alternatives [117] | Technically Feasible | Meets Requirements |
|---|---|---|---|---|---|---|---|
| Baseline Normal Overload Reduction | 328 | 2,338 | 19.6 | **$1,030** | ✓ | × | ✓ |
| Alternate #1 Emergency Overload Elimination* | 121 | 226 | 5.8 | **$184** | ✓ | ✓ | × |
| Alternate #2 Normal Overload Elimination | 545 | 5,771 | 45.7 | **$2,367** | ✓ | × | ✓ |

[117] E3 (2014)

### 8.1.1 *Technological Readiness*

Siting limitations and commercial feasibility in the Eastside area caused Strategen and PSE to identify a chemical (battery) storage solution as the most appropriate technology for this study.

The technology and capability exists for batteries to be deployed for this application at this magnitude, however, no similarly-sized system has ever actually been built or commissioned. Therefore, it is difficult to estimate the time necessary for procurement, construction and deployment.

### 8.1.2 *Siting Feasibility, Permitting, and Interconnection*

The lengthy interconnection study process (1-2 years) and permitting process (2-4 years) would present significant barriers for an ESS beginning development in early 2015 to meet a Winter 2017-2018 online date. This is a particularly acute problem given that procurement of long lead items and construction are likely to take an additional 1-2 years following construction, depending on the willingness of the developer to put capital at risk for procurement before the project is fully permitted. A 2019 online date would be a more realistic expectation for any potential substation-sited storage solution to reach commercial operation.

### 8.1.3 *Technical Feasibility*

The critical technical challenge identified for an energy storage system configured to meet the Eastside system need is the existing transmission system's available capacity to support charging of the storage system.

Strategen determined that the existing Eastside transmission system does not have sufficient capacity to fully charge the Baseline Configuration during system contingency scenarios. Specifically, 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.

### 8.1.4 *Cost-Effectiveness*

As Strategen determined that the Baseline Configuration would not be technically feasible, a cost-effectiveness assessment was only conducted for Alternate Configuration #1. This configuration does appear to be cost effective, with a benefit-cost ratio of approximately 1.13. Strategen did not evaluate the relative cost effectiveness of energy storage versus other types of system resources, as this would require a more robust analysis that is best suited for PSE's Integrated Resource Planning process.

## 8.2 **Key Conclusions**

Based upon the results of the study, Strategen provides the following conclusions for PSE's consideration.

- The Baseline Configuration (a 328 MW / 2,338 MWh storage system) is not technically feasible because the existing Eastside transmission system does not have sufficient capacity to fully charge the system.
- Based on permitting and interconnection requirements identified by PSE combined with likely procurement and construction timelines, Strategen does not believe any studied configuration could come online in time to meet a winter 2017-2018 need. A more feasible online date would be in the 2019 timeframe.
- Strategen estimates that the Baseline Configuration would have a revenue requirement of approximately $1.44 billion (discounted to reflect present value) and a physical footprint of approximately 19.6 acres.
- An energy storage system with power and energy storage ratings comparable to the Baseline Configuration (large enough to reduce normal overloads) has not yet been installed anywhere in the world. Projects comparable to Alternate Configuration #1 (a 121 MW / 226 MWh storage system) have been contracted by other utilities.
- Alternate Configuration #1, while not meeting PSE's operational requirements, does appear to be cost effective, with a benefit-cost ratio of approximately 1.13 and a revenue requirement of approximately $264 million. This configuration would require a physical footprint of approximately 5.8 acres of available land adjacent to PSE-identified substations in the Eastside.
- Strategen's analysis evaluated the absolute cost effectiveness of energy storage in terms of system benefits versus revenue requirements. While the analysis concluded that energy storage appears to be cost effective as a system resource, it did not evaluate the relative cost effectiveness of energy storage versus other types of system resources. Strategen recommends further analysis of the relative cost effectiveness of energy storage to meet PSE's system-wide needs in its upcoming Integrated Resource Plan.

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# 10 Appendices

# Appendix A: Acronyms

| | |
|---|---|
| **AC** | Alternating Current |
| **AEP** | American Electric Power |
| **AMI** | Automated Metering Infrastructure |
| **ANSI** | American National Standards Institute |
| **AS** | Ancillary Services |
| **BOS** | Balance-of-System |
| **BPA** | Bonneville Power Administration |
| **CAES** | Compressed Air Energy Storage |
| **CAP** | Corrective Action Plan |
| **$CO_2$** | Carbon Dioxide |
| **CSP** | Concentrated Solar Power |
| **DG** | Distributed Generation |
| **DOD** | Depth of Discharge |
| **DOE** | United States Department of Energy |
| **DR** | Demand Response |
| **DRA** | Demand Response Agreement |
| **DSR** | Demand-side Resources |
| **E3** | Energy and Environmental Economics |
| **EE** | Energy Efficiency |
| **EPC** | Engineering, Procurement and Construction |
| **EPRI** | Electric Power Research Institute |
| **ESA** | Energy Storage Agreement |
| **ESS** | Energy Storage System |
| **ESVT** | Energy Storage Valuation Tool |
| **FERC** | Federal Energy Regulatory Commission |
| **GHG** | Greenhouse Gas |
| **GW** | Gigawatt |

| | |
|---|---|
| **HECO** | Hawaiian Electric Company |
| **ICE** | Incremental Capacity Equivalent |
| **IOU** | Investor Owned Utility |
| **IRP** | Integrated Resource Plan |
| **kV** | Kilovolt |
| **kW** | Kilowatt |
| **kWh** | Kilowatt-hour |
| **LCR** | Local Capacity Resource |
| **LMP** | Locational Marginal Price |
| **MMBtu** | Million British Thermal Units |
| **MW** | Megawatt |
| **MWh** | Megawatt-hour |
| **NaS** | Sodium Sulfur |
| **NERC** | National Electric Reliability Council |
| **NPV** | Net Present Value |
| **O&M** | Operations and Maintenance |
| **PCS** | Power Conditioning System |
| **PG&E** | Pacific Gas and Electric Company |
| **PPTA** | Power Purchase Tolling Agreement |
| **PSE** | Puget Sound Energy |
| **PUC** | Public Utilities Commission |
| **PV** | Photovoltaic |
| **REM** | Regulation Energy Management |
| **RFO** | Request For Offer |
| **RTE** | Roundtrip Efficiency |
| **SCC** | Social Cost of Carbon |
| **SCE** | Southern California Edison Company |
| **SDG&E** | San Diego Gas & Electric Company |

| | |
|---|---|
| **T&D** | Transmission and Distribution |
| **TOU** | Time of Use |
| **TPL** | Transmission Planning |
| **UPS** | Uninterruptible Power Supply |
| **VAR** | Volt-Ampere Reactive |

# Appendix B: Description of the Eastside System Reliability Need

Puget Sound Energy’s electric grid and infrastructure are facing both regional and localized supply and transmission deficiencies. This chapter summarizes the issues as identified in the 2013 Integrated Resource Plan, as well as the localized King County issues (the “Eastside) addressed in the 2013 Eastside Needs Assessment report (the “Eastside Assessment).

Load growth is straining the Eastside transmission system, and while Corrective Action Plans have mitigated the near term threat, projected growth will continue to exacerbate the risks of overloads, thermal violations and contingencies over the next ten years. Modelling demonstrates that, as early as winter 2017-2018, the PSE system will face a load level of 5,200 MW, leading to a winter peak supply deficiency and NERC contingencies on several system elements, with summer peak deficiencies and contingencies following shortly thereafter.

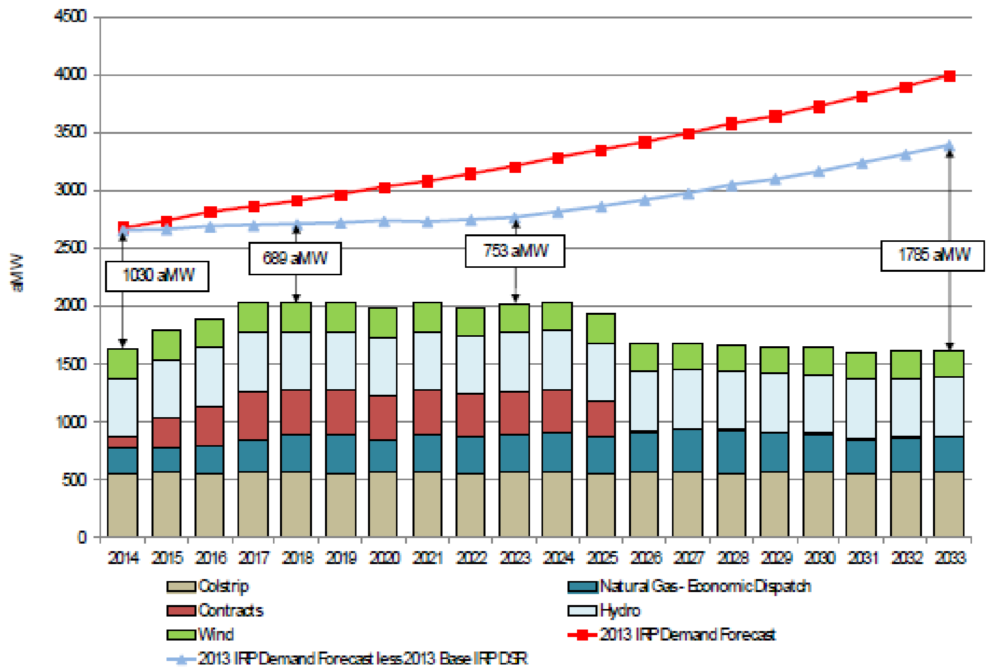
## *B1. Puget Sound Energy Integrated Resource Plan 2013*

The amount of energy generated in the Pacific Northwest has historically been greater than the amount consumed, allowing Puget Sound Energy (PSE) many choices on how best to procure and provide reliable, low cost power to its customers. This resulted in sustained, regional economic and population growth that - in concert with the planned retirement of 2,000 megawatts of generation capacity by 2020 - will soon demand more electricity than current infrastructure can supply.

PSE’s 2013 Integrated Resource Plan attempted to accurately project the regional supply-demand imbalance and determine the best way to address it while keeping customers’ bills as low as possible. It examined population and economic growth rates (well correlated with electricity consumption), and projected how much electricity PSE customers will consume from 2014-2033. After better understanding customer demand and estimating annual supply capacity shortfalls (See Figure 17), PSE modeled hypothetical scenarios that combined a variety of supply resources (conservation and energy efficiency, new renewable or thermal generation, renewing transmission contracts, etc.) to see which combinations would meet customer needs at the lowest cost while also complying with renewable portfolio standards.

Results of the IRP analysis demonstrated that conservation measures and renewal of transmission contracts were least cost options that will play important roles in PSE’s future electric grid. Conservation measures, also called demand-side resources (DSR), have the potential to incrementally reduce demand across PSE territory by 327 MW in 2017 and 800 MW in 2023 (represented by the difference between the red and blue line in Figure 17). The IRP substantiated previous PSE studies showing that DSR are almost always a least cost strategy, which PSE will continue to aggressively acquire. Even though PSE intends to procure as much conservation as possible, DSR alone will not reduce demand enough to balance it with supply: other resources, either new generation or transmission, will have to be secured as well.

**Figure 17. Annual Energy Position for 2013 IRP Base Scenario**




The IRP modelling also demonstrated that renewal of transmission contracts could potentially supply 1,141 MW and 1,407 MW of increased capacity in 2017 and 2023 respectively. In the short term (5-7 years), this is the least cost solution that, when combined with maximal DSR, allows PSE to continue reliably meeting customer demand.

While the IRP looked at the regional electric outlook and modelled the overall PSE territory, there are also specific pockets within the region where increased demand is straining existing infrastructure and presenting a more acute threat. One such pocket is PSE's Eastside system in King County.

## *B2. King County Transmission System*

King County hosts the Seattle-Bellevue-Tacoma Metro Area. It is home to over 2 million people, of whom PSE provides electricity service to more than 500,000. The system relies on transmission interties with neighboring utilities to meet 90% of peak load.

The area load is supplied by four 500 kV substations owned by Bonneville Power Administration (BPA) in Monroe, Renton, Mill Creek, and Covington, and two 500 kV BPA switching stations in Ravensdale and south of Snoqualmie. Additional 230 kV supply is provided by five PSE substations as summarized in Table 47.

**Table 47. King County Substations and Transformers**

| Substation | Location | Transformers (230 kV/115 kV) |
|---|---|---|
| **Sammamish** | Redmond | 2 |
| **Novelty Hill** | Redmond Ridge | 1 |
| **Talbot Hill** | Renton | 2 |
| **O'Brien** | Kent | 2 |
| **Berrydale** | Covington | 1 |

Several studies have assessed potential risks to King County's transmission system including the 2008 Initial King County Transformation Study, 2009 PSE TPL Planning Studies and Assessment, and 2012 PSE TPL Planning Studies and Assessment. The greater Bellevue area, between Talbot Hill and Sammamish Substations, was identified as being especially at risk of potential thermal violations resulting from overloads during certain system contingency events.

A 2009 comprehensive reliability assessment confirmed the risk: given a projected 2010-2011 winter peak load of 5,329 MW,[118] a bus fault at Talbot Hill substation would cause an overload of one 230-115 kV transformer and several 230kV transmission lines if the other transformer tripped off.[119] To address the threat, PSE initiated a Corrective Action Plan (CAP) in 2009: manually switching out two 115 kV lines from Talbot Hill-Lakeside at the ~5,300 MW load level.

CAPs effectively mitigate the immediate risk of overloading at the Talbot Hill and Sammamish Substations, but negatively impact system reliability, and other issues continue to threaten local reliability. To comprehensively address those issues, quantify longer term system needs, and identify effective solutions, PSE partnered with Quanta Technology for a complete analysis of the King County Transmission system in the 2013 Eastside Needs Assessment Report.

## *B3. 2013 Eastside Needs Assessment Report*

[118] 2009 PSE Planning Studies and Assessment TPL-001 to TPL-004 Compliance Report; P. 7.
[119] 2013 Eastside Needs Assessment Report; P. 15.

The 2013 Eastside Needs Assessment Report sought to evaluate the existing transmission infrastructure and its ability to reliably supply future load growth. The Eastside Assessment encompasses the area east of Lake Washington and west of Lake Sammamish, including Bellevue, Redmond, Mercer Island, Renton, Newcastle and Issaquah.

Compiling information from previous King County studies, incorporating the latest population and load growth projections, and accounting for energy efficiency and conservation targets set by the IRP, the report presents a comprehensive reliability analysis of the King County transmission system for 2012-2022.

Specific issues addressed include:

- Overloading of Talbot Hill and Sammamish Substation transformers
- Increasing use of Corrective Action Plans
- ColumbiaGrid recommended infrastructure reinforcements
- Risks associated with uncertain load forecasts

### *Talbot Hill and Sammamish Substations*

The Eastside Assessment verified and elaborated the overloading issues at Talbot Hill and Sammamish Substations. The overload risks identified in 2009 have been temporarily mitigated through the use of CAPs. However, anticipated load growth in the Bellevue area will increase the number of potential future thermal violations and lead to several NERC contingencies, summarized by season in Table 48.

Transformer overloads are projected to occur in both winter and summer, but in different areas. In summer, when peak loads are forecasted to grow annually at the rate of 37 MW, overloads are possible at Sammamish Substation. This is due to regional power flowing primarily north to south and large anticipated increases in commercial loads. In winter, when power flows are reversed and load growth is expected to be 17 MW per year, the Talbot Hill Substation is at risk of overloading.

The transmission supply deficiency that results in overloading at Talbot Hill and Sammamish Substations) are projected to occur even if 100% of IRP conservation targets are met.

**Table 48. Potential NERC Contingencies based on model results**

| Season | Est. Load | Model Year | Contingency | Elements |
|---|---|---|---|---|
| Winter | ~5,200 MW | 2017-2018 | Category B (N-1) [120] | 2 elements (115 kV), loading>98% |
| | | | Category C (N-1-1 & N-2) | 5 elements (115 kV), loading>100% |
| Summer | ~3,500 MW | 2018 | Category B (N-1) | 2 elements (230 kV), loading>100%<br>2 elements (115 kV), loading>93% |
| | | | Category C (N-1-1) | 3 elements, loading>100%<br>1 element, loading>99% |

### *Risks associated with uncertain load forecasts*

As with any projection of future scenarios, load forecasts are approximations based on currently available information and assumptions. The load forecast used in the analysis assumed 100% of IRP-established DSR targets are met and normal (23° F) winter weather conditions.

Analysis demonstrated that load forecasts are highly sensitive to variations in both weather conditions and actual acquired conservation levels. Using the 5,200 MW winter 2017-2018 load estimate as a reference point, models showed that if, for example, only 75% of incremental conservation targets were met, that load could occur in 2015, and overloads in the 2017-2021 period would be significantly greater than planned under the 100% conservation scenario. The overloads would also be significantly greater should extreme weather (13° F) occur, as load growth would be approximately 3.5 times greater than forecasted if the temperature on peak days were to drop from 23° F to 13° F.

The results of the Eastside Assessment rely on normal weather conditions and 100% of IRP-established DSR targets being met. If climatic conditions, planned infrastructure additions, or conservation targets deviate from assumed levels, both the magnitude and timing of transmission reliability threats could vary significantly from the report's projections.

[120] N-1 (n minus one) overloading refers to power requirements that exceed the transmission equipment's design or "normal" power rating. In addition to that normal or design rating, transmission equipment also has an "emergency" power rating. The emergency rating is the absolute maximum amount of power that should be provided – for a limited duration and very infrequently – without significant damage to the equipment and/or outages. Power flow exceeding the emergency rating when one element is taken out of service followed by another element taken out of service is referred to as N-1-1 (n minus one, minus one) overloading.

### *Increasing use of Corrective Action Plans*

The CAPs that currently mitigates overloading at Talbot Hill and Sammamish Substations increases vulnerability across the entire transmission network, thus leaving customers vulnerable to outages.

PSE found that future load growth would require additional CAPs to be employed, thereby further degrading system resiliency and exposing up to 60,000 more customers to outage risks.

### *ColumbiaGrid recommended infrastructure reinforcements*

ColumbiaGrid's Biennial Transmission Expansion Plan addressed Pacific Northwest regional system needs. The plan identified projects needed to buttress system reliability and reduce regional and renewable generation curtailment by installing specific infrastructure reinforcements, including additional PSE 230 kV transmission capacity in King County.

The Eastside Assessment models supported ColumbiaGrid's findings, also finding possible overloads of 230 kV lines in the future.

# Appendix C: Proposed Eastside Solutions

Puget Sound Energy conducted multiple studies to identify and evaluate potential long-term solutions to the identified transmission capacity deficiencies. The Eastside Solutions Study sought to identify transmission upgrade scenarios that met the criteria for a viable alternative. The Non-wires Report estimated the potential for further demand side resources (above IRP targets) to mitigate the transmission capacity shortfall identified in King County and defer the required transmission upgrades to 2021. Results demonstrated that additional conservation, demand response, and distributed generation would be insufficient to alleviate the capacity deficiency, especially if load growth or weather conditions deviate from projections.

## *C1. Transmission Alternatives*

Following the Eastside Needs Assessment Report findings, Puget Sound Energy conducted the Eastside Transmission Solutions Study to rigorously evaluate potential solutions to the identified transmission system issues. A variety of possible solution types and resource combinations were considered, and four principal solution types emerged: generation, transformer addition with minimal system reinforcements, demand side reduction, and transmission lines plus transformers. To be considered viable, a solution had to solve the transmission issues identified in the Eastside Needs Assessment, comply with environmental requirements, and satisfy constructability and longevity requirements.

The addition of new generation, specifically a 300 MW gas turbine, was determined to be a technically feasible solution, and three potential locations were evaluated as possible sites. However, environmental constraints - noise and atmospheric emission standards - and permitting challenges eliminated two sites, while the third, Cedar Hills, remains a potentially viable solution but would require two new transmission lines connecting Cedar Hills to both Lake Tradition and Berrydale transmission substations. This would result in building 17 miles of new 115 kV transmission lines, and rebuilding 21 miles of existing 115 kV transmission lines. In addition, according to PSE's power flow studies, generation at Cedar Hills alone did not prove enough relief to solve the identified capacity problems.

The Sammamish, Talbot Hill, and Lake Tradition substations were evaluated as sites for additional transformers, but modelling revealed that numerous overloads would occur without the additions of new lines as well. Therefore, transformers as a stand-alone solution were deemed unviable.

Potential additional demand side reduction measures were reviewed by the PSE Energy Efficiency Group. And in order to ensure full evaluation and consideration of all non-wires alternatives, PSE engaged an outside consultant to conduct an exhaustive review of non-wires solutions.

Many resource combinations were evaluated based on their effectiveness at resolving the capacity deficiency, operational flexibility, potential to eliminate reliance on CAPs, right of way assessment, and effects on adjacent grid infrastructure. After reviewing each solution type, exploring alternatives, and performing power flow analysis on each, the most viable solution type identified was the combination of new transformers and new/upgraded transmission lines. The five potential upgrades are summarized in Table 49.

**Table 49. Proposed Eastside Transformer and Transmission Solutions**

| 230 kV Line Alternative | Substation Alternative |
|---|---|
| Rebuild one Talbot Hill- Lakeside-Sammamish 115 kV line to 230 kV and loop through new substation | Westminster |
| Rebuild one Talbot Hill- Lakeside-Sammamish 115 kV line to 230 kV and loop through new substation | Lakeside |
| Build new Talbot Hill-Sammamish 230 kV line on new right of way, loop through new substation | Westminster |
| Build new Talbot Hill-Sammamish 230 kV line on new right of way, loop through new substation | Vernell |
| Build new Talbot Hill-Sammamish 230 kV line on new right of way, loop through new substation | Lakeside |

## *C2. Non-Wires Alternatives*

In February 2014 Energy and Environmental Economics (E3) provided a screening-level assessment (the “Non-Wires Report) to examine whether non-wires alternatives could effectively defer the proposed King County Transmission upgrades from winter 2017-2018 until winter 2021. Non-wires alternatives considered include energy efficiency, demand response, distributed generation, as well as solar PV, customer sited backup generation, and combined heat and power.

### *Need*

Using the power flow case data from the Eastside Assessment, PSE planners quantified the supply capacity that would be required to defer transmission upgrades identified in the Eastside Solutions Study until 2021. Analysis focused on the 2021 winter peak load since the most significant overloads occur due to winter peak conditions. Should DSR be able to sufficiently address winter needs, summer loads would then be examined.

PSE determined that a minimum of 70 MW of incremental load reduction would be required for a four year deferral (2017-2021) while maintaining system reliability at 2017 levels,[121] assuming normal weather conditions and 100% of PSE's IRP-identified demand side reduction measures were also successful. Should load growth be higher than planned (either due to extreme weather or less than 100% success with IRP-identified demand side reduction[122]), the need could be as much as 160 MW. Analysis also showed that the incremental load reduction must be realized within the Eastside King County area, as demand reduction outside of that zone was shown to be less effective at mitigating local winter overloading.

Incremental demand reduction between 2017-2021 would maintain a system reliability level relative to that projected for 2017, however, it would not address current system overloading risks that require CAPs.[123] To reduce reliance on currently utilized CAPs, as well as those anticipated as necessary to deal with 2017 peak loads, additional load reduction would be required.

### *Method*

The Non-wires Report considered the potential of incremental non-wires alternatives to meet the minimum 70 MW target. Two main criteria guided the evaluation: ability to reduce loads during critical peak periods[124] and cost-effectiveness.

Supply deficiencies and overloading occur at specific times, called the critical peak period, which, in PSE's winter peak, typically happens on December weekdays from 7-11 AM and 6-10 PM. Resources that would reduce demand during critical peak periods would effectively mitigate upgrade need, but technologies that produce the majority of their power outside of those periods, like solar PV, would not meet the criteria necessary for consideration as a solution.

Cost-effectiveness was determined by incorporating the incremental savings from deferring transmission upgrades (valued at $155 per kW), avoided generation and transmission supply costs (supplied by PSE and valued at the IRP 2013 Base hourly energy price), and aggregating other savings generated from DSR.[125] This results in a broader range of potentially viable non-wires alternatives

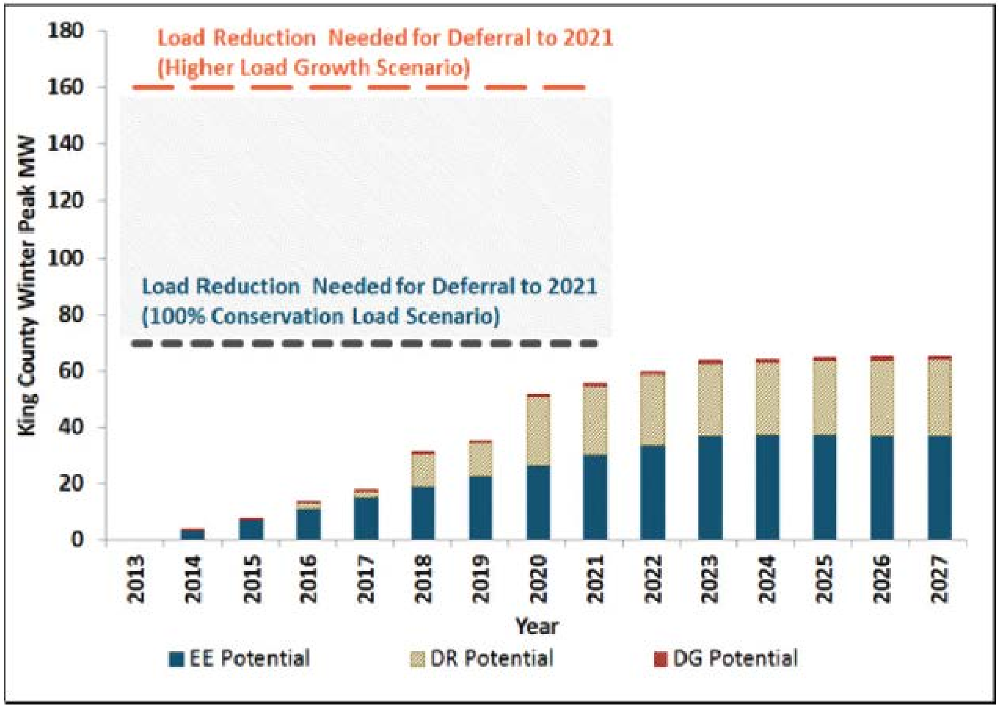
[121] True capacity deficits could be larger if any of the following occurred: Extreme cold weather conditions (models and forecasts are based on 23° F average), faster load growth than expected (based on prevailing economic conditions), or IRP conservation targets were implemented slower than expected.
[122] IRP 2014-2021 DSR targets: 550 MW of energy efficiency and distributed generation, 10 MW from distribution system efficiency, and 108 MW of demand response.
[123] The current energy storage alternatives assessment does look how to reduce reliance on CAPs, as PSE has determined that the capital investment in ESS is significant enough such that the system must restore a higher (more standard) level of system reliability. This is the key contributing factor to the higher megawatt target evaluated in this assessment.
[124] Overloading at Talbot Hill coincides with PSE's system winter peak load, so the latter was used in the analysis.
[125] Savings could include deferred need for distribution upgrades and reducing generation capacity costs.

than the IRP identified as cost-effective, because the threshold for cost-effectiveness would reflect these additional system benefits.

### *Results*

The total non-wires alternatives achievable by 2021 and passing the necessary criteria equaled an incremental 56 MW of resources beyond those identified in the IRP. This included 30 MW of energy efficiency, 25 MW of demand response, and 1 MW of distributed generation. The cumulative, incremental acquisition of available DSR from 2013 to 2027 is displayed in Figure 18.

**Figure 18. Total Non-Wires Potential in Eastside King County**[126]




## *C3. Energy Storage Alternatives*

As discussed above, Puget Sound Energy is actively studying a variety of solutions to remedy their current and projected transmission supply issues. The Eastside Solution Study identified five potential transmission alternative solutions that would effectively address overloading in summer at Sammamish Substation and at Talbot Hill in winter, alleviate transmission supply deficiencies throughout the service area, and increase overall system reliability by reducing CAP reliance. PSE estimates the costs of these projects to range from $155 million to $288 million, but they would each address all of the issues identified in the Eastside Needs Assessment. The Non-wires Report identified 56 MW of incremental cost-effective conservation, in addition to the

[126] E3 (2014)

IRP-established demand-side resource goals. By itself, this level is insufficient to meet the minimum 70 MW required to defer transmission upgrades from 2017-2021.

The Non-wires Report did not consider energy storage as an additional non-wires alternative to help manage the Eastside needs. This Eastside System Energy Storage Alternatives Screening Study builds upon the previous Non-wires Report to determine whether energy storage incremental to other non-wires alternatives would be a technically feasible, commercially viable, and cost effective solution to meet the Eastside need.

# Appendix D: Unquantified and Partially Quantified Benefits

Although only a few of the prospective storage benefits and services applied to the evaluation for the Eastside, it is important to have at least cursory familiarity with the broader spectrum of benefits and services that storage can provide in the future. This appendix provides a very cursory overview of key ones. They are presented in no particular order.

### *Energy Time-Shifting*

Energy time-shifting is perhaps the most familiar storage service. In essence the energy time-shift benefit is related generation and/or purchase of low priced/low cost electric energy when demand is low, for use or sale when demand and price are high (i.e., buy low – sell high). For the Eastside evaluation the energy time-shift benefit was included in the flexibility benefit calculation.

### *Ancillary Services*

Given that most storage types are very responsive they are especially well-suited providing the full spectrum ancillary services including frequency regulation, load following/ramping, balancing, reserve capacity and others.

In general terms, the benefit associated with storage for ancillary services include those related to more efficacious use of generation resources (see dynamic operating benefits) and reduced opportunity cost related to use of generation for ancillary services (rather than for generating electric *energy*).

For this evaluation PSE included the value for ancillary services as part of the "flexibility benefit."

### *Generation Dynamic Operating Benefits*

This benefit involves an overall improvement of electric generation fleet operations due to storage, use sometimes referred to as "dynamic operating benefits." Storage improves generation fleet fuel efficiency, reduces air emission and reduces maintenance cost by enabling more constant, optimized dispatch of generation. Reduced load following/ramping and part load operation and fewer startups 1) reduces equipment wear and related maintenance cost, 2) reduces fuel use and air emissions (per kWh of energy), 3) increases equipment life, and 4) increases generation asset utilization.

Ideally estimating this benefit involves "before and after" (with and without storage) production cost model runs. Furthermore, those runs would require more detailed performance data than is typically used, especially including "curves" for a) fuel efficiency, b) emissions, and c) variable O&M at various levels of operation and cost per start-up.

### *Reduced Need for Flexible Generation Capacity*

In addition to the assessment of PSE's "flexibility benefits" for the *existing* electric supply resource configuration, storage could also reduce the need for *additional* "flexible capacity" (especially combustion turbines) beyond that needed to address load growth and equipment retirement).

However, that benefit is likely to be limited for PSE because hydroelectric generation provides most flexibility during most of the year. Nonetheless, in the future such flexible capacity will be increasingly valuable and may be part of the utility's overall approach to reducing GHG gas emissions, integration of additional renewables generation and will certainly provide generation dynamic operating benefits.

### *Transmission Support and Voltage Control*

Storage can be used to improve the operation of transmission and distribution T&D equipment/systems and to optimize the effectiveness of those T&D assets. Storage located electrically downstream from T&D hot spots can be used to reduce power draw on T&D equipment when/if overloading occurs. Storage can provide more operational flexibility than is possible with just T&D equipment, especially when the utility must respond to existing or looming T&D-related problems. Storage can enable increased throughput of T&D equipment by giving T&D system operators means to provide more stable electricity flow. Key examples include use of storage for damping and to manage excess reactance and sub-synchronous resonance.

Storage is also likely to become an important element of utilities' increasing focus on Volt/VAR control, especially at the distribution and subtransmission levels, and may even be a part of utilities' conservation voltage reduction programs.

### *Reduced T&D $I^2R$ Energy Losses*

Depending on the circumstances, benefits associated with reduced T&D $I^2R$ energy losses may be significant. The benefit accrues if storage a) is charged during night or other off-peak times when temperatures tend to be lower and power draw/current flow and $I^2R$ losses are lowest and b) discharged such that it offsets real-time power draw by loads (i.e., during the day when temperatures, power draw/current flow and $I^2R$ losses are highest).

The effect on capacity requirements is significant because additional equipment is needed to make-up for the energy losses, so that enough energy is delivered to end-users. Consider an example: On-peak T&D $I^2R$ energy losses of 7.5% means that there must be an additional 7.5% of supply capacity to make up for the losses.

Generally the effect on capacity requirements is less significant the closer equipment is to end users. So at the transmission system level, $I^2R$ energy losses may increase transmission capacity required, adding perhaps 4% to 5% to transmission capacity needs. There is a similar but somewhat lower effect at the distribution level although that would only apply to truly distributed resources.

Regarding *energy*, the “net” benefit is a function of $I^2R$ energy losses during times when storage is charged and $I^2R$ energy losses during times when storage is discharging. Consider an example. During peak demand times (presumably when storage is discharging) $I^2R$ energy losses are 7.5% and during off-peak times (when storage is charging) are 4.5% the net benefit (associated with reduced T&D $I^2R$ energy losses) is a function of the net losses avoided or 7.5% - 4.5% = 3%.

### Renewables Integration

Storage can be an important enabler of increased use of renewables, especially those whose output varies (e.g., wind and solar generation). Storage can also enable use of additional energy from hydroelectric generation, especially during years when precipitation is significant and/or times of the year when significant amounts of hydroelectric generated electricity is produced and demand is relatively low.

Regarding integration of renewables with variable output: Storage enables grid system operators to compensate quickly and effectively for renewable generators’ diurnal and short duration output variation. That improves the operation of the thermal generation fleet and allows grid operators to address more localized integration challenges such as voltage fluctuations and current backflow.

And, storage can reduce electricity oversupply (and thus “curtailment” of generation output) that occurs when a) the amount of generation output exceeds demand and b) most or all generation operating is not “dispatachable” (i.e., output cannot be varied without significant cost implications), especially steam-based generation and in some cases hydroelectric generation.

This benefit is very circumstance specific, varying by location, time-of-day, day-of-week, month, and year. Furthermore, it is a composite of several other specific benefits such as increased (RE) energy value, increased (RE generation) supply capacity value, reduced need for ancillary services, (system) dynamic operating benefits (DOBs) and flexibility, improved/optimized localized Voltage and energy flow management.

### Reduced GHG Emissions

Storage can reduce GHG emissions in several ways, including those addressed for the PSE Eastside evaluation: 1) reduced starts and run-time of generation and 2) more optimal generation fleet operation (i.e., for dynamic operating benefits).

Storage may also enable a) reduced use of fossil-fueled generation overall and/or b) increased generation using “cleaner” thermal generation, especially high efficiency combined cycle natural gas fueled resources, and/or c) increased use of demand response and renewables - including increased import of energy from hydroelectric generation. Storage may also help to reduce GHG emissions by enabling more use of electric vehicles.

### *Electric Service Reliability*

The topic of reliability is quite broad and complex. However, in simple terms storage can be an important solution when electric service reliability challenges exist.

Of course end-users can use storage for “back-up power” or, in the future, utilities could provide such services.

Storage can reduce transmission and distribution related challenges that affect service reliability. Storage can improve the power quality on and throughput of T&D equipment by enabling more stable electricity flow (see transmission support below). That reduces the chance that the transmission system will be overloaded or that power quality will be unacceptable, thus reducing the likelihood of transmission related shutdowns and resulting outages. Storage can also be used to reduce peak T&D equipment loading: Even reducing power draw on the equipment by a few percentage points may be important, depending on circumstances. If nothing else it reduces the chance that T&D equipment will be overloaded, which may reduce outages.

The value for such reliability improvements is quite circumstance-specific but generally it is a function of outage-related costs that can be avoided if storage reduces service outages. Key data required to assess those avoided costs include those related to the number and duration of outages and related costs that the storage will obviate. Those costs may include: a) lost revenue during outages, b) utility equipment damage due to overloading before equipment trips off-line, c) utility response cost for outages, d) customer financial losses that the utility must cover such as food spoilage and end-use equipment damage, and e) fines/penalties if any. Significant business-related costs may accrue if outages result in lost productivity and damaged manufactured products.

### *Capacity for Daytime Electric Vehicle Charging*

Storage may become an important element of the overall approach to enabling greater use of electric vehicles. Indeed, without storage there may be too much demand for EV charging during the day (i.e., during peak demand periods) because the existing generation and/or T&D infrastructures may not have enough capacity to serve traditional demand plus power requirements for daytime EV charging.

# **Appendix E:** Generation Capacity Cost *Pro Forma*

**PEAKER REVENUE REQUIREMENT** Based on Generic SCCT from 2013 IRP

| CAPITAL STRUCTURE | Ratio | Pre-Tax Cost | Pre-Tax Weighted | After-Tax Weighted |
|---|---|---|---|---|
| LT Debt | 48.00% | 6.16% | 2.96% | 1.92% |
| ST Debt | 4.00% | 2.68% | 0.11% | 0.07% |
| Preferred | 0.00% | 0.0% | 0.00% | 0.00% |
| Equity | 48.0% | 9.80% | 4.70% | 4.70% |
| | **100%** | | **7.77%** | **6.70%** |

**ASSUMPTIONS**

| | | | |
|---|---|---|---|
| Capex (2017$) | 228,788,000 | Book Life (yrs) | 35 |
| Annual Fixed O&M | 4,978,000 | Insurance Rate (%) | 0.080% |

| **PEAKER BUILT IN 2017** | | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **REVENUE REQUIREMENT CALCULATION** | **Sum** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** | **13** | **14** | **15** | **16** |
| Gross Property, Plant and Equipment ( $ ) | | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 |
| Book Depreciation Expense ( $ ) | 228,788,000 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 |
| Accumulated Book Depreciation ($) | | 6,536,800 | 13,073,600 | 19,610,400 | 26,147,200 | 32,684,000 | 39,220,800 | 45,757,600 | 52,294,400 | 58,831,200 | 65,368,000 | 71,904,800 | 78,441,600 | 84,978,400 | 91,515,200 | 98,052,000 | 104,588,800 |
| Net Property, Plant and Equipment ( $ ) | | 222,251,200 | 215,714,400 | 209,177,600 | 202,640,800 | 196,104,000 | 189,567,200 | 183,030,400 | 176,493,600 | 169,956,800 | 163,420,000 | 156,883,200 | 150,346,400 | 143,809,600 | 137,272,800 | 130,736,000 | 124,199,200 |
| Avg. Net Property, Plant and Equipment ( $ ) | | 225,519,600 | 218,982,800 | 212,446,000 | 205,909,200 | 199,372,400 | 192,835,600 | 186,298,800 | 179,762,000 | 173,225,200 | 166,688,400 | 160,151,600 | 153,614,800 | 147,078,000 | 140,541,200 | 134,004,400 | 127,467,600 |
| Deferred Taxes From Depreciation ( $ ) | (0) | 714,963 | 3,492,792 | 3,058,781 | 2,658,402 | 2,286,850 | 1,944,126 | 1,626,225 | 1,333,148 | 1,285,102 | 1,284,301 | 1,285,102 | 1,284,301 | 1,285,102 | 1,284,301 | 1,285,102 | 1,284,301 |
| Accumulated Deferred Taxes ( $ ) | 419,002,229 | 714,963 | 4,207,755 | 7,266,536 | 9,924,938 | 12,211,788 | 14,155,914 | 15,782,139 | 17,115,287 | 18,400,389 | 19,684,691 | 20,969,793 | 22,254,094 | 23,539,197 | 24,823,498 | 26,108,600 | 27,392,902 |
| Average accumulated Deferred Taxes ( $ ) | 402,987,069 | 357,481 | 2,461,359 | 5,737,145 | 8,595,737 | 11,068,363 | 13,183,851 | 14,969,027 | 16,448,713 | 17,757,838 | 19,042,540 | 20,327,242 | 21,611,944 | 22,896,645 | 24,181,347 | 25,466,049 | 26,750,751 |
| Rate Base ( $ ) | | 225,162,119 | 216,521,441 | 206,708,855 | 197,313,463 | 188,304,037 | 179,651,749 | 171,329,773 | 163,313,287 | 155,467,362 | 147,645,860 | 139,824,358 | 132,002,856 | 124,181,355 | 116,359,853 | 108,538,351 | 100,716,849 |
| Wtd. After-Tax Cost of Capital ( % ) | | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% |
| Return on Rate Base ( $ ) | 205,596,606 | 15,075,730 | 14,497,193 | 13,840,191 | 13,211,123 | 12,607,897 | 12,028,583 | 11,471,385 | 10,934,641 | 10,409,317 | 9,885,629 | 9,361,940 | 8,838,251 | 8,314,563 | 7,790,874 | 7,267,185 | 6,743,497 |
| Grossed-up (for FIT) Return on Rate Base ($) | 316,302,471 | 23,193,430 | 22,303,374 | 21,292,602 | 20,324,805 | 19,396,764 | 18,505,512 | 17,648,285 | 16,822,525 | 16,014,334 | 15,208,659 | 14,402,984 | 13,597,310 | 12,791,635 | 11,985,960 | 11,180,285 | 10,374,610 |
| Depreciation ($) | 228,788,000 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 |
| Fixed O&M | | 4,978,000 | 5,102,450 | 5,230,011 | 5,360,762 | 5,494,781 | 5,632,150 | 5,772,954 | 5,917,278 | 6,065,210 | 6,216,840 | 6,372,261 | 6,531,567 | 6,694,857 | 6,862,228 | 7,033,784 | 7,209,628 |
| Insurance | | 180,416 | 175,186 | 169,957 | 164,727 | 159,498 | 154,268 | 149,039 | 143,810 | 138,580 | 133,351 | 128,121 | 122,892 | 117,662 | 112,433 | 107,204 | 101,974 |
| Property Taxes | | 1,066,806 | 1,035,429 | 1,004,052 | 972,676 | 941,299 | 909,923 | 878,546 | 847,169 | 815,793 | 784,416 | 753,039 | 721,663 | 690,286 | 658,909 | 627,533 | 596,156 |
| Pre-Tax Revenue Requirement | | 35,955,452 | 35,153,239 | 34,233,423 | 33,359,769 | 32,529,142 | 31,738,653 | 30,985,623 | 30,267,581 | 29,570,717 | 28,880,066 | 28,193,206 | 27,510,232 | 26,831,240 | 26,156,330 | 25,485,605 | 24,819,169 |
| Gross-up Factor for State Revenue Taxes | | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 |
| **Revenue Requirement** | **475,248,209** | 37,403,423 | 36,568,904 | 35,612,045 | 34,703,209 | 33,839,131 | 33,016,808 | 32,233,453 | 31,486,495 | 30,761,566 | 30,043,102 | 29,328,582 | 28,618,103 | 27,911,767 | 27,209,678 | 26,511,942 | 25,818,668 |
| **NPV Revenue Requirement @ 7.77%** | | 384,897,217 | | | | | | | | | | | | | | | |
| Plant Capacity (kW, winter) | | 221,000 | | | | | | | | | | | | | | | |
| Rev Req per Unit Capacity ($/kW) | | 1,742 | | | | | | | | | | | | | | | |
| Levelized Cost (35 years) ($/kW-yr) | | 146 | | | | | | | | | | | | | | | |

**PEAKER REVENUE REQUIREMENT**

**ASSUMPTIONS**
Capex (2017$)
Annual Fixed O&M

| PEAKER BUILT IN 2017 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 | 2048 | 2049 | 2050 | 2051 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **REVENUE REQUIREMENT CALCULATION** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** | **27** | **28** | **29** | **30** | **31** | **32** | **33** | **34** | **35** |
| Gross Property, Plant and Equipment ( $ ) | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 | 228,788,000 |
| Book Depreciation Expense ( $ ) | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 |
| Accumulated Book Depreciation ($) | 111,125,600 | 117,662,400 | 124,199,200 | 130,736,000 | 137,272,800 | 143,809,600 | 150,346,400 | 156,883,200 | 163,420,000 | 169,956,800 | 176,493,600 | 183,030,400 | 189,567,200 | 196,104,000 | 202,640,800 | 209,177,600 | 215,714,400 | 222,251,200 | 228,788,000 |
| Net Property, Plant and Equipment ( $ ) | 117,662,400 | 111,125,600 | 104,588,800 | 98,052,000 | 91,515,200 | 84,978,400 | 78,441,600 | 71,904,800 | 65,368,000 | 58,831,200 | 52,294,400 | 45,757,600 | 39,220,800 | 32,684,000 | 26,147,200 | 19,610,400 | 13,073,600 | 6,536,800 | - |
| Avg. Net Property, Plant and Equipment ( $ ) | 120,930,800 | 114,394,000 | 107,857,200 | 101,320,400 | 94,783,600 | 88,246,800 | 81,710,000 | 75,173,200 | 68,636,400 | 62,099,600 | 55,562,800 | 49,026,000 | 42,489,200 | 35,952,400 | 29,415,600 | 22,878,800 | 16,342,000 | 9,805,200 | 3,268,400 |
| | | | | | | | | | | | | | | | | | | | |
| Deferred Taxes From Depreciation ( $ ) | 1,285,102 | 1,284,301 | 1,285,102 | 1,284,301 | (501,389) | (2,287,880) | (2,287,880) | (2,287,880) | (2,287,880) | (2,287,880) | (2,287,880) | (2,287,880) | (2,287,880) | (2,287,880) | (2,287,880) | (2,287,880) | (2,287,880) | (2,287,880) | (2,287,880) |
| Accumulated Deferred Taxes ( $ ) | 28,678,004 | 29,962,305 | 31,247,407 | 32,531,709 | 32,030,320 | 29,742,440 | 27,454,560 | 25,166,680 | 22,878,800 | 20,590,920 | 18,303,040 | 16,015,160 | 13,727,280 | 11,439,400 | 9,151,520 | 6,863,640 | 4,575,760 | 2,287,880 | (0) |
| Average accumulated Deferred Taxes ( $ ) | 28,035,453 | 29,320,155 | 30,604,856 | 31,889,558 | 32,281,014 | 30,886,380 | 28,598,500 | 26,310,620 | 24,022,740 | 21,734,860 | 19,446,980 | 17,159,100 | 14,871,220 | 12,583,340 | 10,295,460 | 8,007,580 | 5,719,700 | 3,431,820 | 1,143,940 |
| | | | | | | | | | | | | | | | | | | | |
| Rate Base ( $ ) | 92,895,347 | 85,073,845 | 77,252,344 | 69,430,842 | 62,502,586 | 57,360,420 | 53,111,500 | 48,862,580 | 44,613,660 | 40,364,740 | 36,115,820 | 31,866,900 | 27,617,980 | 23,369,060 | 19,120,140 | 14,871,220 | 10,622,300 | 6,373,380 | 2,124,460 |
| Wtd. After-Tax Cost of Capital ( % ) | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% |
| Return on Rate Base ( $ ) | 6,219,808 | 5,696,119 | 5,172,431 | 4,648,742 | 4,184,861 | 3,840,567 | 3,556,080 | 3,271,594 | 2,987,108 | 2,702,621 | 2,418,135 | 2,133,648 | 1,849,162 | 1,564,675 | 1,280,189 | 995,703 | 711,216 | 426,730 | 142,243 |
| Grossed-up (for FIT) Return on Rate Base ($) | 9,568,935 | 8,763,260 | 7,957,586 | 7,151,911 | 6,438,247 | 5,908,564 | 5,470,893 | 5,033,222 | 4,595,550 | 4,157,879 | 3,720,207 | 3,282,536 | 2,844,864 | 2,407,193 | 1,969,521 | 1,531,850 | 1,094,179 | 656,507 | 218,836 |
| Depreciation ($) | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 | 6,536,800 |
| Fixed O&M | 7,389,869 | 7,574,616 | 7,763,981 | 7,958,081 | 8,157,033 | 8,360,958 | 8,569,982 | 8,784,232 | 9,003,838 | 9,228,934 | 9,459,657 | 9,696,148 | 9,938,552 | 10,187,016 | 10,441,691 | 10,702,734 | 10,970,302 | 11,244,560 | 11,525,674 |
| Insurance | 96,745 | 91,515 | 86,286 | 81,056 | 75,827 | 70,597 | 65,368 | 60,139 | 54,909 | 49,680 | 44,450 | 39,221 | 33,991 | 28,762 | 23,532 | 18,303 | 13,074 | 7,844 | 2,615 |
| Property Taxes | 564,780 | 533,403 | 502,026 | 470,650 | 439,273 | 407,896 | 376,520 | 345,143 | 313,766 | 282,390 | 251,013 | 219,636 | 188,260 | 156,883 | 125,507 | 94,130 | 62,753 | 31,377 | - |
| Pre-Tax Revenue Requirement | 24,157,128 | 23,499,594 | 22,846,679 | 22,198,497 | 21,647,180 | 21,284,817 | 21,019,563 | 20,759,535 | 20,504,863 | 20,255,682 | 20,012,128 | 19,774,342 | 19,542,468 | 19,316,654 | 19,097,052 | 18,883,817 | 18,677,108 | 18,477,088 | 18,283,924 |
| Gross-up Factor for State Revenue Taxes | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 | 0.961 |
| **Revenue Requirement** | 25,129,966 | 24,445,952 | 23,766,743 | 23,092,459 | 22,518,939 | 22,141,983 | 21,866,047 | 21,595,548 | 21,330,620 | 21,071,403 | 20,818,041 | 20,570,679 | 20,329,467 | 20,094,560 | 19,866,114 | 19,644,292 | 19,429,258 | 19,221,183 | 19,020,240 |

# Appendix F: Storage Cost *Pro Forma*

## STORAGE SYSTEM REVENUE REQUIREMENT

### CAPITAL ACQUISITION

**INPUTS**

| | | | | | |
|---|---|---|---|---|---|
| System Size (kW) | 121,000 | Book Life (yrs) | 20 | System Size (MWh) | 225.6 |
| System Cost ($/kWh) | 813 | State Revenue Tax | 4.5873% | | |
| Hours of Discharge | 1.86 | Property Tax | 0.4800% | | |
| Capex ($) | 183,420,000 | FIT Rate | 35.0% | | |
| Fixed O&M ($/kW-yr) | 5.00 | Insurance Rate (%) | 0.08% | | |
| O&M Escalation | 2.50% | | | | |

| REVENUE REQUIREMENT CALCULATION | Sum | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Gross Property, Plant and Equipment ( $ ) | | 183,420,000 | 183,420,000 | 183,420,000 | 183,420,000 | 183,420,000 | 183,420,000 | 183,420,000 | 183,420,000 | 183,420,000 | 183,420,000 |
| Book Depreciation Expense ( $ ) | 183,420,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 |
| Accumulated Book Depreciation ($) | | 9,171,000 | 18,342,000 | 27,513,000 | 36,684,000 | 45,855,000 | 55,026,000 | 64,197,000 | 73,368,000 | 82,539,000 | 91,710,000 |
| Net Property, Plant and Equipment ( $ ) | | 174,249,000 | 165,078,000 | 155,907,000 | 146,736,000 | 137,565,000 | 128,394,000 | 119,223,000 | 110,052,000 | 100,881,000 | 91,710,000 |
| Avg. Net Property, Plant and Equipment ( $ ) | | 178,834,500 | 169,663,500 | 160,492,500 | 151,321,500 | 142,150,500 | 132,979,500 | 123,808,500 | 114,637,500 | 105,466,500 | 96,295,500 |
| | | | | | | | | | | | |
| Deferred Taxes From Depreciation ( $ ) | 0 | (802,463) | 1,424,531 | 1,076,584 | 755,599 | 457,725 | 182,961 | (71,901) | (306,862) | (345,380) | (346,022) |
| Accumulated Deferred Taxes ( $ ) | 21,349,996 | (802,463) | 622,069 | 1,698,653 | 2,454,251 | 2,911,976 | 3,094,937 | 3,023,037 | 2,716,175 | 2,370,795 | 2,024,773 |
| Average accumulated Deferred Taxes ( $ ) | 21,349,996 | (401,231) | (90,197) | 1,160,361 | 2,076,452 | 2,683,114 | 3,003,457 | 3,058,987 | 2,869,606 | 2,543,485 | 2,197,784 |
| | | | | | | | | | | | |
| Rate Base ( $ ) | | 179,235,731 | 169,753,697 | 159,332,139 | 149,245,048 | 139,467,386 | 129,976,043 | 120,749,513 | 111,767,894 | 102,923,015 | 94,097,716 |
| Wtd. After-Tax Cost of Capital ( % ) | | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% |
| Return on Rate Base ( $ ) | 121,331,424 | 12,000,728 | 11,365,859 | 10,668,083 | 9,992,702 | 9,338,039 | 8,702,546 | 8,084,784 | 7,483,419 | 6,891,210 | 6,300,313 |
| Grossed-up (for FIT) Return on Rate Base ($) | 186,663,730 | 18,462,659 | 17,485,937 | 16,412,436 | 15,373,388 | 14,366,214 | 13,388,532 | 12,438,129 | 11,512,953 | 10,601,862 | 9,692,789 |
| Depreciation ($) | 183,420,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 |
| O&M | | 620,125 | 635,628 | 651,519 | 667,807 | 684,502 | 701,615 | 719,155 | 737,134 | 755,562 | 774,451 |
| Insurance | | 143,068 | 135,731 | 128,394 | 121,057 | 113,720 | 106,384 | 99,047 | 91,710 | 84,373 | 77,036 |
| Property Taxes | | 836,395 | 792,374 | 748,354 | 704,333 | 660,312 | 616,291 | 572,270 | 528,250 | 484,229 | 440,208 |
| Pre-Tax Revenue Requirement | | 29,233,247 | 28,220,670 | 27,111,702 | 26,037,585 | 24,995,748 | 23,983,822 | 22,999,601 | 22,041,046 | 21,097,026 | 20,155,484 |
| Gross-up Factor for State Revenue Taxes | | 0.954 | 0.954 | 0.954 | 0.954 | 0.954 | 0.954 | 0.954 | 0.954 | 0.954 | 0.954 |
| **Revenue Requirement** | | **30,638,738** | **29,577,478** | **28,415,193** | **27,289,433** | **26,197,506** | **25,136,928** | **24,105,387** | **23,100,747** | **22,111,340** | **21,124,530** |

| REVENUE REQUIREMENT CALCULATION | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Gross Property, Plant and Equipment ( $ ) | 183,420,000 | 183,420,000 | 183,420,000 | 183,420,000 | 183,420,000 | 183,420,000 | 183,420,000 | 183,420,000 | 183,420,000 | 183,420,000 | - |
| Book Depreciation Expense ( $ ) | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | - |
| Accumulated Book Depreciation ($) | 100,881,000 | 110,052,000 | 119,223,000 | 128,394,000 | 137,565,000 | 146,736,000 | 155,907,000 | 165,078,000 | 174,249,000 | 183,420,000 | - |
| Net Property, Plant and Equipment ( $ ) | 82,539,000 | 73,368,000 | 64,197,000 | 55,026,000 | 45,855,000 | 36,684,000 | 27,513,000 | 18,342,000 | 9,171,000 | - | - |
| Avg. Net Property, Plant and Equipment ( $ ) | 87,124,500 | 77,953,500 | 68,782,500 | 59,611,500 | 50,440,500 | 41,269,500 | 32,098,500 | 22,927,500 | 13,756,500 | 4,585,500 | - |
| | | | | | | | | | | | |
| Deferred Taxes From Depreciation ( $ ) | (345,380) | (346,022) | (345,380) | (346,022) | (345,380) | (346,022) | (345,380) | (346,022) | (345,380) | (346,022) | 1,432,235 |
| Accumulated Deferred Taxes ( $ ) | 1,679,394 | 1,333,372 | 987,992 | 641,970 | 296,590 | (49,432) | (394,812) | (740,833) | (1,086,213) | (1,432,235) | 0 |
| Average accumulated Deferred Taxes ( $ ) | 1,852,083 | 1,506,383 | 1,160,682 | 814,981 | 469,280 | 123,579 | (222,122) | (567,822) | (913,523) | (1,259,224) | (716,118) |
| | | | | | | | | | | | |
| Rate Base ( $ ) | 85,272,417 | 76,447,117 | 67,621,818 | 58,796,519 | 49,971,220 | 41,145,921 | 32,320,622 | 23,495,322 | 14,670,023 | 5,844,724 | 716,118 |
| Wtd. After-Tax Cost of Capital ( % ) | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 6.70% | 0.00% |
| Return on Rate Base ( $ ) | 5,709,415 | 5,118,517 | 4,527,619 | 3,936,721 | 3,345,823 | 2,754,925 | 2,164,027 | 1,573,129 | 982,231 | 391,334 | - |
| Grossed-up (for FIT) Return on Rate Base ($) | 8,783,715 | 7,874,641 | 6,965,567 | 6,056,494 | 5,147,420 | 4,238,346 | 3,329,273 | 2,420,199 | 1,511,125 | 602,052 | - |
| Depreciation ($) | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | 9,171,000 | - |
| O&M | 793,812 | 813,658 | 833,999 | 854,849 | 876,220 | 898,126 | 920,579 | 943,594 | 967,183 | 991,363 | - |
| Insurance | 69,700 | 62,363 | 55,026 | 47,689 | 40,352 | 33,016 | 25,679 | 18,342 | 11,005 | 3,668 | - |
| Property Taxes | 396,187 | 352,166 | 308,146 | 264,125 | 220,104 | 176,083 | 132,062 | 88,042 | 44,021 | - | - |
| Pre-Tax Revenue Requirement | 19,214,414 | 18,273,828 | 17,333,738 | 16,394,157 | 15,455,097 | 14,516,571 | 13,578,593 | 12,641,176 | 11,704,335 | 10,768,083 | - |
| Gross-up Factor for State Revenue Taxes | 0.954 | 0.954 | 0.954 | 0.954 | 0.954 | 0.954 | 0.954 | 0.954 | 0.954 | 0.954 | 0.954 |
| **Revenue Requirement** | **20,138,214** | **19,152,406** | **18,167,118** | **17,182,363** | **16,198,155** | **15,214,506** | **14,231,431** | **13,248,945** | **12,267,062** | **11,285,796** | **-** |

| **Revenue Requirement, Scaled ($Million)** | |
|---|---|
| $Current ($000) | 414,783 |
| $/kW | 3,428 |
| | |
| **$NPV ($000)*** | **264,217** |
| **$/kW*** | **$2,183.61** |
| **$/kW-year Levelized*** | **$218.58** |

* Life: 20 years, WACC (Discount Rate): 7.77%

# Appendix G: About Strategen

Strategen Consulting brings the insight and hands-on experience required to make intelligent decisions about clean energy and advanced grid solutions.

## Strategen Expertise

The Strategen team, including its extended network of senior advisors, has extensive experience in the electric power system, energy markets, renewable energy, energy storage, and smart grid technology:

### *T&D/Electric Infrastructure Planning:*

- California, WECC and FERC Order 1000 interregional transmission planning processes
- Load and system resource planning
- NERC reliability criteria
- Transmission & distribution deferral, and non-wires alternatives analysis
- Resource interconnection processes
- FERC and state regulation

### *Wholesale Energy Markets:*

- Market design & regulatory policy
- Ancillary Services
- System, Local and Flexible Capacity
- GHG Pricing / Cap & Trade
- CAISO Energy Imbalance Market (EIM)

### *Energy Storage:*

- Storage value proposition and cost-effectiveness analysis (including both customer sited as well as distribution and transmission interconnected projects)
- Storage regulatory landscape
- Storage project/business due diligence
- Storage project development and financing
- Storage contracting and bid strategies

*Renewable Energy:*

- Solar project development and financing
- Solar regulatory landscape
- Solar value proposition analysis
- Solar technology/business due diligence
- Wind project development and financing
- Integrated solar + energy storage project development

*Corporate Strategy:*

- Related corporate diversification
- Venturing within large organizations
- White-space business and program development

*Related Energy Industry:*

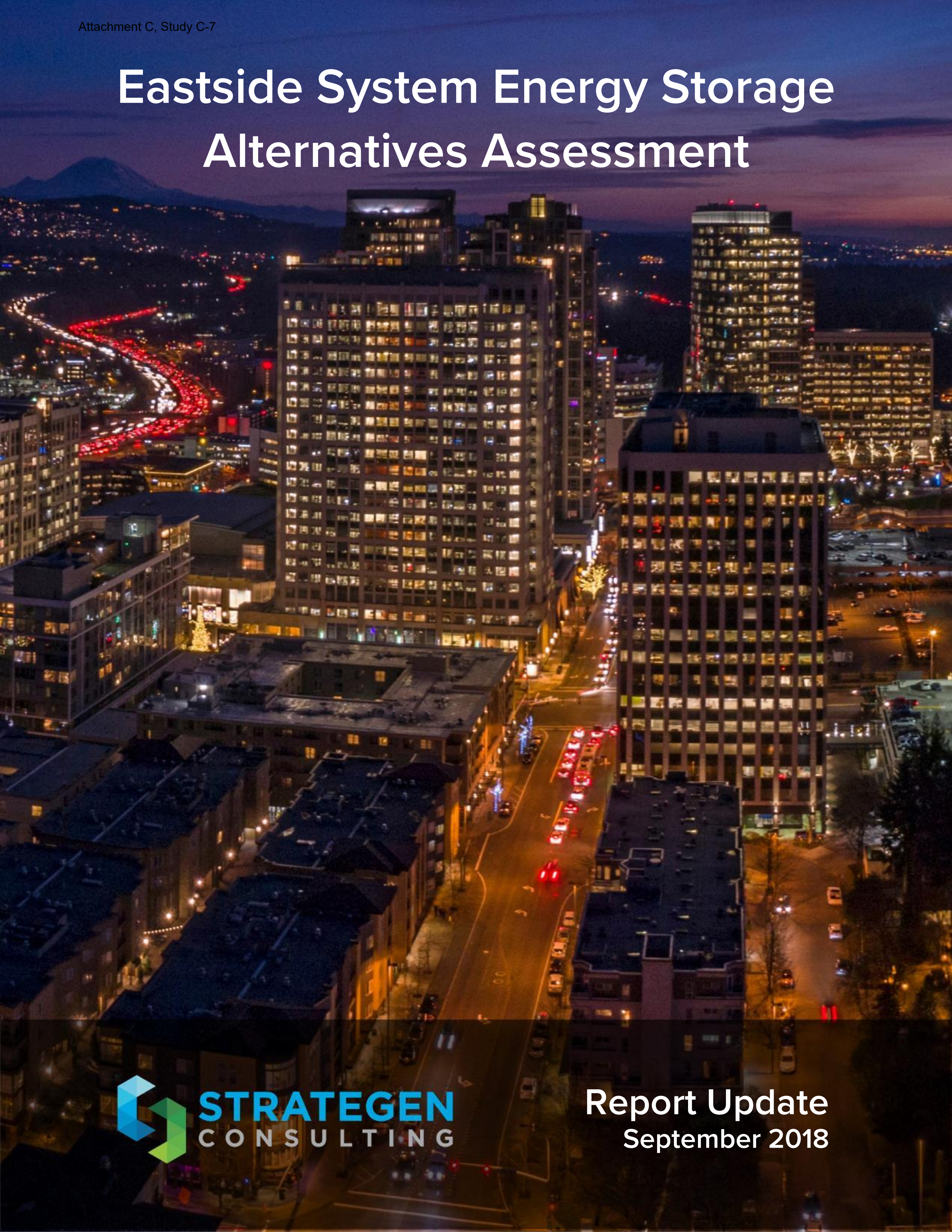
- Utility programs and regulation
- Electric distribution system automation
- Energy controls systems
- Advanced sensors and metering
- Demand response

*Supporting Functional Expertise:*

- Strategic planning/vision development
- Energy regulatory strategy development
- Strategic marketing and sales forecasting
- Financial risk modeling and evaluation
- Project team development and recruitment

Attachment C, Study C-7

# Eastside System Energy Storage Alternatives Assessment



STRATEGEN CONSULTING

## Report Update

September 2018

# Eastside System Energy Storage Alternatives Assessment Report Update – September 2018

**Prepared by:**
**Mark Higgins**
**Stephen Sproul**

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**Prepared for:**
**Stoel Rives LLP and**
**Puget Sound Energy**

PSE PUGET SOUND ENERGY

# Table of Contents

# Executive Summary

## Background

In 2014, Puget Sound Energy ("PSE") commissioned Strategen Consulting, LLC ("Strategen") to assess energy storage options for PSE's Eastside transmission capacity deficiency. At the time, PSE was evaluating several possible solutions to meet the transmission capacity deficiency identified in its North American Electric Reliability Corporation ("NERC")-required transmission planning studies. These studies concluded that growth in the Eastside area could cause demand for electricity to exceed the capacity of the Eastside's transmission system as early as winter 2017-2018.

Strategen's assessment culminated in the Eastside System Energy Storage Alternatives Screening Study issued in March 2015 (the "March 2015 Study").[1] Strategen's March 2015 Study concluded that an Eastside energy storage solution was not practical given the unique circumstances of the Eastside transmission system. The study recognized that while energy storage technologies were on the cusp of being commercially viable for some types of large-scale deployments, energy storage is not an effective solution for every type of power system constraint or application. The Energize Eastside constraint is a transmission and distribution ("T&D") reliability application, which differs from the applications of most energy storage deployments globally to date (see Figure 34)[2].

In January 2018, Strategen Consulting was asked to update the March 2015 Study to consider:

- Changes to equipment ratings on the Eastside, such as PSE's development of more seasonally precise and equipment-specific rating of the transformer bank capabilities at both Talbot Hill and Sammamish Substations.[3]
- 2017 refreshed PSE system load forecasts, as well as recent advances in the energy storage market.

## 2018 Findings

The conclusion of this updated analysis is consistent with the conclusion of the original March 2015 Study: energy storage is not a practical solution for the Eastside. Despite the significant commercial and technological progress made by the energy storage industry in recent years, energy storage is still not a practical solution to meet the Eastside transmission system capacity deficiency.

Notably, the technological and commercial readiness of energy storage is not the factor limiting its ability to meet the Eastside transmission capacity deficiency. Rather, the magnitude of the Eastside transmission system capacity deficiency renders storage an impractical solution. The required system (or systems) would be of unprecedented scale, thereby making it difficult to source, site and construct, even if it were broken into multiple smaller projects. And the physical impact of a storage solution would likely exceed that of a poles & wires solution.

[1] The March 2015 Study can be found here: http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/eastside_system_energy_storage_alternatives_screening_study_march_2015.pdf.

[2] While energy storage is becoming more frequently considered for distribution reliability applications, the large power/energy requirements typically necessary at the transmission level have historically rendered storage less practical for transmission reliability.

[3] This rerating dynamically accounts for the age of each individual transformer bank and the effects of seasonal weather on the thermal carrying capacity of each bank.

In this updated analysis, two storage solutions were considered-- an interim solution to meet constraints through 2019 and a complete solution to meet 2027 forecasted need.

1. **Interim Solution**
   The Interim Solution was developed in response to stakeholder interest. Here, Strategen evaluated the feasibility of interim measures sized only to meet the winter 2018/2019 and summer 2019 overload constraints for Talbot Hill Substation and Sammamish Substation, respectively. The Interim Solution assumed all other non-wires alternative ("NWA") load reduction solutions are implemented. The Interim Solution does not comply with planning criteria.

2. **Complete Solution**
   The Complete Solution evaluated an energy storage solution sized to meet the company's 2027 forecasted need, which is required for PSE to be in compliance with planning criteria (the same criteria met by the proposed transmission solution[4]). In this scenario, additional NWA solutions are also included.

The conclusions in this report update are consistent with the findings of the March 2015 Study. The characteristics of an energy storage system designed to meet planning requirements of a solution for the Eastside system are summarized as follows:

1) An energy storage system would be ***significantly more expensive than the proposed transmission wires solution***, costing approximately $825 million for the Interim Solution and increasing to approximately $1.4 billion for the Complete Solution,[5] compared to an estimated $150-$300 million[6] for the transmission wires solution;

2) The energy storage system would need to be of an unprecedented size, ***roughly 19 times the size of Tesla's Hornsdale facility in Australia (the largest currently installed system), just to meet the interim need by summer 2019, and 43 times the size of Hornsdale to meet the 10-year (2027) need***;

3) The commercial and supply-chain viability of an energy storage system for the Eastside area is unclear as ***it would exceed total US energy storage deployments in 2017[7] by approximately 6-13 times[8];***

4) The energy storage capacity required for Eastside by summer 2019 ***is approximately double the 1,233 MWh of total forecasted total energy storage deployments in the US[4] for 2018[5]***; and

5) The physical footprint of an energy storage system of the required scale would be significant: ***approximately 49 acres.***[9]

Strategen also investigated deployment of distributed energy resources such as the installation of small storage systems at homes, businesses, and other buildings in PSE's network. Distributed storage is neither viable nor cost-effective in this case. Even if there was significant customer adoption of behind-the-meter energy storage, it would not materially affect the Eastside transmission capacity deficiency: if every customer in PSE's Eastside area installed a storage system sized comparably to a Tesla Powerwall 2, only about half of the 2019 Eastside transmission

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[4] PSE's proposed transmission solution builds a new substation and upgrades approximately 16 miles of existing transmission lines from Redmond to Renton.
[5] See page 55 for cost assumptions.
[6] https://energizeeastside.com/faq/who-will-pay-for-the-project-and-how-much-will-it-cost
[7] Residential, non-residential and in-front-of-the-meter storage systems.
[8] https://energystorage.org/news/esa-news/us-energy-storage-market-tops-gwh-milestone-2017-annual-deployments-exceed-1000-mwh (Accessed: Apr. 25, 2018; 2,394MWh/431MWh = 5.55 & 5,500MWh/431MWh = 12.76)
[9] Based on a double-stacked/two-level battery facility for the Complete Solution

capacity deficiency would be met, and less than a quarter of the 2027 Eastside transmission capacity deficiency[10] would be met. Theoretically, if enough distributed storage could be deployed to meet the entire Interim Solution, the cost would range from $1.1 to $1.7 billion, and $2.1 billion to $3.1 billion for the entire Complete Solution[11].

We focused our 2015 analysis on the batteries required to prevent system overload at the Talbot Hill substation, which was identified as having the largest need during required planning scenarios. By analyzing the system element with the largest constraint (i.e., the largest energy need on peak days), we were able to calculate the battery size needed to prevent overloads for the entire system. Following the imposition of updated equipment- and seasonally-specific transformer ratings and information from the 2017 King County load forecast, our 2018 analysis found that the largest system constraint moved from the Talbot Hill to Sammamish substation. Peak energy demand also shifted from winter to summer.

Table 1, which follows, summarizes our 2015 findings for Talbot Hill and our 2018 findings for both Talbot Hill and Sammamish substations. Sammamish substation results for 2015 are omitted as they were not analyzed in detail in that report as we concluded that overloads would be prevented with the installation of a storage system sized to meet the larger Talbot Hill constraint. In this table, the Interim Solution represents the most optimistic case for the smallest storage system that can meet the immediate 2019 system need. The Interim Solution does not include cell degradation or the increasing uncertainty in load forecasts as they progress further into the future, because the assessment is for the pending 2018/2019 winter and 2019 summer constraints.

[10] Based on the size required to meet the Interim (2019) and Complete (2027) Solutions.
[11] Indicative cost assuming a quoted price of $6,600 per installed 13.5 kWh system, per www.tesla.com (as viewed on August 16, 2018) for the Interim Solution, and a cost of $4,220 per incremental installed 13.5 kWh system to meet the number of BTM installations required to meet the Complete Solution, per Tables 4 and 5.www.tesla.com (as viewed on August 16, 2018) for the Interim Solution, and a cost of $4,220 per incremental installed 13.5 kWh system to meet the number of BTM installations required to meet the Complete Solution, per Tables 4 and 5.

*Table 1: Sizing comparison of the March 2015 Study vs the 2018 Analysis*

| Constrained Element | Power (MW) | Energy (MWh) | Duration (hours) | Meets 2019 System Need | Meets Solution Requirements Through 2027[12] | Feasibility[13] |
|---|---|---|---|---|---|---|
| ***Original March 2015 Study Results***[14] | | | | | | |
| **Talbot Hill** | **545** | **5,771** | **10.6** | ✔ | not evaluated | ✘ |
| Sammamish[17] | *Assessed to be less than Talbot Hill sizing* | | | | | |
| ***2018 Analysis*** | | | | | | |
| ***Interim Solution for 2019***[15] | | | | | | |
| Talbot Hill | 290 | 1,689 | 5.8 | ✘[16] | ✘ | ✘ |
| **Sammamish**[17] | **365** | **2,394** | **6.6** | ✔ | ✘ | ✘ |
| ***Complete Solution through 2027*** | | | | | | |
| Talbot Hill | 338 | 3,679 | 10.9 | ✔ | ✘[16] | ✘ |
| **Sammamish**[17] | **549** | **5,500** | **10.0** | ✔ | ✔ | ✘ |

Both the Interim and Complete Solutions would be of globally unprecedented size. This can be seen in Figure 1 where a comparison to total US energy storage deployments[18] per quarter and year can be seen, as well as the largest currently installed system in the world, the Hornsdale Power Reserve in South Australia (developed by Tesla), and the largest proposed procurement in the world, PG&E's 2,270 MWh local capacity procurement, which is comprised of multiple projects and is pending review by the California Public Utilities Commission[19].

[12] Meets 2027 requirements means satisfying the NERC/FERC planning criteria through 2027, the same planning criteria against which the ultimate Eastside solution must be judged (whether a wires or non-wires solution).
[13] Feasibility relates to electrical sizing, physical sizing, timing and the ability of the market to respond.
[14] The March 2015 Study evaluated solution requirements to meet a deferral need through 2021.
[15] Sized only to meet immediate 2019 constraint assuming all other NWAs per E3 NWA Report (2014) are implemented; size requirement would be larger if other NWAs are unable to be implemented.
[16] The Talbot Hill sizing is insufficient to meet the Sammamish need and therefore does not meet the system need for that entire year.
[17] Sammamish was assessed in the March 2015 Study, but Talbot Hill was the more significant constraint that defined the energy storage sizing. Due to several factors detailed in this report, Sammamish is now the greatest constraint that defines the size while Talbot Hill also exceeds NERC requirements.
[18] This includes all types of energy storage (residential, non-residential and utility) in-front-of-the-meter systems installed in a given timeframe.
[19] Source: Utility Dive. https://www.utilitydive.com/news/pges-landmark-energy-storage-projects-snagged-by-pushback/530007/. Accessed August 21, 2018.https://www.utilitydive.com/news/pges-landmark-energy-storage-projects-snagged-by-pushback/530007/. Accessed August 21, 2018.

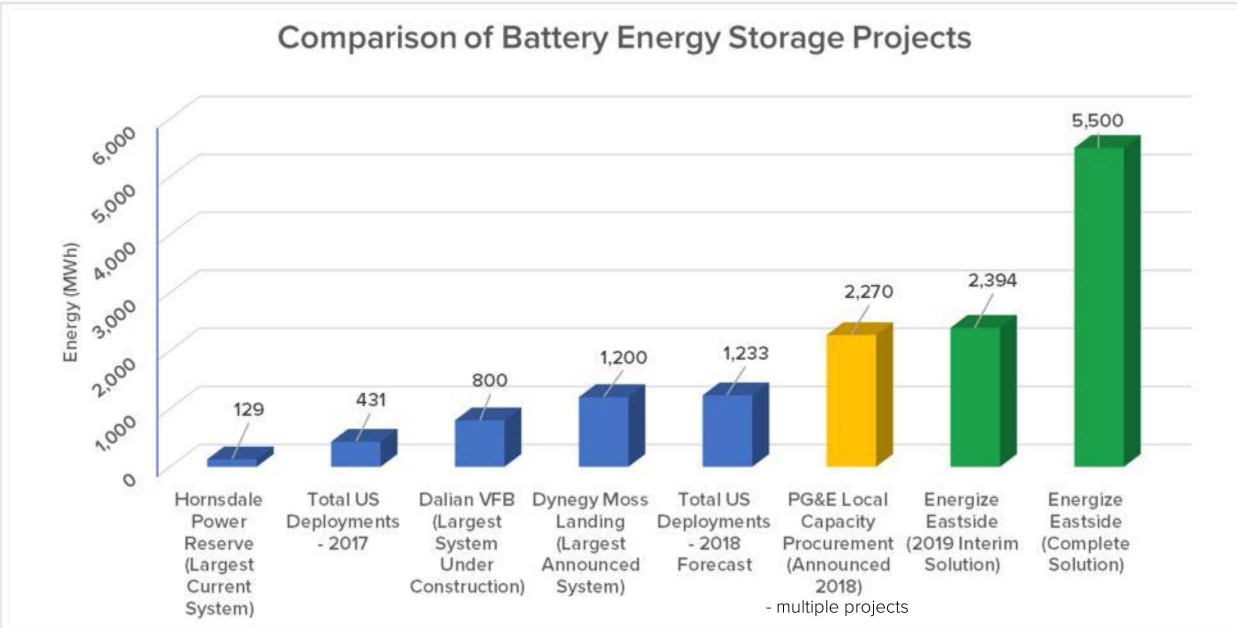


*Figure 1: An energy storage system to solve the Eastside constraint in comparison to other projects*[20]

In terms of physical impact, the footprint of the Complete Solution is estimated to be 49 acres, approximately one and a half times the size of CenturyLink Stadium. This assumes the solution is built as a single facility, with the Interim solution built as a single-level system and expanded vertically into a double stacked/two-level configuration to meet the Complete Solution. Figure 2 shows an indicative footprint that these arrangements would require if built as a single facility.


*Figure 2: Approximate indicative footprint of the Eastside storage solution. Red represents a single-level interim Solution, 59 acres, and yellow represents a double-level Complete Solution, 49 acres.*

[20] Source: UtilityDive, PG&E, GTM Research and ESA. PG&E local capacity procurement represents multiple projects with online dates ranging from December, 2019 to December, 2020 if approved by the California Public Utilities Commission.

While storage is becoming a technology embraced by the power sector to modernize and enhance the grid, the specific circumstances and requirements driving the Eastside transmission capacity deficiency are not well-suited to an energy storage solution. Such a solution would need to be of unprecedented scale, exceeding the total forecast 2018 US energy storage deployments,[21] both behind and in front of the meter. It would therefore be impractical to source, site and construct. In addition, it would come at a cost many times that of the traditional poles & wires solution.

For these reasons, despite the commercial and technological progress of energy storage in recent years, the conclusion of this updated analysis remains consistent with the conclusion of the original March 2015 Study. Strategen does not believe energy storage to be a practical option to meet the Eastside transmission capacity deficiency, either as an alternative to the proposed transmission solution or as a way to defer it.

[21] This includes all types of energy storage; residential, non-residential and utility in-front-of-the-meter systems.

# 1. Eastside System Storage Configurations and Feasibility

Strategen conducted a refreshed analysis to assess how updated conditions in the Eastside area (and of the energy storage market) affect the technical requirements and sizing of an energy storage system that meets the Eastside transmission capacity deficiency.

## 1.1 Overall Objectives and Methodology

This report evaluates the amount of storage that would be necessary to eliminate overloads at Talbot Hill and Sammamish substations during certain system contingencies each year between 2018 through 2027. Storage deployed in such a use case would avoid or defer the need for a traditional "poles and wires" solution for the Energize Eastside project.

The 2018 Analysis generally used the same methodology developed for the March 2015 Study, with certain exceptions as identified in this report which were designed to refresh or enhance the original March 2015 Study. The methodology is summarized below and detailed in subsequent sections, and sizing using the original methodology was also run for reference, which can be found in the Appendix. The 2018 Analysis did not rerun the cost-effectiveness analysis conducted as part of the March 2015 Study; however, it did reassess whether the original unit cost assumptions remain accurate.

The methodology used to size the storage system relied upon loading forecasts provided by PSE for impacted transformer elements under normal conditions and during N-1-1 system contingencies. In the case of the March 2015 Study, the element loading forecasts were generated using systemwide and King County load forecasts from PSE's 2013 Integrated Resource Plan. In the case of the 2018 Analysis, the element loading forecasts were generated using systemwide and King County load forecasts from PSE's 2017 Integrated Resource Plan.

Strategen assumed that all cost-effective NWAs (other than energy storage) would be implemented according to the timeline identified in the 2014 E3 Non-Wires Alternative Report (see the Appendix for details). Other NWAs include incremental energy efficiency, distributed generation, and demand response.

The remaining need was identified by running hourly power flow assessments assuming:

1. PSE is meeting 100% of its conservation and efficiency goals described in its Integrated Resource Plan; and
2. Normal weather conditions would set the demand forecasts.[22]

To serve as an alternative to the Energize Eastside project, energy storage must reduce loading on the affected transformer banks enough to eliminate overloads that would violate equipment normal thermal operating limits. Given that storage is modular, Strategen evaluated the amount of storage to solve the overloads through 2027 (the "Complete Solution"), along with the amount needed to address the Eastside transmission capacity deficiency incrementally beginning in winter 2018/2019 (the "Interim Solution").

As noted above, the Appendix contains refreshed sizing using the original methodology. It also contains a comparison of the assumptions between the March 2015 Study and the 2018 Analysis. The original methodology and assumptions are detailed in Section 3.1 of the March 2015 Study.

[22] In other words, weather conditions that represent the middle of the climatological bell curve, occurring in approximately 1 out of every 2 years

 

## 1.2 Talbot Hill Methodology and Results

### 1.2.1 Talbot Hill Interim Solution

In this section, we describe the methodology used to calculate the Talbot Hill Interim Solution and discuss the results. In the 2018 Analysis, Strategen found that there may be opportunities to recharge the system in the middle of the day, which the March 2015 Study did not account for. This is because, depending on the load profile, there may be a period during the day between morning peak and evening peak when recharging could occur. This would reduce the total required energy capacity seen in Table 2 (see p. 13 below). This would cycle the battery more than once a day. Increased battery cycling reduces battery operating life; however, more battery cycling allows a system smaller than that identified in Table 2 to be utilized to meet the system need for the Interim Solution. The method described below was used to do this analysis.

- The peak week N-1-1 data was extracted from the complete data set and was shown to occur in January 2019 for Talbot Hill. This represents the peak transformer loading at Talbot Hill within the next five years[23].
- The discharge requirements to maintain the loading on the Talbot Hill transformer were considered and the state of charge ("SOC") of the energy storage system tracked. Any opportunity where the loading was less than the normal rating, the system would be charged as much as possible without exceeding the rating.
    - Over the course of the week, the storage system was assessed, and the sizing increased to maintain the SOC above the minimum 2%.[24]
    - Figure 3 shows the results, where the green line is the loading on the Talbot Hill transformer with the energy storage operating to relieve the constraint through charging and discharging. This system is 290MW/1,689MWh (5.8-hour system).
    - It can be seen in the orange highlighted sections the loading is below the normal rating and during these times the energy storage system can charge, reflected in the SOC increasing. Without these opportunities, the SOC would continue to fall and a larger energy storage system would be required.[25]
    - A cost-benefit analysis could be undertaken to evaluate the reduction in life versus the cost of adding more energy capacity. Figure 4 shows the energy storage output during this period.

[23] The data analyzed assumed other NWA solutions (distributed energy resources) also contributed to reducing the load on Talbot Hill, including energy efficiency, demand response, and DG solar per E3's NWA Report (2014).
[24] Refer to assumptions for 2% minimum SOC.
[25] 2,083MWh – refer to Table 3

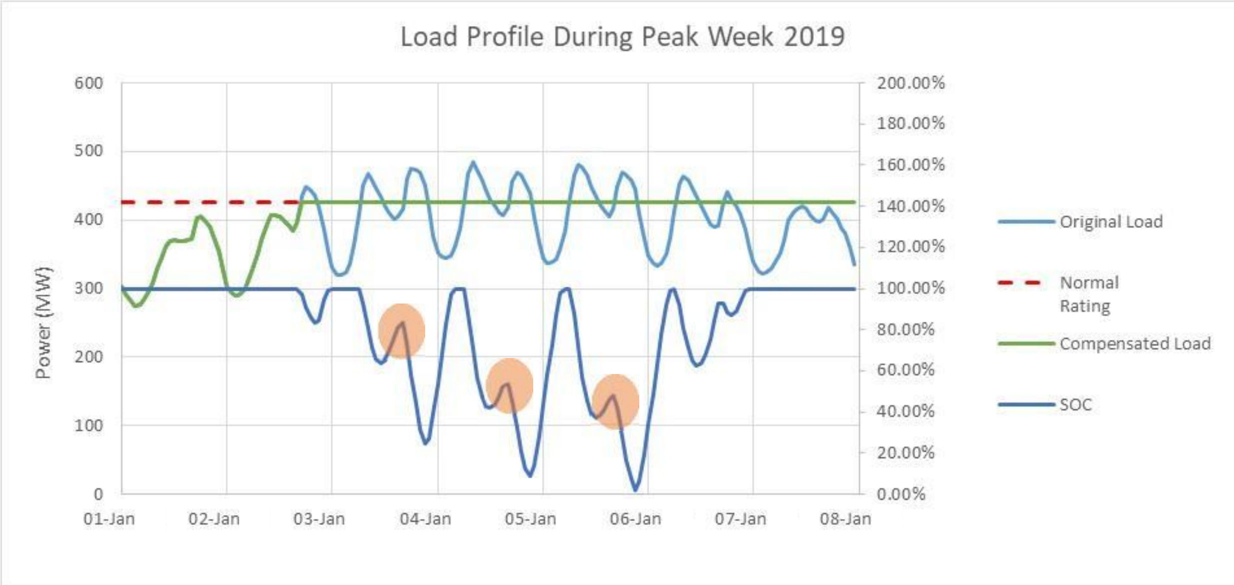


*Figure 3: The Interim Solution using the updated methodology during the peak week: 290MW/1,689MWh (5.8-hour system) – circles highlight intra-day recharging*

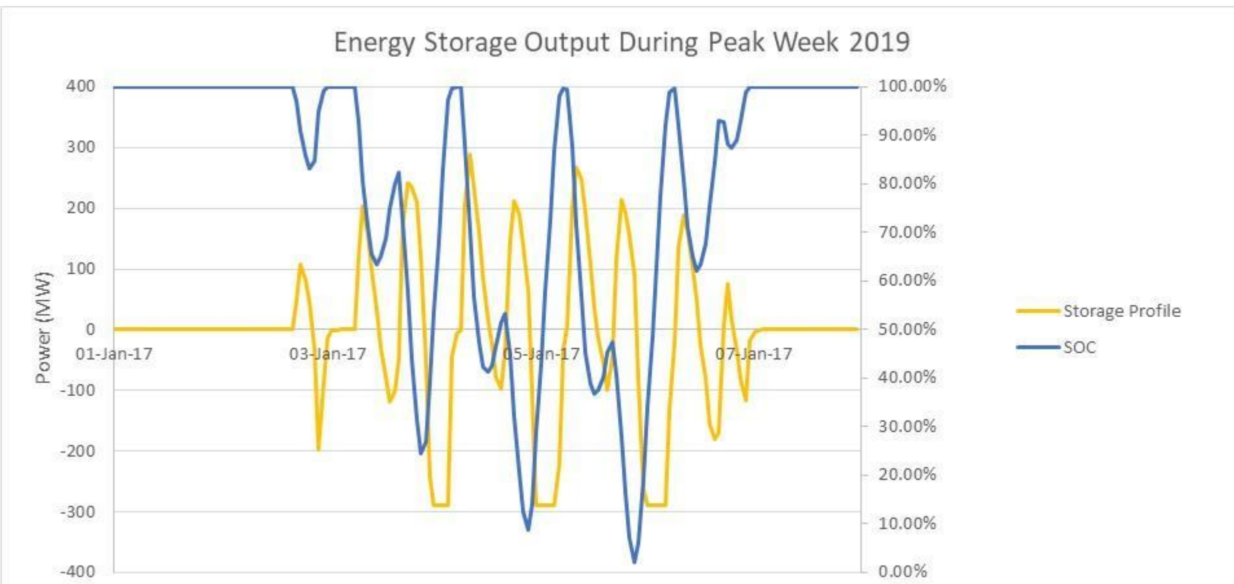


*Figure 4: Output of the Interim Solution during the peak week, 290MW/1,689MWh (5.8-hour system)*

### 1.2.2 Talbot Hill Complete Solution

The Complete Solution evaluates an energy storage solution that meets the required 2027 NERC planning criteria (the same as met by the proposed Energize transmission solution). In this scenario, additional NWA solutions[26] are also included to define the minimum plausible energy storage system. In this analysis it was found there was insufficient network capacity to charge the system on a daily basis. However, when there is not enough network capacity to fully recharge the system every day, a larger battery (with a longer duration) can theoretically overcome this issue. The method described below was used to do this analysis.

[26] NWA per E3 NWA Report (2014)

- The January 2027 peak week N-1-1 data for Talbot Hill was extracted from the complete data set. This represented the maximum loading during the 10-year planning horizon.
- The discharge requirements to maintain the loading on the Talbot Hill transformer were considered and the SOC of the energy storage system tracked.
    - o Over the course of the week, the storage system was assessed, and the sizing increased to maintain the SOC above 18%. 18% was used to consider cell degradation of 2% per year for nine years.
    - o Figure 5 shows the results, where the green line is the loading on the Talbot Hill transformer with the energy storage operating to relieve the constraint by maintaining the loading at the normal rating through charging and discharging. This system is 338MW/3,679MWh (10.9-hour system).
    - o Unlike the Interim Solution, where there are actually periods when the system can recharge between morning and evening peak and fully recharge at night, it can be seen in the orange highlighted sections the SOC does not recover to 100% each day as there is insufficient network capacity to allow full charging.
    - o Over time the SOC becomes more and more depleted until the load reduces toward the end of the peak week. Therefore, the system is oversized to meet the normal planning overload and maintain a SOC above 18%.
    - o At the end of the week the SOC does return to 100% and as this is the peak week, the system should have enough capacity to meet the requirements for all other weeks in 2027. Figure 6 shows the energy storage output during this period.

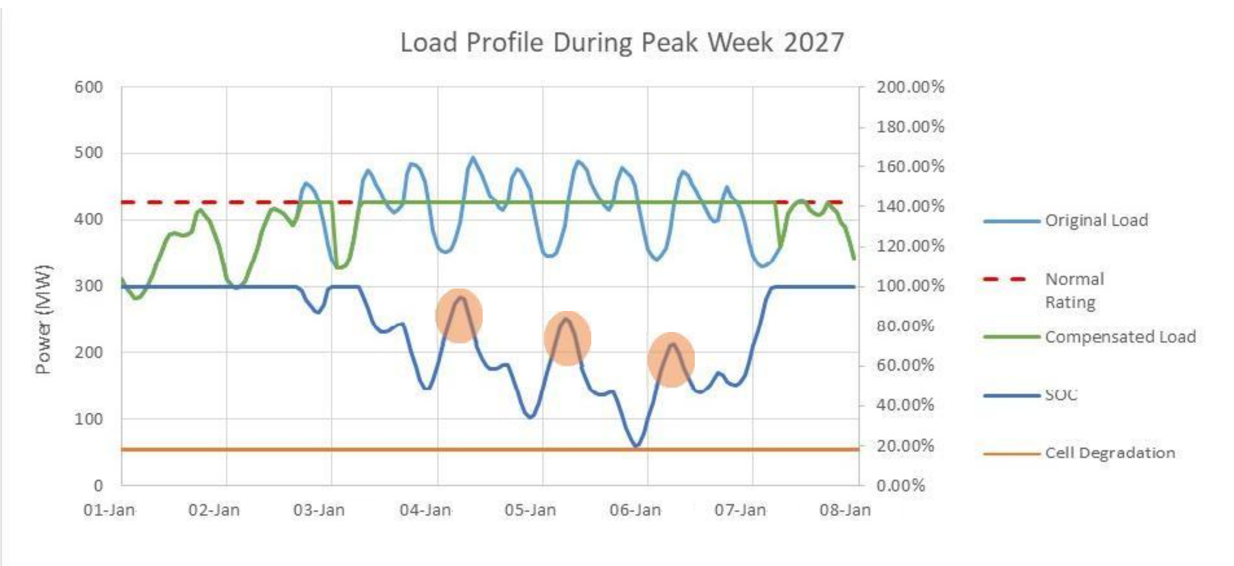


*Figure 5: The Complete Solution during the peak week, 338MW/3,679MWh (10.9-hour system) – circles highlight that off-peak recharging insufficient to restore 100% state of charge each night*

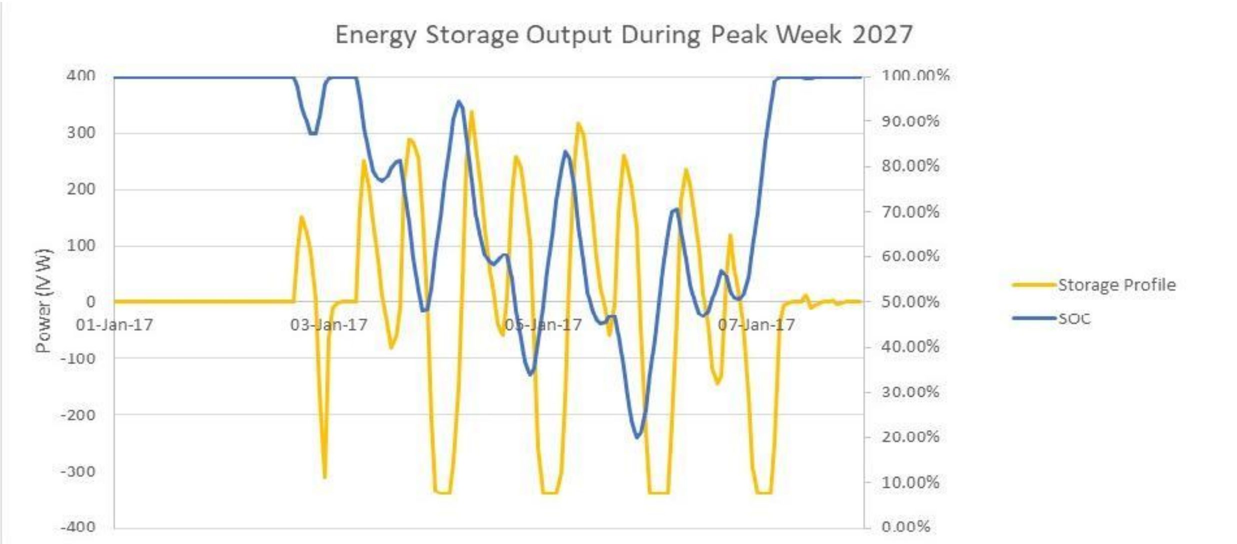


*Figure 6: Output of the Complete Solution during the peak week, 338MW/3,679MWh (10.9-hour system)*

By considering the Interim Solution and the Complete Solution, a clear picture can be obtained regarding the immediate need that must be met in 2019 and the solution that meets the full requirements over the 10-year planning period for Talbot Hill. Any incremental solution or staged approach would need to be deployed to meet both situations and is summarized in Table 2 below.

*Table 2: Talbot Hill Substation Sizing Summary*

| | MW | MWh | Hours |
|---|---|---|---|
| Interim Solution (2019) | 290 | 1,689 | 5.8 |
| Complete Solution (2027) | 338 | 3,679 | 10.9 |

## 1.3 Sammamish Methodology and Results

### 1.3.1 Sammamish Interim Solution

As noted above, the 2018 Analysis represents an update on the methodology used in the March 2015 Study because it considers SOC over the course of the peak week. This allows a more accurate energy storage sizing to be calculated. The methodology and results for the Sammamish analysis are described below.

- N-1-1 data was extracted for the peak week at Sammamish (occurring in August 2019), to determine the peak summer transformer loading within the next five years. This again includes NWA load reductions.
- The discharge requirements to maintain the loading on the Sammamish transformer were considered and the SOC of the energy storage system tracked. If opportunities occurred to recharge mid-day (when loading was less than the normal rating), the system would be charged as much as possible to reduce the system size.
    - Over the course of the week, the storage system was assessed, and the sizing adjusted to maintain the SOC above the minimum 2%.[27]
    - Figure 7 and Figure 8 show the results, where the green line in Figure 7 is the loading on the Sammamish transformer with the energy storage system operating to relieve the constraint.

[27] Refer to the Appendix, p.35, for pre-SOC sizing and assumptions for information about the 2% minimum SOC.

- o This system maintains the loading below the normal rating through charging and discharging. This system is 365MW/2,394MWh (6.6-hour system).
- o Figure 8 shows the energy storage output during this period.
- o Figure 9 shows data from the peak month, which validates the system sizing is appropriate as the SOC remains above the minimum 2%.

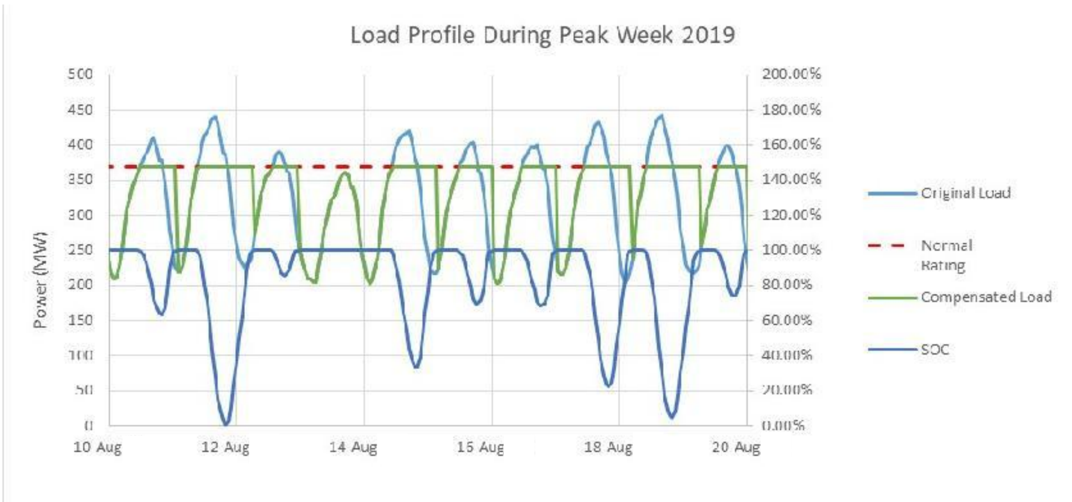


*Figure 7: The Interim Solution during the peak week, 365MW/2,394MWh (6.6-hour system)*

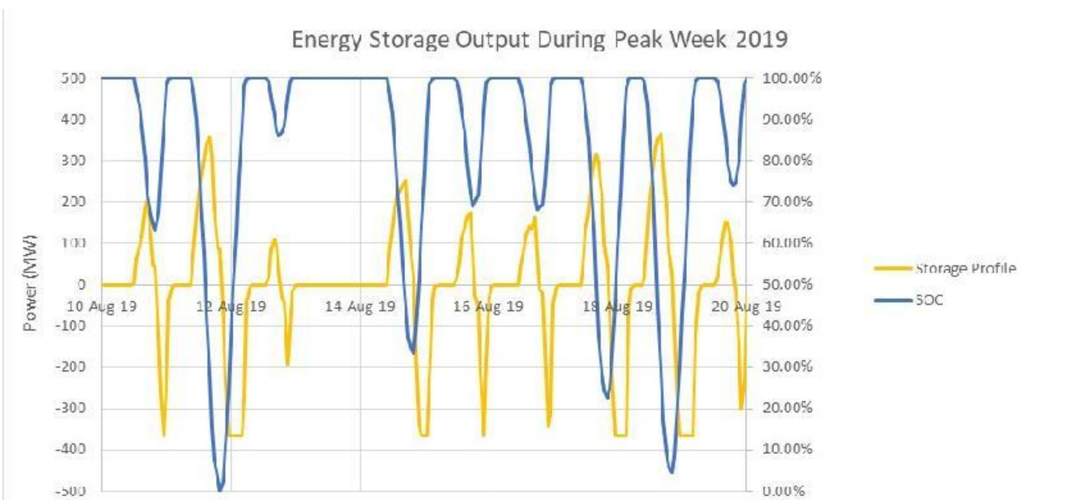


*Figure 8: Output of the Interim Solution during the peak week, 365MW/2,394MWh (6.6-hour system)*

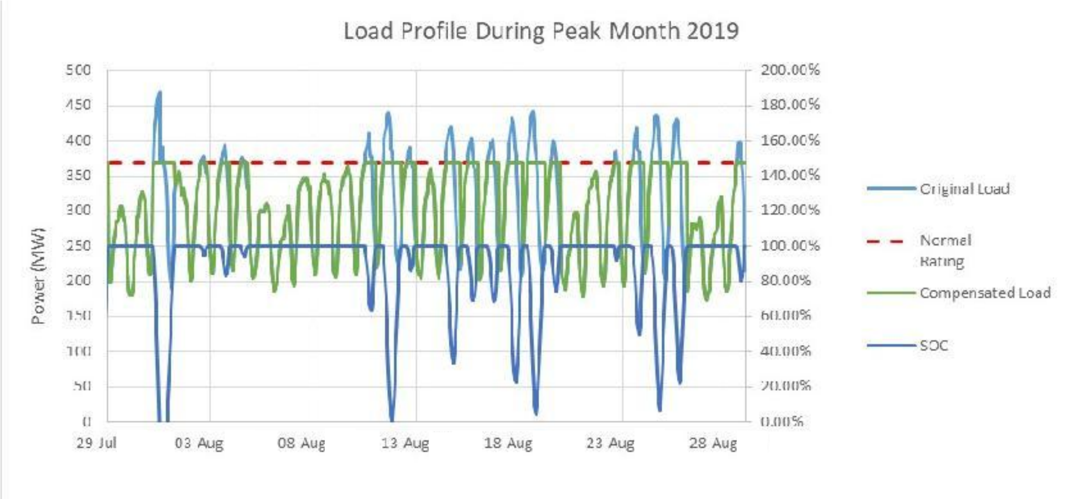


*Figure 9: Performance over peak summer month, 365MW/2,394MWh (6.6-hour system)*

### 1.3.2 Sammamish Complete Solution

As noted above, the Complete Solution for Sammamish evaluates an energy storage solution that meets the required 2027 NERC planning criteria (the same as met by the proposed Energize transmission solution). In this scenario, additional NWA solutions[28] are included to define the minimum plausible energy storage system sizing to meet the Sammamish transmission capacity deficiency.

- N-1-1 data was extracted from the peak week in August 2026, which is when the maximum summer loading during the 10-year planning horizon is forecasted to occur.[29]
- The discharge requirements to maintain the loading on the Sammamish transformer were considered and SOC of the energy storage system tracked.
  - Over the course of the week, the storage system was assessed, and the sizing increased to maintain the SOC above 18%. 18% was used to consider both the minimum SOC of 2%[30] and cell degradation of 2% per year for eight years (16%).
  - Figure 10 and Figure 11 show the results, where the green line in Figure 10 is the loading on the Sammamish transformer with the energy storage operating to relieve the constraint at the normal rating through charging and discharging.
  - This system is 549MW/5,500MWh (10.0-hour system).
  - Figure 12 considers the full month where the peak on the 1st is ignored due to the abnormal system condition.
  - During the remainder of the month it can be seen that the peak days, even where consecutive days face overload, the SOC remains above 18%.

[28] NWA per E3 NWA Report (2014)
[29] PSE's planning forecast shows a slight drop in peak load in 2027.
[30] Refer to assumptions for 2% minimum SOC.

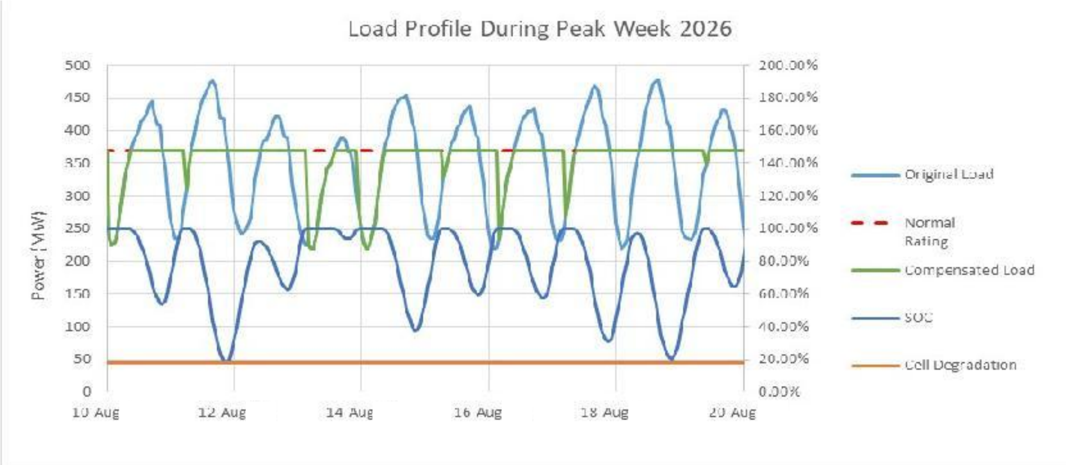


*Figure 10: The Complete Solution during the peak week, 549MW/5,500MWh (10.0-hour system)*

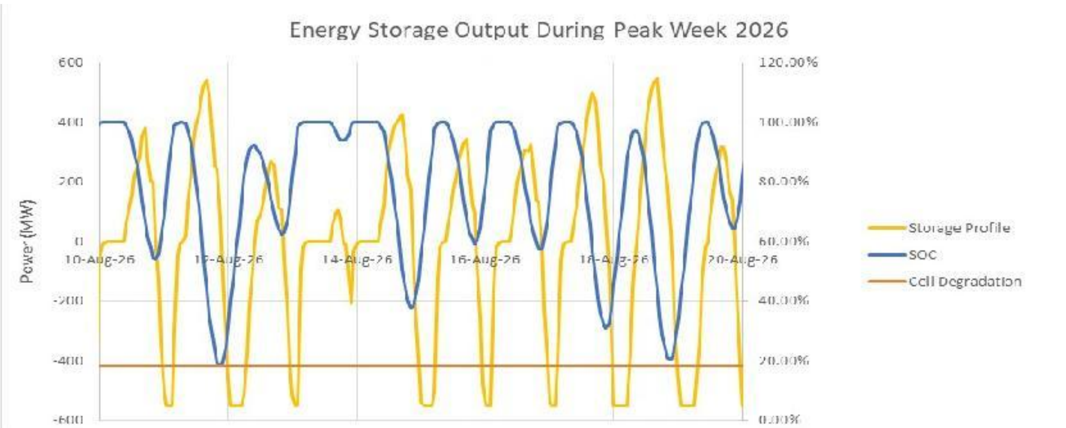


*Figure 11: Output of the Complete Solution during the peak week, 549MW/5,500MWh (10.0-hour system)*

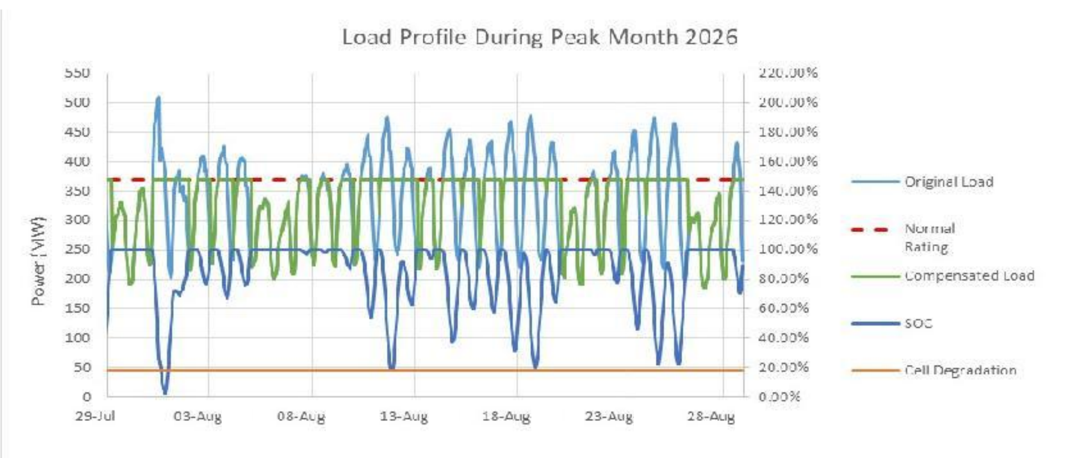


*Figure 12: Performance over peak summer month, 549MW/5,500MWh (10.0-hour system)*

By considering the Interim Solution and the Complete Solution, a clear picture can be obtained regarding the immediate need that must be met in 2019 and the solution that meets the full requirements over the 10-year planning period. Any incremental solution or staged approach would need to be deployed to meet both situations and is summarized in Table 3 below.

*Table 3: Sammamish Substation Sizing Summary*

| | MW | MWh | Hours |
|---|---|---|---|
| Interim Solution (2019) | 365 | 2,394 | 6.6 |
| Complete Solution (2027) | 549 | 5,500 | 10.0 |

## 1.4 Behind-the-Meter Energy Storage

Finally, behind-the-meter ("BTM") energy storage was considered as it is becoming more common within the power system. Its aggregated effects can reduce the load on the system, and BTM energy storage can also be controlled and coordinated by utilities to provide specific grid benefits, such as virtual power plant configurations. These arrangements are undergoing trials now but are not yet fully mature planning tools and, as such, in the short term such configurations may result in technical and contractual challenges.

As previously discussed, the effectiveness factor of various locations within the Eastside area was considered, and all locations had a similar effect on the constrained Talbot Hill and Sammamish Substations. Therefore, whether a centralized energy storage system is installed, or a number of distributed storage systems are interconnected, the power and storage requirements remain the same.

When considering BTM energy storage, whether meeting or contributing to the Energize Eastside area, the Interim Solution for Sammamish (365MW/2,394MWh) or the Complete Solution for Sammamish (549MW/5,500MWh) needs to be met. If the Tesla Powerwall 2, a 13.5kWh system or a larger generic 15kWh system is considered, Table 4 and Table 5 portray the number of these systems required to meet the Interim Solution and Complete Solution respectively.

*Table 4: Number of residential BTM energy storage systems required to meet the Interim Solution*

| BTM Residential Energy Storage System | Number of BTM Systems Required | Number of BTM Systems Required (70% confidence factor)[31] | Number of Customers in Eastside Area (130,000)[32] |
|---|---|---|---|
| **Tesla Powerwall 2 - 13.5kWh** | 177,333 | 253,333 | 195% |
| **Generic - 15kWh** | 159,600 | 228,000 | 175% |

[31] It is not reasonable to assume that all BTM energy storage systems would be online, fully functional, and have all their usable capacity available at the exact time required to relieve the Talbot Hill constraint. Even if controlled and coordinated by the utility, customers would likely use these systems for other utility bill management purposes that could see their system below 100% SOC prior to the event. In addition, even if 1% were offline for maintenance or repair, or on average the SOC was 99% across the entire fleet, this would result in more than a 18MWh shortfall. Therefore, a 70% confidence factor is used to provide a more realistic perspective of the number of BTM energy storage systems required to compensate for some systems being offline, partially discharged or otherwise unable to provide their full usable capacity for the purposes of relieving the Talbot Hill transformer constraint.

[32] Source: (https://energizeeastside.com/need)

*Table 5: Number of residential BTM energy storage systems required to meet the Complete Solution*

| BTM Residential Energy Storage System | Number of BTM Systems Required | Number of BTM Systems Required (70% confidence factor)[31] | Number of Customers in Eastside Area (130,000)[32] |
|---|---|---|---|
| **Tesla Powerwall 2 - 13.5kWh** | 407,407 | 582,011 | 448% |
| **Generic - 15kWh** | 366,667 | 523,810 | 403% |

Tables 4 and 5 show that the number of BTM energy storage systems required exceeds the number of residential customers in the area. In addition to the information presented in Table 4 and Table 5, there are a number of other reasons that BTM energy storage is an impractical solution for the Eastside's T&D deficiency. These are:

1) The number and timing of BTM energy storage systems required to meet the Interim or Complete solution for the Eastside T&D capacity deficiency far exceed the top residential energy storage uptake rates in leading markets, as seen in Figure 13.

| Rank | Residential | Deployments (kW) |
|---|---|---|
| 1 | California | 1,870 |
| 2 | Hawaii | 1,218 |
| 3 | All Others* | 728 |

*Figure 13: Top 3 residential energy storage markets, 2017 Q1 deployments[33]*

2) The installation of the number of BTM systems required to meet the Interim and Complete Solutions is not realistic from the standpoint of either utility interconnection assessments or local authority permitting processes and capabilities. Installation of a BTM storage system requires an electrical permit. From August 13, 2017 to August 13, 2018, the City of Bellevue processed 309 electrical permits, and had a staff of four people handling electrical permit applications and inspections[34].

3) Purchasing the volume of BTM systems to address the Eastside T&D deficiency would exceed the entire US BTM deployments, as seen in Figure 14, which covers multiple segments.

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[33] Source: GTM Research
[34] Source: https://publicrecordscenter.bellevuewa.gov/DSRecords/processing-day-by-permit-type.pdf Accessed August 16, 2018.

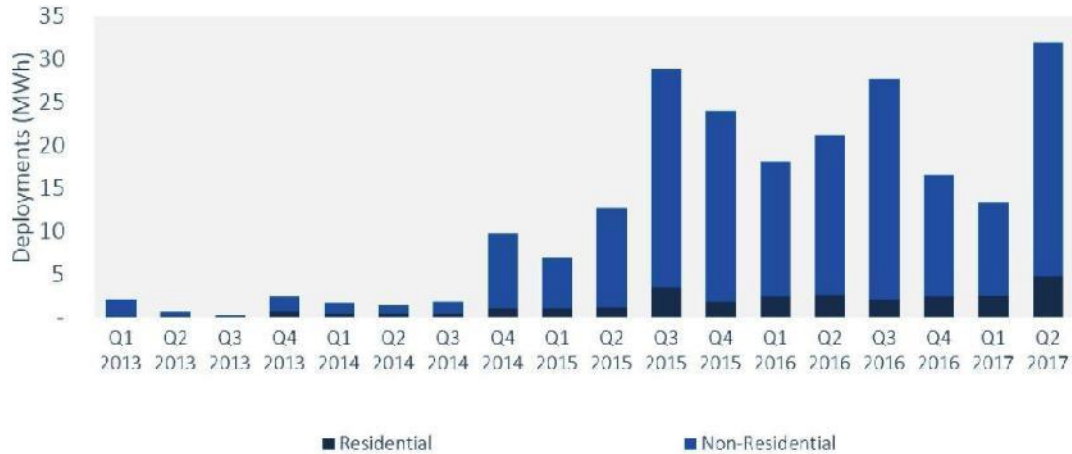


*Figure 14: US BTM Energy Storage Deployments by Segment*[35]

4) Finally, BTM energy storage systems are often coupled with rooftop solar to store solar energy and enable self-generation. Because of this fact, California uses the number and location of existing rooftop solar installations to predict where BTM energy storage will interconnect.[36] While not the only use case of BTM energy storage, a similar predictive methodology might be applied to King County as a way to estimate customers willing to invest in advanced energy technology. The number of residential distributed generation systems (mostly solar) throughout PSE's King County service territory is approximately 2,300 out of approximately 1.2 million total customers.[37]

If the effect of organic growth of BTM energy storage was considered with regard to reducing the loading within the Eastside area, even if the entire US 2017 Q2 deployments occurred on circuits downstream of Sammamish and Talbot Hill Substations, this would only meet approximately 0.5%-1.5% of the Eastside transmission capacity deficiency[38]. Therefore, the effect of actual installations on downstream circuits can be considered negligible with respect to the Eastside transmission capacity deficiency.

## 1.5 Capital Cost of Eastside Energy Storage Solution

Strategen reassessed its unit cost assumptions for energy storage in Section 3.4.1. The transmission solution for Eastside is estimated at $150-$300 million.[39] An energy storage system would be significantly more expensive than the proposed transmission solution. An estimate of capital costs can be seen in Figure 15 below and range from approximately $825 million to $1.4 billion.

[35] Source: GTM Research / ESA US Energy Storage Monitor, Q3 2017
[36] Source: DRP working group meetings
[37] Source: PSE 2017 IRP, p.391
[38] 32.5MWh/5,500MWh=0.006, Complete Solution and 32.5MWh/3,007MWh=0.014, Interim Solution
[39] Source: (https://energizeeastside.com/faqs)

| PERFORMANCE | Units | Interim Solution (Lithium Ion) Single Level | Interim Solution (Flow-Van'm) Single Level | Complete Solution (Lithium Ion) Double Level | Complete Solution (Flow-Van'm) Double Level |
|---|---|---|---|---|---|
| Power | MW | 365 | 365 | 549 | 549 |
| Energy | MWh | 2,394 | 2,394 | 5,500 | 5,500 |
| Discharge Duration | Hours | 6.6 | 6.6 | 10.0 | 10.0 |
| Round Trip Efficiency | % | 85% | 85% | 85% | 85% |
| **ASSUMPTIONS** | | | | | |
| EPC | | | | | |
| Energy Storage | $/kWh | 294 | 313 | 194 for incremental 3,106 MWh[40] | 207 for incremental 3,106 MWh[40] |
| Owners Costs | | | | | |
| Land Required | sq ft | 2,123,866 | 1,302,070 | 2,123,866 | 1,302,070 |
| Land Cost | $/sq ft | 43.60 | 43.60 | 43.60 | 43.60 |
| Permitting | $ | Not available | Not available | Not available | Not available |
| Interconnection | $ | 28,140,000 | 28,140,000 | 28,140,000 | 28,140,000 |
| **RESULTS** | | | | | |
| EPC Costs | | | | | |
| Energy Storage | $ | 703,836,000 | 749,322,000 | 1,287,764,000 | 1,370,522,000 |
| Construction | $ | n/a | n/a | n/a | n/a |
| Owners Costs | | | | | |
| Land | $ | 92,600,558 | 56,770,252 | 92,600,558 | 56,770,252 |
| Interconnection | $ | 28,140,000 | 28,140,000 | 28,140,000 | 28,140,000 |
| Subtotal Costs | $ | 120,740,558 | 84,910,252 | 120,740,558 | 84,910,252 |
| **TOTAL COST** | **$** | **824,576,558** | **834,232,252** | **1,408,504,558** | **1,455,432,252** |
| **Total $ per kWh** | | **344** | **348** | **256** | **265** |

*Figure 15: Capital cost estimate of bulk energy storage to address the Eastside transmission reliability deficiency*

If distributed storage were to be pursued in lieu of a centralized solution, costs would likely be substantially higher. For indicative purposes, the cost would range from $1.14 billion to $1.67 billion for the Interim Solution and $2.14 billion to $3.06 billion for the Complete Solution[41].

[40] Assumes an average 36% reduction in capital costs for incremental storage beyond the Interim Solution. See page 55 for cost assumptions.

[41] Indicative cost for the Interim Solution assumes $6,600 per installed 13.5 kWh system, based on the quoted price for a Powerwall 2 per www.tesla.com (accessed August 16, 2018) multiplied by the range of installed systems indicated in Table 4 to meet the Interim Solution. Indicative cost for the Complete Solution assumes a cost of $4,220 per installed 13.5 kWh system for the incremental number of systems required to meet the range shown for the Complete Solution in Table 5 (resulting in a blended cost of $5,258 per system for the Complete Solution).

The March 2015 Study also evaluated the cost-effectiveness of a storage system based on a comparison of the cost with the system benefits it would provide PSE. It is likely that system benefits may be somewhat different today than what was assumed in the March 2015 Study due to changes to load growth patterns, generation mix, and the inclusion of PSE in the Western Energy Imbalance Market. However, Strategen did not reassess the benefits of an Eastside energy storage solution in the 2018 Analysis.

# 2. Impact Considerations

This part of the report will discuss the physical impacts of energy storage systems and compare these to PSE's preferred transmission solution.

## 2.1 Physical Impact

System requirements were defined in Part 1 of this report. This section considers some of the practical and logistical aspects of deploying a system of the size defined in the technical requirements section. This will include the location of one or more energy storage systems, the physical sizing requirements as well as upgrades to support the operation of storage and the timing of need to build the preferred solution.

### 2.1.1 Location

As indicated, the location of a centralized energy storage system or a number of distributed energy storage systems does not impact the effectiveness factor, and therefore the total power and energy required to meet the normal overload condition remains 365MW/2,394MWh for the Interim Solution or 549MW/5,500MWh for the Complete Solution for Sammamish. A centralized system located somewhere between Talbot Hill Substation and Sammamish Substation would offer similar benefits, again as tested through PSE load flow analysis of the effectiveness factor. Distributed systems (provided they are connected downstream of these substations) could provide the same benefit as a single system, requiring coordination of their operation with each other to resolve the constraint.

### 2.1.2 Footprint

The physical sizing considerations for a centralized Interim Solution and Complete Solution are now considered. Figure 16 shows the Hornsdale Power Reserve, the current largest energy storage project on Earth. This system is approximately 19 times smaller than the Interim Solution and 43 times smaller than the Complete Solution. Its dimensions are used to inform the expected footprint of the Eastside solution along with other projects.

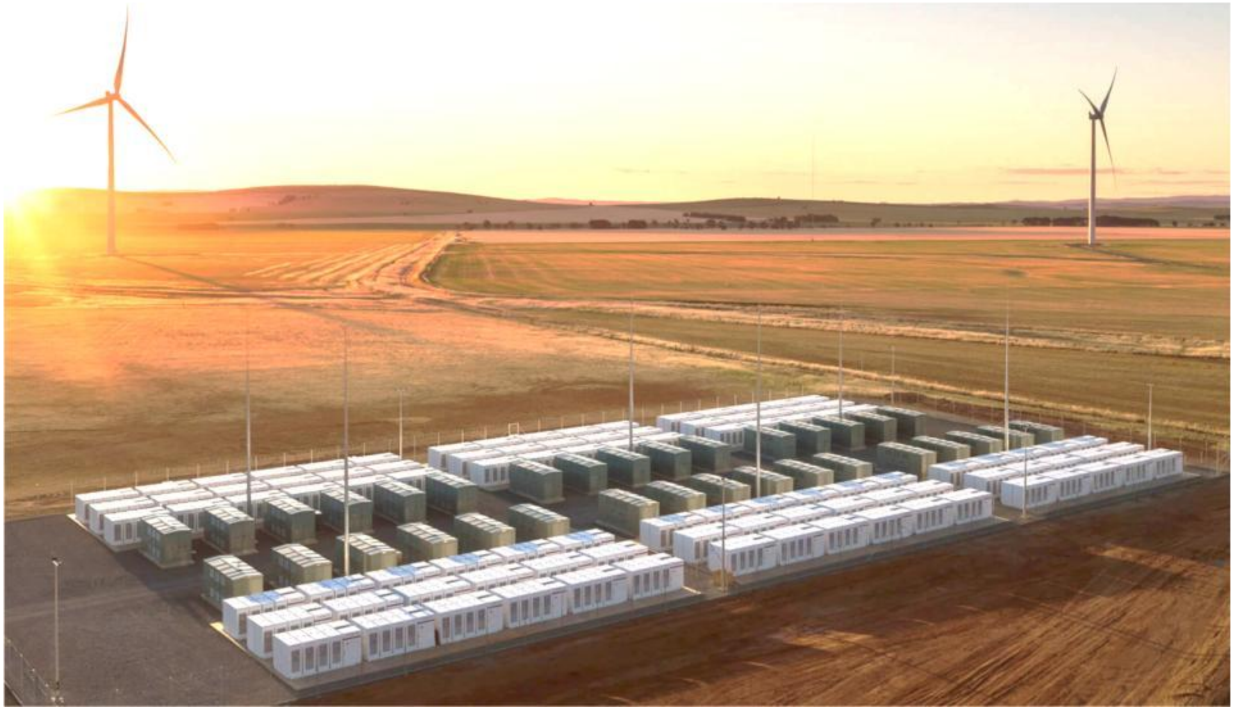

*Figure 16: Hornsdale Power Reserve is 100MW/129MWh, approximately 43 times smaller than the Complete Solution[42]*

Table 6 summarizes deployed and proposed large-scale energy storage systems. These include lithium-ion and flow batteries on one and two levels. This sizing information is then applied to the power and energy requirements of the Eastside solution.

*Table 6: Space requirements for the Energize Eastside solution based on installed and proposed large-scale energy storage projects*

| Per MWh | | Hornsdale Power Reserve | Dalian VFB Rongke Power | Average Single Level | Single Level Halved | Dalian VFB Rongke Power | Average Double Level | Extrapolated Size | Eastside Interim Solution 365 MW 2,394 MWh | | Eastside Complete Solution 549 MW 5,500 MWh | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Single Level | | | Double Level | | | | Single | Double | Single | Double |
| | Acres | 0.04 | 0.01 | 0.025 | 0.013 | >0.01 | 0.01 | | 58.87 | 21.22 | 135.25 | 48.76 |
| | Sq. ft | 1,669 | 473 | 1071 | 536 | 237 | 386 | | 2,564,333 | 924,461 | 5,891,325 | 2,123,866 |
| | | | | | | | | **Size compared to CenturyLink Stadium (1,500,000 Sq. Ft.)** | 171% | 62% | 393% | 142% |

*Note: As the projects considered for the sizing are four hours in duration or less, it is more appropriate to use the energy (MWh) rather than power (MW) rating to calculate the Eastside footprint.*

CenturyLink Stadium has a footprint of 34.4 acres[43] and the Interim Solution Eastside footprint would, therefore, be more than one and a half times the size if designed over one level. The Complete Solution would require a similar footprint to this if double-stacked over two stories, which is the most likely engineering approach. There have not been any large-scale energy storage projects to date that have been deployed with more than two levels. Figure 17 highlights the

[42] Source: (https://hornsdalepowerreserve.com.au/)
[43] 1,500,000 square feet. Source: (http://www.architravel.com/architravel/building/centurylink-field/)

indicative footprint of a single-stacked Interim Solution (red) vs a double-stacked Complete Solution within the Eastside area (yellow)[44].

*Figure 17: Indicative footprint of the Eastside storage solution red, single-level Interim Solution 59 acres, and yellow double-level Complete Solution, 49 acres*

### 2.1.3 Timing of Need to Build the Solution

The 2018/2019 overload constraints represent the largest exceedances in the normal rating within the next five years and drive the timing of any permanent or incremental solution. The following two projects are therefore considered for context on the feasibility of storage given the timing constraint.

**Aliso Canyon – Approximately one year to complete a 94.5MW/342MWh project**

On May 26, 2016, the California Public Utilities Commission ("CPUC") approved a resolution to expedite a competitive energy storage procurement solicitation to help alleviate an emergency capacity constraint in the 2017 summer, due to a gas leak at the Aliso Canyon natural gas storage facility, which constrained local generation capacity in the Los Angeles basin.

The resolution instructed San Diego Gas and Electric ("SDG&E") to "leverage" its ongoing 2016 Preferred Resource LCR RFO to approach "qualified respondents," and determine if an energy storage solution could be online in time to resolve the immediate Aliso Canyon constraint.

By the date the resolution was issued, SDG&E had completed its pre-evaluation and identified qualified contractors for turnkey, utility-owned projects. SDG&E approached qualified bidders to assess their willingness and ability to execute expedited projects in the 2016 timeframe. The RFO had already allowed pre-evaluation of respondents, which materially shortened the pre-bid activity.

To achieve the targeted January 31, 2017 online date, SDG&E required approval from the commission by August 19, 2016, before which the energy storage supplier could not make significant financial investments in battery modules, inverters, transformers, or containers for the project. The project timeline can be seen in Figure 18.

[44] This assumes a square footprint where the Interim Solution requires a 1,601x1,601 ft. (2.56 million sq. ft.) area and the Complete Solution requires a 1,457x1,457 ft. (2.12 million sq. ft.) (two levels).

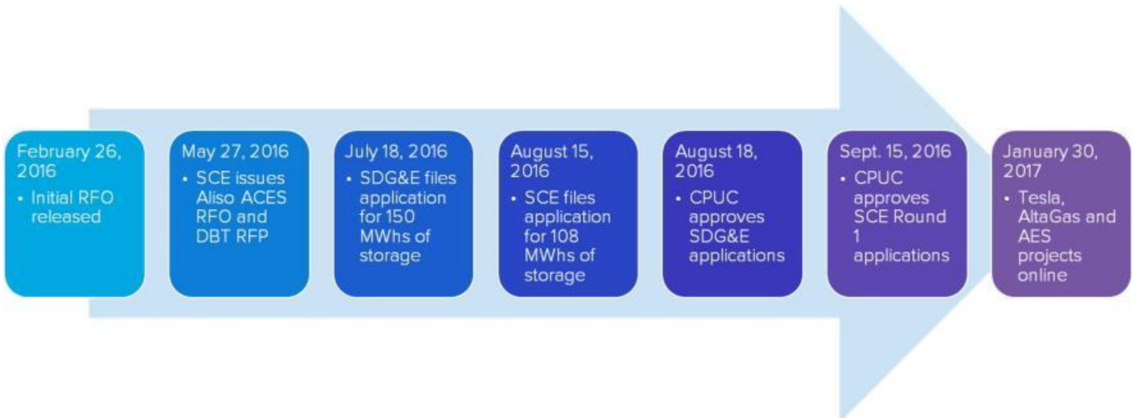


*Figure 18: Aliso Canyon battery energy storage system response timeline*

The Aliso Canyon Energy Storage Project saw a number of energy storage systems that aggregated to 94.5 MW / 342 MWh, brought online in approximately seven months. However, the original RFO began on February 26, 2016, which materially shortened pre-bid activity for this project. The overall project could, therefore, be considered to take approximately one year.

### Hornsdale Power Reserve – Majority of a year to complete 100MW/129MWh project

The Hornsdale Power Reserve, while touted as a 100MW buildout in 100 days, took the majority of 2017 to solicit, award and complete. Neoen and Tesla selected the existing Hornsdale Wind Farm as a suitable site in early 2017 and were selected as the developers in June 2017 after a solicitation. The construction took four months from the signing of the interconnection agreement, which was the period the 100 days focused on. The overall project, therefore, took the majority of 2017.[45] For the Hornsdale Power Reserve, Tesla signed a contract with Samsung to supply the batteries because of uncertainties regarding Panasonic's (its usual supplier) ability to deliver 129MWh of batteries in the required timeframe.

The scale of the Eastside solution is unprecedented but based on a 100MW/129MWh system taking most of 2017 to complete, it is a reasonable assumption that the Interim Solution (365MW/2,394MWh), the most pressing constraint, would take substantially longer. The combination of these factors makes it highly unlikely an energy storage project for Energize Eastside could be permitted, sited, sourced, designed, built and brought online within a year, to relieve the pending 2018/19 winter constraint.

[45] Source: (https://hornsdalepowerreserve.com.au/faqs/)

# 3. Commercial and Technological Developments

As part of the 2018 Analysis, Strategen was asked to evaluate what technological or commercial advancements have occurred with battery energy storage since the publication of the March 2015 Study. The objective was to determine if there were developments that substantively would impact the technological readiness, commercial readiness and/or cost-effectiveness of a storage solution to meet the Eastside reliability need.

## 3.1 Methodology

Strategen reviewed publicly available research and news on battery technology developments and cost data (historic and projections). Further, using publicly available information contained in the US Department of Energy's ("DOE") Global Energy Storage Database,[46] Strategen reviewed commercial deployments since the publication of the original March 2015 Study to characterize the ability of storage to be deployed in a scale of magnitude similar to the Eastside reliability need. We evaluated whether there are energy storage facilities currently in operation at the general scale of magnitude sufficient to meet the Eastside reliability need, and whether there are energy storage facilities with operational experience meeting a transmission reliability need similar to that on the Eastside. Strategen also reviewed publicly available operational data for utility-scale storage projects to evaluate any operational challenges or considerations that may impact the ability of a storage solution to reliably address a transmission deferral need, or additional experience (or limitations) identified in deploying storage as a multi-purpose asset[47] (which would impact its cost-effectiveness).

Key factors that have changed since the original March 2015 Study have been highlighted, along with a qualitative assessment of their likely impact on the technological or commercial feasibility of the storage alternative.

## 3.2 Energy Storage Applications

There are numerous applications for energy storage, which makes energy storage versatile and useful to the modern power system. Figure 19 shows some common applications for energy storage with respect to time.

[46] The Global Energy Storage Database is located at (http://www.energystorageexchange.com).
[47] By multi-purpose asset, we mean the use of storage to meet a transmission reliability need as well as other system needs, such as system (generation) capacity, system flexibility, oversupply reduction, etc.

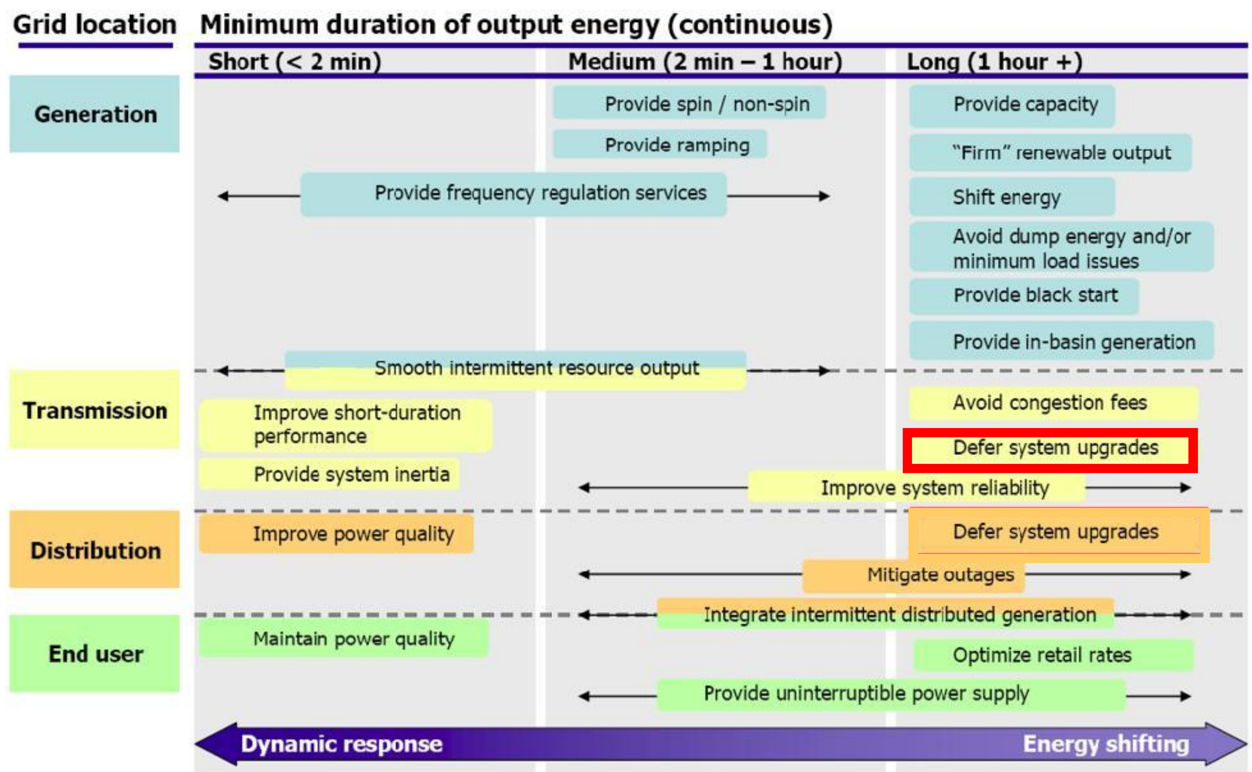


*Figure 19: Various use cases for energy storage with respect to time (red box indicates Eastside storage use case)[48]*

It is important to understand the application required by energy storage to effectively assess its ability to solve the power system constraint. The Energize Eastside constraint is a transmission reliability application, used to defer system upgrades, as portrayed in Figure 19. Energy storage would be used in this case to reduce the loading on the transformers to within their normal rating. In addition, it could provide other services presented in Figure 19 to increase the value proposition of the installation, but only once it has met the primary purpose and resolved the thermal rating issue.

Not all energy storage applications will be discussed below, only the most relevant. These are frequency regulation, capacity, and T&D deferral as they include the most common use cases and the Energize Eastside use case.

### 3.2.1 Frequency Regulation/Response

Frequency regulation/response has been the biggest application for energy storage systems to date.[49] This is a high power, low energy application, as shown by its position in Figure 19. Frequency support is required over a short timeframe, from seconds to minutes, and as such, energy storage systems to meet this need do not require a significant amount of batteries, making this typically a more cost-effective application than applications requiring longer timeframes (such as the Eastside need). Energy storage systems installed for frequency regulation are typically 15 minutes to one hour in duration. The Hornsdale Power Reserve in South Australia is approximately a 1.25-hour system (100MW/129MWh), which provides frequency regulation services in addition to

[48] Source: Southern California Edison
[49] Source: DOE Global Energy Storage Database

capacity services. Most of the large energy storage systems installed to date target frequency or stability services that are located on the left side of Figure 19.

Frequency disturbances are caused by an imbalance between generation and load. The variable output of renewable generation such as wind and solar can also add to frequency instability, which inverter-based energy storage can correct effectively with fast responding charging or discharging. In this application, the location of the energy storage system does not play a major factor, as it can contribute to addressing the net difference between generation and load, anywhere within an interconnected power system. The contribution also has a direct effect where every MW of power injected or absorbed by an energy storage system benefits the discrepancy between generation and load within the interconnected power system at a 1:1 ratio if losses are ignored.

Some examples of frequency response markets and installations are below:

- PJM Frequency Response Market – Approximately 265MW of energy storage[50]
- Hornsdale Power Reserve – Tesla and Neoen - South Australia – 100MW/129MWh (this is a secondary service)
- National Grid (UK) Enhanced Frequency Response Solicitation 2016 – 200MW in total

### 3.2.2 Capacity Services

Capacity services provide power as needed by the power system and as coordinated and dispatched by an electricity market operator. Conventional generation provides capacity services, and battery energy storage can also provide this service by charging at off-peak times to provide this service when required. Capacity services is a growing market for energy storage, particularly coupling energy storage to renewable generation. This allows charging from clean energy sources that are continually becoming more cost-effective, and adding storage to allow the dispatch of this energy at beneficial times as instructed by the market operator. This is the operating method of the Hornsdale Power Reserve in South Australia, which is coupled to an existing wind farm and provides capacity as directed by the market operator.

This capacity service, as discussed, is a fungible service coordinated and dispatched by a market. If there is a failure to deliver, another resource can be procured in its place. Location influences, but is not a major factor in, providing capacity services. This resource fungibility is fundamentally different than what would be required to meet the Eastside reliability need.

Some examples of capacity service installations are below:

- Hornsdale Power Reserve – Tesla and Neoen - South Australia – 100MW/129MWh
  This is the primary application where it is coupled with an existing wind farm to supply energy as directed by the Australian Energy Market Operator.
- Aliso Canyon – Provides capacity at peak times. The gas-fired power station would provide energy during peak times as a "peaker," and Aliso Canyon replicates this service, charging at off-peak times to provide capacity and peak times.

[50] Source: (https://www.energy-storage.news/news/pjms-frequency-regulation-rule-changes-causing-significant-and-detrimental)

### 3.2.3 T&D Deferral

T&D deferrals are additional applications for energy storage as seen in Figure 19. In both cases, storage is used as a location-specific load serving resource that allows a traditional wires-based solution not to be built or upgraded for some amount of time. The location of an energy storage system is critical in T&D deferral use cases, as is the assurance to operate when required. Unlike capacity and frequency response services that are less dependent on location and can be substituted by other resources if they do not provide the required service, T&D deferral use cases cannot be replaced by another resource and therefore the consequences in failing to deliver are more severe.

T&D deferral applications can vary in size and duration. While frequency response systems only require minutes to an hour of duration, deferral cases require the amount of energy to offset load on a constraint element which is determined on a case-by-case basis.

The primary differences between transmission deferral and distribution deferral is that transmission deferral use cases generally require offsetting much more power and energy than distribution deferral projects, and transmission deferral applications are typically on a highly networked grid (so the power flow can go in multiple directions), whereas some distribution deferral projects are able to be located within a radial network topology (so power flow is only possible in limited directions). The effect of this on efficacy is described on page 36.

The energy storage market has not been heavily driven by T&D deferral to date, as it is a more energy-intensive application, as seen in Figure 19, and therefore more expensive. As a result, energy storage projects deployed for T&D deferral to date have been much smaller in scale compared to the notable large installations of storage projects used for other purposes around the world. Deferral use energy storage projects have also generally been sited on the lower voltage distribution system rather than the high voltage, networked transmission system. Nevertheless, the market for T&D applications is growing as market and regulatory barriers are removed. An estimated global energy storage system capacity for T&D deferral in 2017 is 331.7MW.[51] This is expected to grow by about 50-fold over the next 10 years as seen in Figure 20. An Energize Eastside non-wires project, however, would be a transmission deferral use case of unprecedented size.

[51] Source: Navigant Research

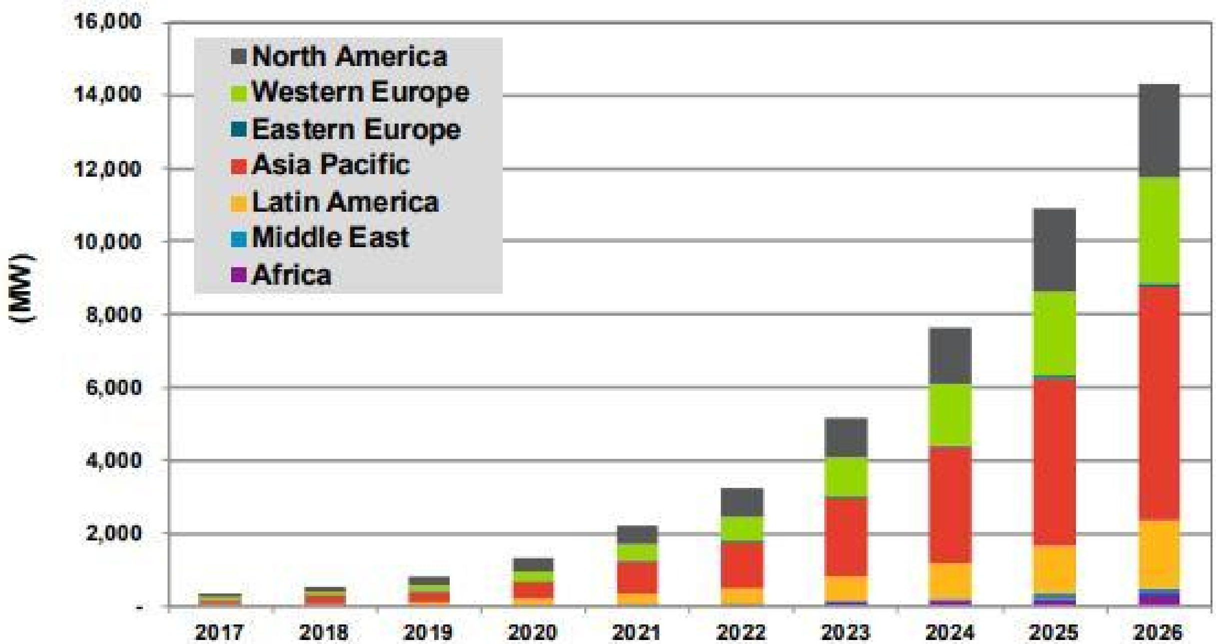


*Figure 20: Forecast annual installed energy storage power capacity for T&D deferral by region, 2017-2026*[52]

Some examples of proposed T&D deferral installations are below:

- Arizona Public Service (Proposed) – 2MW/8MWh (4-hour system)[53]
- National Grid Massachusetts (Proposed) – 6MW/48MWh (8-hour system)[54]

## 3.3 Technological Developments

The March 2015 Study compiled by Strategen suggested an energy storage solution for the Eastside system would be technologically possible, although challenging due to electrical infrastructure constraints, supply chain challenges and physical impact considerations. Some relevant advances to the technical aspects of energy storage are discussed in the Appendix.

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[52] Source: Navigant Research
[53] Source: (https://www.utilitydive.com/news/aps-to-deploy-8-mwh-of-battery-storage-to-defer-transmission-investment/448965/)
[54] Source: (https://www.utilitydive.com/news/national-grid-plans-to-install-a-48-mwh-battery-storage-system-on-nantucket/510444/)

# 4. Conclusion

While storage is becoming a technology embraced by the power sector to modernize and enhance the grid, the specific circumstances and requirements driving the Eastside transmission capacity deficiency are not well suited- to an energy storage solution. Such a solution would need to be of unprecedented scale, exceeding the total forecast 2018 US energy storage deployments,[55] both behind and in front of the meter. It would therefore be impractical to source, site and construct. In addition, it would come at a cost many times that of the traditional poles and wires solution.

For these reasons, despite the commercial and technological progress of energy storage in recent years, the conclusion of this updated analysis remains consistent with the conclusion of the original March 2015 Study. Strategen does not believe energy storage to be a practical option to meet the Eastside transmission capacity deficiency, either as an alternative to the proposed transmission solution or as a way to defer it.

The overall amount of storage required to meet the Eastside transmission capacity deficiency was calculated to be 549 MW, 5,500 MWh, compared with 545 MW, 5,771 MWh in the March 2015 study. See Table 7 below for a complete comparison.

*Table 7: Comparison of the March 2015 Study and 2018 Analysis for the sizing of an energy storage system for Eastside*

| Constrained Element | Power (MW) | Energy (MWh) | Duration (hours) | Meets 2019 System Need | Meets Solution Requirements Through 2027[56] | Feasibility[57] |
|---|---|---|---|---|---|---|
| ***Original March 2015 Study Results[58]*** | | | | | | |
| **Talbot Hill** | **545** | **5,771** | **10.6** | ✓ | not evaluated | ✗ |
| Sammamish[91] | *Assessed to be less than Talbot Hill sizing* | | | | | |
| ***2018 Analysis*** | | | | | | |
| ***Interim Solution for 2019[59]*** | | | | | | |
| Talbot Hill | 290 | 1,689 | 5.8 | ✗ [60] | ✗ | ✗ |
| **Sammamish[61]** | **365** | **2,394** | **6.6** | ✓ | ✗ | ✗ |
| ***Complete Solution through 2027*** | | | | | | |
| Talbot Hill | 338 | 3,679 | 10.9 | ✓ | ✗ [90] | ✗ |
| **Sammamish[91]** | **549** | **5,500** | **10.0** | ✓ | ✓ | ✗ |

[55] This includes all types of energy storage; residential, non-residential and utility in-front-of-the-meter systems.
[56] Meets 2027 requirements means satisfying the NERC/FERC planning criteria through 2027, the same planning criteria against which the ultimate Eastside solution must be judged (whether a wires or non-wires solution).
[57] Feasibility relates to electrical sizing, physical sizing, timing and the ability of the market to respond.
[58] The March 2015 Study evaluated solution requirements to meet a deferral need through 2021.
[59] Sized only to meet immediate 2019 constraint assuming all other NWAs per E3 NWA Report (2014) are implemented; size requirement would be larger if other NWAs are unable to be implemented.
[60] The Talbot Hill sizing is insufficient to meet the Sammamish need and therefore does not meet the system need for that entire year.
[61] Sammamish was assessed in the March 2015 Study, but Talbot Hill was the more significant constraint that defined the energy storage sizing. Due to several factors detailed in this report, Sammamish is now the greatest constraint that defines the size while Talbot ill also exceeds NERC requirements.

# Appendix: Technical Analysis - Additional Information

## Technical Analysis Assumptions

The following assumptions were used to conduct this updated analysis. In general, Strategen maintained the assumptions in the original March 2015 Study but where updated data and details are available, those were updated.

The ***assumptions that have remained*** the same between the original March 2015 Study and this assessment are:

**Effectiveness factor –** The effectiveness factor used in the March 2015 Study was approximately 20%. An explanation and example of effectiveness factor is presented on page 36. *It is important to recognize this is a characteristic of the Eastside system and is not related to the energy storage's round-trip efficiency.*

Note, other energy siting locations were considered (both bulk and distributed) within the Eastside area, and the effectiveness factor remained similar. Therefore, whether the solution is a centralized system located within the area, a distributed solution within the area, or a combination of the two, the total aggregate sizing requirements as identified in this analysis would be very similar. For example, if a 100MW/400MWh system is required, two 50MW/200MWh systems or ten 10MW/40MWh systems would be required and considered equivalent. From an effectiveness factor point of view, there is no benefit to a centralized energy storage system versus a distributed system (or vice versa).

**Round-trip efficiency –** The round-trip efficiency ("RTE") of the energy storage used in the March 2015 Study was 85% and this remained the same in this study. Lazard's latest annual Levelized Cost of Storage Analysis (LCOS 3.0) uses 85% efficiency in its analysis.[62] As an additional reference, the Tesla Powerwall 2 has a 90% RTE. This is at the start of its operating life, prior to any degradation, and under test conditions where the system is discharged at 66% of its rating.[63] A system designed for the Eastside application would not operate at a 90% RTE during peak times due to the higher charge and discharge rate required. 85% RTE, therefore, remains an appropriate RTE for this analysis. Flow batteries generally have lower RTE due to reduced performance at high charge and discharge rates and also require energy to operate the electrolyte pumps.

**Cell degradation –** The original March 2015 Study used a 2% per year rate of cell degradation. This is an industry standard for lithium-ion (it is expected that 80% of the installed energy is available after 10 years) and the same 2% rate was considered in this updated analysis. As the energy storage sizing is assessed to meet the 2019 load forecast, cell degradation has very little impact on this sizing. Flow batteries do not generally degrade as much as lithium-ion batteries over time. However, an 85% RTE is being assumed, which is high for flow batteries and therefore the assumption of 2% cell degradation per year will not unfairly diminish a flow battery's capabilities in the assessment. Cell degradation is inherent to electrochemical energy storage, and anyone with a smartphone would have witnessed reduced battery performance and capacity after several years of use due to this phenomenon.

**2014 E3 NWA Report –** A report in 2014 identified possible NWA and load reductions associated with these measures. As in the March 2015 Study, these were incorporated into the storage sizing

[62] Source: (https://www.lazard.com/perspective/levelized-cost-of-storage-2017/)
[63] Source: (https://www.tesla.com/sites/default/files/pdfs/powerwall/Powerwall%202_AC_Datasheet_en_northamerica.pdf)

analysis to provide the maximum identified reductions. The NWA reductions are presented in Table 8.

*Table 8: 2014 E3 NWA Report with potential load reduction opportunity values*

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Conservation Potential (MW)** | 18.9 | 22.7 | 26.5 | 30.1 | 30.1 | 30.1 | 30.1 | 30.1 | 30.1 | 30.1 |
| **DR Potential (MW)** | 11.7 | 11.9 | 24.3 | 24.7 | 24.7 | 24.7 | 24.7 | 24.7 | 24.7 | 24.7 |
| **DG Potential (MW)** | 0.5 | 0.6 | 0.7 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 |
| **Total (MW)** | 31.2 | 35.3 | 51.6 | 55.6 | 55.6 | 55.6 | 55.6 | 55.6 | 55.6 | 55.6 |

The ***assumptions that have changed*** since the original March 2015 Study due to updated information and data are:

**Load data –**Talbot Hill and Sammamish representative load data was generated by PSE for the updated analysis, and scaled to account for projected load growth from 2018-2027.

**Load forecasts –** As part of its 2017 Integrated Resources Plan ("IRP"), PSE updated its system load forecast reflecting a gradual shift from a winter to a summer peaking system. This reduced winter loading at Talbot Hill, and increased summer loading at Sammamish versus the March 2015 Study, which was based on data from PSE's 2013 IRP. Load forecasts are inherently uncertain, especially further out into the future. For this reason, much of the analysis focuses on the near-term load data. Load forecasts inherently contain some degree of uncertainty: the load may either increase or decrease from the forecast. While energy efficiency and DER offer some load reduction opportunities, electric vehicles may add significant additional load, and the timing of this will be important (and remains uncertain). The load forecast below is consistent with distribution planning approaches to meet NERC and FERC planning requirements and is used for this analysis.

**Scenarios considered –** Both the Talbot Hill winter load data and Sammamish summer load data were evaluated to define the energy storage sizing. The original March 2015 study also considered both data sets but only presented Talbot Hill because it had the greatest exceedance in the normal rating and therefore defined the size of the storage system required to meet the system constraint. In other words, a system that met the larger Talbot Hill exceedance would also meet the lesser Sammamish exceedance. As shown in the load forecast data above, the Sammamish summer load has now become the greatest exceedance and therefore the sizing of both the Talbot Hill and Sammamish are presented.

**Normal and emergency ratings –** The transformer ratings have changed since the previous March 2015 Study due to the adoption of a new computer simulation that provides a more dynamic, seasonally adjusted and element-specific rating for each element designed to maximize infrastructure performance.[64] In June 2017, PSE established new ratings for transformers using this

[64] PSE chose EPRI's PTLOAD program as it is a widely accepted tool in the industry for rating transformers and is being used by nine out of the 11 utilities PSE surveyed. Moreover, the in-house software and EPRI PTLOAD software are developed using the same IEEE standards. EPRI PTLOAD was rigorously tested and compared to in-house software. EPRI PTLOAD calculates both individual and group ratings similar to the in-house software, which is one of the requirements the unit-specific rating process targets when the individual transformer would experience an accelerated loss of life.

simulation. To meet NERC requirements, PSE plans its infrastructure in accordance with facility ratings.[65] This has resulted in an increase in the normal winter rating at Talbot Hill from 398MW to 426MW. With respect to Sammamish, the normal summer rating has increased from 369MW to 387MW.

To meet NERC requirements, PSE plans its system using normal ratings on its equipment. Both the normal winter rating for Talbot Hill Substation and the normal summer rating for Sammamish Substation increased by 28MW, which reduced the required contribution of any energy storage system compared to the sizing of the original March 2015 Study.

**Minimum SOC –** In the additional analysis conducted in this report, the SOC is considered. The minimum SOC limit used was 2%. It is not possible to fully discharge a lithium-ion battery without damage. Such systems have a total energy capacity and a usable energy capacity. For example, the Tesla Powerwall 2 has a total energy capacity of 14kWh but has a usable energy capacity of 13.5kWh. To extract this full amount of energy (13.5kWh), the system must be discharged at 3.3kW or less, (66% of the rated at 5kW continuous discharge).[66] The Eastside application would require higher charge and discharge rates and therefore would not be able to extract as much usable energy, making 2% very aggressive. A flow battery can allow for a 100% depth of discharge and provide all the stored energy as usable capacity; however, the electrolyte pumps consume energy and the 85% RTE assumption is high for a flow battery. Therefore, a 2% SOC limit is used to be technology agnostic and provide a conservative assumption for a lithium-ion system. An actual lithium-ion system would need to be sized larger to cater for the inability to use all of the stored energy capacity.

**N-1-1 configuration –** The N-1-1 configuration occurs when two different elements go out of service in succession. This is the NERC/FERC planning requirement that the system must be able to handle two elements out of service while continuing to reliably supply the system. Due to the specific electrical topology of the Eastside system, the worst-case N-1-1 contingency during the summer has a more significant impact on Sammamish than the worst-case N-1-1 contingency during the winter has on Talbot Hill.

[65] PSE correspondence (3/7/18)
[66] Source: (https://www.tesla.com/sites/default/files/pdfs/powerwall/Powerwall%202_AC_Datasheet_en_northamerica.pdf)

## Explaining "Effectiveness Factor"

The effectiveness factor is the ratio of power injected at particular locations to the reduction of power across a constrained element elsewhere in the system. This differentiates energy storage for T&D applications versus energy storage for frequency response or capacity services. Power for frequency and capacity can be measured at the point of injection, while power for T&D deferral depends on the reduction at the constrained element. Frequency response is a correction to the net imbalance to generation and demand, which is not dependent on where the injected power flows. Similarly, capacity adds power to the system; regardless of where it flows, it provides that capacity to the system. However, in T&D deferral applications, the power flows are critical. The energy storage system's primary purpose is to reduce the power flow through one or more constrained elements and therefore *where* the power flows.

There are two typical configurations for a power system, radial and meshed. Radial, as the name suggests, is one or more radial lines connected in one direction between two nodes, while meshed is a number of lines interconnected to provide more redundancy. Radial configurations are more typical in rural applications at the distribution level while meshed configurations are more common in the urban environment and at the transmission level. The trade-off being radial is cheaper, consisting of fewer lines and connections, but is less reliable because a single failure can cause an outage.

A meshed network, however, can sustain a failure, isolate that section, and provide power through a different line route. Meshed systems allow customers to experience both fewer and shorter duration outages. This reliability aspect is important and is why meshed topologies are typically used to supply urban areas. The comparison between radial and meshed networks can be seen in Figure 23.

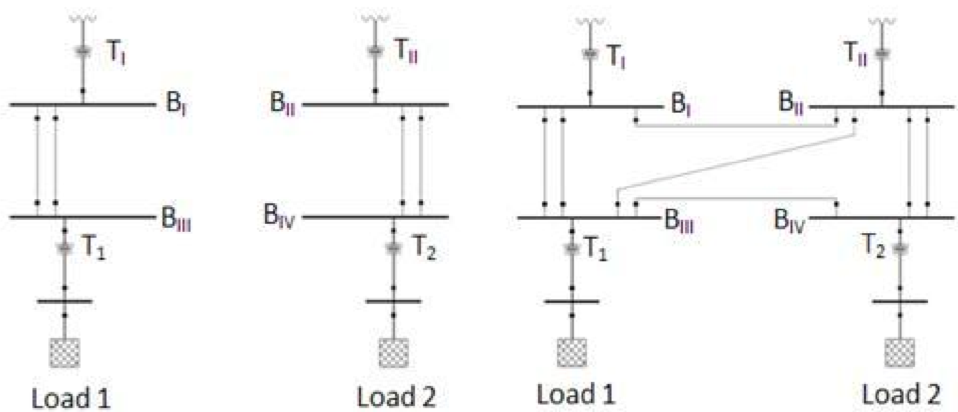


*Figure 23: Radial configuration left (dual circuit) and mesh configuration right*

When considering energy storage for T&D deferral on a radial line, the effectiveness factor is generally much higher as there are fewer paths for injected power to flow. This concept is shown in Figure 24.

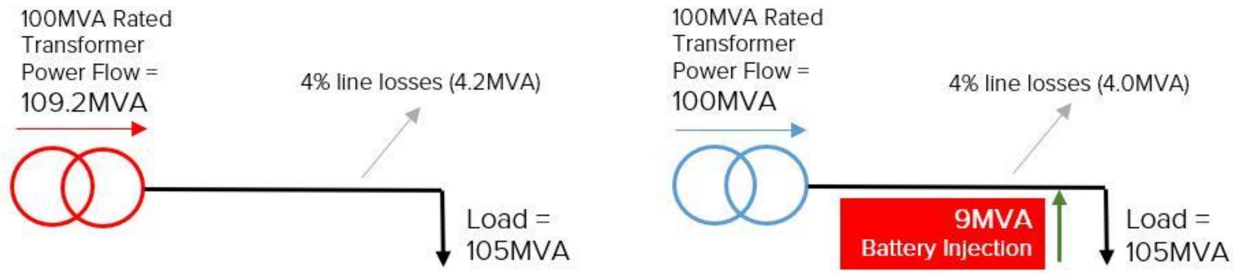


*Figure 24: Example of energy storage providing benefit to a radial system*

In Figure 24, a transformer rated at 100MVA is overloaded to 109.2MVA. This is a thermal constraint due to the downstream load. In this example, 4% line losses were considered to demonstrate an additional benefit of energy storage. The load consumes 105MVA and 4.2MVA is lost in the power system due to heat ($I^2R$ losses). By installing a 9MVA battery energy storage system near the load, the system has reduced the power flow through the transformer and relieved the constraint. The load still consumes 105MVA but now 9MVA comes from the battery while the power through the transformer supplies 96MVA to the load and 4MVA of power system losses. In this case, the effectiveness factor is 1.0222 because 9MVA of injection by the energy storage system reduces the power through the transformer by 9.2MVA (9.2/9=1.0222). The reason the reduction through the transformer is greater than the energy injected is because the storage system is located closer to the load, so its energy reduces the flow through the transformer, while also reducing the flow through the line, thus reducing the line losses.

The Eastside transmission network is a meshed configuration. In a meshed system, the power flows are very different. Electricity, like water, will take the easiest path which is determined by the resistance (impedance) it faces. The only way to change this is if the physical power system is changed through switching (reconfigured). Figure 25 shows this concept.

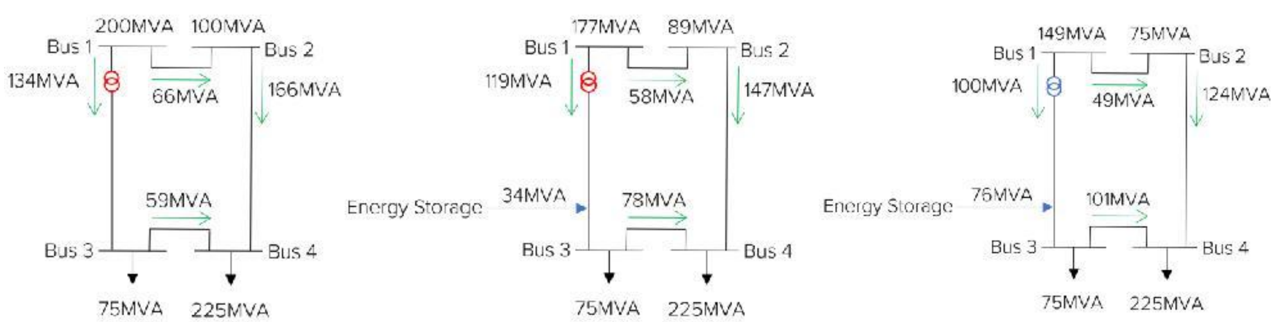


*Figure 25: Example of meshed network response to injection and the fact it is not a 1:1 benefit*

In Figure 25 the transformer again has a 100MVA rating and is overloaded to 134MVA. However, in this case, simply adding 34MVA of storage does not resolve the thermal constraint as seen. This is because power flows take the path dictated by the system impedance. One-third of the battery injection reduces the contribution at bus 2 while the other two-thirds reduce the contribution at bus 1. The resulting power flows then reduce by that seen in Figure 25. Increasing the battery energy storage system to 76MVA does bring the transformer to its 100MVA rating as seen in Figure 25. In this case, the effectiveness factor is 0.4474 (34/76=0.4474). Therefore, to reduce the loading on the constrained transformer by the required 34MVA, 76MVA of energy storage is required because only 44.74% of the injection of energy storage contributes to reducing the constraint while the remainder reduces the power flows on other lines that are not relevant to the constraint.

The Eastside power system has an effectiveness factor of approximately 20%. The system is highly interconnected, much more so than the simple example shown in Figure 25. This is typical of networks supplying high-density urban areas. This is because a failure can affect so many customers, and the power system is designed to be more interconnected to provide more redundancy, ensuring that customers receive a reliable supply. Various locations were considered within the Eastside area, and all interconnection points had a similar effectiveness factor to the transformer constraints. This again is because of the number of interconnected networks. This effectiveness factor is an important point to understand when comparing systems installed for other applications to the need in the Eastside area.

## Explaining "Ability to Charge"

Energy storage, unlike a generator, also acts as a load. For an energy storage system to effectively provide support, it must also have the capability to charge sufficiently without causing a constraint. This ability is determined by network capacity. Figure 26 highlights an example of the required energy discharge (red) and the capacity to charge (green).

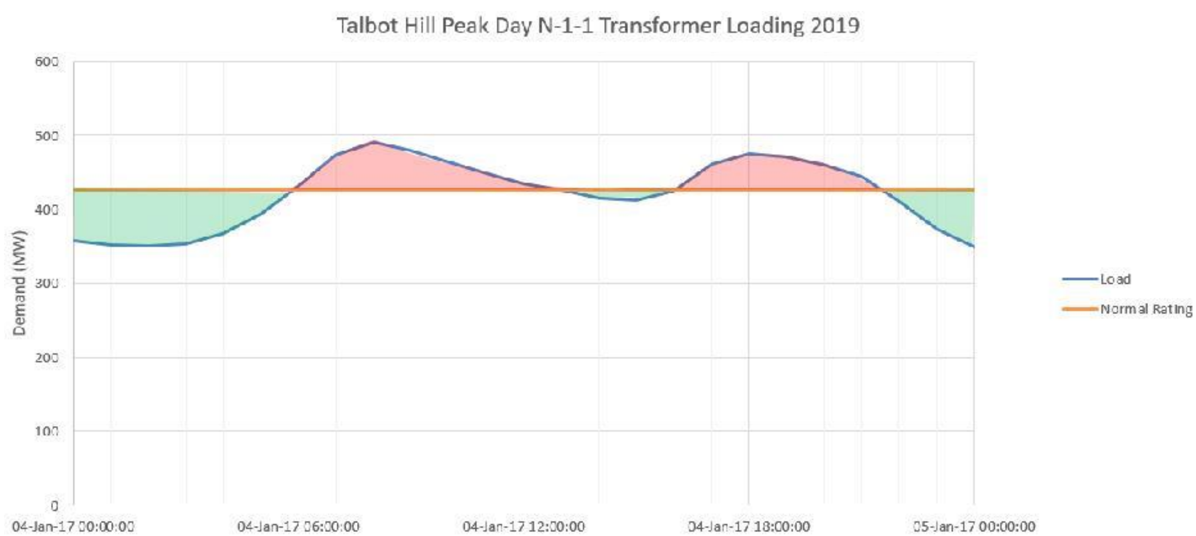


*Figure 26: Talbot peak 2017 day (actual load data) and charge capacity (green) and discharge requirement (red)*

The green area must be greater than the red area by an amount to compensate for the RTE to effectively charge. For example, if the red area is 80MWh and the green area is 100MWh, with an RTE of 85%, there is sufficient energy to charge the system. 100MWh of charging will enable 85MWh of discharge with 15MWh in energy losses. If the red area is 90MWh and the green area is 100MWh, with an RTE of 85%, there is insufficient energy to charge as 100MWh of charging will only allow 85MWh of discharge. To meet the 90MWh discharge requirement, 105.9MWh of charging must be available to cater for the 85% RTE (90MWh/0.85). If the network cannot support this 105.9MWh of charging without causing an overload, there is insufficient network capacity to allow adequate charging within the daily period studied.

## Talbot Hill Solution – Methodology Description, with Comparison to Original Methodology Results

The following steps were taken to assess the energy storage requirements for Talbot Hill Substation based on the original methodology from the March 2015 Study.

1) The recorded Talbot Hill Substation load data was considered and the peak day was extracted. This peak demand is the maximum loading on the substation's two transformer banks and will define maximum power contribution required by a potential energy storage system.
2) During a winter N-1-1 contingency for Talbot Hill Substation, the loading on the remaining transformer at the Talbot Hill Substation would be 78.1% of the full (two transformer) load. The peak day is scaled by this number to compare what the loading would have been on the remaining Talbot Hill transformer.
3) The peak day transformer loading is scaled by the load forecast and relevant N-1-1 scaling factor to provide an N-1-1 load profile for each peak day over the next 10 years, which is presented in Figure 21. Note that even a small change in peak demand has a relatively large impact on the area between the peak loading (solid lines) and the normal transformer rating (dotted red line).

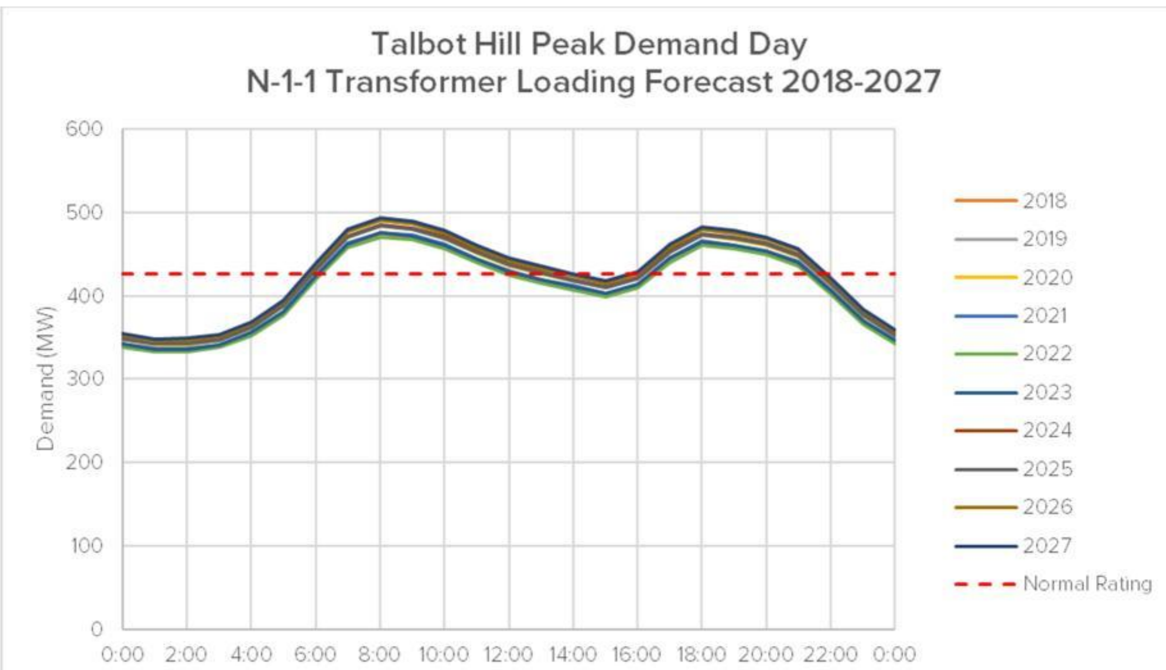


*Figure 21: Peak demand loading forecast from 2018 to 2027*

4) The peak day of each year is then considered with respect to the normal rating seen in Figure 21. By subtracting the normal rating, the amount the load exceeds the rating defines the load reduction required to meet planning standards.

5) Loading on the overloaded transformer element must be reduced to the normal rating by injecting power onto the grid. Injection of power at the appropriate location on a networked (mesh) power system would reduce this loading at ratio less than 1:1, so this exceedance (which is the exceedance on the transformer element) is then divided by the effectiveness factor. Dividing the exceedance by the effectiveness factor determines the required level of energy injection. The effectiveness factors are approximately 20% for all

scenarios. More information on effectiveness factor concept can be found elsewhere in the Appendix.

6) The NWA load reductions, as identified by the 2014 E3 NWA Report, are then subtracted from the required injection to determine the remainder that must be met by an energy storage system. Similar to the effect of the energy storage system, NWA reductions do not reduce the loading on the constrained element at a 1:1 ratio, and therefore must be subtracted after the effectiveness factor is applied. The NWAs also need to be scaled by the same N-1-1 scaling factor to provide the accurate reduction contribution on the remaining transformer loading.

7) This process identifies the required power and energy of an energy storage system **during the peak demand day** (after NWAs are considered) to reduce the load on the constrained transformer element to the normal rating.

*Table 9: Energy storage requirements by year to alleviate Talbot Hill Substation constraint*

| Net Energy Storage Injection Requirement, by Year[67] | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
| Power (MW) | 210 | **290** | 244 | 208 | 181 | 204 | 255 | 247 | 282 | **294** |
| Energy (MWh) | 1,239 | **2,083** | 1,559 | 1,198 | 935 | 1,160 | 1,668 | 1,586 | 1,968 | **2,105** |
| Duration (hrs.) | 6 | **7** | 6 | 6 | 5 | 6 | 7 | 6 | 7 | **7** |

8) It can be seen in Table 9 that 2019 presents the largest energy storage requirement prior to 2027. This year is therefore significant and is considered as the Interim Solution using the old methodology. 2027 is the maximum size required and provides an alternative that is equivalent to the requirements of the proposed transmission solution which meets the need in all years and is therefore considered as the Complete Solution using the old methodology.

9) The sizing required for the Complete (2027) Solution must also be adjusted to assess the energy storage system requirements for a system installed in 2018 and account for 2% per year cell degradation, as any energy storage system installed to meet the Interim Solution requirements will degrade over time prior to meeting the Complete Solution. Table 10 shows the results of cell degradation.

*Table 10: An energy storage system installed in 2018 would need to be 2,515MWh to supply 2,105MWh in 2027*

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|
| Energy (MWh) | **2,515** | 2,466 | 2,418 | 2,370 | 2,324 | 2,278 | 2,234 | 2,190 | 2,147 | **2,105** |

At this point, the original March 2015 Study compared this discharge need to the charging capability discussed elsewhere in the Appendix.

[67] Cell degradation and usable energy capacity are not considered.

## Sammamish Solution – Methodology Description, with Comparison to Original Methodology Results

The following steps were taken to assess the energy storage requirements for Sammamish Substation based on the original methodology from the March 2015 Study.

1) The recorded Sammamish load data was considered and the peak summer day was extracted. This peak summer demand was the maximum loading on the transformer during the 2017 summer that was of a consistent shape and representative of likely future peak load days. This will define the maximum power contribution required by a potential energy storage system.
2) During an N-1-1 contingency for Sammamish, the loading on the remaining transformer at the Sammamish Substation is 101.4% of the full (two transformer) load. The peak summer day is scaled by this number to compare the loading on a Sammamish transformer under an N-1-1 contingency.
3) The peak summer day transformer loading is scaled by the load forecast and relevant N-1-1 scaling factor to provide an N-1-1 load profile for each peak summer day over the next 10 years as seen in Figure 22.

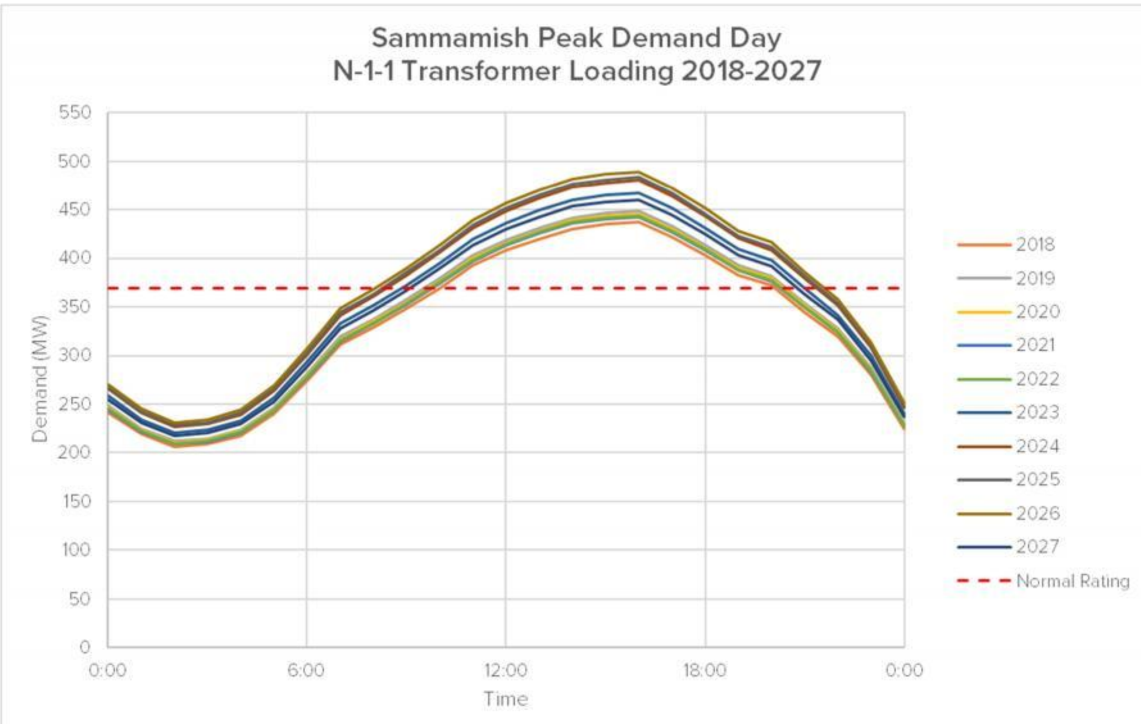


*Figure 22: Peak demand day transformer loading forecast from 2018 to 2027*

4) The peak summer day in each year is then considered with respect to the normal rating. By subtracting the normal rating, the amount the load exceeds the rating defines the load reduction required to meet planning standards.

5) This exceedance (which is the exceedance on the transformer element) is then divided by the effectiveness factor. The overloaded transformer element must be relieved to the normal rating, and the injection of power reduces this at the ratio of the effectiveness factor. Dividing the exceedance by the effectiveness factor determines the required level of energy injection. The effectiveness factors are approximately 20% for all scenarios, and more information can be found in the Appendix.

6) The NWA load reductions, as identified by the 2014 E3 NWA Report, are then subtracted from the required injection to determine the remainder that must be met by an energy storage system. Similar to the effect of the energy storage system, NWA reductions do not reduce the loading on the constrained element at a 1:1 ratio, and therefore must be subtracted after the effectiveness factor is applied. The NWAs also need to be scaled by the same N-1-1 scaling factor outlined in the Appendix, to provide the accurate reduction contribution on the remaining transformer loading.

7) This process identifies the required power and energy of an energy storage system, after NWAs are considered, to reduce the load on the constrained transformer element to the normal rating. These results can be seen in Table 11.

*Table 11: Energy Storage Requirements by year to alleviate Sammamish Substation constraint*

| Net Energy Storage Injection Requirement, by Year[68] | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
| Power (MW) | 310 | **365** | 332 | 313 | 318 | 439 | 504 | 519 | **549** | 405 |
| Energy (MWh) | 1,773 | **2,277** | 1,953 | 1,786 | 1,830 | 3,033 | 3,713 | 3,886 | **4,240** | 2,687 |
| Duration (hrs.) | 5.7 | **6.3** | 5.9 | 5.7 | 5.8 | 6.9 | 7.4 | 7.5 | **7.7** | 6.6 |

8) It can be seen in Table 11 that 2019 presents the largest energy storage requirement prior to 2023. This year is therefore significant and considered as the Interim Solution using the original methodology. 2026 is the maximum size required in Table 11 and provides an alternative that is equivalent to the requirements of the proposed transmission solution which meets the need in all years. 2026 is therefore considered as the Complete Solution for Sammamish.

9) Finally, the sizing required for the Complete Solution using the original methodology, 2026, must be adjusted to assess the energy storage system requirements for a system installed in 2018 and account for 2% per year cell degradation. Any energy storage system installed to meet the Interim Solution will degrade over time prior to meeting the Complete Solution and must be considered. Table 12 shows the results of the cell degradation.

*Table 12: An energy storage system installed in 2018 would need to be 4,968MWh to supply 4,240MWh in 2026*

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|
| Energy (MWh) | **4,968** | 4,871 | 4,775 | 4,682 | 4,590 | 4,500 | 4,412 | 4,325 | **4,240** | 4,155 |

At this point, the original March 2015 Study compared this discharge need to the charging capability as discussed elsewhere in the Appendix.

[68] Cell degradation and usable energy capacity are not considered.

## Technical Readiness

Battery energy storage in the power system, until recently, was primarily installed for research and development purposes and proof of concept pilots. In recent years, however, energy storage has advanced, and systems have and are being installed as effective and credible options in some use cases instead of conventional power system solutions. This is depicted in Figure 27 where the progression from demonstration to deployment and now mature technology can be seen in EPRI's energy storage progression plot.

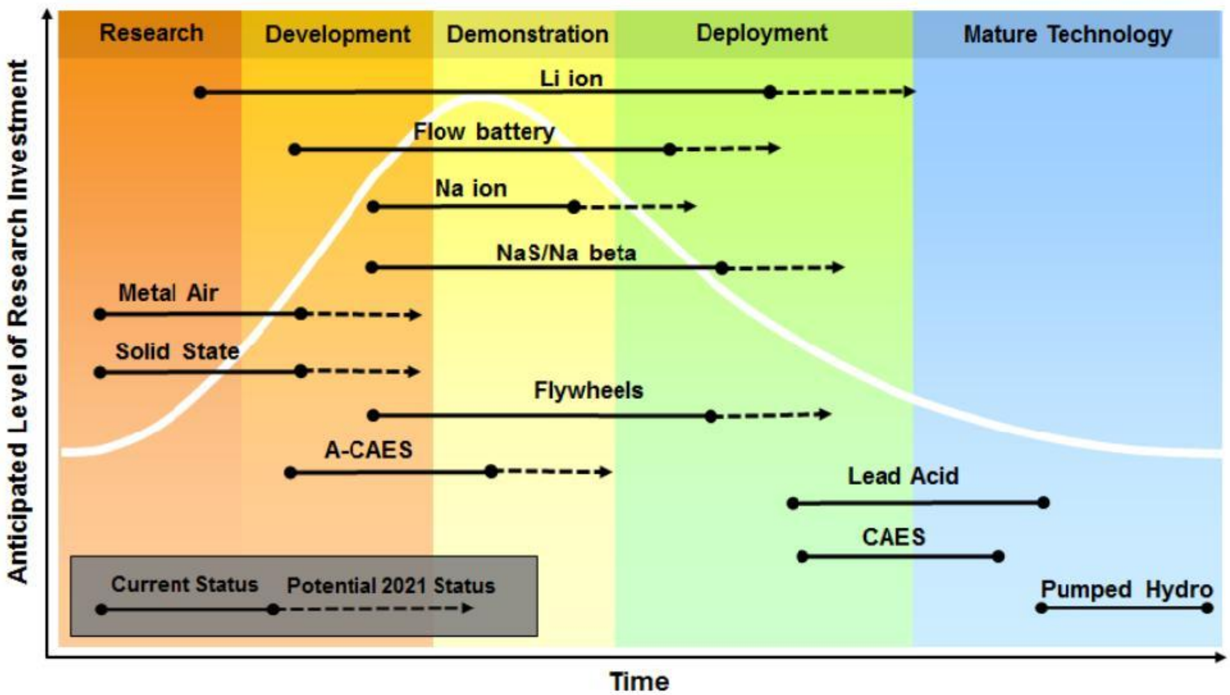


*Figure 27: Energy storage progression plot to 2021[69]*

The progression is shown in Figure 27 and the transition from demonstration and deployment to a mature technology is evident from the growth of the energy storage industry. Since the March 2015 Study, the deployments of energy storage in terms of energy rating have increased approximately 46% year on year. Figure 28 and Figure 29 capture the annual deployments and quarterly deployments of energy storage respectively. 431MWh of energy storage was deployed in the US in 2017 and it is expected approximately 1,233MWh will be deployed in 2018. This growth rate illustrates the increasing maturity of storage as a technology class, such that today it is generally viewed as a technology that is evolving beyond pilot deployments into commercial applications.

[69] Source: MacColl, Barry. "An EPRI Perspective on the future of distributed energy storage". EPRI, 2017.

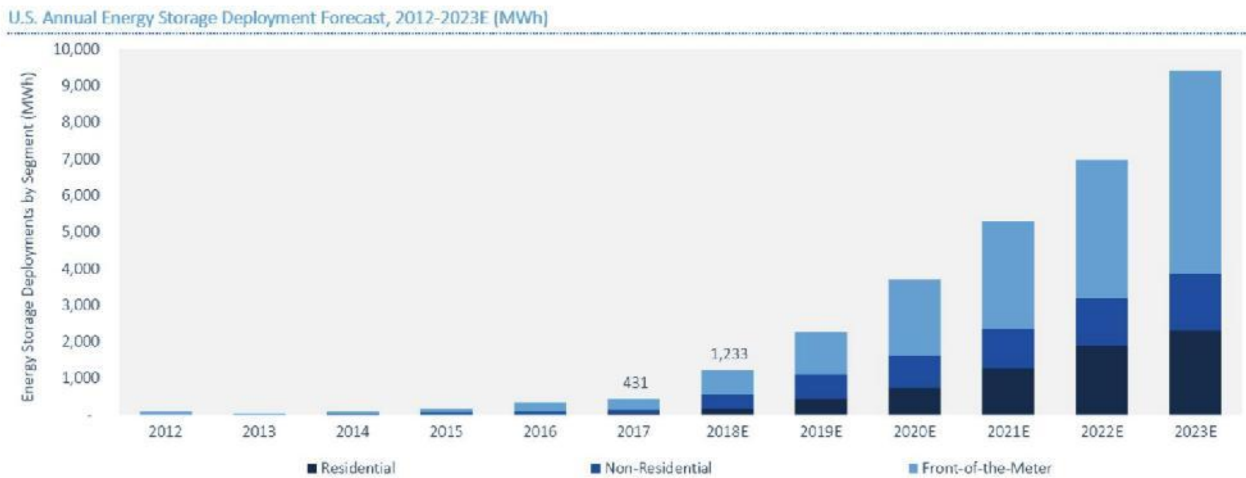


*Figure 28: Annual US energy storage deployments by energy capacity (MWh). E = Estimate[70]*

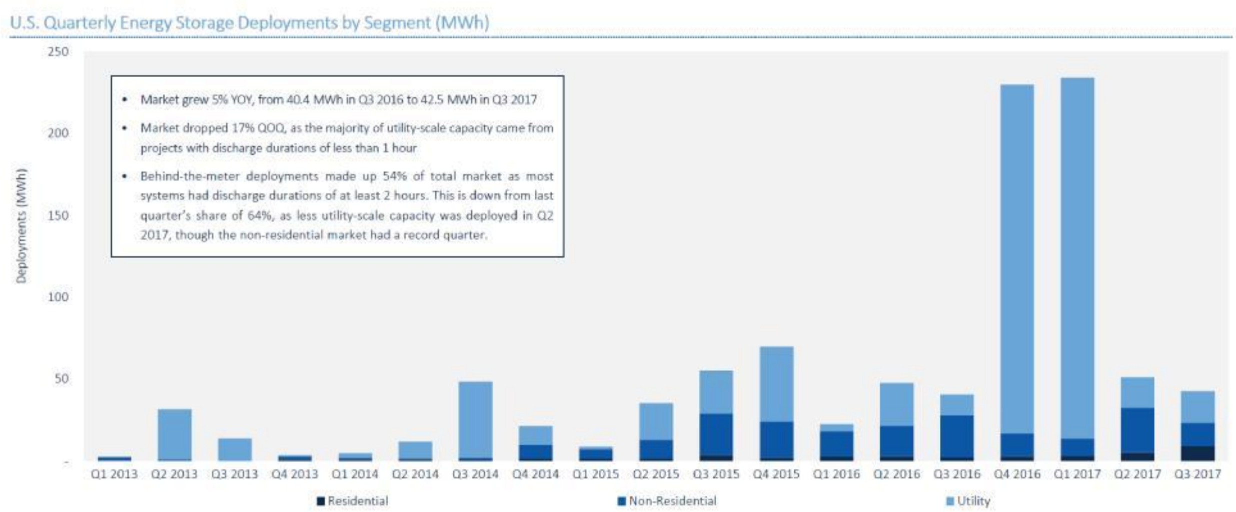


*Figure 29: Quarterly US energy storage deployments by total energy (MWh)[53,71]*

Excluding pumped hydro, approximately 90% of energy storage capacity deployed in 2016 was a lithium-ion battery chemistry. Other battery chemistries (e.g., redox flow or lead acid) amounted to an estimated 5% of capacity additions, and all other storage technologies combined accounted for the remaining 5%.[72] More recent (Q2 2017) data showed that 94.2% of battery energy storage systems installed were lithium-ion varieties, 5% were flow batteries and approximately 0.5% were lead acid.[73]

It is evident that lithium-ion remains the dominant technology, while flow batteries are also seeing deployments for certain applications. The March 2015 Study assessed a lithium-ion storage system as it anticipated this technology to lead the market, which has proved to have been appropriate on the evidence of recent years.

[70] Source: GTM Research and ESA (https://www.greentechmedia.com/research/subscription/u-s-energy-storage-monitor#gs.f6=Ow5Q)
[71] Source: GTM Research and ESA (https://www.greentechmedia.com/research/subscription/u-s-energy-storage-monitor#gs.f6=Ow5Q)
[72] Source: (https://www.iea.org/etp/tracking2017/energystorage/)
[73] Source: (https://www.energy-storage.news/news/flow-batteries-leading-the-way-in-lithium-free-niches1)

While they lack the widespread commercialization of lithium-ion,[74] flow battery technology appears to be gaining ground in proposed utility-scale projects, particularly with the announcement of UniEnergy Technology's partnership with Rongke Power in China to develop a 200MW/800MWh flow battery facility in Dalian province of China. According to recent news about the project, groundwork is underway and the project is anticipated to come online in 2020, and "most of the [vanadium batteries] that will fill the site is already built in the manufacturer's nearby facility."[75]

Flow battery technologies may have a few advantages over lithium-ion applications for transmission deferral applications addressing reliability scenarios similar to the Eastside transmission capacity deficiency. They are capable of providing a long-duration, high-power solution and a 20-year ~15,000 cycle life and, unlike lithium-ion solutions, the operational efficiency of flow batteries generally does not degrade over time. However, flow battery solutions generally have a lower round-trip efficiency than lithium-ion solutions, with UET's product fact sheet estimating AC-AC round-trip efficiency of approximately 70%.[76]

Several major deployments further reinforce battery storage becoming a viable alternative grid solution in appropriate circumstances, either where energy storage has been specifically sought due to its technical benefits or where energy storage has been economically competitive in its own right through procurements for grid services. These include:

> **PJM Frequency Response Market -** Between 2011 and 2015, hundreds of megawatts' worth of energy storage have been interconnected to provide frequency response services in PJM's territory. This strong market signal, which has since reduced due to changes in the market, encouraged development extremely effectively, causing an explosion of growth.[77]
>
> **National Grid (UK) Enhanced Frequency Response Solicitation 2016 -** National Grid sought enhanced frequency response services to assist in stabilizing the power system as the level of synchronous (fossil) generation in the supply mix decreased. The solicitation sought 200MW of service, with a maximum of 50MW from any one system to respond to a frequency disturbance within one second. All winning submissions were energy storage.[78]
>
> **Aliso Canyon Energy Storage Deployment -** In an emergency response to a gas leak at the Aliso Canyon power station storage facility, which resulted in insufficient capacity to meet the 2017 summer load, 94.5MW/342MWh of energy storage from a variety of vendors and with a variety of configurations was procured, installed and commissioned in less than a year.
>
> **Hornsdale Power Reserve -** In South Australia, a 100MW/129MWh Tesla energy storage system was installed at the end of 2017 in response to a series of high-profile power outages. This system, coupled to an existing wind farm, will provide capacity, peak shifting, and frequency stability services to the National Energy Market of Australia. The Hornsdale

[74] Source: (https://www.lazard.com/perspective/levelized-cost-of-storage-2017/)
[75] Source: (https://electrek.co/2017/12/21/worlds-largest-battery-200mw-800mwh-vanadium-flow-battery-rongke-power/)
[76] Source: (http://www.uetechnologies.com/images/product/UET_UniSystem_Product_Sheet_reduced.pdf)
[77] Source: (https://www.greentechmedia.com/articles/read/new-market-rules-destroyed-the-economics-of-storage-in-pjm-what-happened#gs.=X5cRS4)
[78] Source: (https://www.nationalgrid.com/uk/electricity/balancing-services/frequency-response-services/enhanced-frequency-response-efr)

Power Reserve energy storage system has since outperformed conventional generation in providing frequency response services.[79]

In addition to these large in-front-of-the-meter energy storage deployments, there are planning mechanisms in place to routinely consider NWAs, such as energy storage, within the distribution planning process. These assist the distribution network by resolving constraints to avoid or defer conventional infrastructure upgrades. Such frameworks highlight that energy storage is now an important consideration in the distribution planning process and implementable as a solution to enhance the grid. Two of these frameworks include:

**New York Joint Utilities Non-Wire Alternative Solicitations -** The joint utilities of New York were directed by the Reforming the Energy Vision initiative to pursue NWAs to grid constraints in lieu of building conventional infrastructure. This will both allow the optimal solution to be selected, conventional or NWA, with the likely result being that energy storage may play a larger and larger role in the distribution systems of New York in conjunction with other technologies.

The Brooklyn-Queens Demand Management ("BQDM") program was one project that arose from this process. Since this initial project, NWA opportunities are now regularly identified by joint utilities and request for proposals ("RFPs") listed on their websites.[80] And while every NWA need is unique,[81] we note that some projects such as the West 42nd Street Substation deferral are designed to meet transformer overloads in the tens of megawatts.

**California Energy Storage Solicitations -** As part of the energy storage targets set by the State of California, the CPUC explicitly enabled energy storage to meet the target as being a combination of BTM, third-party owned, and utility-owned. The investor-owned utilities have designed energy storage RFPs and local capacity resources RFPs to routinely procure energy storage to add capacity and defer the need for distribution upgrades.

Energy storage has become a credible tool used in grid planning, and there have also been various technical advances including energy density, manufacturing, configuration, operating life and operation. These all present the case that energy storage has matured since the March 2015 Study, although the deployments have still been significantly smaller than would be needed for the Eastside need. Some of these aspects will be further discussed.

## Energy Density/Physical Sizing

Energy density is the amount of energy that a battery can store per given weight or volume. Historically, the energy density of lithium-ion cells has doubled approximately every 10 years, as seen in Figure 30. This represents an increase in density of approximately 8% per year.

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[79] Source: (https://electrek.co/2017/12/19/tesla-battery-save-australia-grid-from-coal-plant-crash/)
[80] Source: (https://www.coned.com/en/business-partners/business-opportunities/non-wires-solutions)
[81] For example, distribution deferral needs might be more easily offset by distributed energy resources, such as storage, because the distribution substation acts as a radial "bottleneck" through which all power must flow, one way or the other, whereas transmission infrastructure may require a higher ratio of generation or storage to offset the need, because power flows are not similarly constrained to flow through a particular point.

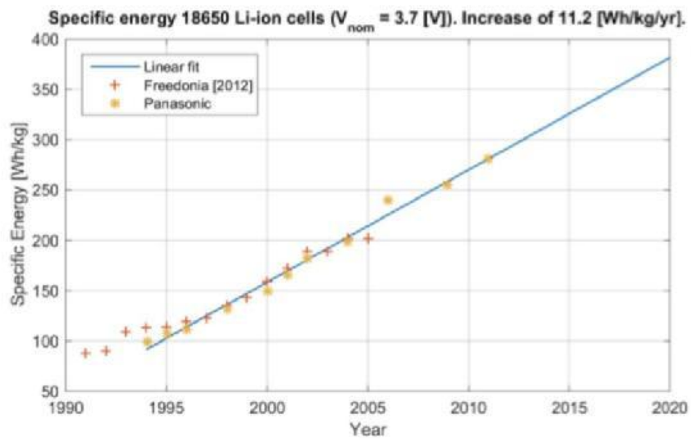


*Figure 30: Historic and projected energy density improvement*[82]

However, the cells, packing of modules, configuration and auxiliary equipment all contribute to the overall space requirements of an energy storage system, and advances in all areas will ultimately determine the space consumed by a potential energy storage solution. The March 2015 Study provided information on the size of an energy storage solution for the Eastside system. Recent deployments provide additional context for the likely footprint of a modern solution in the Eastside area. The Hornsdale Power Reserve, a 100MW/129MWh energy storage system installed at the end of 2017 in Australia, comprises approximately five acres and can be seen in Figure 31.


*Figure 31: Hornsdale Power Reserve (100MW/129MWh) is approximately 2 hectares in size*[83]

The Alamitos Energy Center, being constructed by AES in Long Beach, was initially proposed as a 300MW/1200MWh system[84] while it now appears the sizing may have been reduced.[85] The proposal for 300MW called for three 100MW containment buildings. Each building would be 50 feet in height, 270 feet in length, and 165 feet in width and would be composed of three levels: two battery storage levels separated by a mezzanine level. The mezzanine level would contain mechanical equipment such as electrical controls and heating, ventilation, and air conditioning (HVAC) units. Buildings would be set back at least 50 feet from each other and more than 50 feet

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[82] Source: Prof. Maarten Steinbuch, Director Graduate Program Automotive Systems, Eindhoven University of Technology
[83] Source: (https://hornsdalepowerreserve.com.au/overview/)
[84] Source: (http://www.renewaesalamitos.com/Alamitos-Fact-Sheet.pdf)
[85] Source: (https://www.businesswire.com/news/home/20170724006035/en/AES-Breaks-Ground-Alamitos-Energy-Center)

from off-site properties.[86] Figure 32 shows the footprint of the original 300MW/1200MWh proposed system in the Long Beach area.

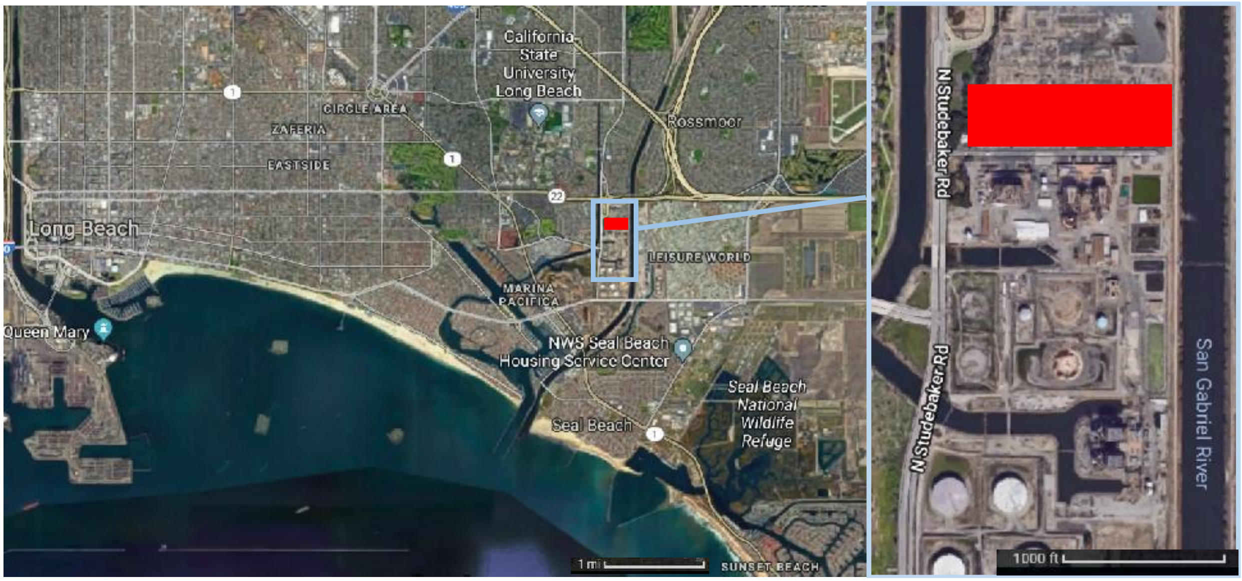


*Figure 32: Aerial view of long beach area with Alamitos Energy Center, 300MW/1200MWh shown in red.*

As noted above, Rongke Power is developing a 200MW/800MWh flow battery in the Dalian province of China that will be supplied by UET. UET states the following footprint for its flow battery solution on its website:

- Up to 92MWh/acre[87] behind-the-fence deployed footprint
- Up to 184MW/acre[88] behind-the-fence deployed footprint (double-stacked configuration)

Based on these three case studies, Table 13 presents a summary of energy storage system footprint. This will be used to provide an updated perspective for the Eastside system in Section 2.1.2.

*Table 13: Summary of space requirements for large-scale energy storage systems constructed and proposed*

| Per MWh | | Hornsdale Power Reserve | Dalian VFB Rongke Power | Average Single Level | Single Level Halved | Dalian VFB Rongke Power | Average Double Level | Extrapolated Size | Eastside Interim Solution 365 MW 2,394 MWh | | Eastside Complete Solution 549 MW 5,500 MWh | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Single Level | | | Double Level | | | | Single | Double | Single | Double |
| | Acres | 0.04 | 0.01 | 0.025 | 0.013 | >0.01 | 0.01 | | 58.87 | 21.22 | 135.25 | 48.76 |
| | Sq. ft | 1,669 | 473 | 1071 | 536 | 237 | 386 | | 2,564,333 | 924,461 | 5,891,325 | 2,123,866 |
| | **Size compared to CenturyLink Stadium (1,500,000 Sq. Ft.)** | | | | | | | | 171% | 62% | 393% | 142% |

## System Life

The March 2015 Study modeled a 20-year system life with 2% per year cell degradation[89]. In other words, after 10 years, the system's energy discharge capacity would be 20% lower than at commercial operation date (although the power rating or maximum instantaneous discharge would

[86] Source: (http://www.lbds.info/civica/filebank/blobdload.asp?BlobID=6142)
[87] Assuming a four-hour system based on the 23MW/acre stated on website (http://www.uetechnologies.com/products/unisystem)
[88] Assuming a four-hour system based on the 46MW/acre stated on website (http://www.uetechnologies.com/products/unisystem)
[89] For comparison, the expected system life for the Energize Eastside poles & wires solution is approximately 40+ years.

remain the same). The life of an energy storage system depends on many factors including materials used, operating profile (e.g., depth of discharge and discharge rates), operating environment as well as calendar life.

While it is difficult to predict the life of any proposed solution for the Eastside system, recent deployments can inform what could be expected. The largest energy storage system in the world currently, the Hornsdale Power Reserve in South Australia, has a 15-year warranty.[90] Flow batteries, such as the ones proposed for the Rongke Power Energy Storage System, claim to have an operational life of approximately 15,000 cycles and a cycle and a design life of up to 20 years.[91]

The actual life of a system will vary based on operation. However, the option for 15-year warranties with some products and the potential for longer life for flow batteries mean that an investment in energy storage can be expected to provide a solution for beyond the 10 years expected for many earlier storage systems. This helps validate the assumption of no explicit cost for cell replacement during a 20-year system life.

[90] Source: (https://hornsdalepowerreserve.com.au/faqs/)
[91] Source: (http://www.uetechnologies.com/images/product/UET_UniSystem_Product_Sheet_reduced.pdf)

## Commercial Developments

Since the publication of the March 2015 Study, there has been an increasing awareness of and development of programs utilizing battery storage as a multipurpose grid asset, including applications involving distribution and transmission reliability. Utilities in the western US and elsewhere around the world are frequently considering energy storage as part of a basket of resources being evaluated in their integrated resource planning processes, and all-source solicitations are more frequently being launched where storage is being considered amongst a basket of diverse resources for system capacity.

The most common uses of battery storage to date include providing grid ancillary services such as frequency regulation, energy arbitrage (time shift), renewables integration, providing system (generation) supply capacity and capacity firming, and customer electric bill management.

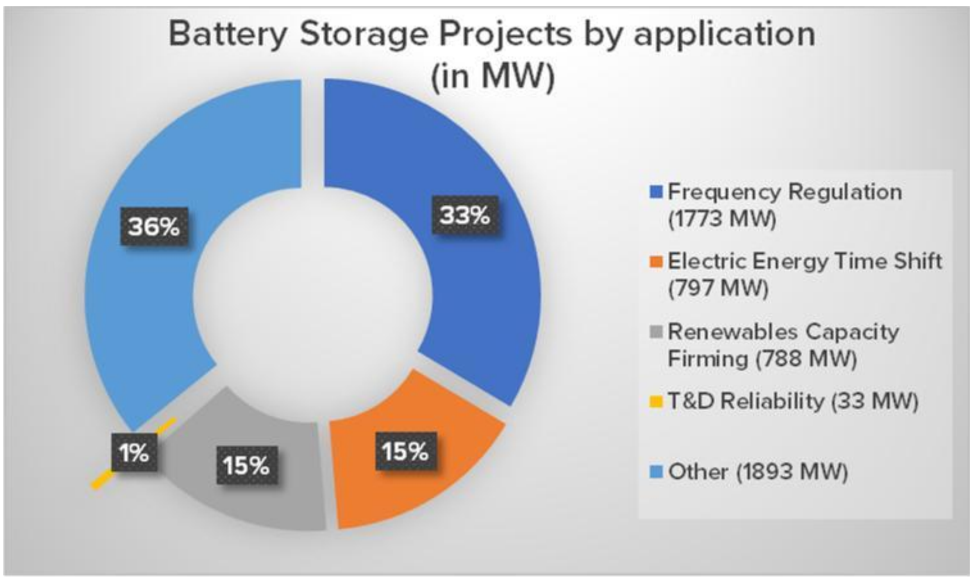


*Figure 34: Battery Energy Storage Primary Applications*

*Source: US DOE Global Energy Storage Database. Accessed 17th of August 2018*

Transmission or distribution reliability applications constituted a small portion of the overall total, with 32.8MW (0.62%) of all operational, under construction, proposed, offline, or decommissioned battery energy storage projects in the Global Energy Storage Database classifying T&D deferral as their primary application, with 2.0MW (0.06%) as transmission congestion relief, and 110kW (0.1 MW – 0.003%) as transmission support. It should be noted, however, that primary applications are self-reported in the DOE Global Energy Storage Database, and the above may not account for potential secondary applications. For example, while Tesla's Hornsdale Power Reserve plant is primarily a merchant plant earning revenues in Australia's wholesale market, it arguably is serving a reliability function in South Australia's grid. However, it is a fungible market asset rather than a transmission asset with location-dependent transmission delivery requirements.

*Table 14: Largest Battery Energy Storage Systems, Operational and Under Construction, by Power Rating*

| Project Name | Technology Type | Rated Power (MW) | Rated Energy (MWh) | Duration (hours) | Status | Primary Application |
|---|---|---|---|---|---|---|
| **Dalian VFB - UET / Rongke Power** | Vanadium Redox Flow Battery | 200 | 800 | 4.0 | Under Construction | Black Start |
| **Alamitos Energy Center - AES** | Lithium-ion Battery | 100 | 400 | 4.0 | Under Construction | Capacity and stability (combined with NG generation) |
| **Hornsdale Power Reserve 100MW / 129MWh Tesla Battery** | Lithium-ion Battery | 100 | 129 | 1.29 | Operational | Frequency Regulation |
| **Kyushu Electric - Buzen Substation - Mitsubishi Electric / NGK Insulators** | Sodium-sulfur Battery | 50 | 300 | 6.0 | Operational | Frequency Regulation |
| **Nishi-Sendai Substation - Tohoku Electric / Toshiba** | Lithium-ion Battery | 40 | 20 | 0.50 | Operational | Frequency Regulation |
| **Minami-Soma Substation - Tohoku Electric / Toshiba** | Lithium-ion Battery | 40 | 40 | 1.0 | Operational | Renewables Capacity Firming |
| **Notrees Battery Storage Project - Duke Energy** | Lithium-ion Battery | 36 | 24 | 0.67 | Operational | Electric Energy Time Shift |
| **Rokkasho Village Wind Farm - Futamata Wind Development** | Sodium-sulfur Battery | 34 | 238 | 7.0 | Operational | Electric Supply Reserve Capacity - Spinning |
| **AES Laurel Mountain** | Lithium-ion Battery | 32 | 8 | 0.25 | Operational | Frequency Regulation |
| **Invenergy Grand Ridge Wind Project BESS** | Lithium-Ion Titanate Battery | 31.5 | 12 | 0.38 | Operational | Frequency Regulation |
| **Beech Ridge Wind Storage 31.5 MW** | Lithium Iron Phosphate Battery | 31.5 | n/a | n/a | Operational | Frequency Regulation |
| **Imperial Irrigation District BESS - GE** | Lithium-ion Battery | 30 | 20 | 0.67 | Operational | Black Start |
| **Escondido Energy Storage** | Lithium-ion Battery | 30 | 120 | 4.0 | Operational | Electric Energy Time Shift |
| **West-Ansung (Seo-Anseong) Substation ESS Pilot Project - 28 MW ESS - KEPCO / Kokam / LG Chem** | Lithium-ion Battery | 28 | 90 | 3.20 | Operational | Frequency Regulation |

*Source: Strategen; US DOE Global Energy Storage Database, www.energystorageexchange.org, 17th of August 2018.*

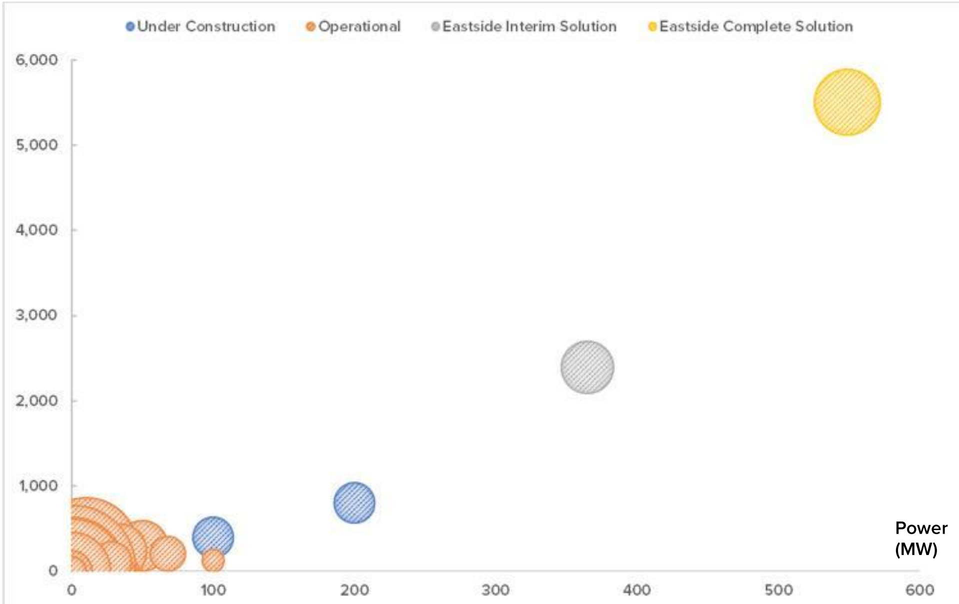


*Figure 35: Visual representation of Eastside solutions versus storage projects that are operational or under construction. Size of bubble represents duration in hours. Source: US DOE Global Energy Storage Database, www.energystorageexchange.org, 5th of January 2018.*

Recently, there have been some announcements of battery storage procurement for T&D reliability applications. For example, in its 2016 Energy Storage RFO, Pacific Gas & Electric Company ("PG&E") announced it was soliciting bids for a new 10MW/40MWh dual-use energy storage system ("ESS") that would enable PG&E to defer otherwise necessary investments at the Llagas Substation, to provide Resource Adequacy capacity credit and to participate in the CAISO Non-Generator Resource market.[92] This system will be entering operation in 2022 and is intended to serve a deferral need through 2031.

Consolidated Edison ("ConEd") in New York is another utility evaluating battery storage and other DER as non-wires solutions to traditional wires-based solutions. ConEd's activities began in earnest with the BQDM program, which was designed to reduce peak load in the affected area by 69MW, of which 52MW ended up being reduced by NWA investments on the customer- and utility-side of the meter and the remaining 17MW reduced through traditional wires-based solutions. ConEd has extended the BQDM to provide additional load reduction beyond the original scope of the pilot and has a number of other active solicitations for non-wires solutions. For example, the 42nd Street Load Transfer Project[93] seeks to achieve a peak load reduction of 42MW from 9 am to 7 pm from 2021 through 2026, implying a substantially higher need in terms of MWh, met through a basket of solutions (distributed generation, storage, advanced controls for demand response, etc.).

[92] Source: (https://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/Energy_Storage_2016/Information_Distribution_ Deferral_ESS_Final.pdf)
[93] Source: (https://www.coned.com/-/media/files/coned/documents/business-partners/business-opportunities/non-wires/west-42-street-non-wires-solutions-soliciation.pdf?la=en)

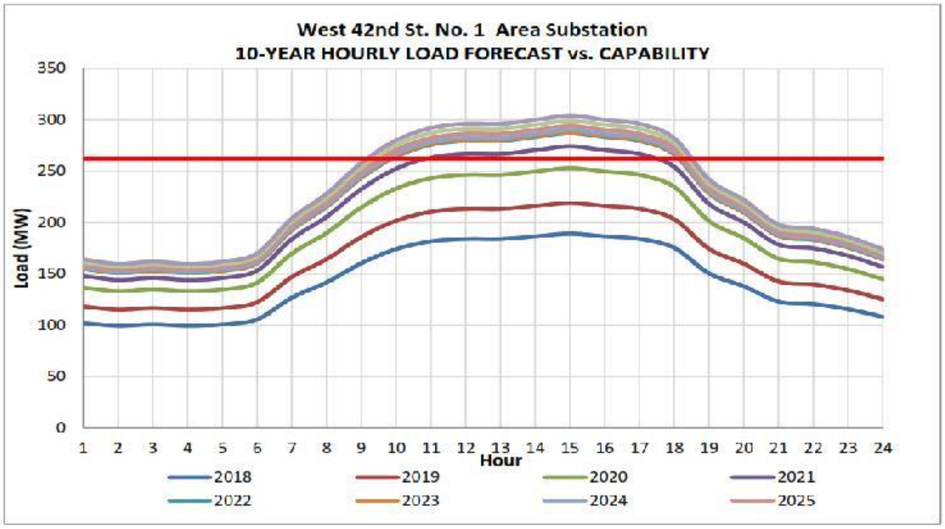


*Figure 36: ConEd''s 42nd Street Transfer Project Overload Profiles (Source: ConEd)*

Currently, operational projects providing demand reduction for transmission/distribution reliability are generally much smaller than those in the planning or solicitation stages, such as the ones mentioned above. The Village of Minster project, as shown in Table 15, is a large solar plus storage project that includes 4.2MW of solar PV, along with a 7MW/3MWh energy storage system that is expected to save the local municipal utility $350,000 in deferred T&D costs over the life of the project.

*Table 15: Largest Battery Energy Storage Systems Used for Transmission/Distribution Reliability, Operational and Under Construction, by Power Rating*

| Project Name | Technology Type | Rated Power (MW) | Energy (MWh) | Duration (hours) | Status |
|---|---|---|---|---|---|
| Village of Minster - S&C Electric Company | Lithium-ion Battery | 7.0 | 3 | 0.42 | Operational |
| Smarter Network Storage | Lithium-ion Battery | 6.0 | 10 | 1.67 | Operational |
| Northern Powergrid CLNR EES1 | Lithium-ion Battery | 2.5 | 5 | 2.0 | Operational |
| SCE Distributed Energy Storage Integration (DESI) Pilot 1 | Lithium-ion Battery | 2.4 | 3.9 | 1.62 | Operational |
| Santa Rita Jail Smart Grid - Alameda County RDSI CERTS Microgrid Demonstration | Lithium Iron Phosphate Battery | 2.0 | 4 | 2.0 | Operational |
| Enel Puglia ESS | Lithium-ion Battery | 2.0 | 1 | 0.50 | Operational |
| Enel Dirillo Substation BESS Project | Lithium-ion Battery | 2.0 | 1 | 0.50 | Operational |
| Enel Chiaravalle Substation | Lithium-ion Battery | 2.0 | 2 | 1.0 | Operational |
| Powercor 2 MW Grid Scale Energy Storage - Kokam | Lithium-ion Battery | 2.0 | 1 | 1.0 | Operational |

*Source: Strategen; US DOE Global Energy Storage Database, www.energystorageexchange.org, 17th of August 2018.*

## Virtual Power Plants

Since the original March 2015 Study, the installation of BTM energy storage systems that are coordinated and aggregated for grid benefits has become a new operating model. This is commonly referred to as a virtual power plant ("VPP") and has mostly been operated as a proof of concept trials, but in early 2018 a significant announcement in South Australia was made where a large number of BTM energy storage systems would be installed to reduce customer energy bills. South Australia is the most relevant market when considering VPP and the role they can play, and both AGL's[94] VPP trial and the recent announcement of the world's largest VPP, in partnership with Tesla, are discussed.

### *Australia – AGL's Virtual Power Plant Project*

The South Australian power system is experiencing several complex challenges as the state progresses towards its clean energy goals and has experienced high-profile blackouts. As large, synchronous generators retire, intermittent, non-synchronous renewable generation comprises a larger share of the energy supply mix. South Australia has the highest level of rooftop solar PV per capita in the world, greater than 25% of customers.[95]

This high proportion of rooftop solar PV in the state's distribution network made it an ideal location to test the potential of a VPP. This VPP helps to stabilize the grid while delivering extra value to customers, the networks, and the retailer. The VPP is a centrally managed network of BTM battery storage systems that can be controlled to deliver multiple benefits to the household, the retailer, and the local network. The VPP is composed of 1,000 homes with existing rooftop solar PV, and BTM energy storage was installed through a shared funding arrangement. These systems aggregate to provide 5MW/7MWh of stored energy. The batteries are charged and discharged using sophisticated algorithms to maximize the benefits to the consumer while ensuring that the network and retailer can also gain value during specific network or wholesale events. Figure 33 shows a diagram of the VPP setup. The VPP can realize multiple benefit streams that can reduce the costs of the system to the customer and provide coordinated and efficient use of the distributed energy resources ("DERs") to support the power system and reduce energy charges for all ratepayers.

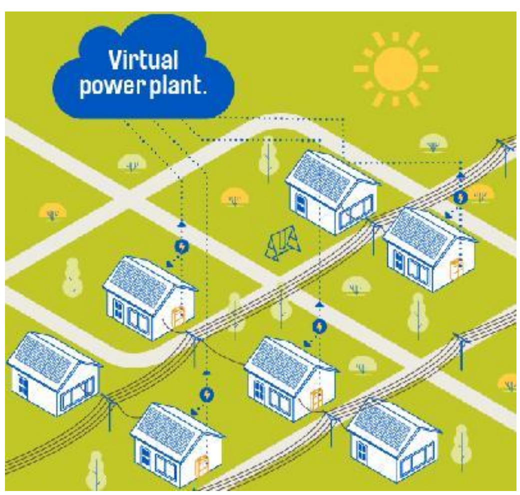


*Figure 33: Diagram of the VPP utilizing dispersed PV coupled energy storage to provide aggregated grid benefits[96]*

[94] AGL is an energy retailer in Australia
[95] Source: (https://www.energycouncil.com.au/media/1318/2016-06-23_aec-renewables-fact-sheet.pdf)
[96] Source: (https://aglsolar.com.au/blog/virtual-power-plant-bringing-solar-energy-everyone/)

Given the expected increase in BTM battery storage and the reducing opportunities to gain value from exporting excess solar, VPPs represent an important opportunity to provide benefits to individual customers as well as the grid as a whole. The VPP can potentially provide a cost-effective medium-term solution to smooth intermittent renewable energy. In aggregated form, VPPs can add frequency response to the network and allow location-specific DER to be operated to avoid peak demand capacity investment. It also offers opportunities for customers to maximize the value of their existing solar PV systems. To effectively implement, a VPP needs to innovate in the way that technology is deployed and operated through appropriate commercial arrangements and balance the utilization of the batteries between grid and customer benefits.[97]

### *World's Largest Virtual Power Plant Announcement 2018*

In early 2018, the State Government of South Australia unveiled a plan to roll out a network of at least 50,000 home solar and battery systems to form the world's largest VPP over the next four years. Beginning with a trial of 1,100 Housing Trust properties, a 5kW solar panel system and 13.5kWh Tesla Powerwall 2 battery will be in participating homes. For perspective, this trial that is being implemented over four years would meet approximately 28% of the Interim Solution and 13% of the Complete Solution for Eastside.

Following the pilot, which has now commenced, systems are set to be installed at a further 24,000 Housing Trust properties, and then a similar deal offered to all South Australian households, with a plan for at least 50,000 households to participate over the next four years.

## Cost Trends

In the March 2015 Study, Strategen reviewed publicly available data on utility energy storage projects, as well as research reports identifying cost trends over time. These sources were evaluated to come up with a cost estimate for a generic multi-hour lithium-ion solution.

The key cost components for utility-scale energy storage projects include battery cells, balance of system, power electronics, building facilities, and interconnection, permitting, land and other indirect/soft costs.

At the time, cell pricing was approximately \$600/kWh, and price forecasts suggested costs in the \$200-\$354/kWh range in the 2015-2020 timeframe. Balance-of-system costs at the time were estimated to be in the \$400-\$500/kWh range (although Strategen found that estimating this on a per kW basis to be a more accurate methodology). Strategen also evaluated the 100MW/400 MWh system developed by AES and recently procured by Southern California Edison ("SCE") and deemed it to be a reasonable cost comp, despite having a 2021 online date.

Strategen estimated the total cost and revenue requirements of storage alternatives, using cell costs of approximately \$250/kWh and balance-of-system costs of approximately \$500/kW, with land, permitting, and interconnection costs estimated by PSE. This resulted in a 20-year levelized cost of \$218.60/kW-yr, of which approximately 57% was attributable to the cells, power electronics, and building structures, while 43% was attributable to the interconnection facilities, land, permitting, and contingency.

Recent case studies suggest Strategen's original assumptions remain accurate estimates of current pricing. Lazard's Levelized Cost of Storage v3.0 provided an Illustrative Value Snapshot of a 100MW/400MWh CAISO Peaker Replacement case study, assumed to be built in 2017, based on

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[97] Source: (https://arena.gov.au/projects/virtual-power-plant/)

cost estimates developed with data from DOE, Enovation Partners, and Lazard's internal estimates, using storage module costs of $97.6 million ($244/kWh), and inverter/AC system, balance of system, and EPC costs of $72.9 million ($729/kW or $182/kWh, depending on the metric used),[98] while assumptions for interconnection facilities, land, and permitting were not explicitly detailed. Translated into a levelized cost, Lazard indicates that the range for such unsubsidized "peaker replacement" storage systems built in 2017 ranged from $395-$486/kW-yr, and Lazard estimates a median cost of $375/kW-yr[99] for projects built in 2018, assuming a 10-year useful life. Strategen's assumption of a 20-year useful life is the driving factor in the lower levelized cost assumption used in our March 2015 Study.

Utility capacity procurement efforts provide data points suggesting continued cost declines are likely. However, costs below the estimates provided in Strategen's March 2015 Study are unlikely until well beyond the timeframe needed to meet the Eastside reliability need (at least with respect to the Interim Solution). For example, in Xcel Energy's summary of the Public Service Company of Colorado's ("PSCo") 2017 All-Source Solicitation 30-Day Report published on December 28, 2017, RFP responses by technology were summarized. PSCo received bids for 21 different standalone battery storage projects totaling 1,614MW to meet a capacity need that begins in 2023. The median bid price was $11.30/kW-mo ($135.60/kW-yr).[100] Furthermore, Lazard indicates that "lithium-ion capital costs are expected to decline as much as 36% over the next five years." We therefore estimate capital cost for the incremental capacity necessary to build the Complete Solution to be 36% lower than capital cost for the Interim Solution.

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[98] Lazard's Levelized Cost of Storage Analysis, Version 3.0, published November 2, 2017. https://www.lazard.com/perspective/levelized-cost-of-storage-2017/, p.35. We assume the balance-of-system cost also includes some estimate of cost for interconnection, land, etc., although these costs are not explicitly broken out in the analysis.
[99] Ibid., p.13.
[100] PSCo, 2017 All-Source Solicitation 30-Day Report, CPUC Proceeding No. 16A-0396E. https://www.documentcloud.org/documents/4340162-Xcel-Solicitation-Report.html, p.9.

## Impact on Technical Readiness, Commercial Feasibility, and Cost-Effectiveness

The March 2015 Study did not identify any overt barriers to technical readiness, commercial feasibility or cost-effectiveness of energy storage to meet a generic transmission reliability need. However, the scale of projects deployed as of the date of the March 2015 Study was many orders of magnitude smaller than the identified Eastside transmission capacity deficiency, which indicated a higher commercial risk may exist than for technologies with a track record of deployments in similar circumstances.

Globally, there are no currently operational deployments of energy storage on a scale comparable to that necessary to meet the Eastside transmission capacity deficiency. The operational project with the closest scale is Tesla's 100MW/129MWh Hornsdale Power Reserve project in South Australia,[101] and the Dalian VFB 200MW/800MWh Vanadium Redox project currently under construction in China for Rongke Power[102] is the closest proposed project. In addition, there is limited operational history at that scale, and the largest *operational* project (as identified by the DOE's Global Energy Storage Database) *specifically intended to meet a distribution or transmission reliability need* as its primary purpose is the 7MW/3MWh Village of Minster project.[103]

Given that the current cost of storage appears consistent with the cost forecast contained in the March 2015 Study, and because the March 2015 Study indicated that certain storage configurations would already be potentially cost-effective in PSE's system, further assessment of the cost-effectiveness of energy storage was not completed as part of this update. The March 2015 Study showed energy storage within PSE's system (albeit a smaller system than is needed to meet the Eastside reliability need) had a positive benefit-cost ratio. This is because it could leverage its capacity to provide a variety of system services. With the market progressing there is no reason to suggest that energy storage (broadly speaking) within PSE's system would now no longer have a positive benefit-cost ratio.

[101] Source: (https://energystorageexchange.org/projects/2271)
[102] Source: (https://energystorageexchange.org/projects/2169)
[103] Source: (https://energystorageexchange.org/projects/1976)

STRATEGEN CONSULTING

# Assessment of Proposed Energize Eastside Project

Technical review with respect to Section 18.44.052 of the City of Newcastle Municipal Code

Prepared for the City of Newcastle

June 2020 Update[1]

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[1] This core update contains data furnished by PSE in May 2020.

# CONTENTS

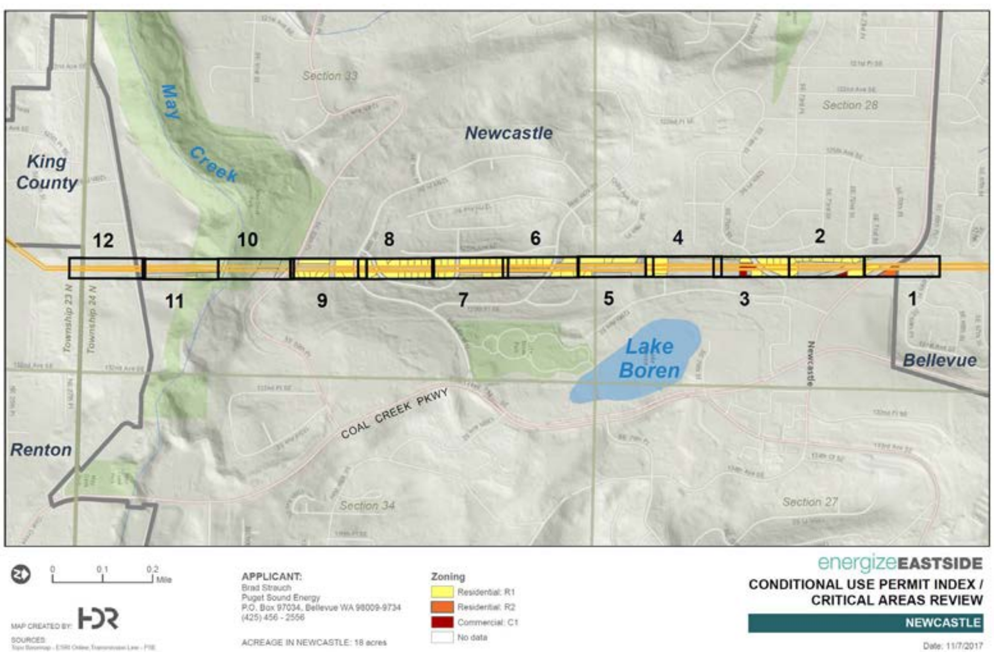
# 1. EXECUTIVE SUMMARY

Background

Puget Sound Energy (PSE) is projecting rapid load growth in the Eastside area near Lake Washington in Washington State. As a result, the utility identified the need to upgrade its substation and transmission infrastructure as early as 2008. To meet this need PSE proposed the Energize Eastside project in 2013, which entails building a new substation and upgrading transmission lines. PSE also investigated alternatives to building the substation, including energy conservation, batteries, and solar panels. However, the company concluded that such alternatives would not sufficiently address reliability concerns caused by the expected load growth.

As part of the Energize Eastside project, PSE applied to the City of Newcastle for a Conditional Use Permit (#CUP17-002) for a Regional Utility Facility. PSE asked to upgrade its electric transmission facilities for approximately 1.5 miles in the existing utility corridor, Willow 1, that spans approximately 1.5 miles in Newcastle; see Figure 1 below.

**Figure 1. PSE proposed Energize Eastside electric transmission route, Newcastle**




*Source: PSE Site Plans, Energize Eastside Project, November 2017.*

The upgrades in Newcastle are part of a large transmission project plan[2] that extends from the Sammamish transmission substation in Redmond to the Talbot Hill transmission substation in Renton (Figure 2). This plan was proposed to address several identified contingency[3] deficiencies in transmission capacity that PSE claims are triggered by summer and winter peak demand in King County. The proposed Energize Eastside project would build a new electric substation, the Richards Creek substation in Bellevue, and upgrade existing transmission lines in Redmond, Bellevue, Newcastle, and Renton.

In parallel with two other local communities affected by the project, the City of Newcastle is investigating PSE's Eastside filings to assess the need for the Energize Eastside project and to determine whether to provide the utility a city permit to allow PSE to upgrade its transmission infrastructure. MaxETA and Synapse Energy Economics were hired by the City of Newcastle to aid this investigation.

**Figure 2. PSE proposed Energize Eastside electric transmission facilities and route**


*Source: Energize Eastside Project Newsletter Summer 2017*

<u>Methodology</u>

As part of this need assessment, MaxETA and Synapse team assessed:

a) Whether PSE's load forecast methodology and assumptions, as well as forecast results, are reasonable and technically sound;

b) Whether there is a regional need for additional transmission capacity to maintain reliability;

c) Whether PSE has taken all necessary and cost-effective measures (including demand-side measures) to prevent an operational need from arising.

MaxETA and Synapse team reviewed various publicly available reports prepared by PSE as well as additional data obtained from PSE regarding historical and updated forecasted loads, conservation, and other demand-side resources.[4] The team also carried out a load flow model analysis to evaluate regional

[2] Energize Eastside, https://energizeeastside.com/.
[3] Contingency – an event where one or more electric facilities suffer an outage.
[4] See Section 4, Reviewed Material.

load conditions under contingencies, including whether the regional capacity thresholds estimated by PSE are reasonable.

Key Findings

- Our assessment of power flows finds that current or projected electric peak demand arising solely from the City of Newcastle does not trigger an operational need for the proposed transmission expansion.[5] However, our analysis shows that the current summer electric peak demand in King County has already triggered an operational need for the proposed transmission expansion to address system contingency scenarios and ensure the security of the Bulk Electric System.[6]
- Our power flow model assessment finds that the regional capacity thresholds in King County estimated by PSE are reasonable.
- The PSE load forecast approach follows a standard industry practice, although it has some limitations regarding the way it identifies and incorporates demand-side resources.
- Our review of historical summer peak loads and the capacity thresholds in King County provided by PSE shows that there is a summer transmission capacity deficiency in King County under N-1-1 contingencies even at today's peak load level. We further find that this capacity deficiency for the summer season has been 13 to 20 percent (or 200 to 300 megawatts, or MW) above the area's capacity threshold.
- Our review of historical winter peak loads and the capacity thresholds in King County shows PSE's winter peak load actually has been declining over the past several years. While we found that PSE's own winter load forecast is above the capacity threshold, we cannot conclude based on the data we analyzed whether there is a clear need for transmission capacity expansion for serving winter peak loads. PSE's past winter peak load forecasts have over-predicted winter peak loads and the current forecast does not appear to fully incorporate either the declining trend seen in winter peak over the last decade or potential emerging conservation opportunities.[7]
- PSE has adequately conducted transmission planning that seeks to prevent a facilities outage from becoming a customer interruption.

[5] This finding addresses a question posed by Newcastle. It is outside the scope of this evaluation to determine if the question posed by Newcastle is consistent with municipal code requirements.
[6] An unsecured Bulk Electric System could impact the reliability of electric service in Newcastle.
[7] By its very nature, load forecasting is a forward-looking planning tool.

Conclusions

PSE has demonstrated that the proposed transmission upgrades are needed to safeguard the operational reliability of the electric system as a whole.[8] To maintain system security, power systems are operated so that overloads do not occur either in real-time or under any statistically likely contingency. Not securing the bulk electric system to operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies could affect the electric supply reliability in Newcastle. This peer review verified that under specific contingencies (N-1-1 and N-2) the as-is bulk electric system serving Newcastle is already susceptible and operationally reliant in the implementation of Corrective Action Plans (CAPs).This means that PSE's application has met the threshold for approval described in Newcastle City Code C-5 under NMC 18.44.052 Utility facilities – Regional: "[t]he applicant shall demonstrate that an operational need exists that requires the location or expansion at the proposed site."

The current transmission deficiency can be cured by upgrading one of the 115kV transmission lines between the Talbot Hill and Sammamish substations to 230kV and installing an additional 230kV/115kV 325MVA transformer at the proposed Richards Creek substation in Bellevue. Upgrading the second 115kV transmission line that currently travels through the same corridor, Willow 1, to 230kV is consistent with good system planning, particularly because the facilities to support these higher voltages will already be deployed.

[8] Electric system as a whole is also referred to as Bulk Electric System.

Recommendations

We recommend that the Conditional Use Permit to PSE to upgrade the identified approximately 1.5 miles of existing 115kV lines with 230kV lines come with a condition: PSE should conduct an independent design assessment of the overhead transmission facilities traversing Newcastle to verify compliance with the clearance safety rules for the installation and maintenance of overhead electric supply of the 2017 National Electrical Safety Code (NESC), ANSI C2 Part 2. [9] We also recommend that the City of Newcastle send field inspectors during the transmission line upgrades to ensure compliance with the 2017 NESC.

[9] https://apps.leg.wa.gov/WAC/default.aspx?cite=296-45-045

# 2. INTRODUCTION AND NEWCASTLE MUNICIPAL CODE REVIEW

Puget Sound Energy's (PSE) past and current load forecasts show continued growing electric load in the Eastside area near Lake Washington in Washington State. The utility examined the expected growing demand in detail and identified the need to upgrade its substation and transmission facilities as early as 2008. In 2013, the PSE proposed the Energize Eastside project to address this load growth issue, including a proposal to build a new substation and upgrade transmission lines. PSE also investigated alternatives to building new substation and transmission facilities, specifically energy conservation, demand response, batteries, and solar panels. However, PSE's studies concluded that such alternatives would not sufficiently address reliability concerns caused by the expected load growth.

In parallel with two other local communities affected by the project, the City of Newcastle is investigating PSE's Eastside filings to assess the need for the Energize Eastside project and to determine whether to provide the utility a city permit to allow PSE to upgrade its transmission infrastructure. MaxETA and Synapse Energy Economics were hired by the City of Newcastle to aid this investigation.

The City of Newcastle requires that "[p]roposals that include new or expansions to existing utility facility – regional shall demonstrate compliance with" several criteria under NMC 18.44.052 ("Utility facilities – Regional") in addition to the conditional use permit criteria listed in NMC 18.44.050. For the purposes of NMC 18.44.052, expansions include "a modification of an existing regional utility facility by an increase in the size, height, impervious coverage, floor area, or parking area of the facility by greater than 10 percent."

Among others, our review specifically investigates whether PSE as an applicant to the City of Newcastle has complied with the following criteria under NMC 18.44.052:

> C-5. The applicant shall demonstrate that an operational need exists that requires the location or expansion at the proposed site;
>
> C-6. The applicant shall demonstrate that the proposed utility facility – regional improves reliability to the customers served and reliability of the system as a whole, as certified by the applicant's licensed engineer;

To find answers to these code requirements, this independent consultant report assesses:

a) Whether PSE's load forecast methodology and assumptions, as well as forecast results, are reasonable;

b) Whether there is a regional need for additional transmission capacity to maintain reliability; and

c) Whether PSE has taken all necessary and cost-effective measures (including demand-side measures) to prevent an operational need from arising.

# 3. Overview of Eastside Needs Assessment and Eastside Project

## 3.1. History of Eastside Needs Assessments

Since 2008, PSE has conducted numerous studies on the reliability of its transmission facilities to meet future peak load conditions and needs for transmission facility expansion. These studies identified a variety of concerns, and the studies conducted in recent years identified and examined solutions to the concerns in detail.

Earlier studies include the 2008 Initial King County Transformation Study, 2009 PSE TPL Planning Studies and Assessment, and the 2012 PSE TPL Planning Studies and Assessment.[10] These studies found that "potential thermal violations may occur on facilities from Talbot Hill Substation to Sammamish Substation," as noted in a 2013 study commissioned by PSE called the "2013 Eastside Needs Assessment."[11]

More recent studies focused on transmission facilities in the Eastside area and examined both the transmission needs as well as solutions. The studies that focused on the need for the transmission facilities are:

- 2013 Eastside Needs Assessment Report ("2013 Needs Assessment") prepared by Quanta Technology
- 2015 Supplemental Eastside Needs Assessment Report ("2015 Supplemental Needs Assessment" or "2015 Needs Assessment") prepared by Quanta Technology

Notably the 2013 Eastside Needs Assessment found that there would be a transmission deficiency in the winter of 2017–2018 and in the summer of 2018. More specifically, these key findings are as follows:

- "For the Winter peak at approximately 5,200 MW (2017–18 in the model) there are two 115 kV elements with loadings above 98% for Category B (N-1) contingencies and five 115 kV elements above 100% for Category C (N-1-1 & N-2) contingencies."
- "For the Summer peak at approximately 3,500 MW (2018 in the model), there are two 230 kV elements above 100% and two 115 kV elements above 93% loadings for Category B (N-1) Contingencies. There are also three elements above 100% loading and one above 99% loading for Category C (N-1-1) contingencies."[12]

[10] Descriptions of these studies are provided on page 23 of the 2013 Eastside Needs Assessment.
[11] Quanta Technology 2013. Eastside Needs Assessment Report – Transmission System King County.
[12] Quanta Technology 2013. Page 8.

The 2013 Needs Assessment also found that a summer load level of need (3,340 MW) could occur as early as 2014. However, the study emphasizes that the PSE summer load level where King County starts to have significant issues is at about the 3,500 MW level projected for 2018.[13]

The 2013 Eastside Needs Assessment report also indicated the need to expand the use of Corrective Action Plans ("CAPs") to manage these overloads. CAPs are implemented according to the regional entity's procedures to remedy a specific system problem using a list of actions and an associated timetable for implementation. These actions include:[14]

- Installation, modification, retirement, or removal of transmission and generation facilities and any associated equipment
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violation
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan
- Use of rate applications, Demand Side Management (DSM), new technologies, or other initiatives
- If situations arise that are beyond the Transmission Planner or Planning coordinator that prevent CAP implementation in the required timeframe:
    - Non-Consequential Load Loss
    - Curtailment of Firm Transmission Service

PSE does not advocate for the use of CAPs as a solution to an identified need.[15] As a temporary operational alternative, NERC Standard TPL-001-4 allows curtailment and loss of load for specific contingencies to meet performance requirements. However, it is best practice to avoid the use of these operating procedures.

The 2013 Needs Assessment also indicated the overloads could be more severe if peak loads were higher as a result of other factors, such as extreme cold weather conditions, higher load growth due to local economic conditions, or lower conservation achievements relative to PSE's conservation targets.

The 2015 Supplemental Needs Assessment verified that there was still an expected transmission capacity deficiency in the Eastside area in the winter of 2017–2018 and in the summer of 2018. This

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[13] Quanta Technology. 2013. 2013 Eastside Needs Assessment, page 8, 9, 13 and 70; Quanta technology. 2015. 2015 Supplemental Eastside Needs Assessment Report, page 18.

[14] NERC Standard TPL-001-4 R2.7

[15] 2015 Supplemental Eastside Solutions Study Report.

study further identified that the summer capacity deficit is worse than what was identified in the 2013 Needs Assessment. The 2015 study found expected needs to use CAPs and load shedding to mitigate the system deficiency while the 2013 study found CAPs would be required, but not load shedding.[16]

To address these potential transmission deficiency problems, PSE carried out numerous studies to examine potential solutions including traditional supply-side solutions and non-wires solutions such as energy efficiency, demand response, and batteries: [17]

- 2013 Eastside Solutions Study Report (Updated February 2014), prepared by Quanta Technology
- 2014 PSE Screening Study, prepared by E3
- 2014 Eastside 230 kV Project Underground Feasibility Study, prepared by Power Engineers
- 2015 Supplemental Eastside Solutions Study Report, prepared by Quanta Technology
- 2015 Eastside System Energy Storage Alternatives Study, prepared by Strategen
- 2015 Lake Washington Submarine Cable Alternative Feasibility Study, prepared by Power Engineers
- 2018 Eastside System Energy Storage Alternatives Assessment Update, prepared by Strategen

## 3.2. PSE's Latest Eastside Contingency Load Threshold Analysis

The 2013 Eastside Needs Assessment Report includes a heat map that PSE claimed is a depiction of electric load density. However, we note that this map shows the most densely populated areas in and around the Eastside (see Figure 3) which do not necessarily coincide with electric demand. We conducted power flow models in the Northwest area serving the South King county zone using historical and projected peak demand for King County.[18] We ran the models employing the base cases provided by the Western Electricity Coordinating Council (WECC) and varying key sensitivities while maintaining the projected peak demand constant to evaluate regional grid conditions under various contingency events.

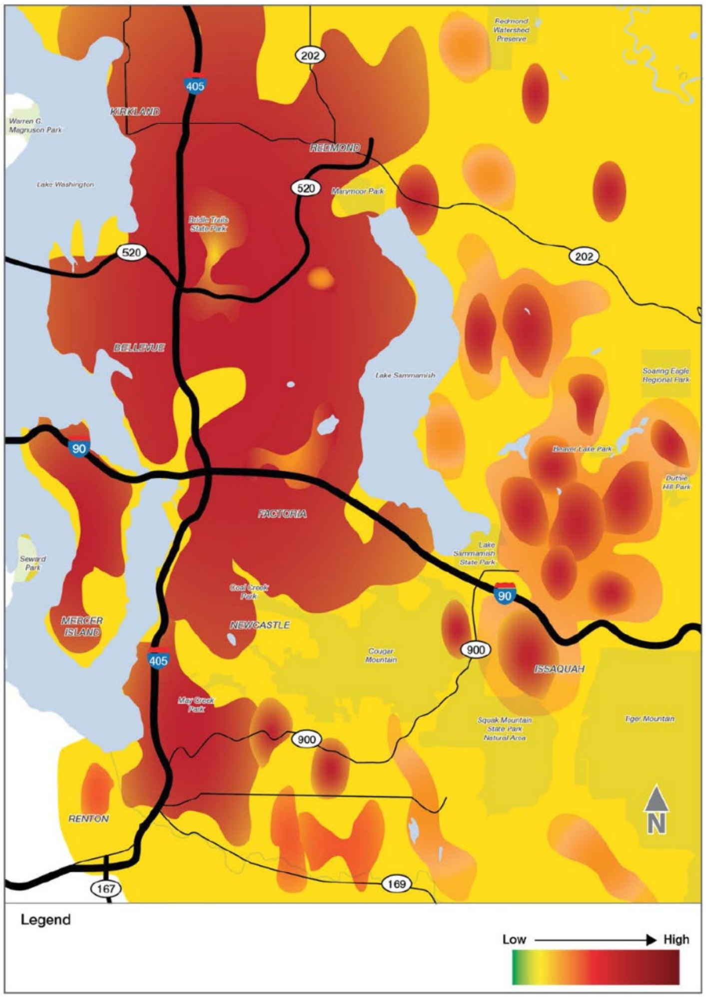
For Summer 2018, our load flow analysis verified that under N-1-1 contingencies the 230/115kV transformers at the Sammamish substation will overload when modeled using reasonable transformer series resistances and reactances and MVA operational limits. However, we also found that realistic increases in peak demand arising solely from the City of Newcastle, primarily served by the Hazelwood substation in the South King County zone, have negligible effect in the thermal transformer overloads identified for the Sammamish substation.

[16] Quanta Technology. 2015, page 4.

[17] These studies are available at https://energizeeastside.com/.

[18] An assessment of historical and projected peak demand is discussed in Section 5, for summer peak loads, see Figure 10 in Section 5.

**Figure 3. Modified heat map**




*Source: 2013 Eastside Needs Assessment Report depicts population density.*

We were able to verify that under several contingencies certain facilities of the bulk electric system serving Newcastle will overload. The operational need arises from having to comply with NERC reliability standards that safeguard the security of the bulk electric system and not due to the discrete electric peak demand in Newcastle. We want to highlight that Newcastle will experience electric supply reliability issues if the bulk electric system is not secured.

Page 18 of the 2015 Supplemental Needs Assessment references 3,340 MW of area summer load as a threshold above which PSE's transmission facilities will be overloaded under extreme system contingency events. Table 6-12 from the 2013 Eastside Needs Assessment further justifies the 3,340 MW as a level of concern by demonstrating equipment is overloaded to 100 percent of emergency rating during N-1-1 contingency at 3,340 MW of area summer load. In 2017, PSE switched to Electric Power Research Institute's PTLOAD program to calculate load limits for transformers because the existing in-house software was unmaintainable. The PTLOAD program is a widely accepted tool in the industry for rating transformers. With the new software, PSE adjusted its level of concern downward to

3,125 MW in the summer. The level of concern load level difference between 2013 and 2019 is mainly due to a change to a more widely accepted method of determining the individual transformer ratings. The latest estimate of the level of concerns by PSE is provided in Table 1 below for the PSE's entire service territory and for King County. Our load flow analysis confirmed that these load thresholds are reasonable.

**Table 1. PSE's revised load thresholds**

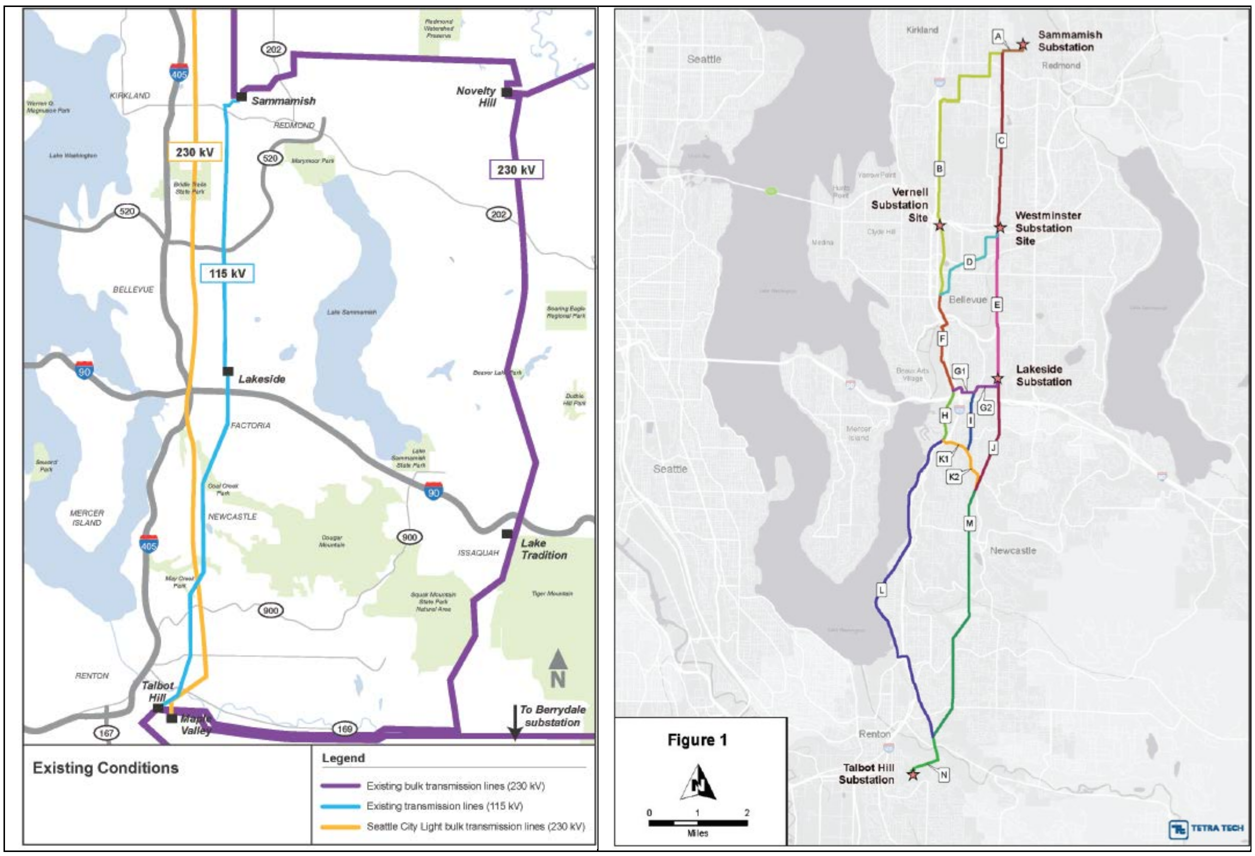
| | Summer (MW) | Winter (MW) |
|---|---|---|
| **PSE Area Load (Native + Transportation)** | 3125 | 5000 |
| **King County (Native + Transportation)** | 1594 | 2436 |

*Source: PSE Data Request Response – September 9, 2019; Note: These load levels were calculated by scaling 2018 TPL seasonal caseloads until the emergency rating exceeded 100 percent during N-1-1 contingency.*

## 3.3. Description of Proposed Eastside Project

PSE identified several contingency[19] deficiencies in its transmission capacity that are triggered by summer peak demand in King County. To address these deficiencies, PSE proposes a transmission expansion plan[20] that extends from the Sammamish transmission substation in Redmond to the Talbot Hill transmission substation in Renton (Figure 4). The proposed Energize Eastside project will also build a new electric substation, the Richards Creek substation in Bellevue, and upgrade existing transmission lines in Redmond, Bellevue, Newcastle, and Renton. PSE claims that these upgrades and new facilities are needed to ensure the bulk electric system continues to perform reliably under several contingencies.

**Figure 4. Energize Eastside project's proposed upgrade to the Sammamish-Talbot Hill 115kV transmission line (blue line left) to 230kV and new substation, the Richards Creek substation, in Bellevue**




*Source: Tetra Tech (December 2013) Eastside 230kV Project Constraint and Opportunity Study for Linear Site Selection.*

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[19] Contingency – an event where one or more electric facilities suffer an outage.

[20] Energize Eastside, https://energizeeastside.com/.

# 4. Load Forecasts and Need Assessment

## 4.1. PSE Load Forecast Methodology

The PSE load forecast approach follows a standard industry practice, although it has some limitations regarding the way it incorporates demand-side resources. PSE uses typical econometric models to forecast energy and peak loads over a 20-year time period. PSE's forecasting approach mainly consists of a regional economic and demographic model and a billed sales and customers model. The former uses both national- and county-level data to produce a forecast of various economic and demographic factors (*e.g.*, employment, types of employment, unemployment, personal income, population, households, building permit, etc.). The latter model takes the outputs from the former model and projects the number of customers by class as well as the energy use per customer by class. This model then multiplies the number of customers and energy use per customer to arrive at the billed sales forecast by class.

PSE uses another regression model to estimate electric peak loads based on observed monthly peak system demand and monthly weather normalized delivered demand.[21] It is not clear how much historical data are used in PSE's load forecast models, but one report produced by a consultant for Bellevue (Bellevue Consultant report) stated that key historical statistics are available for the entire system from 2000 and for King County and Eastside area from 2006.[22]

PSE's current forecasts are produced for each county. However, PSE also produced a forecast specific to the Eastside area in the 2013 and 2015 Eastside Needs Assessment studies. The Bellevue Consultant report noted that PSE started to produce county-by-county forecasts starting in 2015. The report also noted that for the 2013 and 2015 Eastside Needs Assessment studies, PSE produced the Eastside-specific forecast from the King County forecast using census tract data.[23] However, our data request to PSE revealed that PSE has not updated its forecast for the Eastside area since then, despite the fact that the Eastside was the most critical area of the Needs Assessment studies.[24]

PSE also makes some further adjustments to its load forecasts. Most notably, PSE reduces annual energy and peak load demands to account for the cost-effective amount of energy conservation (also called demand-side resources) identified in PSE's integrated resource plan (IRP) process.[25] The 2013 and 2015 Eastside Needs Assessment studies included several conservation scenarios, including one scenario called 100% Conservation (including 100 percent of the conservation potential estimated in the most recent IRP) and a 75% Conservation scenario. PSE has been including the impacts of electric vehicles in

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[21] PSE. 2017. 2017 PSE Integrated Resource Plan, Chapter 5.

[22] Utility System Efficiencies, Inc. 2015. Independent Technical Analysis of Energize Eastside, prepared for the City of Bellevue, Page 19.

[23] Utility System Efficiencies, Inc. 2015. Page 15.

[24] PSE response on June 14, 2019 to Newcastle Consultants' data request on May 15, 2019.

[25] PSE. 2017. 2017 PSE Integrated Resource Plan, Chapter 5, page 5-2.

its load forecast since its 2017 IRP.[26] PSE also includes the impacts of specific new construction projects in its near-term load forecasts, but correctly transitions those projects out of the forecast over several years to reflect the fact that new construction is included in the econometric projections of the base load forecast.

## 4.2. PSE Evaluation of Conservation and Other Demand-Side Resources

As mentioned above, PSE commissioned several studies to examine the potential of energy conservation and other demand-side resources as NWAs to the Energize Eastside project. These studies specifically examined whether there are sufficient demand-side resources available to reduce peak loads to the levels below critical thresholds under transmission contingency events (*e.g.*, N-1-1 conditions). Below we briefly summarize each of the key studies. Appendix A lists these studies as well as other studies we reviewed.

- **2013 Eastside Needs Assessment by Quanta Technology**: As mentioned above, in order to examine the need for transmission expansion, this study analyzed the impact of energy conservation measures on peak load forecasts based on the most recent IRP. The study assessed the capacity overloads for the entire PSE system and for the Eastside area with various conservation levels including a 100% Conservation scenario. The study identified system overloads by 2017–2018 for winter peak and as early as 2014 for summer peak under normal weather conditions, assuming 100 percent of the energy conservation estimated in the recent IRP. The study is not clear regarding which version of the IRP was used to develop conservation estimates, but it is likely that the study used PSE's 2013 IRP given the timing of the study.

- **2015 Supplemental Eastside Needs Assessment by Quanta Technology**: This report updated the load forecasts and reassessed the need for transmission capacity expansion in the Eastside area. The report indicates no changes to its energy conservation assumptions or methodologies. Unlike the 2013 study, this report clearly indicates that it used conservation targets from the 2013 IRP, although Quanta did not include the active demand response from that IRP because PSE did not implement active demand response following the IRP's publication.[27]

- **E3 study**: In early 2014, E3 assessed the potential for NWAs in King County to defer the proposed transmission upgrades in the Eastside area, including energy efficiency, demand response, and distributed generation.[28] Using additional avoided benefits of deferring the transmission upgrades, the study assessed as NWAs incremental amounts of cost-effective demand-side resources beyond the level of resources selected in PSE's 2013 IRP. The study found a total of 56 MW of incremental demand-side resource potential (30 MW from energy efficiency, 25 MW from demand response, and 1 MW from distributed generation) in King County. The study concluded that these demand-

[26] PSE. 2017. 2017 PSE Integrated Resource Plan, Chapter 5, page 5-37.

[27] Quanta Technology. 2015. Page 7.

[28] E3. 2014. 2014 PSE Screening Study.

side resources are not sufficient to defer the transmission need because the region will be 75 MW short with PSE's 100% Conservation scenario or 100 MW short with its 75% Conservation scenario (which also acts a proxy for the higher load growth scenario or extreme winter conditions). The study focused on winter peak loads, apparently because winter peak is the main focus of the 2013 Needs Assessment. Detailed examination of this study is outside of the scope of our analysis. However, it is not clear to us whether the amount of demand-side resources identified in this study is still valid today, mainly because the study is more than six years old and because potential amounts likely have changed since then.

- **Strategen 2015:** PSE commissioned Strategen to evaluate the feasibility of electric battery storage as an incremental measure to the additional demand-side resources identified by the E3 study.[29] The study examined annual hourly load data and determined that Talbot Hill substation was the substation with the most significant normal and emergency overloads that occur during the winter period. Assuming the demand-side resource results from the E3 study, the study examined load flows of the network transmission system and determined the battery sizes necessary to resolve normal overload reductions in the short term (Baseline), emergency overload elimination (Alternative #1), and normal overload elimination in the long term (Alternative #2). The resulting battery sizes are 328 MW, 121 MW, and 544 MW respectively.[30] The study also examined the technical feasibility and cost-effectiveness of large-scale batteries and concluded that batteries are not technically feasible under the Baseline and the Alternative #2 scenarios due to the excessive size of the batteries, siting limitations, long project timeline, and limited transmission system capacity to charge the batteries. The study then found that while the Alternative #1 (121 MW battery for resolving 34 MW of emergency overload) is technically feasible and cost-effective with a benefit-cost ratio of 1.13 and a $264 million net present value cost estimate, this scenario does not meet PSE's reliability requirements. However, we note it is likely that the estimated battery sizes are overestimated for addressing winter peak loads because the historical winter peak loads have been substantially lower than projected in the past. Nevertheless, the study's results for addressing the summer peak overloads are likely still applicable.

- **Strategen 2018**: PSE commissioned Strategen to conduct a new study updating the Strategen 2015 study to consider changes to substation equipment ratings, PSE's updated load forecasts in 2017, and recent advancements in the energy storage market.[31] This study analyzed the feasibility of two scenarios: (a) the Interim Solutions that meet the Winter 2018/2019 and Summer 2019 overload constraints and (b) the Complete Solution that meets PSE's 2027 forecasted need. The conclusions of this study are mostly consistent with the findings of the Strategen 2015 study. The 2018 Strategen Study found that energy storage is still not a practical solution to meet the expected

[29] Strategen. 2015. Eastside System Energy Storage Alternatives Screening Study.

[30] These estimates take into account battery degradation factors and the study's finding that only 20 percent of the battery capacity is effective in reducing load at the substation and the rest of the battery outputs are expected to affect loads in other substations due to the interconnected nature of the network transmission system.

[31] Strategen. 2018. Eastside System Energy Storage Alternatives Assessment - Report Update.

Eastside transmission overloads. The study found that required battery systems would be substantially more expensive than the proposed transmission upgrades and would require large land areas (*e.g.*, 19 times the size of Tesla's Hornsdale facility in Australia, the world's largest currently installed system). The study also found that the largest system constraints have shifted from Talbot Hill substation for the winter peak period to Sammamish substation for the summer peak period. The required system size for the Complete Solution is 549 MW to serve the expected summer peak load in 2027. However, our review of PSE's latest load forecasts (discussed in the following section) reveals that the summer peak gap is about 460 MW in 2027 without demand response, solar PV, and other distributed generation (See Figure 10 in this section). Thus, it is likely the Strategen 2018 study overestimated the size and cost of battery options.

- **Latest conservation estimate**: PSE's latest load forecasts include the impacts of the 100% Conservation scenario that is consistent with the latest Conservation Potential Assessment included as Appendix J to the 2017 IRP, with the exception of demand response and distributed generation. This conservation potential includes PSE's energy efficiency programs, distribution efficiency (*e.g.*, conservation voltage reduction) and savings from codes and standards. Based on data from PSE, we found that PSE assumes 361 MW of winter conservation potential for 2023 (224 MW from energy efficiency programs, 132 MW from codes and standards, and 4 MW from distribution efficiency) while PSE's IRP selected 374 MW of conservation for the same year.[32]

[32] PSE. 2017. 2017 PSE Integrated Resource Plan, Chapter 1, Figure 1-4; File "Newcastle DR Q1 partG.xlsx" obtained from PSE data response on September 10, 2019 to Newcastle Consultants' data request on August 8, 2019.

## 4.3. PSE Winter Peak Load and Needs Assessment

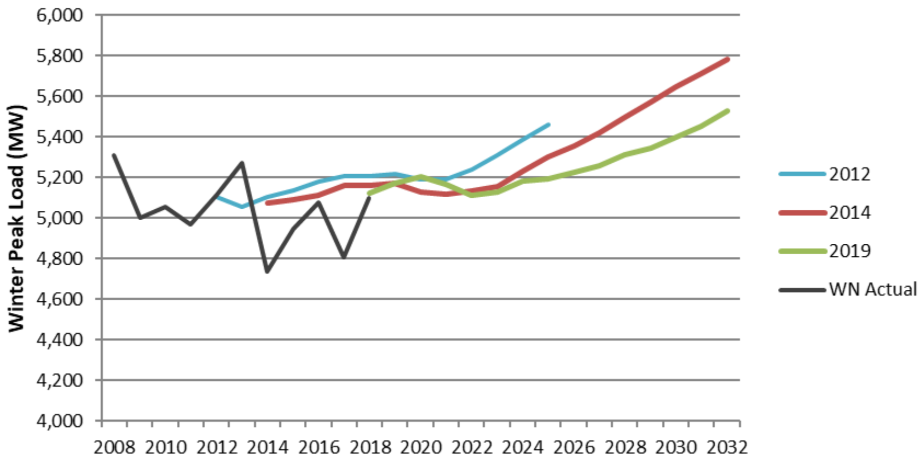
We conducted a review of historical winter and summer peak loads and the winter and summer peak load forecasts that PSE has made over the last several years. We obtained PSE's latest historical load data and load forecast through the data request process and compared them with PSE's previous analyses provided in the 2013 and 2015 Needs Assessment report. This sub-section focuses on our assessment of PSE's winter peak load estimates.

Figure 5 presents PSE's load forecasts for its service territory made in 2012, 2014, and 2019 along with weather-normalized actual winter peak loads (*i.e.*, loads adjusted for the specific weather impacts seen each year). These loads represent loads including the demand-side resource potential estimated in PSE's IRPs except peak load impacts from any demand response or distributed generation. These load data are also adjusted for PSE's transmission-level customers that are not included in PSE's corporate load forecasts.[33] This figure shows that the historical winter peak loads have been lower than what PSE's load forecasts have projected in the past, except in 2012.[34] It is also important to note that there has been a slight declining trend in the historical weather-normalized peak loads over the past 10 years. The annual average growth rate over the past 10 years is -0.4 percent. PSE did not project this decline. In fact, PSE's forecasts show increasing loads into the future years, and past forecasts showed increasing load during the time period when actual loads have declined. In addition, newer forecasts show lower peak loads than previous forecasts, and the time at which peak loads are projected to rise substantially appears to be shifting into the future with each forecast.

[33] We assume 270 MW of peak load for transmission-service customers per page 8 in the 2015 Supplemental Needs Assessment.

[34] This finding reflects updated weather normalized winter peak demand of PSE entire service territory furnished by PSE in May 2020.

**Figure 5. PSE entire service territory: winter peak load forecasts and actual peak load**




*Source: Compiled from PSE load forecast documents and discovery responses—WN Actual is weather-normalized actual peak load.*

PSE's load forecasts have historically over-projected loads relative to actual loads. This was noted by Washington Utilities and Transportation Commission (WUTC) in its "Acknowledgement letter attachment" to PSE's 2017 IRP. In this letter WUTC noted, "historically, PSE's load forecasts have been overly optimistic" and included an assessment of PSE's load forecasts by the Lawrence Berkeley National Laboratory in terms of average annual growth rate of energy (AAGR) as shown in Table 2 below.[35]

**Table 2. PSE's projected and actual average annual growth rate of electric energy**

| Period | LSE-Projected AAGR | Actual AAGR |
|---|---|---|
| **2006-2014** | 1.75% | -0.19% |
| **2012-2014** | 1.90% | -1.19% |

*Source: WUTC Acknowledgement letter to PSE's 2017 IRP.*

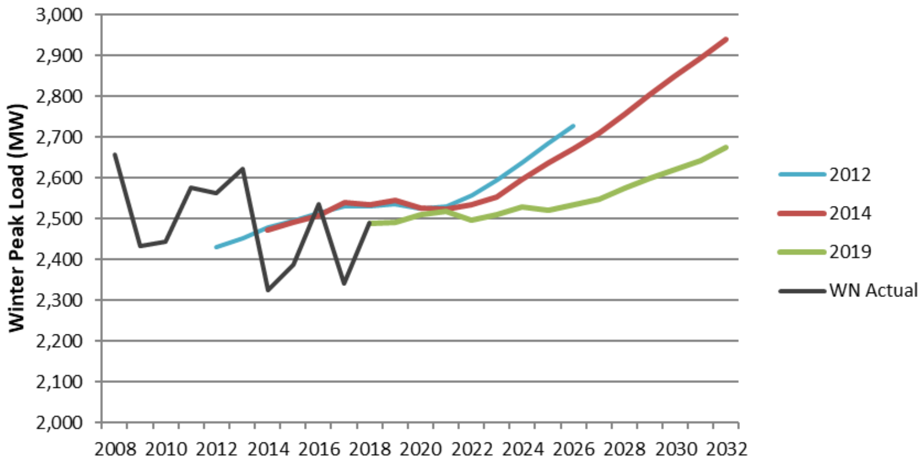
Historical loads and PSE's peak load forecasts for King County also show similar trends to what we have observed in PSE's entire jurisdiction, as shown in Figure 6. Both the historical loads and projected loads in this figure include additional peak loads expected from transmission-level customers.[36] Historical

[35] Washington Utilities and Transportation Commission (WUTC). 2018. Acknowledgement letter attachment: Puget Sound Energy's 2017 Electric and Natural Gas Integrated Resource Plan, Dockets UE-160918 and UG-160919. Page 11. Available at https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=1743&year=2016&docketNumber=160918.

[36] We assumed 81 MW of peak loads from those customers per PSE's data response on September 9, 2019 to our data request on August 8, 2019.

weather-normalized peak loads have been lower than forecasted weather-normalized peaks in four of the five most recent years (from 2014 to 2018 except 2016).[37]

**Figure 6. PSE King County: winter peak load forecasts and actual peak load**




*Source: Compiled from PSE load forecast documents and discovery responses. WN Actual is weather-normalized actual peak load.*

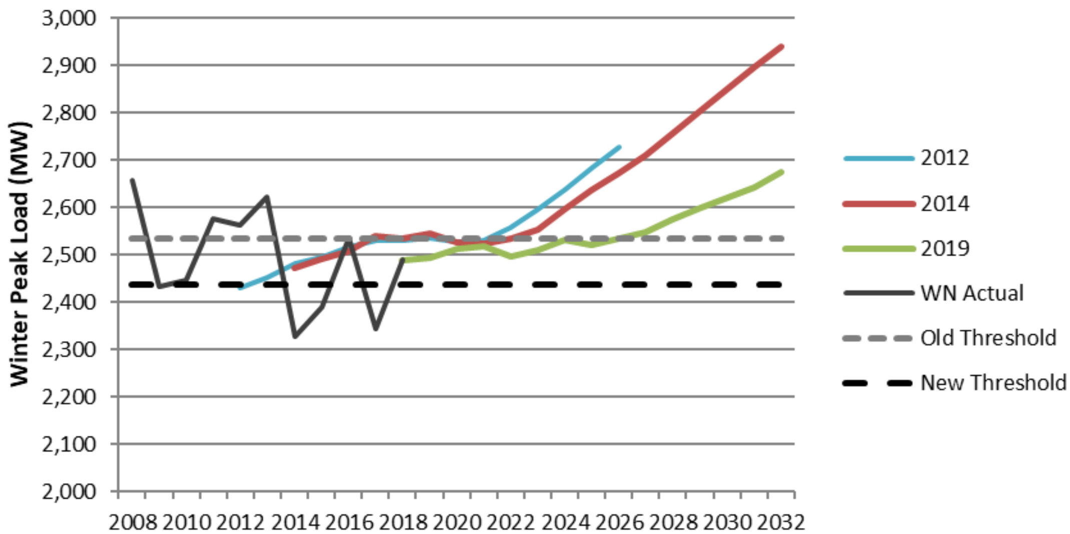
Finally, we examined the potential for winter transmission capacity constraints in King County—that is, whether and to what extent King County currently has or is expected to have any transmission capacity deficiency based on PSE's projections. We compared King County's current and projected winter peak loads with PSE's estimates for peak load thresholds. In other words, we examined the load levels of concern above which PSE's transmission facilities (*i.e.*, Talbot substation for the winter peak) are expected to experience capacity deficiency under contingency events (*i.e.*, N-1-1 conditions). This analysis is presented in Figure 7. Our analysis focuses on King County because PSE identified load constraints in the Eastside area and because PSE has not produced any updated historical loads or forecasts for the Eastside area since the 2015 Supplemental Needs Assessment, despite the fact that the Eastside was the most critical area of the Needs Assessment studies.

Figure 7 includes two separate estimates for load thresholds, labeled as "Old Threshold" and "New Threshold." The "Old Threshold" represents a load threshold (or a level of concern) that was estimated in the 2013 and 2015 Eastside Needs Assessment report, scaled from the full PSE service territory to King County. During our investigation of the needs for the Eastside, we learned that PSE switched to EPRI's PTLOAD software to characterize its transformers. This change resulted in a reduction in the MW threshold, primarily due to different assumptions regarding the performance of grid components that are built into the PTLOAD model. The "New Threshold" in Figure 7 reflects this new estimate. For the PSE service territory, the thresholds were reduced from 5,200 MW to 5,000 MW for the winter period

[37] This finding reflects updated weather normalized winter peak demand of PSE King County service territory furnished by PSE in May 2020.

(representing a 4 percent reduction) and from 3,340 MW to 3,125 MW for the summer period (representing a 6 percent reduction).[38] For King County, the new peak load thresholds are 2,436 MW for the winter and 1,594 MW for the summer. Because the 2013 and 2015 Needs Assessment reports did not provide any load threshold for King County, we estimated the “Old Threshold” for King County by taking the ratio of load threshold changes at the level of PSE’s service territory.

**Figure 7. PSE King County: winter peak load estimates vs. peak load thresholds**




*Source: Compiled from PSE load forecast documents and discovery responses. WN Actual is weather-normalized actual peak load.*

A comparison of the loads in Figure 7 reveals that the recent actual winter peak loads have been lower than the Old Threshold, but were above the New Threshold in 2016 and 2018.[39] PSE’s latest load forecast developed in 2019 shows projected load levels above the new load threshold starting in 2018, although only by about 50 to 80 MW (or 2 to 3 percent) over the next few years. The average annual growth rate over the past decade is -0.65 percent. As with the case of the system-wide peak load forecasts, PSE did not project this declining peak load in its past forecasts. PSE’s latest forecast still shows an increasing winter peak trend. While the 2018 peak load is above the New Threshold, we are not convinced that the loads will remain above the New Threshold because PSE’s winter peak load forecasts have historically over-projected winter peak loads. The current forecast may have a bias in projecting higher peak loads and not fully reflecting historical winter peak trends, just like the gap the WUTC identified between the annual electric sales forecasts and actual sales from 2006 to 2014 as mentioned above. Further, there is a possibility that future loads may not increase as much as PSE is projecting or even could be lower than the New Threshold if PSE follows the WUTC’s recommendation

[38] PSE data response on September 10th to Newcastle’s August 8th data request 4(b).

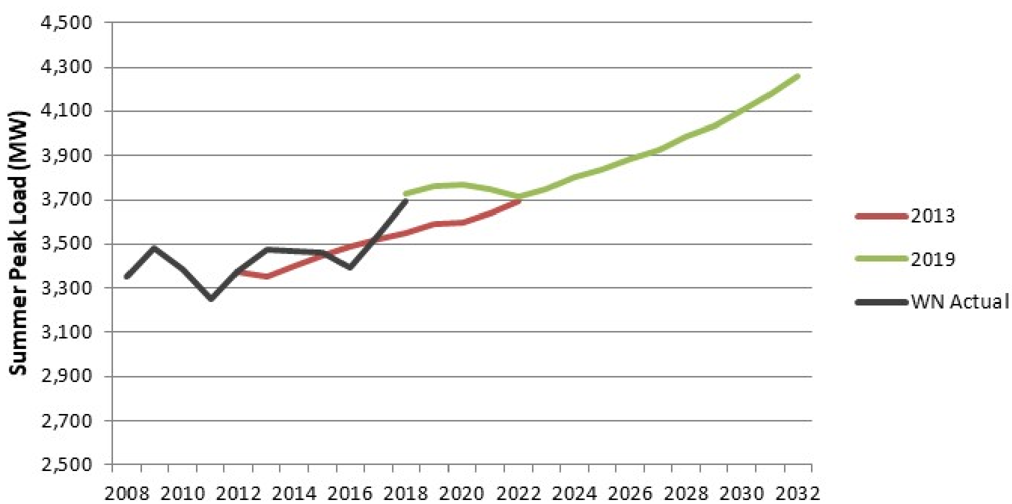
[39] This finding reflects updated weather normalized winter peak demand furnished by PSE in May 2020.

that "PSE should assume in years 11 through 20 that a reasonable level of emerging retrofit conservation measures will be available in the market at cost-effective rates even though they cannot be accurately identified or predicted now."[40]

## 4.4. PSE Summer Peak Load and Needs Assessment

PSE's summer peak loads present a very different story than the winter peak loads. Figure 8 presents PSE's load forecasts for its entire service territory made in 2013 and 2019, along with weather-normalized actual, historical summer peak loads through 2018 (*i.e.*, loads adjusted for annual specific weather impacts). As with the winter peak load estimates, the summer peak load estimates include loads for PSE's transmission level customers.[41] The load forecasts also represent loads adjusted for 100 percent of the demand-side resource potential estimated in PSE's IRPs. This figure shows that, unlike the historical winter peak loads, the historical summer peak loads have been increasing over the past several years, as forecast by PSE in 2013. Further, unlike PSE's winter peak forecast, the load for the first year for each forecast matches closely with the weather-normalized actual, historical loads (*i.e.*, year 2012 and 2018).

**Figure 8. PSE service territory: summer peak load forecasts and actual peak**



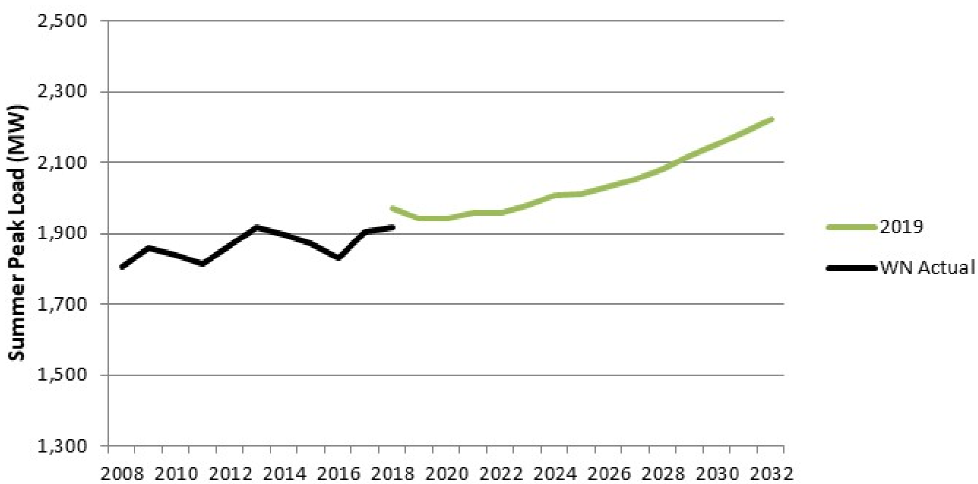

*Source: Compiled from PSE load forecast documents and discovery responses. WN Actual is weather-normalized actual peak.*

[40] WUTC. 2018. Page 11.

[41] We assume 270 MW of peak load for transmission-service customers per page 8 in the 2015 Supplemental Needs Assessment.

Historical and forecasted summer peak loads for King County show similar trends to the loads for PSE's entire service area, as shown in Figure 9.[42] Summer peak loads have been gradually increasing over the past several years, and PSE's forecast shows a growing peak load trend into the future. This figure includes just one forecast (made in 2019) because PSE's Eastside Needs Assessment studies did not analyze summer peak loads at the King County level, but instead focused on winter peak loads for the Eastside area as well as for the entire service territory.[43]

**Figure 9. PSE King County: summer peak load forecasts and actual peak load**




*Source: Compiled from PSE load forecast documents and discovery responses. WN Actual is weather-normalized actual peak load.*

Finally, we examined the potential of summer capacity constraints in King County. Figure 10 presents this review by providing a comparison of the summer peak loads with peak load thresholds (the load levels of concern in King County at which key transmission facilities will be overloaded under contingencies (*i.e.*, N-1-1)). As mentioned above in the winter peak load discussion, PSE revised its previous load threshold calculation methodology. Its new estimate is shown as "New Threshold" (1,594 MW) in Figure 10. Because the 2013 and 2015 Needs Assessment reports did not provide any load threshold for King County, we estimated the "Old Threshold" for King County based on the ratio of load threshold changes at the PSE's service territory level. At the total system level, the 2013 and 2015 Needs Assessment reports found system overloads could occur as early as 2014 and become more serious by Summer 2018.[44]

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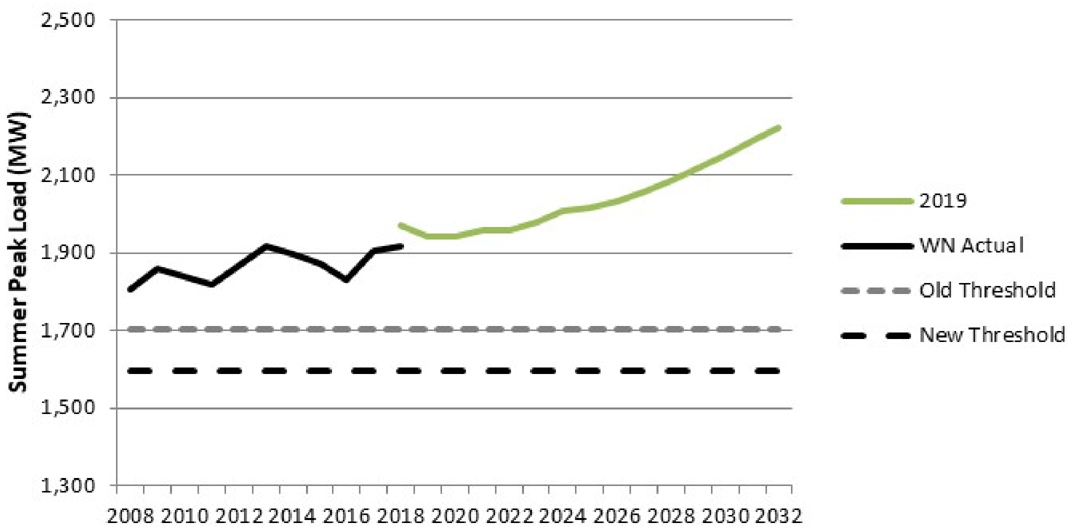
[42] We assume 81 MW of peak loads from transmission-service customers based on PSE's data response on September 9, 2019 to our data request on August 8, 2019.

[43] As mentioned previously, our analysis focuses on King County because PSE has not produced any updated historical or forecasted load estimates for the Eastside area despite the focus of its Needs Assessment reports being on the Eastside area.

[44] Quanta Technology. 2013, page 8, 9, 13 and 70; Quanta Technology. 2015, page 18 to 19.

A comparison of the load thresholds in Figure 10 reveals a more severe situation than found in the 2013 and 2015 Needs Assessment for the summer peak period: King County's summer peak loads have been exceeding the level of load concerns under N-1-1 contingencies both at the old and new threshold levels. More specifically, the peak load levels in King County have been 13 to 20 percent (or 200 MW to 300 MW) above the new threshold (assuming PSE's latest threshold is accurate). Given this current severe condition, we do not need to rely on load forecasts to determine the capacity needs because it would be infeasible to acquire sufficient demand-side resources to reduce this substantial gap within just a few years. At the current load levels, we have to conclude that there is an operational need to expand the transmission capacity in the region.

**Figure 10. PSE King County: summer peak load estimates vs. peak load thresholds**




*Source: Compiled from PSE load forecast documents and discovery responses. WN Actual is weather-normalized actual peak load.*

# 5. ASSESSMENT OF THE PROPOSED EASTSIDE PROJECT

## 5.1. The Proposal

PSE's proposed Energize Eastside project consists of upgrading the 115kV transmission lines to 230kV lines in the existing Willow 1 transmission line corridor and the construction of the Richards Creek substation in Bellevue. Our assessment finds that the upgraded transmission facilities proposed to traverse approximately 1.5 miles through Newcastle serve an operational need to safeguard the security of the bulk electric system.

## 5.2. Operational Need

We conducted a power flow analysis of PSE's transmission system with a focus on the Eastside project using the PowerWorld power flow model. Our analysis found that the facilities supplying the Eastside are currently experiencing a transmission capacity constraint that is especially pronounced during the summer in the Northwest area serving the South King County zone. A part of PSE's transmission planning responsibilities is to ensure the reliability of the transmission system it operates. This includes no long-term reliance on operating procedure corrective action plans.

Power systems are operated so that overloads do not occur either in real-time or under any statistically likely contingency. Contingencies can consist of several actions or elements, such as an outage of a single transmission line or an outage of several lines, a number of generators, and the closure of a normally open transmission line. The North American Electric Reliability Corporation (NERC) develops and enforces standards to ensure the reliability of power systems in North America. The Transmission Planning Standard (TPL) defines system performance requirements under both normal and various contingency conditions. The NERC transmission planning standards currently subject to enforcement are NERC TPL-001-4 and TPL-007-3.[45] We used these requirements to analyze PSE's transmission system, which is part of the Western Interconnection bulk electric system. The analyzed contingencies included (1) no contingencies, (2) events resulting in loss of a single system element, and (3) events resulting in loss of two or more system elements.

Under several contingencies, our power flow analysis verified that transformers at the Sammamish and Talbot Hill substations experience overloads when modeled using reasonable simulation parameters and MVA limits for normal and emergency operations. If these overloads are left unaddressed, Newcastle may experience reliability issues with its electric supply.

Electricity is primarily served to customers through distribution substations that are close to the loads. The city of Newcastle is primarily served by the Hazelwood Substation in the South King zone of the

[45] North American Electric Reliability Corporation. n.d. "Mandatory Standards Subject to Enforcement." Available at https://www.nerc.net/standardsreports/standardssummary.aspx.

Northwest area. Based on the power flow analysis we conducted to verify the claims of transmission constraints used to justify the proposed facility upgrades, we found that increasing the load served by the Hazelwood substation had little effect in the flows through the Sammamish transmission substation. We conclude that the operational need claimed by the utility is not triggered by peak demand solely arising from Newcastle, but instead the operational need results from the requirement to secure the system at a regional level and comply with NERC reliability standards for the bulk electric system. We note that if the bulk electric system fails, Newcastle will be without electric supply unless island-able distributed generation (*i.e.*, generation near load centers) is available. Our review did not identify significant distributed generation capacity in the Newcastle area.

There is a possibility that the power flow through the Northern Intertie to PSE's territory is affecting the summer peak situation in King County. Our power flow models verify that even with the Northern Intertie adjusted to zero flow, the Talbot Hill 230kV/115kV transformer on circuit #2 would still be overloaded when accounting for secondary contingencies. Note that the Northwest system that serves King County has interchange schedules with several other systems including BC Hydro, and during the summertime most of the interchanges are power imports into the Northwest area. The Northwest–BC Hydro interchange transfers take place through the High Voltage Northwest transmission system. Our assessment found that these transfers have minimal impact on the transmission power flows that supply the distribution facilities that feed the load centers of the Eastside.

## 5.3. Reliability Improvement

Electric utilities commonly experience facilities outages, either planned or unplanned. A well-planned system will feature redundancy and absorb these outages to maintain continuity of supply to customers and ensure service reliability in the Eastside.

In order for Newcastle to benefit from this level of reliability, PSE proposed to upgrade the existing 115kV line in the Willow 1 transmission line corridor (Figure 11 and Figure 12, next page) to 230kV lines. Under this proposal, residents in Newcastle would see the higher transmission towers needed to comply with the 2017 National Electrical Safety Code.

**Figure 11. Existing two 115kV electric transmission facilities on H-frame poles travel in existing transmission corridor through Newcastle around SE 80th Way, Newcastle, WA 98056**


*Source: Google Earth, retrieved September 2019. Note: City of Newcastle Public Notice of Proposed Land Use Action is visible.*

**Figure 12. Current 115kV electric transmission facilities around 12828 SE 80th Way, Newcastle, WA 98056**


*Source: Google Earth, retrieved September 2019.*

We highlight that a dual 230kV transmission line operated by Seattle City Light (SCL) already travels through Newcastle (Figure 13 below).

**Figure 13. Seattle City Light 230kV Transmission Line at Donegal Park [SE 74th ST, Newcastle, WA 98056]**


*Source: Google Earth, retrieved September 2019.*

# 6. Key Findings, Conclusions, and Recommendations

## 6.1. Key Findings

Power flow cases analysis shows that the current summer electric peak demand in King County has already triggered an operational need for the proposed transmission expansion under system contingency scenarios.

Our power flow model assessment finds that the regional capacity thresholds in King County estimated by PSE are reasonable.

Our assessment of PSE's load forecasting methodology finds that the PSE load forecast approach follows a standard industry practice, although it has some limitations regarding the way it incorporates demand-side resources.

Our assessment of PSE's historical peak loads found that PSE's winter peak load actually has been declining over the past several years. While our assessment did not find a need at today's load level using the Old Threshold used in PSE's studies (the 2013 and 2015 Quanta studies), the 2018 load was above the New Threshold that PSE developed using revised methodology in 2016.

While we found that PSE's own winter load forecast is above the load threshold for concern in King County, we cannot conclude based on the data we analyzed whether there is any clear need created by the winter peak load for transmission capacity expansion in the future. PSE's past winter peak load forecasts have been over-predicting winter peak loads. The current forecast does not appear to fully incorporate the declining trend in weather-normalized winter peaks. Further, the current forecast does not appear to have incorporated the WUTC's recommendation to assume that in the longer term "a reasonable level of emerging retrofit conservation measures will be available in the market at cost-effective rates even though they cannot be accurately identified or predicted now."[46]

On the other hand, based on PSE's latest estimate for load thresholds in King County, which our power flow analysis verified, we found there is a summer transmission capacity deficiency in King County under N-1-1 contingencies even at today's peak load level. We further found that the capacity deficiency for the summer season has been 13 to 20 percent (or 200 MW to 300 MW) above the area's capacity threshold.

[46] WUTC. 2018. Page 11.

## 6.2. Conclusions

PSE demonstrated that the proposed transmission upgrades are needed to safeguard the operational reliability of the electric system as a whole. To maintain system security, power systems operators need to ensure overloads do not occur either in real-time or under any statistically likely contingency. Not securing the bulk electric system to operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies can affect the electric supply reliability in Newcastle. This peer review verified that under specific contingencies (N-1-1 and N-2) the as-is bulk electric system serving Newcastle is already operationally stressed. This means that PSE's application has met the threshold for approval dictated by Newcastle City Code C-5 under NMC 18.44.052 Utility facilities – Regional: "[t]he applicant shall demonstrate that an operational need exists that requires the location or expansion at the proposed site."

The current transmission deficiency can be resolved by upgrading one of the 115kV transmission lines between the Talbot Hill and Sammamish substations to 230kV and installing an additional 230kV/115kV 325MVA transformer at the proposed Richards Creek substation in Bellevue. Upgrading the second 115kV transmission line that currently travels through the same corridor, Willow 1, to 230kV is consistent with good system planning, given that facilities to support these higher voltages will already be deployed.

## 6.3. Recommendations

### Transmission solutions

We recommend that the Conditional Use Permit to PSE to upgrade the identified approximately 1.5 miles of existing 115kV lines with 230kV lines be conditioned on conducting an independent design assessment of the overhead transmission facilities traversing Newcastle. That assessment should verify compliance with the clearance safety rules for the installation and maintenance of overhead electric supply of the 2017 National Electrical Safety Code (NESC), ANSI C2 Part 2. [47] We also recommend that the City of Newcastle sends field inspectors during the transmission line upgrades to ensure compliance with the 2017 NESC.

[47] https://apps.leg.wa.gov/WAC/default.aspx?cite=296-45-045

# APPENDIX A. REVIEWED MATERIAL

We reviewed the following materials in order to evaluate PSE's filings against the City of Newcastle's code requirements.

- Quanta Technology (2013) Eastside Needs Assessment
- Quanta Technology (2013) Eastside Solutions Study Report
- Quanta Technology (2015) Supplemental Eastside Needs Assessment
- Quanta Technology (2015) Supplemental Eastside Solutions Study Report
- Energy and Environmental Economics (2014) PSE Screening Study
- Strategen (2015) Eastside System Energy Storage Alternatives Screening Study
- Strategen (2018) Eastside System Energy Storage Alternatives Assessment – Report Update.
- PSE (2017) 2017 PSE Integrated Resource Plan
- PSE's Annual Report of Energy Conservation Accomplishments
- PSE (2019) Overview of Integrated Resource Plans and Cost-Effective Conservation in Washington
- Portland General Electric 2019 Draft Integrated Resource Plan
- Navigant (2017) 2017 IRP Demand-Side Resource Conservation Potential Assessment Report, Appendix J to PSE's 2017 Integrated Resource Plan
- Utility System Efficiencies, Inc. (2015) Independent Technical Analysis of Energize Eastside for the City of Bellevue, WA
- CADMUS Group (2013) Comprehensive Assessment of Demand-Side Resource Potentials (2014-2033)
- November 2017 Newcastle Site Plans, Variance and Non-Variance
- Tetra Tech (December 2013) Eastside 230kV Project Constraint and Opportunity Study for Linear Site Selection
- PSE (2017) Newcastle Alternative Siting Analysis

# ATTACHMENT D

## Community Advisory Group Report

Attachment D

PUGET SOUND ENERGY

# energize**EASTSIDE**

# community advisory group **FINAL REPORT**

January 2015

prepared by: enviroissues

# Community Advisory Group Final Report

## Table of Contents



*The Community Advisory Group reviewed and provided feedback on this report.*

# Executive summary

The Energize Eastside project will build a new electric substation and higher capacity (230 kV) transmission lines on the Eastside. In order to provide a forum that would generate robust input from diverse community stakeholders, Puget Sound Energy (PSE) convened a Community Advisory Group comprised of 24 representatives from various interests across the Eastside.

The Community Advisory Group's goals were to help identify and assess community values in the context of evaluating which route the new transmission lines should follow, and to develop a route recommendation for PSE's consideration.

## Meeting schedule

The Community Advisory Group met eight times between Jan. 22 and Dec. 10, 2014. The advisory group discussed the following topics at each meeting:

- **Jan. 22:** Role of the advisory group and introduction to the project
- **Feb. 12:** Solution selection process and project routing
- **June 4:** Review key findings from the sub-area workshops and Sub-Area Committee meetings
- **June 25:** Review potential route options
- **July 9:** Narrow potential route options and finalize evaluation factors
- **Oct. 1:** Review key findings from the open houses and prepare for route evaluation
- **Oct. 8:** Develop a preliminary route recommendation
- **Dec. 10:** Finalize a route recommendation for PSE's consideration

Additional meeting details are included in section IV (Community Advisory Group activities).

## Community outreach

The Community Advisory Group process was supplemented by broad and ongoing community outreach, including public events at key milestones. At outreach events, the community learned about outcomes of the advisory group process to date and submitted feedback that the advisory group considered in their discussions. Key outreach events included:

- **Jan. 29 and 30:** Open House #1
- **March - May:** Six sub-area workshops and three Sub-Area Committee meetings
- **April 21:** Question and Answer Meeting #1
- **July 7:** Question and Answer Meeting #2
- **Sept. 10 and 11:** Open House #2
- **Nov. 12 and 13:** Open House #3

Along with feedback collected at these outreach events, members of the public could also submit input and ask questions via email, voicemail and an online comment form on the project website. To help inform their discussion, the advisory group received monthly public comment summaries of more than 2,300 comments and questions received from the public, as well as summaries of comments received at open houses. Additional activities are detailed in section V (Community involvement).

## Recommendation

On Dec. 10, the Energize Eastside Community Advisory Group selected route options Oak and Willow as their final route recommendation for PSE's consideration. Of the 22 advisory group members and four residential association alternates participating in the recommendation discussion, 20 supported the final recommendation.[1]

1 The above count includes the advisory group members and residential association alternates present at the Dec. 10, 2014 meeting, as well as six members and residential association alternates who did not attend the meeting but later provided feedback on the recommendation.

The final recommendation was based on the advisory group's work throughout 2014, including discussion of community feedback collected throughout the year. Six advisory group members and residential association alternates dissented from the recommendation and supported none of the routes.

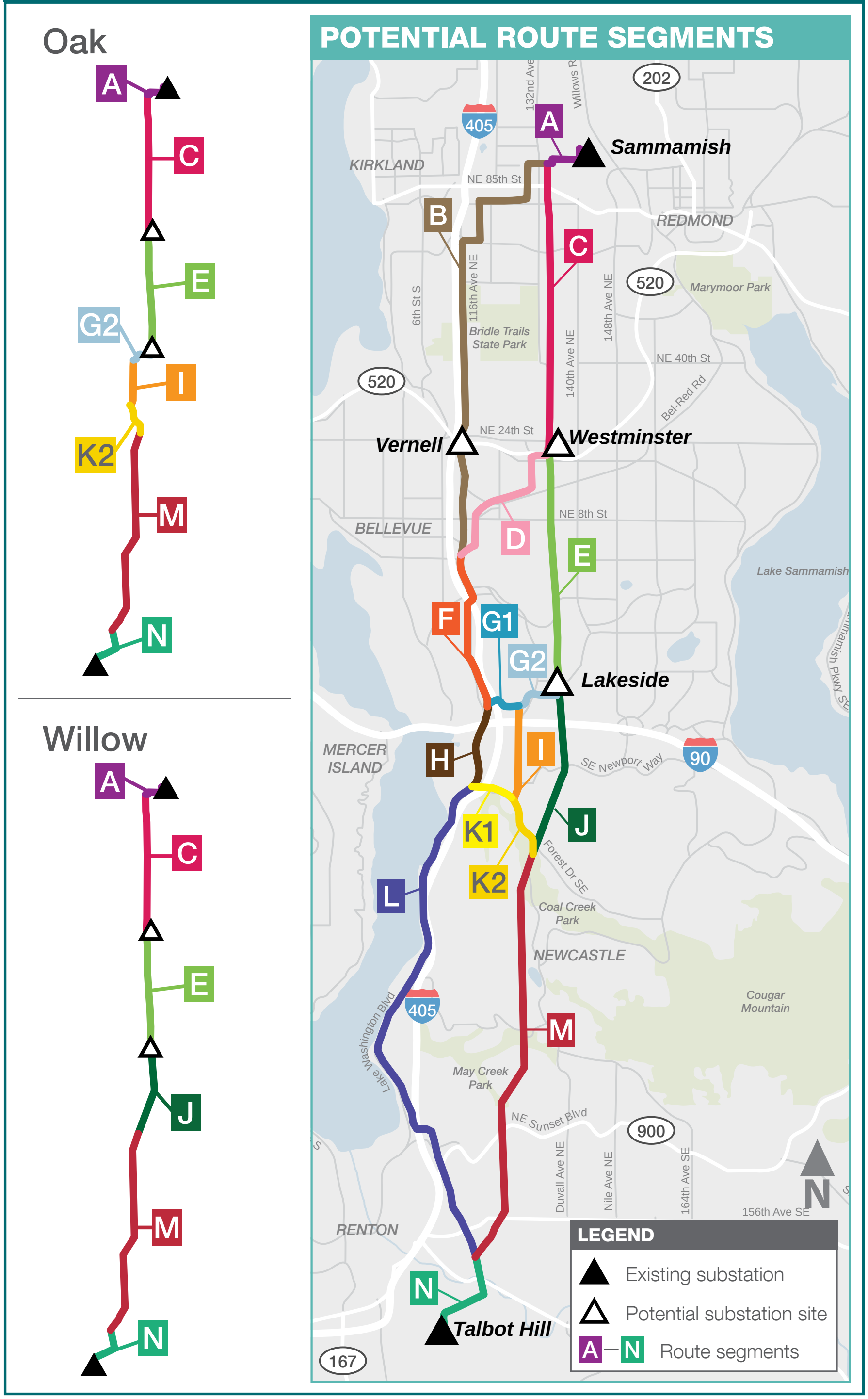
## Next steps

Following the completion of the Community Advisory Group's process, PSE's next steps in 2015 are to:

- Take the Community Advisory Group's recommendation under consideration and make an announcement about routing that balances the needs of customers, the local community, property owners and PSE
- Work directly with property owners and tenants to begin detailed fieldwork to inform environmental review, design and permitting
- Ask for community input on project design, which may include pole height, finish and other design considerations
- Work with the City of Bellevue and other affected jurisdictions and agencies on the project's Environmental Impact Statement (EIS) process

Once these steps are complete, PSE will apply for necessary permits from appropriate agencies and jurisdictions. The project design and permitting phase is expected to run through early 2017. Once fully designed and permitted, project construction is expected to begin in 2017, with project completion planned for 2018.

## COMMUNITY ADVISORY GROUP FINAL ROUTE RECOMMENDATION



# I. Introduction

Growth studies presented by Puget Sound Energy (PSE) and third-party experts project that demand for reliable power on the Eastside will exceed capacity as early as the winter of 2017/2018.[1] These studies indicate that without substantial electrical infrastructure upgrades and aggressive conservation efforts, the Eastside's power system will lose redundancy, increasing the risk of more disruptive and longer outages for as many as 60,000 customers.

The Energize Eastside project will build a new electric substation and higher capacity (230 kV) transmission lines on the Eastside. The new 230 kV transmission lines will extend from the existing Sammamish substation in Redmond to the existing Talbot Hill substation in Renton, connecting with a new substation site in between. These upgrades will provide dependable power for Eastside communities for many years to come.

In January 2014, PSE convened a Community Advisory Group comprised of 24 representatives[2] from various interests across the Eastside. The purpose of the advisory group was to provide a forum that would generate robust input from diverse community stakeholders in compliance with comprehensive plan goals and policies, which promote public participation and/or coordinated utility siting. The Community Advisory Group's goals were to help identify and assess community values in the context of evaluating which route the new transmission lines should follow and to develop a final route recommendation for PSE's consideration.

1 Quanta Technology and Puget Sound Energy, *Eastside Needs Assessment Report*, 2013.

2 The Community Advisory Group consisted of 24 members at the beginning of the process; however, two member organizations (King County and Renton Technical College) withdrew without replacement.

*Project Manager Jens Nedrud leads Community Advisory Group members on a tour of the project area.*

## Purpose of report

The purpose of this report is to document the work and summarize the recommendations of the Community Advisory Group convened by PSE to explore community preferences, priorities and concerns and to assess segments that could be combined to form a final route for the Energize Eastside 230kV transmission lines.

# II. Project background

PSE's existing Eastside electric system had its last major upgrade in the 1960s. The electric system serves communities between Redmond to the north, Renton to the south, Lake Washington to the west and Lake Sammamish to the east. Power is currently delivered throughout the Eastside region using 115 kV transmission lines that run between two 230 kV substations – one in Redmond and one in Renton (see Figure 1).

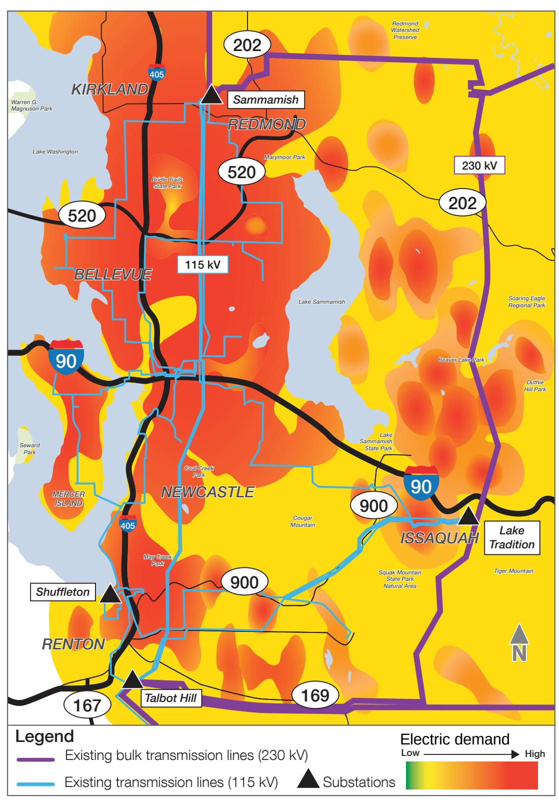
Since the system's last upgrade, the Eastside population has grown from approximately 50,000 to nearly 400,000 people, and this growth trend is expected to continue. Puget Sound Regional Council projections indicate that the Eastside population will grow by more than a third between 2010 and 2040.[1] Not only have Eastside communities grown and prospered, but the way Eastside residents use electricity has changed. Home square footage has increased, requiring more energy for lighting, heating and air conditioning. Additionally, most devices and appliances plugged in today did not exist years ago. Despite improvements in energy efficiency and aggressive conservation efforts, demand for electricity has grown dramatically.

Federal standards require PSE to plan for future forecasted loads and upgrade the system accordingly. Forecasted loads for transmission purposes are based on historical load data as well as a variety of other inputs, including information about weather, regional and national economic growth, demographic changes, conservation, and other customer usage and behavior factors. In 2013, PSE published the *Eastside Needs Assessment*. Prepared with assistance from independent experts, the study demonstrated that the increased demand is already placing a strain on the electric system. As growth continues, the existing system will only become more stressed, increasing the possibility of widespread outages, especially during peak winter loads when customer electricity use is greatest.

To determine a solution, PSE and independent experts conducted multiple independent analyses of the existing system and studied a variety of options to address the growing need on the Eastside, including further reducing demand through conservation, increasing the capacity of existing electric transmission lines, generating energy locally, and building new infrastructure.

After a comprehensive review, PSE determined that a combination of continued conservation and infrastructure upgrades – a new substation and higher capacity 230 kV transmission lines – will meet growing demand on the Eastside and ensure reliable electricity for years to come. [2,3]

**Figure 1.** The Eastside's electric system and demand




1 Puget Sound Regional Council 2013 Land Use Baseline: Maintenance Release 1 (MR1), update April 2014.

2 Energy + Environmental Economics, *Non-wire Solutions Analysis*, 2014.

3 Quanta Technology and Puget Sound Energy, *Eastside Transmission Solutions Report*, 2013.

# III. About the Community Advisory Group

## Purpose

The purpose of the Community Advisory Group was to evaluate the potential route options identified by PSE and independent experts, help PSE better understand community and property owner values and concerns, and determine a route recommendation for PSE's consideration. The Community Advisory Group process and final route recommendation will help PSE evaluate and consider routes that balance the needs of its customers, the local community, property owners and PSE.

Throughout the community outreach process, the Community Advisory Group:

- Developed an understanding of the Energize Eastside project and project need
- Reported back to the constituents they represented on project details, gathered feedback from the interests they represented, and provided ongoing communication between PSE and their constituents throughout the process
- As community representatives, provided advice on ways to address community concerns
- Participated in geographic Sub-Area Committee meetings to identify local concerns and values
- Worked collaboratively and constructively to help consider community and property owner values
- Engaged in a process to evaluate route options
- Determined a final route recommendation for PSE's consideration

The Community Advisory Group codified its purpose, process and guidelines in its Charter (Appendix A), agreed upon by consensus.

## Membership

The Community Advisory Group was made up of representatives from various interests, including neighborhood organizations, cities, schools, social service organizations, major commercial users, economic development groups, an environmental organization and a property developer. See Table 1 for members, including which interests each member represented and their specific organization or affiliation.

*Learning about the project need and advisory group process at Community Advisory Group Meeting #1 in Bellevue.*

**Table 1:** Community Advisory Group members

| Interest | Organization or affiliation | Name |
|---|---|---|
| City | City of Bellevue | Nicholas Matz |
| | City of Kirkland | Rob Jammerman |
| | City of Newcastle | Tim McHarg |
| | City of Redmond[1] | Pete Sullivan (primary)<br>Lori Peckol (alternate)<br>Cathy Beam (alternate) |
| | City of Renton | Gregg Zimmerman |
| Economic development organization | OneRedmond | Bart Phillips |
| | Renton Chamber of Commerce | Brent Camann |
| Environmental organization | Mountains to Sound Greenway | Floyd Rogers |
| Jurisdiction | King County[2] | David St. John (primary)<br>Mary Bourguignon (alternate) |
| Major commercial/ industrial user | Overlake Hospital Medical Center | Sam Baxter (primary)<br>Jeff Fleming (alternate) |
| | Renton Technical College[3] | Steve Hanson |
| Property developer | Master Builders Association | David Hoffman |
| Puget Sound Energy | Puget Sound Energy | Andy Swayne |
| Residential organization (Bellevue) | Somerset Community Association | Steve O'Donnell |
| | Wilburton Community Association | Robert Shay |
| | Bridle Trails Community Club | Norm Hansen |
| Residential organization (Kirkland) | South Rose Hill/Bridle Trails Neighborhood Association | Deirdre Johnson (primary)<br>Jim McElwee (alternate) |
| Residential organization (Newcastle) | Olympus Neighborhood Association | David Edmonds (primary)<br>Sean McNamara (alternate)<br>Sue Stronk (alternate) |
| Residential organization (Redmond) | Redmond Neighborhoods | David Chicks |
| Residential organization (Renton) | Kennydale Neighborhood Association | Darius Richards |
| School district | Bellevue School District | Jack McLeod (primary)<br>Kyle McLeod (alternate) |
| | Lake Washington School District | Brian Buck |
| Social service organization | Coal Creek Family YMCA | Marcia Isenberger (primary)<br>Paul Lwali (alternate) |
| | Hopelink | Nicola Barnes |

**1** In October 2014, Pete Sullivan relocated and was unable to attend meetings thereafter, but remained involved in the process.

**2** King County was invited to have a staff representative serve on the advisory group. King County staff attended two introductory meetings but then withdrew from the process.

**3** In October 2014, Steve Hanson of the Renton Technical College resigned due to lack of availability to participate fully in the process.

### Residential association alternates

To provide an opportunity for additional input and representation from the residential community, four residential association alternates were appointed. These alternates were appointed from different neighborhood associations than the advisory group members representing residential interests. The four residential association alternates included:

- **Scott Kaseburg**, Lake Lanes Community Association (Bellevue)
- **Bill Taylor**, Liberty Ridge Homeowners Association (Renton)
- **Lindy Bruce**, Sunset Community Association (Bellevue)
- **Barbara Sauerbrey**, Woodridge Community Association (Bellevue)

### Past members and residential association alternates

Over the course of the advisory group's work, the following membership changed due to varying circumstances:

- **Mark Rigos**, City of Newcastle (replaced by Tim McHarg)
- **Jules Dickerson**, Lake Lanes Community Association (replaced by Scott Kaseburg)
- **Lynn Wallace**, Renton Chamber of Commerce (replaced by Brent Camann)
- **Debra Grant**, Hopelink (replaced by Nicola Barnes)

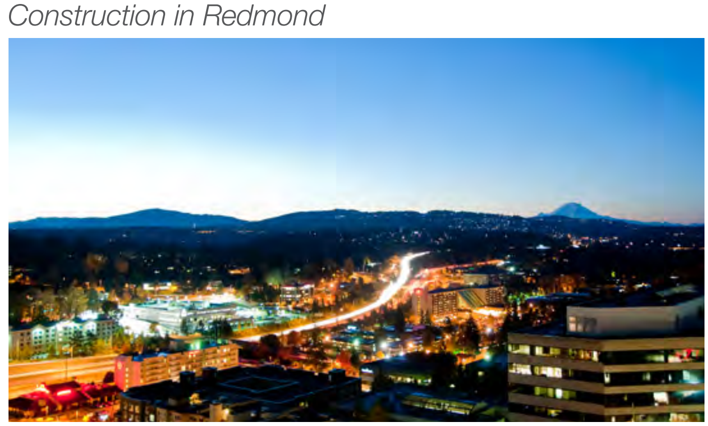
### Invited

The following entities were invited and chose not to participate in the Community Advisory Group process, but were informed of project milestones and meetings through postcards and newsletters:

- Muckleshoot Tribe
- Yakama Nation

*Aerial view of downtown Renton*


*Construction in Redmond*



*Downtown Bellevue at night*

# IV. Community Advisory Group activities

## Meeting schedule

The Community Advisory Group met eight times from January to December 2014. All Community Advisory Group meetings were open to the public and included a period for public comment. For links to advisory group meeting materials, presentations and summaries, see Appendix C.

During this process, PSE hosted three series of public open houses, during which the public could learn about major advisory group milestones and consult with PSE and advisory group representatives. The advisory group used community input from these open houses as well as from sub-area workshops and Sub-Area Committee meetings, community surveys, public comment periods, monthly public comment summaries, and personal communications with constituents to inform their discussions. See Table 2 for a list of advisory group and community meetings held in 2014.

**Table 2:** 2014 Community Advisory Group and public outreach meeting schedule

| Date | Meeting type | Purpose |
|---|---|---|
| Jan. 22 | Community Advisory Group meeting | Learned about project need and Community Advisory Group process |
| Jan. 29 & 30 | Open House | Broader community learned about the project need, the Community Advisory Group process, and opportunities to get involved |
| Feb. 12 | Community Advisory Group meeting | Learned about PSE's solution selection process and project routing |
| February – May | Project area tours and sub-area process | Learned about the potential route segments via project area tours provided by PSE; attended sub-area workshops to identify local community values and concerns; determined key findings from sub-areas (See Table 3 for more details) |
| June 4 | Community Advisory Group meeting | Reviewed key findings about the segments gathered at sub-area workshops and Sub-Area Committee meetings; developed community values-based evaluation factors to be used to evaluate the route options |
| June 25 | Community Advisory Group meeting | Reviewed qualitative and quantitative information about the 18 potential route options made by combining route segments |
| July 9 | Community Advisory Group meeting | Narrowed potential route options and finalized evaluation factors |
| Sept. 10 & 11 | Open House | Broader community provided feedback on narrowed route options and weighting of evaluation factors via survey |
| Oct. 1 | Community Advisory Group meeting | Reviewed key findings from September open houses and prepared for a Multi-Objective Decision Analysis evaluation of the routes |
| Oct. 8 | Community Advisory Group meeting | Determined preliminary route recommendation for public review at November open houses |
| Nov. 12 & 13 | Open House | Broader community provided feedback on advisory group's preliminary route recommendation |
| Dec. 10 | Community Advisory Group meeting | Reviewed key findings from the November open houses; finalized route recommendation for PSE's consideration |

## Key Community Advisory Group discussion topics

The Community Advisory Group discussed many topics over the course of the process. The following topics were most commonly addressed. Descriptions include the advisory group's expressed concerns and PSE's response shared over the course of the advisory group process.

### *Scope confined to an overhead solution*

Some members of the advisory group asked whether PSE would consider other alternatives besides an overhead solution. Those members also asked if considering other alternatives could fall under the advisory group's purview. Before launching the Energize Eastside, PSE studied several different solutions in addition to building the new overhead transmission lines. Those alternatives included reducing demand through conservation, increasing the capacity of PSE's existing electric transmission lines, generating energy locally, and building new infrastructure. However, PSE concluded other solutions were inadequate to solve the problem, and the advisory group was formed to gather feedback on an overhead transmission line solution.

### *Underground transmission lines*

Among the most discussed alternatives to an overhead solution was underground transmission lines. PSE explained that overhead transmission lines are PSE's first option for service due to reliability and affordability. The biggest challenge to underground transmission lines is cost. The construction costs for an overhead transmission line are about $3 million to $4 million per mile, versus $20 million to $28 million per mile to construct the line underground. Per state-approved tariff schedule 80, section 34, the local jurisdiction or customer group requesting underground transmission lines must pay the difference between overhead and underground costs. PSE explained they are willing to sit down with interested communities to discuss undergrounding as an option; however, those communities must decide how to pay for the difference in costs, which must be provided up front.

### *Submarine cables*

Some advisory group members expressed interest in PSE pursuing transmission lines submerged under Lake Washington, and pointed to other submerged transmission projects, such as one in San Francisco. PSE presented research on that project, and noted that it costs an average of $56.2 million per mile, compared to the $3 million to $4 million per mile of overhead transmission. As with undergrounding, according to tariff schedule 80, section 34, the local jurisdiction or customer group requesting submerged transmission lines must pay the difference between overhead and submarine costs.

### *Batteries*

Some advisory group members were interested in learning more about battery technology and local energy storage as an alternative to the project. PSE explained that using batteries instead of building a new substation was considered during the solutions identification process, but the technology has not been used for the type and scale of problem facing the Eastside. Additionally, new transmission lines would still be required to distribute electricity from the battery site to PSE's customers.

### *Seattle City Light corridor*

Some advisory group members also asked PSE about using the Seattle City Light (SCL) utility corridor as an alternative to site the new transmission lines. Early on in the solution identification process, PSE identified the SCL transmission corridor as a potential solution to meet the Eastside's energy needs. PSE asked SCL for permission to use their transmission corridor. However, SCL has told PSE that their corridor is a key component of Seattle City Light's transmission system and not available for PSE's use. A letter from SCL articulating this position is available on the Energize Eastside project website. See Appendix D.

### *Olympic Pipeline safety*

Some advisory group members expressed concern over the safety of building the project near the Olympic Pipeline. PSE explained that building 230 kV lines along the Olympic Pipeline (owned and operated by British Petroleum (BP)) would be safe. The Olympic Pipeline has coexisted with PSE transmission lines in the Eastside corridor for over fifty years. PSE also has a long history of working closely with BP and is a natural gas pipeline operator itself. PSE and its contractors are very familiar with concerns regarding pipeline safety and employ safe construction practices when performing work in the vicinity of pipelines. If a selected route is comprised of segments that include the Olympic Pipeline, PSE will continue to work with BP to ensure safety during and after construction.

### *Property values*

Some advisory group members expressed concern about the effects on property values as a result of the Energize Eastside project and asked whether property values could be considered as a factor for evaluating route options. Property values are comprised of many factors, including economic outlook and location, as well as proximity to jobs, schools, transportation, parks and other amenities. PSE explained that it does not use property values as a factor when selecting routes out of fairness to and in consideration for customers of all income levels, noting that it is socially inequitable to site infrastructure based on income-related considerations. Similarly, a project's potential effects on surrounding property values are excluded from consideration of impacts to the environment under Washington's State Environmental Policy Act (SEPA).

### *Electric and magnetic fields*

Several advisory group members asked whether exposure to electric and magnetic fields (EMF) had any effect on health. A third-party, board-certified health physicist explained that over the past 45 years, there have been many scientific studies conducted to determine whether EMF from transmission lines (called "power frequency EMF") has any effect on human health. To date, this large body of research does not show that exposure to power frequency EMF causes adverse health effects.

## January-February 2014: Learned about the electric system, project need and routing

The Community Advisory Group began their process by learning about the current electrical system, the need for the project and the solution selection process. During this learning period, the advisory group asked PSE questions on a variety of topics, including transmission line siting, other options considered for the project (e.g., battery technology and conservation), and how a solution was determined. PSE's real estate, engineering and system planning staff provided detailed responses to these questions.

*Communications Manager Gretchen Aliabadi explains the undergrounding tariff at Community Advisory Group Meeting #3 in Redmond.*

PSE explained in detail its process to identify a solution and route options, which included the following steps:

1. **Determine the potential approaches to meet the Eastside's electricity needs:** PSE evaluated the potential of several approaches – conservation, local generation and new infrastructure – to meet the Eastside's electricity needs.
2. **Review approaches to provide enough electricity to meet the Eastside's needs:** Engineers reviewed alternatives to each approach, and found that only new generation on the Eastside or new infrastructure located near the center of high electricity demand could meet the Eastside's needs. Additionally, aggressive conservation goals would need to continue.
3. **Review solutions that best deliver electricity to the Eastside:** Engineers reviewed different generation and electric infrastructure alternatives based on system performance, flexibility and longevity. A new generation facility on the Eastside was eliminated from consideration due to difficulties related to siting and operational limitations. It was determined that the best solution to meet the Eastside's electricity needs was to 1) construct a new 230 kV substation and 2) construct new 230 kV transmission lines connecting the new substation with the two existing substations in Redmond and Renton.
4. **Determine which solutions PSE can move forward with:** PSE eliminated the Seattle City Light Corridor and one of the potential Bellevue substation sites as possible new infrastructure locations. Neither the corridor nor the proposed substation property is owned by PSE and other viable sites for new infrastructure were available.
5. **Review where PSE could build a solution:** Engineers used a computer-based modeling tool to analyze key criteria like geographic barriers, land uses and impacts to the environment. Based on this analysis, route segments were identified that could be combined into various complete route options that connect to potential substations (see Figure 2).[1]
6. **Ask what the public thinks:** PSE asked the public to provide input on the combination of route segments that best serves the Eastside's needs. The Community Advisory Group process was part of a larger public outreach process that also included neighborhood briefings, community meetings at key milestones, question and answer sessions, and an interactive project website.

**Figure 2.** Potential route segments


## March-May 2014: Sub-area process and route segment input

In spring 2014, members of the Community Advisory Group participated in one or more of three Sub-Area Committees focused on the following geographic areas:

- North: Kirkland, Redmond and North Bellevue
- Central: Bellevue
- South: Newcastle and Renton

Sub-Area Committee membership included advisory group members and residential association alternates from the geographic

1 TetraTech, *Eastside 230 kV Project Opportunity and Constraints Study for Linear Site Selection*, 2013.

sub-areas. Invitations to serve on the committees were also extended to a representative from each potentially affected neighborhood association (i.e., those who lived near a potential segment) that did not have a member or residential association alternate on the advisory group.

PSE hosted six sub-area workshops and three Sub-Area Committee meetings across the project area. The three Sub-Area Committees developed findings on specific sub-area values, concerns and considerations about route segments from the workshops conducted in each of the sub-areas. The committees' findings served as a source of information that the Community Advisory Group considered in developing evaluation factors and narrowing the route options. See Table 3 for details on schedule and objectives of the sub-area workshops and Sub-Area Committees.

*Discussion about route segments at a Central sub-area workshop in Bellevue.*

*Discussion about route segments at a South sub-area workshop in Renton.*

**Table 3:** Sub-area workshops schedule and objectives

| Dates | Meeting type | Purpose |
|---|---|---|
| North: March 19, 2014<br>Central: March 26, 2014<br>South: March 27, 2014 | Sub-Area Workshop #1 | Community members:<br>• Identified key issues and considerations for segments in the sub-area<br>• Brainstormed community values<br>• Requested data that would be helpful to compare segments |
| North: April 16, 2014<br>Central: April 23, 2014<br>South: April 24, 2014 | Sub-Area Workshop #2 | Community members:<br>• Reviewed data and photo simulations PSE prepared based on requests from Workshop #1<br>• Used data to score all the route segments individually and as a group<br>• As a group, wrote key messages to the Sub-Area Committee |
| North: May 7, 2014<br>Central: May 14, 2014<br>South: May 15, 2014 | Sub-Area Committee meeting | Sub-Area Committees determined key findings from sub-areas to share with the Community Advisory Group |

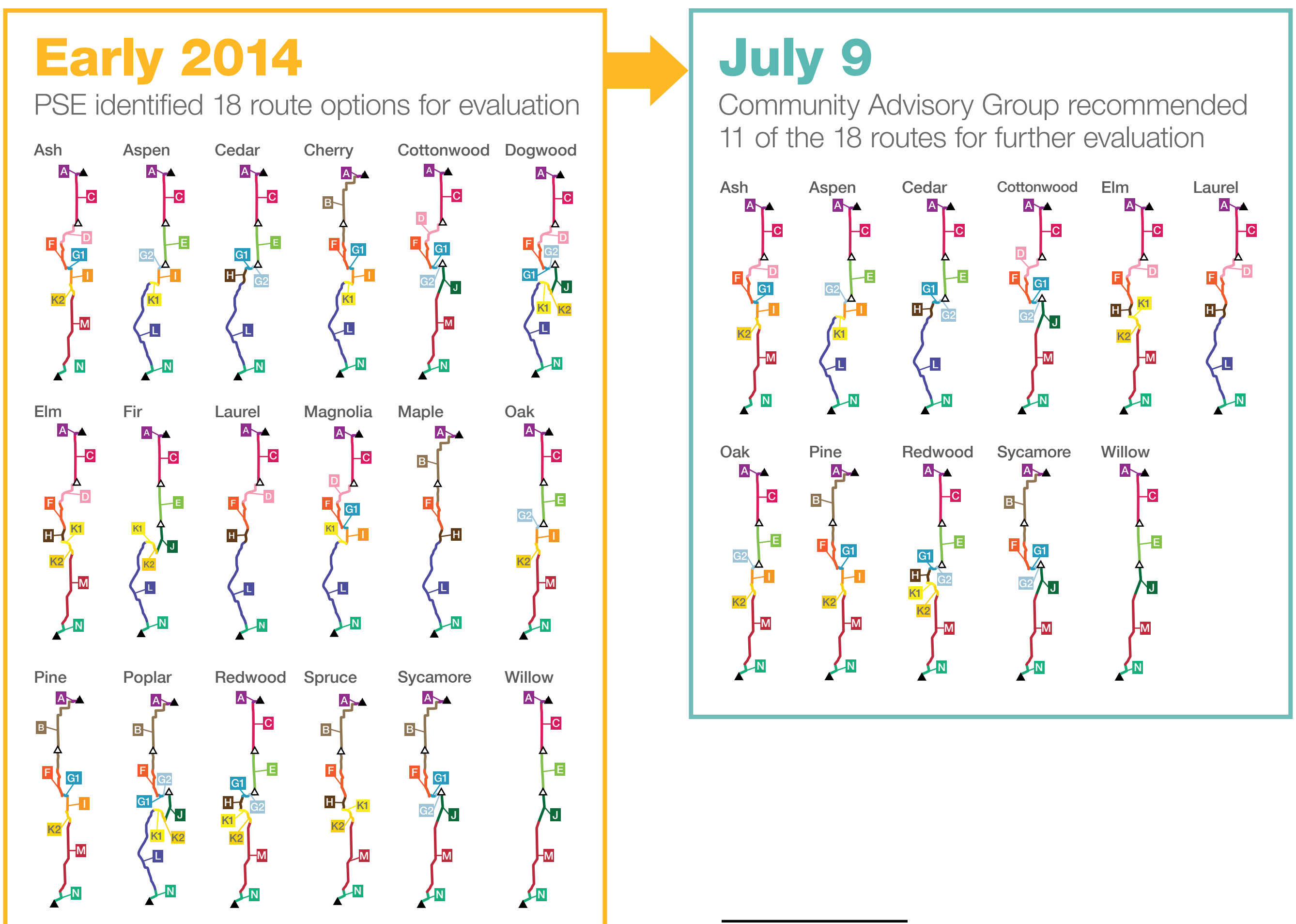
## June-July 2014: Narrowed the route options

After segment-specific input was collected through the sub-area process, the Community Advisory Group considered 18 route options made from combining the route segments. (These route options were assigned tree names, such as "Ash," "Aspen," and "Cedar," for easier reference.) The advisory group also identified community values-based evaluation factors.

At their meeting on July 9, the advisory group reviewed the 18 route options and recommended 11 route options for further evaluation.[2] (See Figure 3.) Information that aided their discussion included:

- Feedback from sub-area workshops and Sub-Area Committee meetings, as well as other community input
- Quantifiable data on route options, photo simulations, and information from PSE on route cost, constructability and maintainability
- Results from a blind evaluation of the 18 route options completed by 23 advisory group members
- Initial recommendations submitted before the meeting by eight advisory group members on which route options to remove from further evaluation[3]
- Discussion of route segments and the 18 route options at advisory group meetings

**Figure 3:** Narrowed route options in July 2014




2 Four advisory group members initially recommended that all or a majority of the 18 routes should move forward for further evaluation.

3 While eight advisory group members provided their initial input before the meeting, all members present at the meeting on July 9 discussed what route options to remove from further evaluation.

## October 2014: Evaluated the narrowed route options

The Community Advisory Group used nine evaluation factors (see Table 4), as well as specific route option data, to evaluate the narrowed route options through a process called Multi-Objective Decision Analysis (MODA). MODA is a process for making decisions when there are complex issues involving multiple criteria and multiple parties who may have an interest in the outcome.

Using MODA allows individuals to consider and weight factors and trade-offs while evaluating each alternative (in this case, each route option). Evaluation factors were weighted to reflect the relative importance ascribed to each factor. After scoring each route option for each evaluation factor, the advisory group then discussed the combined group results to help decide on a recommendation. See Figure 4 for a description of the MODA steps and how the advisory group used MODA.

Between Oct. 2 and Oct. 6, 2014, 19 of 24 advisory group members completed individual evaluations of the 11 route options recommended for further evaluation as part of the MODA process. Using online software called Transparent Choice, advisory group members individually scored each route option using each of the nine evaluation factors on a five-point scale. The software then applied two sets of weightings – one determined by the advisory group and another determined by community members who participated in a summer 2014 feedback survey – to the group's averaged scores. See Table 4 for descriptions of the evaluation factors and the two weighting schemes.

**Figure 4:** Multi-Objective Decision Analysis (MODA)

### MODA steps

1. **Factors** - Discuss and agree on evaluation factors
2. **Weighting** - Determine relative importance of each factor and assign corresponding weights
3. **Route options** - Determine route options to evaluate
4. **Scoring** - Score each route option for each weighted factor
5. **Decision** - Discuss results and determine decision

### How the Community Advisory Group used MODA

1. **Selected nine evaluation factors** based on community values
2. **Used two sets of weightings** - one determined by the advisory group and a second determined by a community survey
3. **Selected 11 route options** out of 18 to include in the evaluation
4. **Scored** the 11 route options for how well they each met the nine evaluation factors using an online software called Transparent Choice
5. **Considered MODA results** along with community feedback and other sources of information to select four routes as their preliminary route recommendation

**Table 4:** Evaluation factors and their weightings determined by the advisory group and a community survey

| Evaluation factor | Advisory group weighting | Community survey weighting |
|---|---|---|
| **Avoids impacts to aesthetics**<br>(Pole design and views) | 5% | 14% |
| **Avoids residential areas**<br>(Number of residences) | 24% | 31% |
| **Avoids sensitive community land uses**<br>(Parks and other recreational areas, schools, religious institutions, etc.) | 13% | 10% |
| **Avoids sensitive environmental areas**<br>(Wetlands, wildlife habitat, steep slopes, fault lines, etc.) | 7% | 12.5% |
| **Least cost to the rate payer**<br>(Estimated monthly increase to average residential customer; calculation based on total cost) | 14% | 7% |
| **Maximizes longevity**<br>(When in the future additional 230 kV infrastructure is anticipated based on current technology and growth projections) | 9% | 4% |
| **Maximizes opportunity areas**<br>(Runs along existing utility corridors, railroad right of way, public right of way, etc.) | 15% | 6% |
| **Protects health and safety**<br>(Electric and magnetic fields, Olympic Pipeline, etc.) | 9% | 9% |
| **Protects mature vegetation**<br>(Number of trees greater than four inches impacted) | 4% | 6.5% |
| Total | 100% | 100% |

On the following page, Figures 5 and 6 present the MODA results for each route option, first using the advisory group weighting and second the community survey weighting. Within the results bar for each route option, colors represent the evaluation factors and show the advisory group's averaged and weighted score for each factor. A higher number equals a better score. Weighting percentages are shown in the weighting keys.

**Figure 5:** MODA results - Advisory group weighting

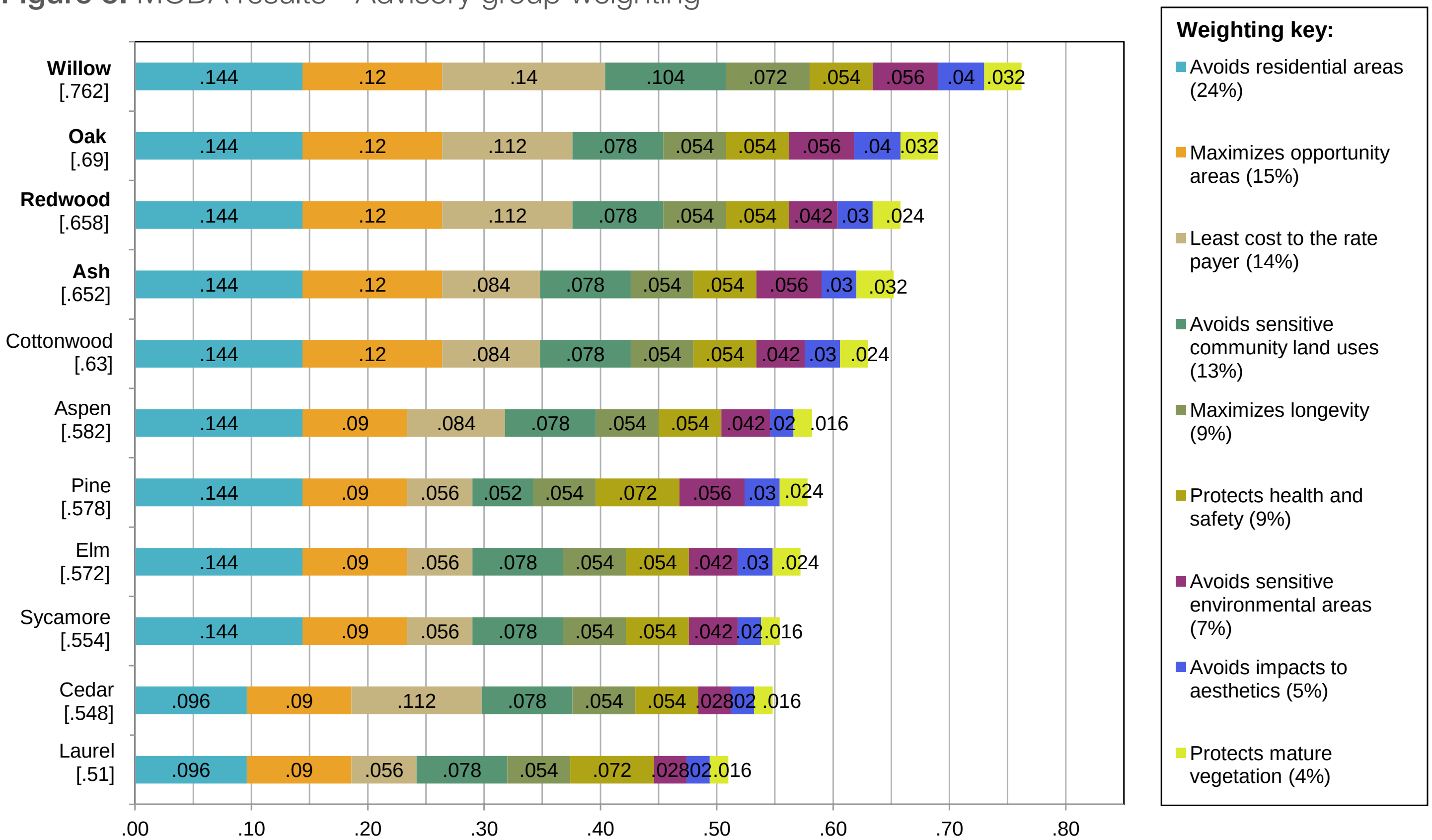
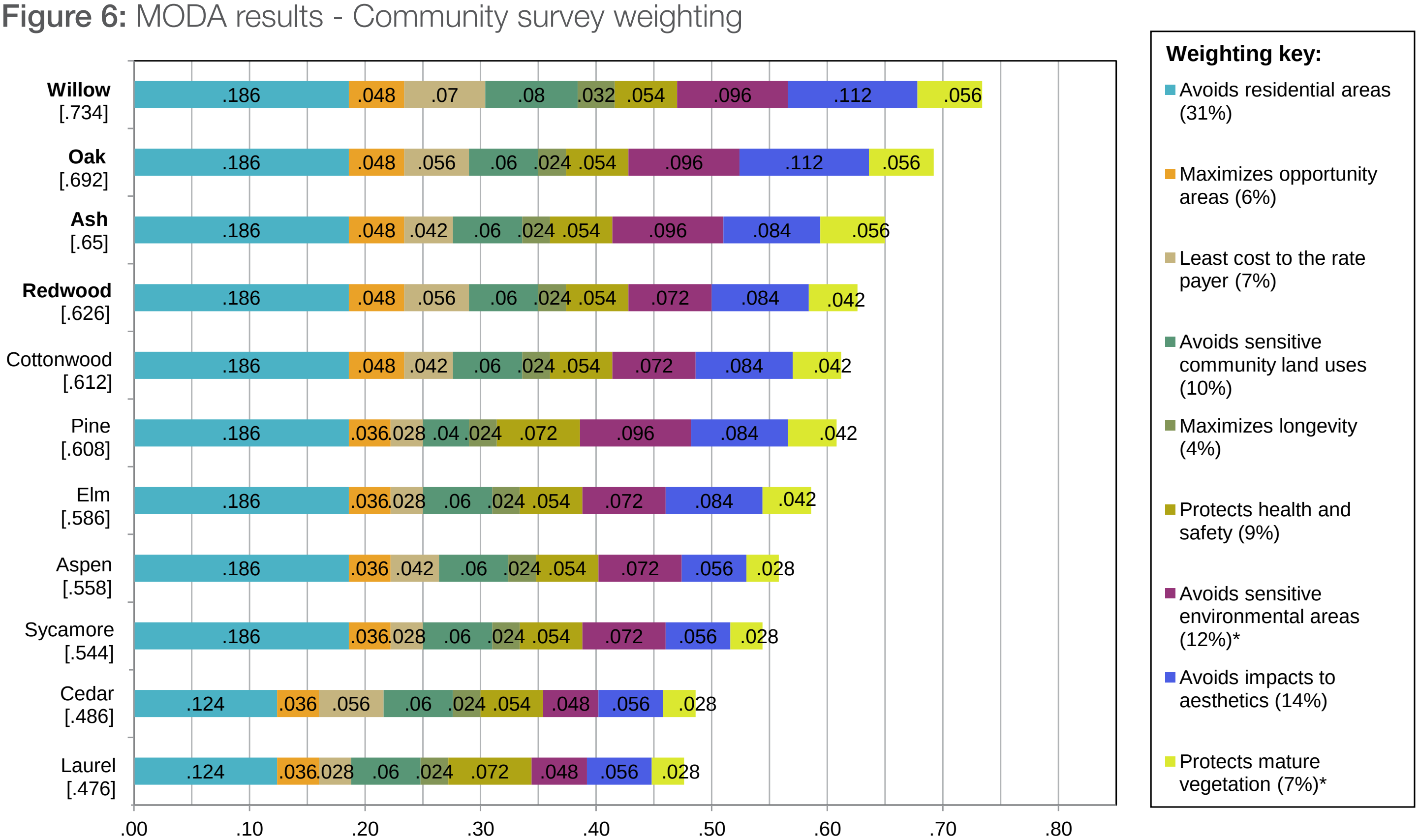



**Figure 6:** MODA results - Community survey weighting



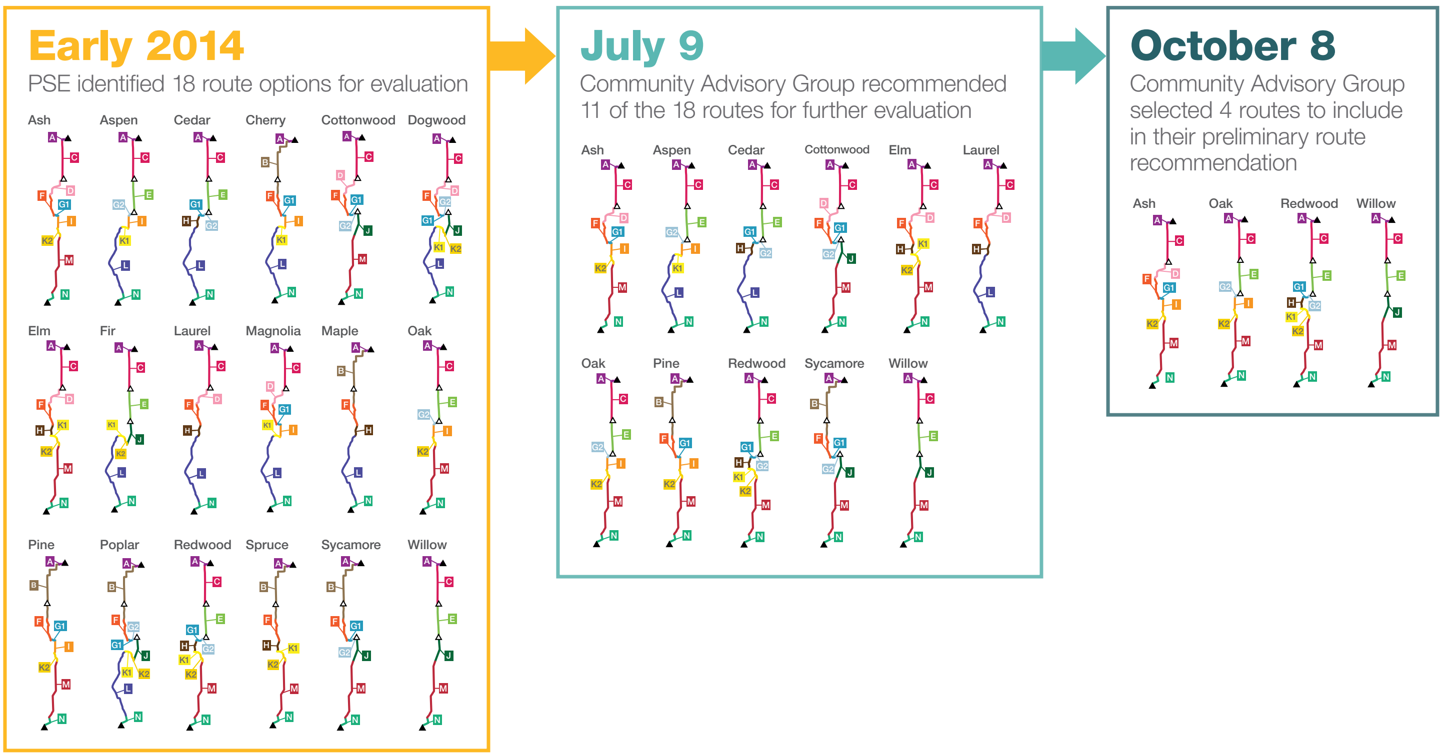

* Note: Transparent Choice, the online MODA software used to compile and calculate results, can only use weighting values that are whole numbers. As a result, the evaluation factors "Avoids sensitive environmental areas" and "Protects mature vegetation" were rounded to the nearest whole number.

## October 2014: Preliminary route recommendation

At their Oct. 8 meeting, the advisory group selected four route options – Ash, Oak, Redwood and Willow – as their preliminary route recommendation (see Figure 7).[4] Information sources that helped the group determine their recommendation included:

- Results of the Multi-Objective Decision Analysis (MODA) using evaluation factor weightings from both the advisory group and community survey results
- Feedback from the summer community survey and other community input
- Discussion of the 11 route options at advisory group meetings

**Figure 7.** Narrowed route options and the preliminary route recommendation in October 2014




4 Of the 18 members present, 15 supported the recommendation, two members abstained and one had a dissenting opinion to include only three routes.

*Reviewing results from the blind evaluation at Community Advisory Group Meeting #4b in Renton.*

# V. Community involvement

In addition to convening the Community Advisory Group, PSE involved the community in the public routing discussion from announcement of the project (December 2013) through the completion of the advisory group process (December 2014) by hosting community meetings, briefing organizations and gathering and responding to comments about the project.

PSE community involvement included:

- More than 240 briefings with individuals, neighborhoods, cities and other stakeholder groups
- 6 public open houses at key project milestones
- 2 online open houses
- 2 question and answer community meetings
- 1 webinar on undergrounding and electric and magnetic fields

Additional project outreach included:

- More than 2,300 comments and questions received from the public, summarized in monthly public comment and open house summaries made available to the advisory group
- 6 project newsletters and postcards sent to more than 50,000 residents and business owners
- Attendance at more than 60 community events
- A traveling kiosk displaying project updates throughout the Eastside
- Project update emails to distribution list, community organizations and elected officials
- Targeted outreach to traditionally underrepresented populations

*Reviewing route option maps at Open House #1 in Renton.*


*Community Projects Manager Jackson Taylor providing project background at the Bellevue Strawberry Festival.*

*Public comment at Question and Answer Meeting #1 in Renton.*

# VI. Recommendation of the Community Advisory Group

On Dec. 10, 2014, the Community Advisory Group selected routes Oak and Willow as their final route recommendation for PSE's consideration (see Figure 8).

With this recommendation, the Community Advisory Group fulfilled their purpose as outlined in their charter:

*"Work collaboratively, creatively and constructively to help determine community/property owner values and engage in a process to evaluate route segments and select a recommended route option."*

Twenty-two advisory group members and four residential association alternates participated in the recommendation discussion. Twenty supported the final recommendation as follows:[1]

- Ten expressed preference for the Oak route
- Five expressed preference for the Willow route
- Five did not express a preference

**Figure 8.** The Community Advisory Group final route recommendation


Four advisory group members and two residential association alternates[2] – representing Bridle Trails Community Club, City of Newcastle, Liberty Ridge Homeowners Association, Olympus Neighborhood Association, Somerset Community Association, and Sunset Community Association – dissented from the recommendation and supported none of the routes. Refer to Appendix B for the dissenting opinion.

1 The above count includes the advisory group members and residential association alternates present at the Dec. 10, 2014 meeting, as well as six members and residential association alternates who did not attend the meeting but later provided feedback on the recommendation.

2 Darius Richards (Kennydale Neighborhood Association) and Scott Kaseburg (Lake Lanes Community Association), who supported the final recommendation in the meeting, signed the dissenting report after the meeting.

At the Dec. 10 meeting, advisory group members and residential association alternates who expressed a preference for Oak or Willow discussed several benefits and tradeoffs of each. See Table 4.

**Table 4.** Route benefits and tradeoffs noted by Community Advisory Group members and residential association alternates with a route preference expressed at the Dec. 10 meeting[3]

| Routes | Benefits | Tradeoffs |
|---|---|---|
| **Oak** (Segments: A-C-E-G2-I-K2-M-N) | • Has fewer adjacent residential parcels (524) of the two routes<br>• Has one quarter of adjacent residential parcels (31 in segments G2, I, K2) compared to same portion in Willow (123 in Segment J) and less than half the residences within 600 feet (289 vs. 721)<br>• Avoids residential areas by using Segment I, which is a largely commercial corridor | • Estimated cost is $22 million more than Willow ($176 million total cost; $1.03 estimated monthly increase to an average residential customer)<br>• Requires building infrastructure in new areas (83% of the route is within the existing corridor)<br>• Has a larger number of adjacent residential tax accounts (1,425) |
| **Willow** (Segments: A-C-E-J-M-N) | • Has fewer adjacent residential tax accounts (1,422) of the two routes (One advisory group member noted that the difference in residences between Oak and Willow was minor.)<br>• Is the most direct route<br>• Has the highest percentage of route within the existing corridor (100%)<br>• Is the least expensive ($154 million total cost; $0.90 estimated monthly increase to an average residential customer)<br>• Has the greatest longevity (2038) | • Has a larger number of adjacent residential parcels (616) of the two routes<br>• Uses Segment J, which is a view neighborhood |

3 For more data on Oak, Willow, and all route options considered by the Community Advisory Group, refer to the complete route options data table on the Energize Eastside project website.


*Discussing the final route recommendation at Community Advisory Group Meeting #6 in Bellevue.*

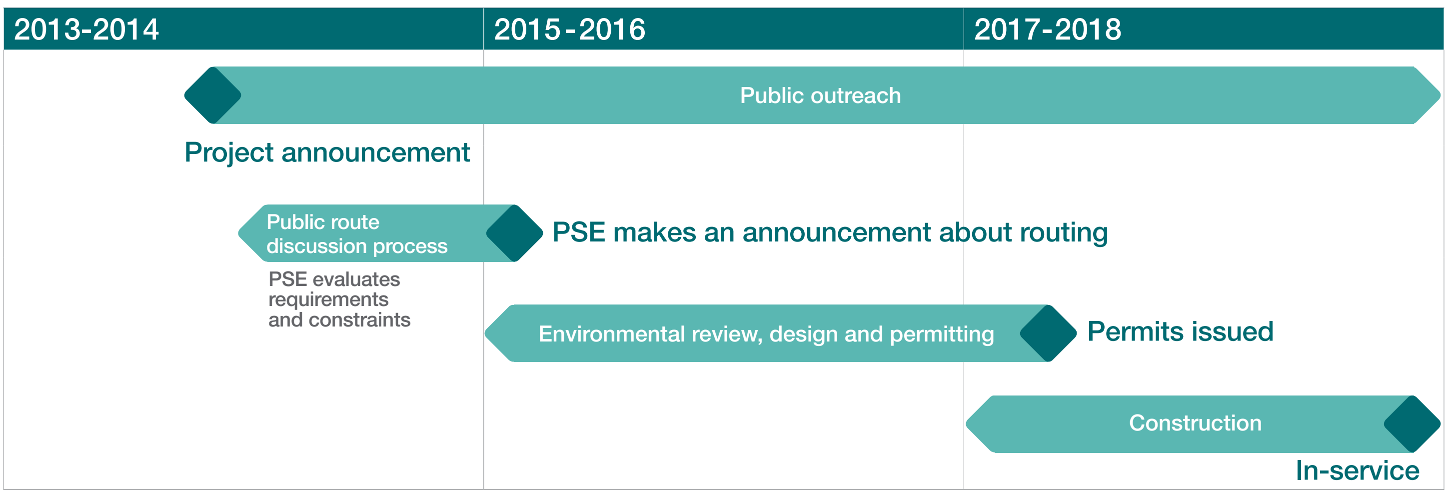
# VII. Puget Sound Energy's next steps

Following the completion of the Community Advisory Group's process, PSE's next steps in 2015 are to:

- Take the Community Advisory Group's recommendation under consideration and make an announcement about routing that balances the needs of customers, the local community, property owners and PSE
- Work directly with property owners and tenants to begin detailed fieldwork to inform environmental review, design and permitting
- Ask for community input on project design, which may include pole height, finish and other design considerations
- Work with the City of Bellevue and other affected jurisdictions and agencies on the project's Environmental Impact Statement (EIS) process

Once these steps are complete, PSE will apply for necessary permits from appropriate agencies and jurisdictions. The project design and permitting phase is expected to run through early 2017. Once fully designed and permitted, project construction is expected to begin in 2017, with project completion planned for 2018. See Figure 9.

**Figure 9:** Project schedule and next steps



# Appendices

**Appendix A:** Community Advisory Group Charter

**Appendix B:** Minority Report

**Appendix C:** Community Advisory Group meeting materials, presentations and summaries

**Appendix D:** Bibliography

# Appendix A: Community Advisory Group Charter

## Community Advisory Group Charter

*Revised:3/24/14*

### Purpose

The main purposes of the Community Advisory Group are to:

- Learn about PSE's proposed route segments, PSE's route analysis work to date, and the complexity of identifying the route segments, and to work with PSE to combine segments to develop a Community Advisory Group-recommend route to inform PSE as PSE selects a final route.
- Collaborate with PSE to decide on a community values-based evaluation process that will be used by the Community Advisory Group to consider PSE's various route segments, combine into possible route options, and narrow route options down to a Community Advisory Group-recommended route.
- Provide a forum for the community to give meaningful input on route segments and route options.
- Help PSE better understand community/property owner values as PSE selects the preferred route that balances the needs of their customers, the local community, property owners and PSE.

### The Community Advisory Group will:

- Develop an understanding of the Energize Eastside project and project need.
- Report back to the people/groups they represent on project details, gather feedback from the interests they represent and provide ongoing communications between PSE and the group they represent throughout the process.
- Provide advice, as community representatives, on ways to address community concerns.
- Participate in geographic Community Advisory Group Sub-Area Committee meetings to determine recommended route segments.
- Work collaboratively, creatively and constructively to help determine community/property owner values and engage in a process to evaluate route segments and select a recommended route option.
- Partner with PSE to combine route segments into one Community Advisory Group recommended route.

### Community Advisory Group Sub-Area Committees

- Sub-Area Committees will consist of Community Advisory Group members and their residential association alternates from each of the geographic sub-areas (North – Kirkland, Redmond and North Bellevue; Central – Bellevue; and South – Newcastle and Renton), as well as a representative from each potentially affected neighborhood association that does not have a member or residential association alternate on the advisory group. Additional community representatives will be invited as needed to ensure comprehensive discussion of issues.
- Community Advisory Group members are expected to attend the Sub-Area Committee meetings for their geographic sub-area. In order to participate in the Sub-Area Committees, members should attend the first two advisory group meetings to ensure they have an understanding of the project.
- Residential association alternates are required to attend the Sub-Area Committees to ensure balanced representation from neighborhoods. Alternates representing other interests are recommended to attend, but it is not required.
- The purpose of the Sub-Area Committees is to have an interest-based conversation on route segments and preferred sub-area options. The outcome of the Sub-Area Committee meetings will

be to develop sub-area segment combination recommendations for the full Community Advisory Group discussion.

### PSE staff will:

- Provide information on the area's growth, the need for the project and the factors involved in developing route segments.
- Provide draft materials to Community Advisory Group members one week before meetings.
- Provide technical experts to provide a greater understanding of the topics at hand and inform Community Advisory Group dialogue.
- Consult with the Community Advisory Group, listen carefully and consider advisory group input prior to making final decisions on key technical issues, and explain all decisions made.
- Listen and take into consideration recommendations from the advisory group with regards to providing data and requests for analysis and research to support advisory group deliberations.

### Norms for individual work as members of the Community Advisory Group

- We acknowledge our group's diversity and value different points of view. We will respect each other's opinions and will operate in consistently constructive ways.
- We will make every effort to attend meetings, to participate actively, to read and be prepared to discuss information and issues, and to be available for work between formal meetings.
- We will keep an open mind and come to meetings with interests, not entrenched positions. We will share our interests and objectives with all Community Advisory Group members. We will openly explain and discuss the reasons behind our statements, questions and actions.
- We will be responsible for representing the interests and concerns of the community we represent at the table. We will consult with our constituencies on a regular basis concerning the discussions and preferences of the Community Advisory Group.
- We will listen carefully to the views expressed by others, avoid interruptions, and seek ways to reconcile others' views with our own. We will represent information accurately and appropriately.
- We will adhere to the ground rules and respect the procedural guidance and procedural recommendations of the facilitator.

### Norms for our work together

***Use of time***

- We will respect each other's time by being on time. Meetings will begin and end on time, unless otherwise agreed to by the Community Advisory Group members.
- When making our comments, we will consider the time needed for others to share their perspectives.

***Recommending a route***

- Community Advisory Group members will strive to collectively make reasonable requests and suggestions through a cooperative and collaborative discussion process with PSE. PSE will inform the Community Advisory Group of any areas of flexibility in the route recommendation development process.
- In discussions, suggestions may not represent unanimity. The facilitator is responsible for seeking and probing for group preferences. It is the responsibility of each stakeholder group member to voice dissent if s/he cannot live with any particular suggestion.
- Any recommendations from the Community Advisory Group and sub-area committees will be considered by PSE. PSE will evaluate requirements and constraints, and select a preferred route. PSE is the final decision maker regarding selecting a preferred route.
- If PSE chooses not to move forward with the recommended route as PSE's preferred route for permitting, PSE will explain the reason for its decision.

***Facilitator***

- We give the facilitator permission to keep the group on track and "table" discussions to keep the group moving.
- We expect the facilitator to help the Community Advisory Group accomplish our purpose in a completely neutral, balanced and fair manner.
- We want the facilitator to:
    - Develop draft meeting agendas.
    - Manage Community Advisory Group meetings and discussions.
    - Consult with Community Advisory Group members between meetings about how to manage the process and address issues of concern.
    - Prepare meeting summaries.

***Role of alternates***

- Each Community Advisory Group member may have one alternate who will be available to stand in for Community Advisory Group members who are unable to attend meetings. Alternates are encouraged to attend all meetings but will not be asked to participate unless called upon.
- Alternates can participate in the Sub-Area Committee meetings if they have attended both of the initial Community Advisory Group meetings.
- Community Advisory Group members are expected to update alternates between meetings so they can replace members on a moment's notice.

***Role of residential association alternates***

- Each Community Advisory Group member representing a residential organization may have an appointed residential association alternate that represents a different neighborhood within their city. Residential association alternates are intended to help balance representation from neighborhoods along the route segments.
- Residential association alternates can ask Community Advisory Group members to yield their seat to ask a question or make a comment during Community Advisory Group meetings.
- Residential association alternates serve as members of their geographic Sub-Area Committee and are expected to attend Sub-Area Committee meetings.

***Proposed meeting ground rules***

- Start / end on time
- Silence cell phones
- Come prepared
- Listen respectfully
- Speak from interests, not positions
- Participate in the process

**Norms for our work with others outside the Community Advisory Group**

***External communications***

- All Community Advisory Group meetings shall be open to the public.
- The public will be given the opportunity to comment during each Community Advisory Group meeting. Those wishing to provide public comment to the advisory group will be strongly encouraged to direct their comments towards the issues and topics of focus on the advisory group's agenda.

- We will avoid characterizing the views or opinions of other Community Advisory Group members outside of any advisory group meeting or activity.
- We will accurately describe Community Advisory Group preferences that are conveyed to PSE.
- Community Advisory Group meetings will be announced on the Energize Eastside website, and meeting announcements with date, time and location, will be provided to local blogs and other media outlets for distribution to the broader community.
- Community Advisory Group meeting products, such as agendas, summaries, and PowerPoint presentations will be posted at pse.com/energizeeastside and will be available to advisory group members for distribution to their constituents. Note: Community Advisory Group member names and affiliations will be included in these materials and will be listed on the project website.

# Appendix B: Minority Report

Some Community Advisory Group members did not concur with the consensus recommendation. The report of the minority is provided here in the interest of inclusiveness. The Community Advisory Group majority has not reviewed this report; consequently, it has not been verified by the Community Advisory Group majority for consistency with the Community Advisory Group charter or for technical accuracy, either independently or in conjunction with engineering support from Puget Sound Energy. This report reflects only the opinion of its signatories.

# Appendix B: Minority Report

## Dissenting Report

We, the undersigned members of the “Community Advisory Group” (CAG) for PSE’s Energize Eastside project, declare our dissent from the recommendations included in the Final Report of the CAG.

The CAG did not truly represent the wishes of the community for the following reasons:

1. CAG members were selected by PSE, not the community.
2. PSE misrepresented the full purpose of Energize Eastside.
3. PSE did not provide real data establishing the need for the project.
4. PSE did not provide a complete list of alternative solutions, and CAG members weren’t allowed to discuss alternatives.
5. The CAG was not given real choices, because some of the route segments were never viable.
6. Few CAG members participated in critical evaluations.
7. The CAG facilitator was not impartial and frequently pressured members to support the group’s conclusions.
8. CAG members were not asked to officially endorse the outcome of the CAG process.

The remainder of this report will provide additional detail regarding these eight objections.

### 1. CAG selection

Composition of the CAG was determined by PSE, not the community. PSE diluted the votes of residential neighborhoods that had the most at stake. Only one quarter of the voting members represented neighborhoods, and many affected neighborhoods had no representative. Some members represented organizations which receive generous donations from the PSE Foundation.

### 2. The full purpose of Energize Eastside

Documents available from ColumbiaGrid, Seattle City Light, and the Bonneville Power Administration make it clear that Energize Eastside solves three simultaneous problems: 1) load for PSE, 2) load for Seattle City Light, and 3) regional grid reliability for Bonneville Power Administration (a federal agency). According to a 2012 Memorandum of Agreement signed by PSE, SCL, and BPA, transmission lines in the Puget Sound region can become congested when high local needs coincide with high flows of electricity to British Columbia, especially when there are faults on BPA’s trunk lines. This is a concern because the United States is obligated to provide electricity to Canada through the Columbia River Treaty. The large scale of the Energize Eastside project addresses both local and international electricity needs. However, Energize Eastside is not the only solution that can do this. It might not even be the most economical solution, when the project’s impact on the community is considered. Reduced property values along the entire 18-mile length of the line cause declines in economic activity and tax receipts, which must be compensated by increasing tax rates on other residents, or decreasing support to people who need tax-funded services.

PSE never disclosed the whole purpose of the project to CAG members. The company sought to minimize regional questions by claiming only 3-8% of power flow serves Canada. While this might be true on a normal day, Energize Eastside is designed to handle extraordinary power flows that occur in rare emergency conditions. Without a full disclosure of the scope and purpose of the project, CAG members were not able to accurately represent the views of their constituents regarding the project.

## 3. Eastside need

PSE illustrates the need for Energize Eastside using a graph titled "Eastside Customer Demand Forecast."[1] This graph has been simplified so it can be easily grasped by the public. It shows demand growing at an average rate of 1.9% per year, crossing the "System Capacity" line in 2017. According to PSE, electricity outages will become more likely after that.

CAG members are well-informed individuals who had months to understand the issues. Therefore, we expected PSE would provide CAG members with more detailed information regarding the need for the project. There are many questions that members had. How has the Eastside's electricity demand grown over time? Why is demand supposedly growing at a much faster rate than population or economic growth? Why is PSE's projection of Eastside's demand growth more than double that of Seattle's or Portland's? Would programs such as Demand Response help mitigate our demand growth?

PSE did not answer these questions, saying that they were outside the scope of the CAG's stated mission. The CAG was formed only to provide recommendations on which route the overhead lines should take through the five Eastside cities. PSE said that community input was not needed regarding any other aspect of the project.

## 4. Alternative solutions

CAG members also raised questions about alternative solutions. They wondered why alternatives were eliminated from consideration and further discussion of alternatives was not allowed.

We believe it is important to list reasonable and viable alternatives to Energize Eastside here, since these ideas do not appear in the limited Final Report. The alternatives described below address only the Eastside's local need. BPA would have to build its own project to solve Canadian reliability issues, at a lower cost to PSE's customers.

The issue of cost is of critical importance to many CAG members, especially organizations representing low-income residents like Hopelink and the YMCA. It is also of interest to businesses that are sensitive to the cost of electricity. Adding 1-2% to electricity costs for the next 40 years may affect their profitability. Many CAG members would have supported lower-cost alternatives if PSE had allowed them to be explored by the CAG.

a. **Demand-side Resources.** Demand-side Resource (DSR) programs are used by utilities in almost every state to reduce the stresses of peak load service and avoid construction of new generation and transmission infrastructure. In the Northwest, Portland General Electric devotes 14 pages of its latest Integrated Resource Plan to descriptions of various programs, including a curtailment tariff, residential direct load control, critical peak pricing, and conservation voltage reduction. Similar programs were studied in a detailed report created by the Cadmus Group for PSE's most recent IRP[2]. Which of these programs is PSE planning to implement? The IRP says, "Demand response program costs are higher than supply-side alternatives at this time, and PSE does not currently have a program in place." Translation: it's cheaper to burn coal in a plant located in Colstrip, Montana (one of the dirtiest coal plants in the nation) that provides nearly 1/3 of the Eastside's electricity. The economics of cheap coal

[1] http://energizeeastside.com/Media/Default/AbouttheProject/2013_1030_Single_Line_Load_Chart_v3.png
[2] https://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_AppN.pdf

and guaranteed returns for capital improvements like Energize Eastside provide little financial incentive for PSE to pursue DSR programs.

b. **Lake Tradition transformer.** For several years before Energize Eastside was conceived, PSE proposed to meet Eastside demand by adding a new 230/115 kV transformer located at Lake Tradition (near Issaquah). Additional power would be delivered on existing 115 kV lines to the Lakeside substation. PSE now claims that this solution causes other transformers to overload in power flow simulations conducted by the company. However, these simulations include the surge of electricity caused by faults in BPA's trunk lines. If BPA were to solve those problems with their own project, Lake Tradition might become a viable solution with much lower costs and community impacts than Energize Eastside.

c. **Upgrade 115 kV lines.** It's possible to use thicker wire and higher capacity transformers on existing lines to increase capacity by approximately 29%. That is enough to delay further action for at least a decade. During that time, it's likely that technologies such as grid batteries, distributed generation, and increasing efficiency will make other solutions possible. This will be cheaper than Energize Eastside, and better for the environment. Upgrading the lines at their current voltage will spare nearly 8000 mature trees that must be cut or removed along the Oak or Willow routes to accommodate a 230 kV line (according to PSE's counts). There is no record that PSE studied this option. It was never mentioned during CAG meetings.

d. **Gas powered plant.** PSE studied the possibility of meeting Eastside needs using a gas-powered generation plant. They dismissed this option in 3 sentences in their Solutions Study. Two of the potential sites for the plant were judged to be too difficult to permit, although this determination was made solely by the company without input from city officials. A third site was dismissed because it would require construction of transmission lines. Neither the CAG nor the cities were given further details about the costs of such a plant, where the transmission lines would be located, how reliability of local generation compares to remote generation, how it impacts the community, or how it might help reduce use of coal that creates much higher emissions of atmospheric carbon, mercury, and sulfur.

e. **Micro-grids and small turbines.** A national expert says that the Puget Sound area is an ideal place to use small gas turbines to inexpensively and incrementally serve peak loads. There is no record that PSE studied this option.

f. **Grid batteries.** PSE says grid batteries are likely to play an important role in the future. The company already has a pilot battery project in Bainbridge. But according to PSE, batteries are too expensive and too risky to use at this time. The company says it can forecast future demand, but it can't forecast the viability of technology solutions that might address that demand.

We believe that one or more of the above solutions would address Eastside's demand and reliability needs for many years at a lower cost than Energize Eastside, allowing us time to develop clean, sustainable solutions rather than rushing a project that is out of scale for our needs as well as our beautiful scenery.

For completeness, we will mention two other alternatives that CAG members were interested in. Both of these would solve Canadian reliability issues as well as Eastside need, but for a considerably higher price tag:

g. **Underground lines.** We list this alternative because it is the most frequently asked question by the public: "In this day and age, why can't we bury our transmission lines?" PSE has made this option politically impossible, due to a tariff the company proposed to the Washington Utilities and Transportation Commission (and which the UTC subsequently adopted). The tariff requires each community who requests an underground line to bear the high cost of underground infrastructure on their own. With the exorbitant costs estimated by PSE, this is not a realistic option for any community. While this tariff seems reasonable for local distribution lines, we hope its application to regional transmission lines will be revisited by the UTC.

h. **Underwater lines.** There are many examples in the U.S. of high-voltage transmission lines being placed in lakes, rivers, and bays. This technology is maturing rapidly. PSE said they would write a white paper on this alternative. The white paper was not released in time for consideration by the CAG.

## 5. No real choices

It should be no surprise that the final routes selected by the CAG mostly follow the existing transmission corridor. This is the result PSE expected from the beginning, and was confirmed by a senior PSE engineer who said the process of route selection was needed to help the public feel like they were involved in the project.

In particular, the choice between the L and M segments was a false choice. The L segment was never a legally viable option due to well-known conflicts and impacts. PSE should have known this. It is also highly questionable that the B segment was viable, due to the large amount of new right-of-way that would need to be acquired to construct that segment.

We believe the CAG process was more about PR for PSE than real choices for the community.

## 6. CAG participation

In several cases, only a few CAG members participated in important evaluations. For example, at the July 9th meeting, it was revealed that only 8 CAG members (less than a third of the CAG membership) participated in an evaluation process to eliminate potential routes. These low participation rates didn't occur because CAG members were lazy or on vacation. Many of the residential representatives refused to participate because they objected to the process.

## 7. CAG process

The facilitator for the CAG was a contractor hired by PSE, harming the appearance of impartiality. The facilitator appeared to have two goals: 1) produce a route recommendation that isn't too onerous to PSE, and 2) achieve this result using "consensus building" techniques.

Unfortunately, these goals were achieved by pressuring or cajoling CAG members to abandon their preferences and join the consensus view. For example, the facilitator would often say to a reluctant member, "Could you live with the emerging consensus of the group?" Or, "Do you want your name to be listed as the dissenting vote?" There were many times when a dissenting member would reluctantly give up significant objections to avoid appearing obstinate or going against the other members. An anonymous ballot would have produced a different result than the facilitated outcome.

Do decisions made in this manner truly represent community values? One need only observe the audience at the final CAG meeting to answer that question. At least 90% of the 400-member audience enthusiastically supported dissenting remarks made by members of the CAG. We conclude the recommendations of the CAG do not represent the desires of the community.

This is also evident in the routes that were finally selected. Both the CAG and hundreds of residents voting online agreed that the top factor to be used to judge routes was "Avoids residential areas." For both the CAG and the community, this factor rated significantly higher than any other. However, in the rush to consensus, the CAG ignored the criterion they previously agreed was the most important and focused instead on cost. All of the routes inequitably burden residential neighborhoods with poles as high as 135 feet that are out of scale with residential land use codes.

## 8. No endorsements

As of December 15, CAG members were not asked to endorse the Final Report with their signatures. We note a stark contrast with the outcome of a different advisory group for a previous PSE project:

> *"We, the members of the Sammamish-Juanita 115 kV Project Stakeholder Advisory Group, affirm and support this recommendations report to Puget Sound Energy. We believe PSE's community-involved siting process for this project has been transparent and reflects community input."*

Why aren't members of our CAG signing a similar statement in support of their recommendations for Energize Eastside? Could members of this CAG sign a positive statement like this in good faith?

## Conclusion

Energize Eastside is one possible step towards our energy future. This is a decision that should be made by citizens and their elected representatives, taking into account values such as community impact, environmental impact, cost, reliability, and safety. This decision should not be made by a utility company or an advisory group with little community support.

**The undersigned members of the CAG declare our dissent with the CAG's Final Report.**

(By signing this document, we are not rescinding the opinions we expressed or votes we cast during CAG meetings, but simply stating our dissent with the overall project and process.)

Norman Hansen CAG, BELLEVUE BRIDLE TRAILS COMMUNITY

L Kaseburg

TIM McHARG, CITY OF NEWCASTLE

Attachment D

Darius F. Richards

Steven D. O'Donnell

David T. Edwards

Lindy Bruce Sunset Community Assn.

# Appendix C: Community Advisory Group Meeting Materials, Presentations, and Summaries

The following links provide all Community Advisory Group meeting materials, presentations and meeting summaries:

Jan. 22, 2014 - Community Advisory Group Meeting #1
Convened the advisory group

Feb. 12, 2014 - Community Advisory Group Meeting #2
Learned about the solution selection process and project routing

June 4, 2014 - Community Advisory Group Meeting #3
Reviewed key findings from the Sub-Area Workshops and Committee Meetings

June 25, 2014 - Community Advisory Group Meeting #4a
Reviewed potential route options

July 9, 2014 - Community Advisory Group Meeting #4b
Narrowied potential route options and finalizing evaluation factors

Oct. 1, 2014 - Community Advisory Group Meeting #5a
Reviewed key findings from the open houses and preparing for route evaluation

Oct. 8, 2014 - Community Advisory Group Meeting #5b
Developed preliminary route recommendation

Dec. 10, 2014 - Community Advisory Group Meeting #6
Finalized route recommendation for PSE to consider

# Appendix D: Bibliography

The list below includes key reports developed by PSE and/or third-party experts, the findings of which were shared with the Community Advisory Group. All linked documents are available on the Energize Eastside project website at pse.com/energizeeastside.


Quanta Technology and Puget Sound Energy, *Eastside Needs Assessment Report*, 2013.

- Executive Summary
- Full Report

Quanta Technology and Puget Sound Energy, *Eastside Transmission Solutions Report,* 2013.

- Executive Summary
- Full Report

TetraTech, *Eastside 230 kV Project Opportunity and Constraints Study for Linear Site Selection,* 2013.

- Executive Summary
- Full Report

Energy + Environmental Economics, *Non-wire Solutions Analysis*, 2014.

- Full report

Power Engineers, *Underground Feasibility Study,* 2014.

- Full report
- Appendix A - Aerial Route Drawings (part 1)
- Appendix A - Aerial Route Drawings (part 2)
- Appendix B - Typical Detail Drawings


Additional documents referenced throughout the Final Report:


Puget Sound Regional Council 2013 Land Use Baseline: Maintenance Release 1 (MR1), update April 2014.

Letter from Seattle City Light, June 2, 2014.

Tariff schedule 80, section 34, 2006

energizeEASTSIDE

## ATTACHMENT E

## Coalition of Eastside Neighbors for Sensible Energy v. City of Bellevue and Puget Sound Energy, Inc.

The Honorable Melinda Young
Hearing Dates: Friday, May 22, 2020
Friday, August 14, 2020
With Oral Argument

IN THE SUPERIOR COURT OF THE STATE OF WASHINGTON

IN AND FOR THE COUNTY OF KING

| | |
|---|---|
| COALITION OF EASTSIDE NEIGHBORS FOR SENSIBLE ENERGY, a Washington non-profit corporation,<br><br>Petitioner,<br>v.<br><br>CITY OF BELLEVUE, a Washington municipal corporation, and PUGET SOUND ENERGY, INC., a Washington public utility corporation,<br><br>Respondents. | No. 19-2-33800-8 SEA<br><br>FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER<br><br>(Chapter 36.70C RCW) |

THIS MATTER was heard before the Honorable Melinda Young, the undersigned judge of the above-titled court. The Land Use Petition Act (LUPA) appeal by Petitioner Coalition of Eastside Neighbors for Sensible Energy (CENSE) challenges Respondent City of Bellevue's decision to approve Puget Sound Energy, Inc.'s (PSE) application for a Conditional Use Permit (CUP) for the South Bellevue Segment of the Energize Eastside project. CENSE also challenges the adequacy of the environmental review conducted by the cities of Bellevue,



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Renton, Newcastle, and Redmond (collectively, "the Partner Cities") for the entire Energize Eastside project under the State Environmental Policy Act (SEPA).

The City of Bellevue, PSE and CENSE appeared in this matter through their attorneys of record, and this Court heard the arguments presented by counsel at the February 14, 2020 Initial Hearing and during the May 22, 2020 and August 14, 2020 hearings on the merits. The Court has reviewed the following records in connection with this LUPA appeal and SEPA challenge:

1. Petitioner CENSE's February 6, 2020 Motion on Procedural and Jurisdictional Matters;

2. Respondent City of Bellevue's February 12, 2020 Response to CENSE's Procedural and Jurisdictional Motion;

3. Petitioner CENSE's April 21, 2020 Opening Brief and all attachments thereto;

4. Respondent City of Bellevue's May 12, 2020 Response to Opening Brief of Petitioner CENSE and all attachments thereto;

5. PSE's May 12, 2020 Response to CENSE Opening Brief and all attachments thereto;

6. Petitioner CENSE's May 19, 2020 Reply Brief of Petitioner CENSE and all attachments thereto;

7. The Certified Administrative Record of Proceedings (RCW 36.70C.110);

8. The Excerpts of Record submitted by Petitioner CENSE, Respondent City of Bellevue, and PSE;

9. The March 28, 2019; March 29, 2019; April 3, 2019; and April 8, 2019 Certified Transcripts of Proceedings before the City of Bellevue Hearing Examiner;



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10. The October 16, 2019; November 14, 2019; and December 2, 2019 Certified Transcripts of Proceedings before the City of Bellevue City Council; and

11. All of the argument presented by the parties at the February 14, 2020; May 22, 2020; and August 14, 2020 hearings on this matter.

Based on the Court's review of the foregoing and hearing the argument presented by the parties at the February 14, 2020; May 22, 2020; and August 14, 2020 hearings, the Court now enters the following Findings of Fact, Conclusions of Law, and Order:

## FINDINGS OF FACT

1. PSE's Energize Eastside project is a linear infrastructure project to upgrade sixteen (16) miles of high voltage transmission lines from Renton to Redmond and to construct a new substation in the City of Bellevue (the "Richards Creek substation"). AR 001319.

2. The Energize Eastside project is a single project within the jurisdiction of multiple permitting agencies who will consider various permit applications subject to different land use processes. AR 006823.

3. The purpose of the Energize Eastside project is to meet local electricity peak demand growth and to protect electrical grid reliability in the Eastside of King County, roughly defined as extending from Redmond in the north to Renton in the south, and between Lake Washington and Lake Sammamish. AR 000011-13, 001321, 006812-6815, 011637.

4. The work anticipated as part of the Energize Eastside project is limited to the existing utility corridor, which has existed for almost a century, and PSE's proposed transmission lines and associated infrastructure will generally be in the same location as the existing utility infrastructure. AR 000010-11, 001327, 001340.



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5. Although the Partner Cities and King County each have land use permitting authority over portions of the Energize Eastside project, the City of Bellevue (City) was designated as the lead agency for the Partner Cities' environmental review of the project. AR 000018, 001319, 001387, 006812-6813, 006823.

6. The Partner Cities' environmental review included preparation of a Phase 1 Draft Environmental Impact Statement ("Phase 1 Draft EIS") and Phase 2 Draft EIS, released in January 2016 and May 2017, respectively, and culminated in the issuance of the March 1, 2018 Final EIS. AR 000018-21, 001387, 006793-13385.

7. The environmental analysis presented a comprehensive environmental assessment of the entire Energize Eastside project throughout each jurisdiction, extending from the cities of Renton to Redmond. AR 000018-21, 001387-1398, 006821-6822, 006824-6835, 006891-7182, 007204-7212.

8. The Phase 2 Draft EIS and Final EIS analyzed fourteen (14) transmission line routing alternatives. AR 000018, 06837.

9. The environmental analysis considered potential environmental impacts in the South Bellevue Segment associated with construction of the Richards Creek substation and the transmission line upgrades in south Bellevue. *See* Final EIS (AR 006826, 006860, 006904-6905, 006916, 006923-6928, 006942-6948, 006981-6982, 006986, 007011, 007021-7022, 007033-7034, 007053, 007073, 007111, 007135) & Phase 2 Draft EIS (AR 011683-11686, 011735-11743, 011760-11763, 011769-11770, 011809-11811, 011814-11816, 011818-011823, 011825).



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10. The Final EIS also disclosed and considered PSE's phased construction plan for the Energize Eastside project, and explained the utility and benefit of PSE's phased construction and permitting schedule. AR 006823, 006866, 007557.

11. The Energize Eastside project needs to be built in two construction phases to keep the transmission system on-line to serve customers. AR 006823, 006866. During the construction of the south phase, the Lakeside substation will be served from the north, and after the south phase is complete, the Richards Creek substation will be used to serve the northern phase, located in north Bellevue and Redmond, while this northern phase is permitted and constructed. AR 000021-22, 006823, 006866, 007557.

12. Contrary to CENSE's arguments, the Final EIS never stated that the first phase of construction would be limited to the South Bellevue Segment, or that the first phase of construction from Renton to Bellevue, standing alone, can feasibly attain or approximate PSE's stated objectives for the Energize Eastside project. AR 006823, 006866.

13. Permitting and construction of the South Bellevue Segment will not result in any significant unavoidable adverse environmental impacts in central Bellevue or north Bellevue, and the Final EIS did not identify any significant unavoidable adverse environmental impacts in central or north Bellevue as a result of the entire Energize Eastside project. AR 006826, 007209-7212.

14. Between 2012 and 2015, PSE and the City commissioned three studies that confirmed PSE's conclusion that the Energize Eastside project is needed to meet local electricity peak demand growth and to protect electrical grid reliability. AR 000013, 001323-1324, 001420-1424.



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15. The City also separately commissioned an independent analysis by Utility System Efficiencies, Inc. (USE Study), which evaluated PSE's system and again confirmed the need for the Energize Eastside project. AR 001282, 001978-2053.

16. The independent consulting firm Stantec Consulting Services, Inc. reviewed PSE's analysis of project need (Stantec Report), confirmed that PSE's analysis followed standard industry practice, and confirmed the Energize Eastside project is designed to bring the needed infrastructure to supply the local need. AR 000013, 00016-17, 001864-1873.

17. The Stantec Report explained that PSE must plan for peak demand periods and potentially employ Corrective Action Plans (CAPs) to protect an overloaded system and reduce heating on certain system transformers and lines so that they will not be destroyed. AR 000016-17, 001871-1872.

18. CAPs, load-shedding, and blackouts adversely affect everyone, including residential uses and critical support services like hospitals, nursing homes, fire departments, and police stations. AR 000026, 001872.

19. Consistent with the phased construction plan for the Energize Eastside project identified in the Final EIS, PSE submitted permit applications to the City, Renton, Newcastle, and unincorporated King County for land use approval in connection with the first construction phase of the Energize Eastside project. AR 000010, 001319, 006822, 007557.

20. PSE submitted two land use permit applications to the City for the South Bellevue Segment of the Energize Eastside project simultaneously: (1) the CUP at issue in this lawsuit, and (2) a Critical Areas Land Use Permit (CALUP). AR 001314-1315, 001321-1325.

21. The City's approval of the CALUP has not been challenged by CENSE or any other party and is now final. AR 000006-7, 000027.



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22. PSE's CUP application to the City requested approval to construct the Richards Creek substation and to upgrade 3.3 miles of 115-thousand-volt (kV) transmission lines with 230 kV lines within the existing utility corridor in south Bellevue. AR 000009, 001314, 001319, 006860.

23. PSE's CUP proposal for the South Bellevue Segment of the Energize Eastside project is located in a land use district that currently accommodates the utility corridor and requires the service that PSE's proposal will provide. AR 000022-26, 001328, 001340, 001357, 001539, 001543.

24. The South Bellevue Segment of the Energize Eastside project is being constructed and permitted in exactly the same manner and as part of the same phased construction sequence identified in the Final EIS. AR 000018-22, 001319, 001539, 006823, 006826, 006838, 006842, 006860, 006866, 07557.

25. PSE's CUP application is subject to the Electrical Utility Facilities provisions in the City's Land Use Code (LUC), at LUC 20.20.255, and the CUP decision criteria in LUC 20.30B.140. AR 000005-6, 001416.

26. The Electrical Utility Facilities provisions in LUC 20.20.255 impose additional requirements on PSE's proposal above and beyond standard CUP provisions, including an Alternative Siting Analysis (ASA) and additional decision criteria in LUC 20.20.255.E. AR 001354-1357, 001420-1426.

27. Consistent with the requirements in LUC 20.20.255.D, PSE submitted a comprehensive ASA that described three siting alternatives, the land use districts within which the sites are located, mapped the location of the sites, provided justification for locating the infrastructure upgrades in the existing utility corridor, and depicted the proximity of the sites to



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neighborhood business land use districts, residential land use districts, and transition areas. AR 001355, 001541-1556, 001568-1574.

28. The ASA submitted by PSE provided a location selection hierarchy, as required by LUC 20.20.255.D.2.d., and described the range of technologies PSE considered for its proposal, how the proposal provides reliability to the customers served, how the components relate to system reliability, and how the proposal includes technology best suited to mitigate impacts on surrounding properties. AR 001355-56, 001545-1547, 001553-1562. The ASA explained the community outreach PSE conducted over many years prior to submittal of the CUP application. AR 001356-1357, 001562-001565.

29. The ASA also explained that the Energize Eastside project is needed because cumulative demand on the Eastside is increasing, including in areas along the South Bellevue Segment. AR 001543.

30. Within the City of Bellevue, the CUP application for the South Bellevue Segment is subject to a different land use process (Process I) than a CUP application for the northern construction phase (Process III). AR 00931-938, 01320-1321, 006823.

31. Under the City's Process I land use process, the City's Land Use Director issues a recommendation to the Hearing Examiner, and the Hearing Examiner, after holding a public hearing, issues a decision on the application. LUC 20.35.130 – 20.35.140. The Hearing Examiner's decision may then be appealed to the City Council, and the City Council's quasi-judicial decision on appeal is the City's final decision. *Id.* at 20.35.150.

32. On January 24, 2019, the City's Land Use Director recommended approval, with conditions, of PSE's CUP application. AR 001314, 001354-1357, 001420-1436. In connection



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with the Director's recommendation, the City issued a 151-page Staff Report with fifty-three (53) conditions of approval and ten (10) separate attachments. AR 001314-2825.

33. The Staff Report explained in detail why PSE's proposal satisfied the ASA requirements in LUC 20.20.255.D, the Conditional Use decision criteria in LUC 20.30B.140, and the Electrical Utility Facilities decision criteria in LUC 20.20.255.E. AR 001314-001347 (overview of PSE's South Bellevue Segment proposal and the Energize Eastside project), 001354-001360 (PSE compliance with the ASA requirements in LUC 20.20.255.D), 0001325, 001387-001398 (SEPA analysis), and 001420-001432 (PSE compliance with the Electrical Utility Facilities Decision Criteria in LUC 20.20.255.E and the City's Comprehensive Plan).

34. Prior to the public hearing before the Hearing Examiner, CENSE filed multiple motions, arguing that PSE had violated SEPA by applying for permits for the South Bellevue Segment without simultaneously applying for permits for the northern segment of the Energize Eastside project. CENSE also asked the Hearing Examiner to compel PSE to produce certain energy "consumption data" that CENSE believed was necessary for the public hearing. AR 00841, 001068, 001108.

35. Although the Hearing Examiner denied CENSE's pre-hearing motions, he allowed CENSE to raise the same arguments throughout four (4) days of hearing, and PSE and the City continued to respond to CENSE's arguments throughout the hearing. TR 000605-611, 000654-655, 000682-687. The Hearing Examiner also addressed CENSE's legal arguments at length in his Decision. AR 000020-26, 000032-39.

36. Over the course of the 4 day public hearing, the Hearing Examiner received public testimony from approximately fifty-six (56) individuals. AR 000846, 000007-8, 000022-23.



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37. Local residents, business owners, community leaders, and health care professionals testified in support of PSE's CUP application, citing the need for safe and reliable power as the City and the Eastside continue to grow. AR 000022-23, 0000032-33; TR 000101-108, 000110-113, 000121-124, 000148-157, 000161-164, 000173-174, 000241-245, 000250-252, 000285-288. Conversely, many citizens who live along the existing utility corridor opposed PSE's application, primarily opposing PSE's finding of project "need" and voicing concerns with hazards posed by co-located electrical lines over the existing Olympic petroleum pipeline. AR at 000016, 000023, 000026, 000033; TR 000593-595.

38. Throughout the public hearing, the Hearing Examiner allowed and encouraged CENSE and its members to present their public comments, expert testimony, and legal arguments in opposition to PSE's CUP application and the Energize Eastside project. TR 000090-91, 000130-133, 000146-147, 000296-297, 000621-622, 000644, 000652-653.

39. North Bellevue residents who are members of CENSE and do not reside in south Bellevue also testified at the public hearing in opposition to PSE's CUP application for the South Bellevue Segment. AR 000170-206.

40. By the close of the hearing, CENSE had provided over two (2) hours of presentation, expert testimony, legal argument, and public comment; and the Hearing Examiner admitted and considered a total of thirteen (13) motions, briefs, and written exhibits from CENSE. AR 000841-843, 001312.

41. Contrary to CENSE's argument in its motions and during the public hearing, PSE's evaluation of operational need is based on peak demand and not on the volume of energy consumed over time. AR 000017, 000025, 001864-1873, 13518-13525; TR 000456-459, 000462-463.



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42. If PSE's system cannot meet peak demand, power outages affect everyone, including residential uses along the South Bellevue Segment of the Energize Eastside project and critical support services like hospitals, nursing homes, fire departments, and police stations. AR 000014-18, 000026, 001864-1873.

43. The Hearing Examiner issued his Decision on June 25, 2019. AR 000004-40. The Decision detailed why the technical studies, expert testimony, and argument presented by PSE established that several key aspects of the opposition presented by CENSE were defective and not credible. AR 000023-26. The Decision addressed CENSE's objections to PSE's construction plan and found that the environmental review undertaken by the Partner Cities supported approval of the CUP. AR 000020-21.

44. The Hearing Examiner found that the Staff Report, attachments to the Staff Report, and testimony and evidence submitted by PSE during the public hearing established that PSE satisfied the requirements of LUC 20.20.255.E.3, which requires PSE to demonstrate operational need for its electrical utility proposal. AR 000013-14, 000024-25, 001323-1324, 001420-1424, 001864-1873, 001977-2053; TR 000043-75, 000416-417, 000456, 000483-484, 000562, 000713, 000731.

45. The Hearing Examiner concluded that CENSE, its representatives, and other opponents articulated their concerns but did not offer sufficient, relevant, authoritative, or credible evidence that would rebut the findings and recommendations made in the Staff Report or the substantial evidence presented by PSE throughout the land use process. AR 000024. Ultimately, the Hearing Examiner approved PSE's requested CUP, with conditions. AR 000040, 000042-61.



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46. After the Hearing Examiner issued the Decision, CENSE, three (3) members of CENSE who live in north Bellevue, and another opponent of the Energize Eastside project appealed the Hearing Examiner Decision to the Bellevue City Council. AR 000128-129, 000132.

47. Following an appeal hearing before the Bellevue City Council where CENSE and the other appellants presented argument in opposition to PSE's CUP application, the City's Mayor provided a lengthy explanation of why the Hearing Examiner's Decision was supported by material and substantial evidence in the record. TR 001177-1190. The Mayor explained, on the record, why PSE had satisfied the LUC criteria requiring PSE to demonstrate operational need (TR 001181-1185) and addressed CENSE's objections to PSE's phased construction plan for the Energize Eastside project (TR 001187-1188).

48. On December 2, 2019, the City Council formally and unanimously, with one recusal, adopted the Hearing Examiner's Decision and denied the four appeals through the enactment of Ordinance 6494. AR 000001-3; TR 01202-1203. CENSE then filed the current lawsuit challenging both the City's CUP approval for the South Bellevue Segment and the Partner Cities' environmental review of the Energize Eastside project.

## CONCLUSIONS OF LAW

A. The CUP Challenge

1. Under LUPA, CENSE carries the burden of establishing that the City erred under at least one of following standards of review:

> (a) The body or officer that made the land use decision engaged in unlawful procedure or failed to follow a prescribed process, unless the error was harmless;



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> (b) The land use decision is an erroneous interpretation of the law, after allowing for such deference as is due the construction of a law by a local jurisdiction with expertise;
>
> (c) The land use decision is not supported by evidence that is substantial when viewed in light of the whole record before the court; [or]
>
> (d) The land use decision is a clearly erroneous application of the law to the facts…..

RCW 36.70C.130(1)(a), (b), (c) & (d); *Pinecrest Homeowners Ass'n v. Glen A. Cloninger & Assocs.*, 151 Wn.2d 279, 288, 87 P.3d 1176 (2004).

2. In reviewing a LUPA decision, a reviewing court considers only the administrative record and gives "substantial deference to both the legal and factual determinations of a hearing examiner as the local authority with expertise in land use regulations." *Lanzce G. Douglass, Inc. v. City of Spokane Valley*, 154 Wn. App. 408, 415, 225 P.3d 448 (2010) (citing *City of Medina v. T–Mobile USA, Inc.*, 123 Wn. App. 19, 24, 95 P.3d 377 (2004)).

3. Evidence and any inferences are viewed "in a light most favorable to the party that prevailed in the highest forum exercising fact finding authority." *Id.* (citing *City of University Place v. McGuire*, 144 Wn.2d 640, 652, 30 P.3d 453 (2001).

4. Under the substantial evidence standard applicable to RCW 36.70C.130(1)(c), there must be a sufficient quantum of evidence in the record to persuade a reasonable person that the declared premise is true. *Wenatchee Sportsmen Ass'n v. Chelan County*, 141 Wn.2d 169, 176, 4 P.3d 123 (2000). A finding is clearly erroneous under RCW 36.70C.130(1)(d) only when, although there is evidence to support it, the reviewing court is left with the definite and firm conviction that a mistake has been committed. *Id.*



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5. CENSE's has not sustained its burden of establishing that the Hearing Examiner engaged in an unlawful procedure in violation of RCW 36.70C.130(1)(a) or that the City violated the appearance of fairness doctrine, chapter 42.36 RCW.

6. "The [appearance of fairness] doctrine requires that public hearings which are adjudicatory in nature meet two requirements: the hearing itself must be procedurally fair, and it must be conducted by impartial decisionmakers." *Raynes v. City of Leavenworth*, 118 Wn.2d 237, 245-246, 821 P.2d 1204 (1992), citations omitted.

7. The record shows that CENSE and the public fully participated in the public hearing and that the City allowed CENSE, its members, its experts, its attorneys, and the public substantial opportunity to participate in the land use process and the public hearing before the Hearing Examiner.

8. There is substantial evidence in the record showing that the Hearing Examiner acted as a fair and impartial decision maker and lawfully administered the public hearing. AR 000022-23, 0000032-33, 000841-843, 000846, 001312; TR 000090-91, 000101-108, 000110-113, 000121-124, 000130-133, 000146-157, 000161-164, 000173-174, 000241-245, 000250-252, 000285-288, 000296-297, 000621-622, 0000644, 000666.

9. The Hearing Examiner correctly concluded that PSE complied with the Electrical Utility Facility decision criteria in LUC 20.20.255.E and satisfied the ASA requirements in LUC 20.20.255.D.

10. The Hearing Examiner correctly found that "'load-shedding' – i.e. rolling blackouts – is currently part of PSE's corrective action plan (CAP) options in neighborhoods throughout the Eastside, including residential neighborhoods that are located along the route of the South Bellevue Segment." AR 000026.



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11. The Hearing Examiner correctly found that PSE's CUP proposal for the South Bellevue Segment is located in a land use district that currently accommodates the utility corridor and requires the service that PSE's proposal will provide. AR 000022-26, 001328, 001340, 001357, 001539, 001543.

12. CENSE provides no evidence showing that south Bellevue residents are immune to power outages resulting from an electrical utility system that cannot meet peak demand. AR 000026, 001872.

13. CENSE's argument that operational need has changed based on PSE's phased construction plan is not supported by the record because the South Bellevue Segment is being constructed and permitted in exactly the same manner and as part of the same phased construction sequence described and assessed in the Partner Cities' environmental review. AR 000019, 000021-22, 001354-001357, 001417, 001539, 001545-1547, 001553, 001562, 006491-6498, 006503-6507, 006823, 006866.

14. Although CENSE characterizes PSE's CUP application for the South Bellevue Segment as a "truncated, dead-end line," CENSE provided no evidence establishing that PSE has abandoned the larger Energize Eastside project and/or the northern portion of the project, extending from north Bellevue to Redmond.

15. The Staff Report concluded correctly that PSE submitted an ASA that complied with the requirements of LUC 20.20.255.D. AR 000019, 001327-1328, 001354-1357, 001425-001435, 001535-1566.

16. The Hearing Examiner concluded correctly that the ASA "contains sufficient information regarding the methodology employed, the alternative sites analyzed, the



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technologies considered, and the community outreach undertaken to satisfy the requirements of LUC 20.20.255.D." *Id.* at 000019.

17. Given the substantial deference afforded the Hearing Examiner, CENSE failed to sustain its burden to show that the City's approval of the CUP involved any erroneous interpretation of LUC 20.20.255.E or LUC 20.20.255.D.

18. CENSE failed to appeal the City's approval of the CALUP issued by the City, and the Hearing Examiner correctly held that CENSE cannot collaterally attack any aspect of the final CALUP approval or the electrical utility facility siting evaluated and permitted by the CALUP. AR 000027; *Wenatchee Sportsmen*, 141 Wn.2d at 172, 180-182, 4 P.3d 123; *Habitat Watch v. Skagit County*, 155 Wn.2d 397, 410-411, 120 P.3d 56 (2005).

19. Phased construction and permitting for a linear infrastructure project is not an example of piecemeal environmental review prohibited by SEPA or inconsistent with *Merkel v. Port v. Brownsville*, 8 Wn. App. 844, 509 P.2d 390 (1973).

20. SEPA allows phased review in certain circumstances, but SEPA prohibits the practice of conducting environmental review only on current segments of a project and postponing environmental review of later segments until construction begins. *Concerned Taxpayers Opposed to Modified Mid-South Sequim Bypass v. State, Dept. of Transp.*, 90 Wn. App. 225, 231 & fn. 2, 951 P.2d 812 (1998) (citing *Cathcart-Maltby-Clearview Community Council v. Snohomish County*, 96 Wn.2d 201, 210, 634 P.2d 853 (1981)).

21. The SEPA Rules specifically prohibit environmental review that divides a larger system into exempted fragments, avoids discussion of cumulative impacts, or avoids consideration of impacts that are required to be evaluated in a single environmental document. WAC 197-11-060(5)(d)(ii) & (iii). The City's two-phased EIS process properly and fully disclosed and analyzed the potential impacts of the *entire* Project (Redmond, Bellevue, Newcastle, and Renton).



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22. Within the three-volume document, it also assessed the impacts to specific subsections and under a range of alternative routing option—including the South Bellevue Segment. There is no credible claim that the Project's SEPA review was improperly segmented.

23. The comprehensive and exhaustive environmental review conducted by the Partner Cities for the Energize Eastside project did not divide the project into exempted fragments, avoid discussion of cumulative impacts, or avoid consideration of impacts that are required to be evaluated in a single environmental document.

24. *Merkel v. Port v. Brownsville*, 8 Wn. App. 844, 509 P.2d 390 (1973) does not support CENSE's "segmentation" argument or require that PSE submit all land use permit applications for the entire Energize Eastside project simultaneously. No portion of the Energize Eastside project is subject to the Shoreline Management Act (SMA), and the City of Bellevue's local electrical utility regulations, land use processes, and attendant CUP approval for the South Bellevue Segment of the project is not the functional equivalent of the systematic state-wide shoreline management required by the SMA, chapter 9.58 RCW.

25. In this case, the Final EIS does not disclose any significant unavoidable adverse environmental impacts in central Bellevue or north Bellevue as a result of construction of the South Bellevue Segment or from construction of the entire Energize Eastside project. AR 000018-22, 001319, 001539, 006823, 6826, 006838, 006842, 006860, 006866, 7209-7212, 07557.

26. The Partner Cities complied with the procedures established by SEPA, fully considered the potential environmental effects of the entire Energize Eastside project across all jurisdictions, and there is no evidence in the record that construction of the South Bellevue



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Segment will cause or create significant unavoidable adverse environmental impacts to central Bellevue or to north Bellevue.

27. SEPA contemplates circumstances such as the Energize Eastside project where multiple agencies have permitting authority over a single project. *See* WAC 197-11-922 to -948; and WAC 197-11-055(5). In such a situation, the lead agency prepares the EIS for the proposed project, and other agencies with jurisdiction over the project use the EIS prepared by the lead agency to inform their permitting decisions. WAC 197-11-050(2)(b); WAC 197-11-600(3)(c).

28. The north and south segments of the Energize Eastside project have been combined for environmental review in compliance with SEPA, but SEPA does not require that the north and south segments of the project must be combined by PSE for land use permitting purposes.

29. PSE's CUP for the South Bellevue Segment is not within the East Bellevue Community Council's (EBCC) jurisdiction, and the EBCC does not have any permitting authority over land use decisions outside of its jurisdiction. RCW 35.14.040.

49. Under the City's LUC, the CUP application for the South Bellevue Segment is subject to a different land use process than a CUP application for the northern construction phase, and the record shows that the only CUP application before the City at the time of approval was for the South Bellevue Segment of the Energize Eastside project. AR 001314-1315, 001321-1325; TR 001188.

B. The SEPA Challenge



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1. SEPA requires agencies to integrate environmental concerns into their decision-making processes and study and explain the environmental consequences before pursuing actions. *Stempel v. Dep't of Water Res.*, 82 Wn.2d 109, 117-118, 508 P.2d 166, 171 (1973).

2. An EIS is the most detailed form of environmental review required under SEPA and is prepared when an agency determines that it is probable that a project would have significant environmental impacts. AR 001387; WAC 197-11-400.

3. Under SEPA, the Court's review of EIS adequacy is *de novo*, but the Court gives "substantial weight" to the Environmental Coordinator's determination that the EIS is adequate. *Glasser v. City of Seattle, Office of Hearing Exam'r*, 139 Wn. App. 728, 739-740, 162 P.3d 1134 (2007) (citing RCW 43.21C.090; *Klickitat County Citizens Against Imported Waste v. Klickitat County*, 122 Wn.2d 619, 633, 860 P.2d 390, 866 P.2d 1256 (1993) (citing R. Settle, *The Washington State Environmental Policy Act: A Legal and Policy Analysis* § 14(a)(i) (4th ed.1993)).

4. The Court's *de novo* review gives deference to agency discretion required by SEPA, at RCW 43.21C.090, and the "rule of reason." *Id.*; *Cheney v. Mountlake Terrace*, 87 Wn.2d 338, 344-45, 552 P.2d 184 (1976).

5. Under the "rule of reason," the EIS must present decision makers, in this case the City of Bellevue, with a "'reasonably thorough discussion of the significant aspects of the probable environmental consequences'" of the agency's potential land use decision. *Glasser*, 139 Wn. App. at 740 (citing *Klickitat Cnty.*, 122 Wn.2d at 633, 860 P.2d 390 (quoting *Cheney*, 87 Wn.2d at 344–45, 552 P.2d 184)); *Residents Opposed to Kittitas Turbines v. State Energy Facility Site Evaluation Council*, 165 Wn.2d 275, 311, 197 P.3d 1153 (2008) (citation omitted).



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6. Thus, the determination by the City's Environmental Coordinator that the Final EIS was adequate "shall be accorded substantial weight" under SEPA, and this judicial deference, combined with the "rule of reason," is the standard of review for adjudication of CENSE's challenge to EIS adequacy. *Id.*; RCW 43.21C.090.

7. SEPA requires that an agency consider alternatives to a proposed action. RCW 43.21C.030(c)(iii). Although the purpose of the EIS is to facilitate the decision-making process, it need not list every remote, speculative, or possible effect or alternative. *Klickitat Cnty.*, 122 Wn.2d at 641, 860 P.2d 390. Instead, EIS alternatives must "include actions that could feasibly attain or approximate a proposal's objectives, but at a lower environmental cost or decreased level of environmental degradation." WAC 197–11–440(5)(b); AR 006814.

8. Under SEPA, supplemental environmental review is not required when probable significant adverse environmental impacts are covered by the range of alternatives and impacts analyzed in the existing environmental documents. WAC 197-11-600(3)(b)(ii).

9. CENSE fails to provide any evidence showing that the South Bellevue Segment alone can feasibly attain or approximate PSE's stated objectives for the Energize Eastside project as required by WAC 197-11-440(5)(b).

10. CENSE fails to provide any evidence that construction of the South Bellevue Segment as a "standalone" project would meet local electricity peak demand growth and protect electrical grid reliability in the Eastside of King County, from Redmond in the north to Renton in the south, or provide necessary redundancy to ensure electrical power production remains on-line when equipment in the north or the south is not working. AR 001321, 006815, 011637.

11. The environmental record confirms that the Partner Cities' environmental review complied with SEPA as the Final EIS provided full analysis of potential environmental



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impacts in the South Bellevue Segment and across all jurisdictions from Renton to Redmond. AR 000018, 001325, 001387, 006818-006822, 006824-6835, 06838-6839, 006891-7182, 011642, 011645, 011659-011700, 012469-12470, 012531-012532, 012563-12569, 012583-12584, 012586-12587, 012592-12593, 012597-12600.

12. The Partner Cities' environmental review complied with SEPA because it included a "'reasonably thorough discussion of the significant aspects of the probable environmental consequences'" of the Energize Eastside project within the South Bellevue Segment and across all jurisdictions with permitting authority. *Glasser*, 139 Wn. App. at 740 (citing *Klickitat Cnty.*, 122 Wn.2d at 633, 860 P.2d 390 (quoting *Cheney*, 87 Wn.2d at 344–45, 552 P.2d 184)); *Residents Opposed to Kittitas Turbines,* 165 Wn.2d at 311, 197 P.3d 1153 (citation omitted).

**ORDER**

Now, therefore, it is hereby ORDERED that the City of Bellevue's decision approving PSE's CUP application, with conditions, is AFFIRMED, and Petitioner CENSE's LUPA appeal is DENIED. Likewise, Petitioner CENSE's challenge to the adequacy of the environmental review undertaken by the Partner Cities for the Energize Eastside project is DENIED.

Over the course of the underlying land use process and when issuing its decision on this matter, the City did not engage in an unlawful procedure; the City's approval of PSE's CUP application was not an erroneous interpretation of the law; the City decision was supported by substantial evidence in the record before this Court; and the City's decision was not a clearly erroneous application of the law to the facts present in the record. RCW 36.70C.130(1)(a), (b), (c) & (d). The City did not err when it approved PSE's CUP application for the South Bellevue Segment of the Energize Eastside project or when it certified that the Final EIS was adequate.



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For each of the foregoing reasons, Petitioner CENSE's Land Use Petition, brought under chapter 36.70C RCW, and SEPA challenge, brought under chapter 43.21C RCW, are DENIED in full.

DATED this 21st day of September, 2020.

THE HONORABLE Melinda Young
King County Superior Court Judge



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# King County Superior Court
# Judicial Electronic Signature Page

Case Number: 19-2-33800-8
Case Title: COALITION OF EASTSIDE NEIGHBORS FOR SENSIBLE ENERGY VS CITY OF BELLEVUE
Document Title: ORDER

Signed by: Melinda Young
Date: 9/21/2020 9:00:00 AM

Judge/Commissioner: Melinda Young

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