Email No. 1

Date/Time:

August 31, 2015 – 1:02 PM

From: Bradley Strauch

To: Reema Shakra; Mark Johnson

Subject: E2-PSE Data and Information Request

From: Strauch, Bradley R <bradley.strauch@pse.com>
Sent: Monday, August 31, 2015 1:02 PM
To: Reema Shakra; Mark Johnson
Cc: DeClerck, Keith (Keith.DeClerck@stantec.com); Timothy.Marrinan@stantec.com; Nedrud, Jens V; Steendahl, Denise
Subject: RE: E2-PSE Data and Information Request
Attachments: EnergizeEastside-Alternatives-Phase1DEIS -Part 1 8-31-15.doc

Attached are PSE comments related to the Project Descriptions (Part 1). We will be forwarding the information for part 2 (GIS data) and 3 (Additional Questions) shortly. We are a bit short staffed today as a result of this past weekend's storm.

If you have any questions, please let us know.

Thanks,

Brad Strauch
Sr. Land Planner/Environmental Scientist
PUGET SOUND ENERGY
P.O. Box 97034, PSE-09N
Bellevue, WA 98009-9734
Office: 425-456-2556
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Cell: 425-214-6250

From: Strauch, Bradley R
Sent: Thursday, August 27, 2015 8:56 AM
To: 'Reema Shakra'; Nedrud, Jens V; Steendahl, Denise
Cc: Mark Johnson; DeClerck, Keith (Keith.DeClerck@stantec.com); Timothy.Marrinan@stantec.com
Subject: RE: E2-PSE Data and Information Request

Reema,

We are still tracking some down some information, so I apologize for the delay.

We are sorting through what GIS layers we have, but it would be helpful to know for what and how they will be used. Some of the layers we have are geographically accurate, while others are approximations developed from hard copies drawings.

Brad

From: Reema Shakra [mailto:RShakra@esassoc.com]
Sent: Tuesday, August 25, 2015 2:39 PM
To: Strauch, Bradley R; Nedrud, Jens V; Steendahl, Denise
Cc: Mark Johnson; DeClerck, Keith (Keith.DeClerck@stantec.com); Timothy.Marrinan@stantec.com
Subject: RE: E2-PSE Data and Information Request

Hi Brad, checking in to find out how this is progressing on your end and if any of our questions need further clarification.

Thanks,
Reema

From: Strauch, Bradley R [mailto:bradley.strauch@pse.com]
Sent: Thursday, August 13, 2015 2:40 PM
To: Reema Shakra; Nedrud, Jens V; Steendahl, Denise
Cc: Mark Johnson; DeClerck, Keith (Keith.DeClerck@stantec.com); Timothy.Marrinan@stantec.com
Subject: RE: E2-PSE Data and Information Request

Reema,

We are still working on putting the responses together, but it is taking additional time as we have some staff on vacation. If we do not make tomorrow (Friday), we should be able to get you the information regarding the Project Description – Alternatives, Phase 1 by early next week. The GIS and other Additional Questions may take a bit more time.

If you have any questions or comments, please let me know.

Thanks,

Brad Strauch
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From: Reema Shakra [mailto:RShakra@esassoc.com]
Sent: Tuesday, August 11, 2015 1:27 PM
To: Strauch, Bradley R; Nedrud, Jens V
Cc: Mark Johnson; DeClerck, Keith (Keith.DeClerck@stantec.com); Timothy.Marrinan@stantec.com; records@energizeeastsideeis.org; David Pyle (DPyle@bellevuewa.gov)
Subject: RE: E2-PSE Data and Information Request

This option was a suggestion provided by community member(s) to rely on SCL's existing 230 kV transmission system on the Eastside. We weren't sure if this would require a new 115 kV line to loop SCL's system into PSE's substation. We recognize there was initial inquiry with City Light to determine if this was a feasible option and City Light didn't indicate any interest. But I believe we determined it should still be included in the Phase 1 Draft EIS because it was electrically feasible.

Thank you for working on the data request this week. Let me know if you need clarification on anything else. If you have large GIS files to send, I can provide you with a link to our ESA file transfer system.

From: Strauch, Bradley R [mailto:bradley.strauch@pse.com]
Sent: Monday, August 10, 2015 12:17 PM
To: Reema Shakra; Nedrud, Jens V
Cc: Mark Johnson; DeClerck, Keith (Keith.DeClerck@stantec.com); Timothy.Marrinan@stantec.com; records@energizeeastsideeis.org; David Pyle (DPyle@bellevuewa.gov)
Subject: RE: E2-PSE Data and Information Request

Reema,

Our team will be working on responding to these this week. After our initial review, could you please elaborate on what is intended under Alternative 1 – Option B?

Brad Strauch
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From: Reema Shakra [mailto:RShakra@esassoc.com]
Sent: Friday, August 07, 2015 5:10 PM
To: Nedrud, Jens V; Strauch, Bradley R
Cc: Mark Johnson; DeClerck, Keith (Keith.DeClerck@stantec.com); Timothy.Marrinan@stantec.com; records@energizeeastsideeis.org; David Pyle (DPyle@bellevuewa.gov)
Subject: E2-PSE Data and Information Request

Jens and Brad,

To help us continue to move forward with our Phase 1 Draft EIS analysis, we have crafted a preliminary project description for each of the EIS alternatives, a list of questions specific to certain elements of the environment, and a GIS data request list (see attached). For the project description, we did our best to develop a set of assumptions for each alternative based on PSE documents and our working understanding of electrical systems. Please review and revise where we have any incorrect statements and also please fill in the yellow highlights. If there are questions/assumptions that you cannot validate or describe at this stage that's fine. Just indicate as much. We are also open to having a follow-up phone call to go over any of the details.

Would it be possible to send this back late next week? The sooner you can get it to us the closer we can stick to our overall schedule for preparing internal drafts for the EIS.

Thank you very much.

Have a great weekend.

Reema Shakra, AICP
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Energize Eastside - Project Description - Alternatives - Phase 1 Draft EIS

Please review and revise assumptions where incorrect. Please provide information highlighted in yellow.

PART 1
NO ACTION ALTERNATIVE

The No Action Alternative is defined as actions PSE could undertake to serve the project objectives without requiring issuance of state or local permits (e.g. something they could build or undertake immediately if proposed project is not approved).

1. What actions would PSE likely undertake and what would service be like for customers?

As described in Section xx Project Objectives, PSE has an obligation to serve all electrical customers in its service area. All actions that would completely fulfill the project objectives, would require some sort of state or local approval. Therefore, the No Action alternative does not meet the project objectives.

Because electrical demand on the Eastside is expected to grow, PSE would face challenges in providing reliable service while continuing to meet this need without damaging the regional electrical grid. 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. To address this risk in the near term, PSE would use Corrective Action Plans (CAPs), which are a series of operational steps used to prevent system overloads or large-scale loss of customers' power. CAPs generally involve shutting off or reducing load on overloaded equipment and rerouting the load to other equipment. Some CAPs can keep the entire system operating, but place large numbers of customers at risk if anything else on the system begins to fail. For example, PSE is already using CAPs to prevent winter overloads on the Talbot Hill transformer banks. When these CAPs are employed for Talbot Hill, up to approximately 68,800 customers are at risk of outages if another piece of equipment fails. Under more extreme conditions CAPs can also include temporarily shutting off power to some customers (referred to as load shedding). In the event of load shedding under CAPs, PSE prioritizes delivery of power to emergency and critical public services. Under the No Action Alternative, load growth would place an increasing number of customers at risk of load shedding during summer and winter peak demand periods.

CAPs are only temporary measures and are not long term solutions, nor do they represent best practices in terms of reliability of electrical supply for PSE's customers.

Under the No Action Alternative, PSE would continue to manage its maintenance programs to reduce the likelihood of equipment failure, continue to stockpile additional equipment so that in the event of a failure, repairs could be made more quickly. Regardless of having spare equipment available, components such as 230 kV to 115 kV transformers may still take five to six weeks to replace under emergency conditions [NOTE: Adding additional 115 kV lines does not help solve the problem as it puts additional load on the transformers].

2. Would maintenance be conducted more frequently under the No Action Alternative and would that affect customers?

PSE would not change their maintenance schedule as part of the No Action Alternative, although the equipment would be pushed harder, additional maintenance would not increase reliability.

3. Would additional conservation be part of the No Action Alternative?

No**,** PSE promotes and provides incentives for conservation measures, paid for through customer rates. for all of the Alternatives, including the No Action Alternative, it is assumed that PSE would continue to achieve 100 percent of the company's conservation goals as outlined in its Integrated Resource Plan (2013), systemwide and for the Eastside, therefore, no additional conservation is included with the No Action Alternative. Meeting this conservation goal is an important factor in developing the load forecast. For the Eastside, this means approximately 110 MW of power conserved beyond the baseline load growth expected through 2024. Conservation means a reduction in demand, mainly through customers implementing energy efficiency improvements, beyond energy efficiency measures required by regulations. Table X-1 below shows the total conservation that PSE expects to achieve systemwide and for the Eastside.

Table X-1
Energy Conservation System wide and for the Eastside through 2024 (source: PSE Solutions report)

	2014 System Peak Net of 100% Conservation	**System Peak 100% Conservation 2014**	**2014 Eastside Peak Net of 100% Conservation**	**Eastside Peak 100% Conservation 2014**
Year	**MW (23^o F)**	**MW (23^o F)**	**MW (23^o F)**	**MW (23^o F)**
2014-15	4,803	91	619	21
2015-16	4,820	177	641	31

2016-17	4,844	262	667	41
2017-18	4,891	341	688	51
2018-19	4,891	424	697	61
2019-20	4,904	490	708	74
2020-21	4,856	614	722	86
2021-22	4,850	694	730	96
2022-23	4,863	767	742	107
2023-24	4,888	832	764	110
2024-25	4,961	852	783	113

The types of conservation PSE expects to implement to achieve its conservation goals include:

- Energy Efficiency (weatherization, efficient lighting, etc.)
- Fuel Conversion: converting from an electric to gas
- Distributed Generation: customer combined heat and power (CHP), solar, wind, etc.
- Distribution Efficiency: implemented on PSE distribution systems
- Demand Response: capacity savings programs

Energy Efficiency is by far the largest contributor the total savings. The distributed generation is not cost effective, so while it is considered as an option it is expensive and often not in the cost effective bundle. So the amount of savings from DG in Table X-1 is likely very small. In the past PSE has conducted pilot programs with demand response, however those programs are included in the forecast for future implementation.

4. Would there be other substation or conductor/circuit improvements or are there different or more efficient conductor types that could be used?

PSE has already increased the temperature rating for most of the transmission conductors on the Eastside. As appropriate, conductor replacement on existing lines could occur with the No Action Alternative, but the benefits of any conductor replacements are expected to be very small compared to the transmission capacity deficiency identified by PSE. The problem is not typically conductor overloads, but transformer overloads. Increasing the conductor size would result in additional loading on the transformers.

PSE also already uses advanced systems such as Conservation Voltage Reduction, to improve system efficiency and reduce overall loading. There are no specific known new technologies that PSE would employ that could substantially affect the transmission capacity deficiency on the Eastside. Under the No Action Alternative, PSE would not be precluded from seeking out new technologies, provided there are technologies that do not require permits or are exempt from SEPA review.

ALTERNATIVE 1 - NEW TRANSFORMER AND 230 KV TRANSMISSION LINE

1. What possible actions would PSE undertake under Alternative 1?

Under this alternative, PSE would install a new transformer somewhere near the center of the Eastside to convert 230 kV bulk power to 115 kV to feed the Eastside distribution system. The new transformer would be installed at or near one of three PSE owned properties that are either adjacent to existing or that have been purchased for future substations (Lakeside [adjacent], Westminster [future], or Vernell [future] substation), all within Bellevue city limits. These locations are located where multiple 115 kV lines come together providing the most efficient and effective power injection to the system. However, the property adjacent to the existing Lakeside 115 kV substation is the most effective electrically because of the immediate proximity of the existing 115 kV substation and the multiple existing 115 kV lines. Both the Westminster and Vernell sites would require the addition of one or more new 115 kV lines. At any of these sites, development of a new 230 kV yard would be required to accommodate the new transformer and supporting equipment.

To supply this new transformer, two new 230 kV transmission lines would be needed to bring power from existing 230 kV sources. PSE's Talbot Hill substation in Renton and Sammamish substation in Redmond are the closest existing 230 kV sources to the center of the Eastside, and are considered the southern and northern termini of this alternative. While PSE's preferred location could be in one of its existing transmission easements or rights-of-way, the Phase 1 Draft EIS considers that transmission lines could be placed in existing or new corridors, including adjacent to roads or highways. Seattle City Light (SCL) also has a 230 kV transmission line that traverses the Eastside and is a potential power source. PSE did pursue the idea of using the SCL line as an option; however, SCL stated that they need this line to serve their customers. While the SCL facility does not belong to PSE and currently does not have adequate capacity, for purposes of this analysis, tying into this source is considered one option that PSE could pursue to supply the new transformer. However, this approach does not meet all of the project objectives.

2. What types of transmission lines are being considered as part of Alternative 1?

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

Solutions considered part of this alternative include "single circuit" lines as well as solutions that would allow for addition of a second 230 kV circuit on the same poles or in the same underground or underwater facility. In the near term, one of the existing 115 kV lines between the Lakeside substation and the Talbot Hill substation would need to be uprated to a higher capacity. While there is not an immediate need for a second 230 kV circuit, there are cost efficiencies with installing double circuit transmission facilities that PSE considers important in its efforts to identify the least costly infrastructure to serve its customers. A single circuit transmission line includes three conductors (wires). A double circuit includes six conductors. An additional wire would be installed on top of the new poles for lightning protection. The existing fiber optic cable will need to be transferred to the new poles.

The types of lines being considered for Alternative 1 have been categorized into four options as follows:

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

Option B – Use existing 230 kV overhead transmission lines such as the Seattle City Light's 230 kV overhead transmission line (see Figure X), includes rebuilding and re-conductoring both of the Seattle City Light SnoKing-Maple Valley 230 kV transmission lines, looping one 230 kV line to a new transmission substation called Lakeside and looping the other 230 kV line to Sammamish Substation. System operational studies have shown that this would require a complete rebuild of the SCL lines, including replacing most of the existing structures and the conductors as they are not rated for the necessary capacity. Another consideration is that the SCL lines may be difficult to take out of service; therefore, the replacement line may need to be constructed adjacent to the existing line and placed into service, prior to removing the existing structures and conductor. The longevity of this option is not as good as Option A and SCL has stated that need the existing capacity for their system needs.

Option C – This option considers that any portion of the alignments of new transmission lines considered for Option A or B could be placed underground. There are specific state tariffs that would need to be considered for this option; however, these are not part of the environmental review process.

Option D – Underwater transmission in Lake Washington and/or Lake Sammamish. This option would need to be connected to the Talbot Hill and Sammamish substations and another centrally located substation with the new transformer, using either overhead or underground lines. There are specific state tariffs that would need to be considered for this option; however, these are not part of the environmental review process. Technical practicalities also suggest these options may be limited.

New Transformer

3. What would be generally involved in installing a new transformer?

PSE owns three properties that are for future substations in the central portion of the Eastside that could potentially serve the project objectives with a new 230 kV to 115 kV transformer. In order to accommodate a new transformer, the selected substation property would have to be developed, and could require acquisition of adjacent property.

Development of the substation yard would need to be large enough to accommodate the new transformer and associated electrical equipment such as breakers, bus, and connections to the new transmission lines. The gravel yard would include the necessary foundations, access ways, stormwater drainage, and security fencing (typically 8 foot-tall chain-link). Because of the size and weight of transformers, very large trucks are used for transport, and hours of transport are typically restricted. Delivery would be made at a time that would reduce traffic impacts. Unloading and placing the transformer is typically done by crane. Depending on site access and configuration, these activities could require temporary street closures and detours.

Transmission Overhead

4. Where could overhead lines possibly be installed under Option A?

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

Specific pole locations would be determined based on site engineering, but locations would generally be based on tensioning needs for the wire (including where turns are needed along the route), obstacles underground where pole foundations would be proposed, and allowable structural heights, all while attempting to use as few poles as possible.

5. What are the pole types and heights for overhead lines?

Poles would likely be steel or laminated wood monopoles; however other designs such as H-frames using wood or steel poles could be used in some locations. Concrete poles are not commonly used in this region. The diameter of the poles is dependent on height and would be greatest at the base. However, typical in-line (tangent poles) would be 2 to 4 feet in diameter at the base, while typical corner and dead-end poles may need to be 4 feet to 6 feet in diameter depending on the angle and the terrain. Termination poles as well as pole locations where the transmission line changes direction, would need to be heavier duty, which can contribute to a larger diameter necessary to handle the increased line loading.

In order to meet National Electric Safety Code (NESC) and FERC/NERC requirements, adequate clearances must be maintained between each conductor, the ground, adjacent buildings, and trees, to prevent contact. Pole height therefore would vary depending on the number of circuits, the arrangement of the circuits on the poles, topography, and surrounding land cover. Figure XX shows the typical range of pole dimensions. Generally, for double circuit system, pole heights would range from 85 to 100 feet. In special cases, such as crossing a ravine or highway, pole heights could be shorter or taller.

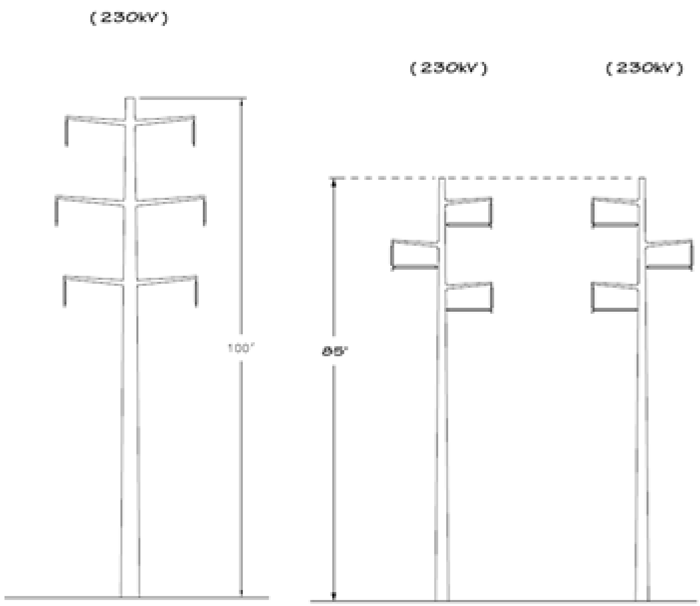

Figure XX Potential Pole Dimensions

6. How are overhead lines installed?

Installation methodology of the poles will depend on the type of pole used and both its physical and operational location. A foundation system is constructed depending on if a pole is to be directly embedded in the ground or utilize an anchor bolt cage. For a directly embedded pole, a hole is created by means of an auger or vacuum truck to the required depth and diameter. For anchor bolt cages, a drilled pier foundation is typically utilized that involves setting the anchor bolt cage in a poured column of concrete. Poles are set and anchored to the respective foundations. Once the pole is set in place, the transmission wire would be installed. The wire-stringing operation requires equipment at each end of the section being strung. Wire would be pulled between these temporary "pulling sites" through pulleys at each structure. These pulling sites would be set up at various intervals along the right-of-way, typically one to three miles apart. Specific pulling sites would be determined close to the time the stringing activity takes place. Once the wire is strung, the stringing blocks (i.e., guide rollers) would be removed and the wire clipped into its final hardware attachment.

Use of Seattle City Light’s 230 kV Transmission Lines

7. What would be involved with the option to use Seattle City Light’s 230 kV lines (Option B)?

This option would require approval by SCL, which has not been provided. It would also require both 230 kV SCL lines to be rebuilt for approximately 15 miles to 230 kV high capacity conductors from BPA’s Maple Valley substation to the loop to PSE’s Sammamish substation, which would require rebuilding or replacing the existing structures. Both lines will be reconductored for approximately 10 miles to high capacity lightweight conductor using the existing structures from the loop to Sammamish substation north to BPA's SnoKing substation. One 230 kV line will be extended on separate double circuit poles to loop through from the SCL corridor to the Lakeside substation. The other 230 kV line will be extended on separate double circuit poles to loop through from the SCL corridor to the Sammamish substation. The new Lakeside[1] substation would connect to the existing 115 kV switching station with a new 115 kV transmission line connection.

Transmission Underground

8. Where could underground lines possibly be installed?

The route alignment for new 230 kV underground transmission lines would have to be studied since construction of underground lines has more construction and operational considerations than those associated with aboveground lines. It is possible that underground lines could be placed within PSE's existing 115 kV overhead line rights-of-way, public road right-of-way, or other right-of-way that PSE owns, purchases, or obtains rights to. However, some of PSE's existing 115 kV overhead line corridors would not be conducive to underground lines due to topographic and operational challenges as well as existing underground utilities. Regardless of the location, permanent access must be maintained in order to make the necessary inspections and repairs. Woody vegetation is not typically allowed within corridors containing underground transmission lines. Relocation of existing utilities, including the Olympic Pipeline, may be required.

9. What types of construction are used for installing underground transmission lines?

When routing the underground transmission lines, the type of development and terrain that the line would be crossing play critical roles in the design, which in turn affects the type of construction to be used. Most underground installations are open cut trench construction, where the ground is excavated from the surface down to a suitable depth, which varies depending on future use of the area, location of other utilities, obstructions, and other factors. Additionally, excavation would be required to accommodate the access and splice vaults. Construction typically involves excavators, concrete trucks, tractor trailers, cranes, and cable reel trucks. There are several construction techniques that can be used to install underground transmission lines.

- Flat terrain – This is normally the easiest type of terrain to perform open cut trenching for transmission cable installation. Typically, a temporary construction road is constructed along the full length of the trenching operation to provide the necessary construction access.

- Rolling hills – where slopes are not extreme (less than 10 percent) open trench construction is typically used. Extreme slopes can limit access for necessary construction equipment. In some cases access roads must be constructed by cutting into

[1] PSE's existing 115 kV switching substation is called Lakeside. Although for simplicity, the new 230 kV station has been referred to as Lakeside during the initial outreach, the new 230 kV station would actually be called Richards Creek substation if built adjacent to the Lakeside 115 KV substation.

the hill or designing switchbacks to climb steeper slopes. Horizontal directional drilling (HDD), or trenchless construction, can sometimes be utilized to cross a series of hills to avoid the slope issue.

- Rock - If bedrock is encountered, explosives may need to be used to ensure adequate burial depths.
- Wetlands – while open cutting can sometimes be used to cross wetlands, there are significant environmental controls typically applied to the process. In some cases, HDD can be used to span a wetland area.
- Other obstructions – There are other situations where open trenching is not practical. This includes crossing of streams, rivers, waterways, highways, railroad tracks, and other situations where open cutting is not allowed or practical. Various trenchless techniques or routing changes may be needed in these cases.

An underground transmission line would likely be a cross-linked polyethylene cable system consisting of stranded copper or aluminum conductor surrounded by insulation and a series of protective barriers. The outermost barriers are typically concrete or steel. Access vaults are needed periodically along an underground route to facilitate cable installation, maintenance, and repairs. Reinforced concrete vaults (8 feet wide by 26 feet long being a common foot print) are typically spaced every 1,500 to 2,500 feet along the route. A more detailed description of construction methods for underground transmission lines is provided in Appendix X-1.

Transmission Underwater

10. Where could underwater lines possibly be installed?

Underwater cable could possibly be installed in either Lake Washington or Lake Sammamish; provided an overland 230 kV line from appropriate end-points could be installed to the cable landing points and the appropriate equipment and materials could be transported to the water body.

For the Phase 1 Draft EIS, a study area was selected that assumes cables could be installed within 1,000 feet the western shoreline of Lake Washington from Kirkland to Renton, and also includes the entire channel between Mercer Island and the eastern shore of the Lake Washington. The study area also assumes that cables could be installed within 1,000 feet of the eastern shoreline of Lake Sammamish adjacent to Bellevue and Redmond. This lake route has not received any technical review; however, there are significant logistical challenges that would have to be overcome, such as getting the necessary equipment and materials to the lake.

There are existing submarine cables in Lake Washington that would need to be crossed and adequate spacing from those cables would be required. Appropriate design steps would need to be taken to protect both existing and new cable systems.

Since it is unknown exactly where or how submarine cables would be installed, worst-case assumptions are used for installing the cables and shore landings. The underwater cable system would likely be composed of three conductors spaced a minimum of 16.5 feet apart from one another. However, the likely scenario for Lake Washington would be six such cables in order to meet system demands. These cables could be buried 3 to 5 feet below the lake bottom, although in some areas that are deep enough to avoid potential conflicts with deep draft vessels, cables may be laid directly on the lake bottom. Shore landings would be constructed using open cut trenching, sheet-piling and dredging. Trenchless installation is possible but requires larger cable sizes and higher costs.

In-water and land transition locations depend on the parameters listed in Table X-2. (reference Power Engineers' study):

Table X-2 Design Parameters for Submarine Cable

Ambient soil/water temperature (maximum summer)	23 °C (May to Oct)
Ambient soil/water temperature (maximum winter)	15 °C (Nov to Apr)
Burial depth (minimum)	3 ft. (1.0 m)
Burial depth (maximum)	5 ft. (1.5 m)
Soil and lake bottom thermal resistivity (maximum)	1.0 °C-m/W
Cable separation distance in water (minimum)	16.5 ft. (5.0 m)
Cable separation on land (minimum)	3 ft. (1.0 m)

11. How are underwater lines installed?

Installation would require special vessels to dredge trenches in the lake bottom and lay cable. Because of the limitations on the size of vessels capable of passing under the I-90 floating bridge, multiple passes with a smaller vessel may be required for the complete installation of the cable system. Also there may be limitations on vessel access to Lake Sammamish that could restrict installation of any underwater lines in that water body. The feasibility of underwater lines in Lake Sammamish has not received any technical analysis.

At cable landing points, it is assumed underground duct bank would be necessary to connect the submarine cable lengths to overhead lines. This would include three splicing vaults to transition the submarine cables to land cables. Each of the three cable runs would be physically separated with individual vaults and termination structures so that any two could continue to operate if the third were taken down (de-energized) for maintenance activities.

Additional information about laying submarine cable can be found in Appendix X-1 (Power Engineers' study).

Conservation

12. Would PSE's approach to energy conservation change under Alternative 1?

Under this alternative, PSE would not change the conservation efforts called out in their Integrated Resource Plan, as described in the No Action Alternative. Continued conservation is an important part of all the Alternatives.

ALTERNATIVE 2 - DEMAND SIDE REDUCTION/NON-WIRES TECHNOLOGIES

In order to fully address the need, this alternative would include a combination of energy storage units, demand response devices, distributed generation, and energy efficiency improvements.

1. How much additional conservation would have to be implemented to address the project objectives for Energize Eastside?

In order to meet the project objectives for the Energize Eastside project with conservation, the amount of conservation accomplished would need to be approximately 4 times what is currently planned by PSE to be accomplished in the Eastside area. This means that by the winter of 2017-2018, instead of accomplishing 50 MW of conservation as currently planned, PSE would need to accomplish approximately 213 MW of conservation. By winter 2024, the amount of conservation needed within the Eastside needed to meet the project objectives would be 324 MW, instead of the 110 MW currently planned for that area. If growth continues as predicted, then additional conservation or a system upgrade would be necessary to reliably serve the area beyond 2024. For comparison, PSE's current plan for the entire PSE system is to implement 832 MW of conservation by 2024, with the Eastside representing approximately 14 percent of the total load for the PSE system. The additional conservation needed may not be technically achievable; therefore a study would need to be done.

2. What assumptions are being made for this EIS about energy storage units?

Feasibility of using energy storage combined with other previously identified non-wires alternatives were studied in March 2015 by Strategen Consulting, LLC. Results of this study can be found in the Eastside System Energy Storage Alternatives Screening Study.

Conclusions from that study stated the following:

- 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.
- 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.
- 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.
- Summer requirements were not studied as the winter study results were definitively disqualifying.

3. What is a demand response system?

Demand response is end-use electric customers reducing their electricity usage in a given time period, or shifting that usage to another time period, in response to a price signal, a financial incentive, an environmental condition, or a reliability signal. Demand Response requires special metering and control equipment that can be used to adjust electricity usage, usually automatically according to pre-agreed parameters. Some of the features of a demand response system could include:

- Meters that provide customers and PSE information about when and how much energy each customer is using, including on-line real-time information
- Programmatic options to reduce peak demand during system emergencies, improve system reliability, and balance variable-load resources (such as wind energy)
- Incentives for customers to curtail loads during specified events or offer pricing structures to induce customers to shift load away from peak periods
- Price- and incentive-based options for major customer segments and end users
- These systems typically send a continuous wireless signal to the utility
- Installation of in-home monitoring and control equipment that would allow PSE to control heating and cooling systems

4. What assumptions are being made for this EIS about use of demand response?

PSE includes demand response in its Integrated Resource Plan, and has estimated that these will result in 116 MW system wide reduction in capacity needed by 2024, which is estimated at 2.3 percent of the system load. In order to address the deficiency projected for the Eastside, adoption of this program within the Eastside would have to be expanded dramatically in the near future (more than in the system as a whole).

5. What is distributed generation?

Distributed generation (DG) means generating power on-site. Distributed generation reduces costs and interdependencies associated with transmission and distribution and can shift control to the consumer. On-site energy generation can include: solar photovoltaic systems, gas turbine, anaerobic digesters, reciprocating engine, microturbines, fuel cell, and small hydro, and wind turbines.

6. How much DG capacity would be needed to address the Eastside transmission capacity deficit?

In order to address the Eastside transmission deficiency with DG alone, approximately 300 MW of capacity would be needed by 2024. For comparison, a typical 6 kW rooftop solar photovoltaic system generates 6,000 kWh per year, and a typical customer based wind turbine generates 300 kWh (1 MW = 1,000 kW). Winter peak system loading occurs in the morning and evening, when solar is not effective because of the shorter daylight hours. The Eastside communities have limited wind resource as a result there are only two small scale wind turbines on the eastside.

7. Why is more new DG capacity required than if the need were addressed with EE?

New DG resources would need to be capable of producing power when needed at peak times, such as during winter cold snap or a summer warm spell, or be associated with an energy storage system that would allow use of the energy during peak periods. For an energy generating resource to be effective, it also has to be reliable, which means it must be well-maintained and capable of producing a specified amount of energy when needed. To ensure adequate capacity even when some equipment is not working, a substantial degree of redundancy is needed in DG resources. In addition, the DG needs to be located at or near the load in order to be effective, which also contributes to the need for an overall higher capacity requirement.

8. What additional energy efficiency would need to be implemented to meet the project objectives?

The energy efficiency needed would be the same types of efforts planned for the longer term under PSE's IRP, as described in the No-Action Alternative, such as replacement of older, inefficient appliances and lighting, and adding insulation and weatherproofing. However, to meet the project objectives for Energize Eastside, these efforts would need to be substantially accelerated and expanded on the Eastside provided the Eastside has sufficient availability and thus potential to achieve the increased energy efficiency. It is not known whether there is a technical potential to achieve this level of conservation at any cost. A study would need to be done to make this assessment. This would likely entail higher costs for promotion and incentives.

9. Would implementation of Alternative 2 still eventually require new infrastructure such as Alt 1 or Alt 3?

No alternative guarantees that there would not be some future need for infrastructure. However, the transmission line options in Alternatives 1 and 3 would provide a longer period of reliability before additional capacity would be needed than would Alternative 2, if it is assumed that each year there is just enough conservation accomplished to avoid needing additional transmission capacity. Under that assumption, at the end of the 10-year target period, an additional solution would be required to address future growth. That solution could theoretically be continued conservation efforts, but because of stricter building codes already in place and the acceleration of retrofitting assumed under this alternative, the availability of additional capacity for conservation is uncertain. Therefore, it is likely that additional transmission infrastructure would be needed.

ALTERNATIVE 3 - NEW 115 KV LINES AND TRANSFORMERS

1. How many new transformers would be needed for this alternative?

Under this alternative, three new 230 kV to 115 kV transformers would be installed at existing substations.

2. Where would the transformers go?

The substations include the Lake Tradition, Talbot Hill, and Sammamish substations. In order to accommodate the additional transformers it is assumed at a minimum Talbot Hill substation would need to be expanded, and that additional security measures would be required at all three substations.

3. If new or expanded substations are needed, what does that involve?

The construction methods would be the same as described in Alternative 1. In addition, delivery of equipment would require special trucks and space for special equipment such as a crane. This would be the same as described in Alternative 1. In addition, in order to accommodate the new 115 kV lines, Table XX provides a summary of the substation work that would be required. Some stations could accommodate the new lines, while five substations would require complete rebuilds and expansion for this alternative.

Table XX
Substation Work required for Alternative 3.

Substation	Install New 230/115 kV Transformer	Install New 115 kV Line Connections	Fits in Existing Substation Footprint	Notes
Sammamish	Install 3rd 230/115kV Transformer	Ardmore and Clyde Hill	No	Will need to expand the substation footprint by approximately 10-20 percent.
Lakeside 115 kV	-	Pickering and Talbot Hill	No	Will need to expand the substation yard to fit additional buswork. Will not likely need to buy property, but will need to extend approximately 10-20 percent of the existing fence footprint.
Lake Tradition	Install 1st 230/115kV Transformer	Novelty Hill and Berrydale	Yes	Will require an existing BPA 230 kV line to be extended to bring 230 kV to Lake Tradition substation.
Talbot Hill	Install 3rd 230/115kV Transformer	Lakeside and Hazelwood	No	Only enough space for one 115 kV line bay and three would be needed. Would need to expand the yard by approximately 5-10 percent.
Ardmore	-	Sammamish	Yes	Would require a fourth line and should be possible to fit within the existing substation footprint.
Clyde Hill	-	Sammamish	No	Would require reconfiguring the substation. Preliminary

				rebuild designs have the substation increasing about 50-60 percent larger than existing yard.
Pickering	-	Lakeside 115 kV	Yes	
Berrydale	-	Lake Tradition	Yes	
Novelty Hill	-	Lake Tradition	Yes	
Hazelwood	-	Talbot Hill	No	Would require rebuilding the substation. A preliminary layout has the substation increasing about 200 percent larger than the existing yard. Additional property potentially needed.

4. What general assumptions are made in this EIS about where new 115 kV transmission lines could be installed?

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

5. What height poles would be needed for these 115 kV overhead lines?

For a typical single circuit 115 kV system, without distribution underbuild, heights will vary from 60 feet to 75 feet depending on span length, structure configuration, and topography. However, in some instances taller poles may be required to span obstacles and topography. If co-location is required with existing 115 kV lines (a very likely scenario) then pole heights would mostly likely need to be taller in order to meet NESC requirements.

6. How are overhead 115 kV lines installed?

Standard single circuit 115 kV lines are constructed on direct embed wood poles and use guy wires as necessary. The hole is augured or created using a vacuum truck, pole placed, and the annulus is backfilled with crushed rock. For locations that lack space or rights for adequate guying, self-supporting poles may be utilized that are typically steel or laminated wood. Insulators are usually installed directly on the poles, followed by the conductor using the same general methodology as described above for the 230 kV system. In many situations, the difference between 115kV construction and 230 kV construction can be de minimus.

7. Would the poles or conductors be different for 115 kV than for the 230 kV overhead lines?

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

8. Are the ongoing conservation measures that PSE would continue the same as for Alternative 1?

Yes. All the proposed Alternatives assume that PSE's conservation goals will be met. This is a very important parameter.

Email No. 2

Date/Time:

September 24, 2015 - 3:18 PM

From: Bradley Strauch

To: Reema Shakra; Mark Johnson

Subject: Energize Eastside Response to Questions – Part 3

From: Strauch, Bradley R <bradley.strauch@pse.com>
Sent: Thursday, September 24, 2015 3:18 PM
To: Reema Shakra; Mark Johnson
Cc: Steendahl, Denise; Nedrud, Jens V
Subject: RE: Energize Eastside Response to Questions - Part 3
Attachments: Substation Fire Risk Text.pdf

Reema,

Please see that attached document. Let me know if you have any additional questions.

Brad

From: Reema Shakra [mailto:RShakra@esassoc.com]
Sent: Wednesday, September 23, 2015 5:21 PM
To: Strauch, Bradley R; Mark Johnson
Cc: Steendahl, Denise; Nedrud, Jens V
Subject: RE: Energize Eastside Response to Questions - Part 3

Brad,

Can you let me know when you think you'll be able to provide a response to question #4 under utilities (see page 6 of the attachment you sent below)? This will help us determine which version of the Draft EIS that we deliver to the city will include the answer.

Thanks,

Reema Shakra, AICP
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From: Strauch, Bradley R [mailto:bradley.strauch@pse.com]
Sent: Thursday, September 10, 2015 2:34 PM
To: Mark Johnson; Reema Shakra
Cc: Steendahl, Denise; Nedrud, Jens V
Subject: Energize Eastside Response to Questions - Part 3

Attached are the response for the Additional Questions Specific to Section of the EIS Phase 1 Draft. We are working on getting the GIS data together (Part 2).

If you have any questions please let us know.

Thanks,

Brad

Excerpt from Denny Substation – please modify or insert comments to indicate which parts of the discussion are relevant to the new transformer.

The types of equipment that would be operated (at the substation) and that have caused fires at other substations are oil-insulated equipment, such as capacitors, transformers, and inductors. Oil is used to insulate electrical equipment because it is more effective than air as an insulator and allows equipment to be more compact and placed closer to each other and/or underground. Oil insulation comes with the risk that when an element (for example, a capacitor) becomes overheated, the oil can convert to a gaseous state and, if it leaks and is exposed to sparks or high heat, can ignite and cause a fire or even an explosion.

Activities or events that pose risks of igniting a fire include the following:

- Electrical fault
- Cable overheating
- Arcing, such as at switches
- Lightning strike
- Hot work, such as welding
- Equipment failure

When these events occur at substations, they typically do not cause fires because of the safety systems that have been installed.

A fire is not considered a probable outcome of building and operating the substation. However, if a fire were to occur, it would most likely be similar to the types of fires described in the following paragraphs, and the fail-safe systems described below would also be in place to contain the damage (Orth, 2014).

Electrical faults can occur in any type of electrical equipment. A typical substation will experience three to five electrical faults per year. Substation equipment has relays and circuit breakers to cut power to a piece of equipment when a fault occurs. Faults typically occur when there is an unexpected event, such as a lightning strike, a break in a cable, or equipment malfunction. When relays and circuit breakers function properly, they are designed to disconnect power within a fraction of a second to protect equipment and prevent fires that could damage substation equipment and transmission and distribution lines. However, there is a very small risk that a fault would go undetected and the equipment could overheat, cause sparks, catch fire, or even explode before being detected.

Oil used in insulating electrical equipment is monitored for the presence of acetylene and other dissolved gasses that are byproducts of arcing. If these dissolved gases are detected, the equipment may be subject to a combination of the following: being monitored more frequently, inspected, repaired, and/or replaced.

Although lightning occurs relatively infrequently in the project area, it still poses a risk of damaging substation equipment if the equipment is struck or if there is a lightning strike nearby. The risk is primarily to aboveground equipment; underground equipment is not expected to be at risk of lightning strikes. The Richards Creek Substation would be equipped with mechanical means (such as a system of lightning rods) to convey lightning to the ground to avoid equipment damage and harm to workers on the site. These systems are expected to largely eliminate risk from lightning, but a small risk would remain. The other fail-safe systems described in this section are designed to operate if a lightning strike caused a fault or cable overload or other system malfunction.

Hot work such as welding can pose risks and is sometimes necessary to repair or modify equipment in a substation. While precautions, such as removing the piece of equipment that needs to be welded and welding it inside and away from electrical equipment, would reduce the potential for starting a fire, a small risk would remain. Crews conducting hot work are also trained to shut down equipment being worked on, shield equipment from exposure to intensive heat and sparks, let equipment cool adequately before re-energizing, and monitor any repairs to limit risk of fire.

In addition to the relays and circuit breakers described above, a number of other features are included as fail-safe systems to provide protection in case another system does fail. PSE has personnel that remotely monitor for conditions of overloading in the system, malfunctions, and other factors that could lead to a fire.

If a fire were to start in a substation, PSE personnel and the local Fire Departments are trained to deal with substation fires, including how to protect surrounding properties, minimize risk to substation personnel and firefighters, and avoid exacerbating the fire. The protocol is to contain the fire and prevent it from spreading beyond the substation site rather than entering the facility and risking injury to firefighters.

While the risk of a fire is low, if a fire were to occur, it would be similar to a building fire, however, the extinguishing the methodology is different as foam is used. A substation fire could occur relatively rapidly if the fail-safe systems did not work. Based on experience, PSE believes that the measures described in the preceding paragraphs and below in Section 5.7.5 would ensure that the substation would operate safely.

If a fire were to occur at the substation, firefighting services would be needed. Eastside area firefighters are trained to fight electrical fires and fires from burning oil, so no special training would be needed. The risk of fire would be low, as discussed in Chapter 6 of the Draft EIS. Because of the low fire risk, an increased demand for firefighters is not expected as a result of the Richards Creek Substation.

<u>Mitigation Measures - Operation</u>

In order to reduce the risk of fire, PSE would routinely do the following:

- Use Sulfur hexafluoride (SF_6) gas for closely-spaced equipment. SF_6 is a non-flammable greenhouse gas, which is an excellent insulator.
- Install relays and circuit breakers to shut down equipment experiencing a fault or malfunction.
- Install lightning mitigation system to conduct lighting to the ground rather than through lines or equipment.
- Monitor oil insulation for evidence of arcing and gassing.
- Monitor substation for evidence of overloading, overheating, or malfunctions.

Email No. 3

Date/Time:

September 30, 2015 - 3:19 PM

From: Bradley Strauch

To: Reema Shakra; Mark Johnson

Subject: EE230: Line Loading Information

From: Strauch, Bradley R <bradley.strauch@pse.com>
Sent: Wednesday, September 30, 2015 3:19 PM
To: Reema Shakra; Mark Johnson
Cc: Nedrud, Jens V; Steendahl, Denise
Subject: RE: EE230: Line Loading information

One additional item, the method used to calculate magnetic fields generated by transmission lines is a two dimensional analysis assuming the phase conductors form infinitely long straight lines parallel to each other. The magnetic field strengths are directly proportional to the loading of the lines. The computer software used to calculate EMF levels is the Bonneville Power Administration (BPA) Corona and Field Effects program.

Brad

From: Strauch, Bradley R
Sent: Wednesday, September 30, 2015 3:07 PM
To: 'Reema Shakra'; Mark Johnson
Cc: Nedrud, Jens V; Steendahl, Denise
Subject: EE230: Line Loading information

Reema and Mark,

As requested, below are the actual average loadings for the existing 115 kV lines and the forecasted loadings for the new 230 kV and high capacity 115 kV lines (Energize Eastside). Rose Hill is the substation located between the Sammamish substation and the Lakeside (future Richards Creek) substation. Additionally, attached are graphs of the calculated and measured average electric and magnetic fields along the existing 115 kV corridor.

If you have any questions, please let me know.

Thanks,

Brad Strauch
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Bellevue, WA 98009-9734
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Average Existing 115kV and Average Forecasted 230 kV / 115kV Loadings

Two Existing 115 kV Lines - Winter 2013-14 (Actual Measured Loadings):					
Line Name:	Talbot Hill-Lakeside #1	Talbot Hill-Lakeside #2	Sammamish-Lakeside #2	Sammamish-Rose Hill #1	Rose Hill - Lakeside #1
Voltage Level:	115 kV	115 kV	115 kV	115 kV	115 kV
Average loading (amps):	382	382	30	25	60

Two Existing 115 kV Lines - Summer 2014 (Actual Measured Loadings):

Line Name:	Talbot Hill-Lakeside #1	Talbot Hill-Lakeside #2	Sammamish-Lakeside #2	Sammamish-Rose Hill #1	Rose Hill - Lakeside #1
Voltage Level:	115 kV	115 kV	115 kV	115 kV	115 kV
Average loading (amps):	286	286	55	80	50

Proposed New Single 230 kV and existing 115 kV Lines - Winter 2017-18 based on 2014 Load Forecast (Forecasted Future Loadings):					
Line Name:	Talbot Hill-Richards Creek #1	Talbot Hill-Lakeside #2	Sammamish-Richards Creek #1	Sammamish-Rose Hill #2	Rose Hill - Lakeside #2
Voltage Level:	230 kV	115 kV	230 kV	115 kV	115 kV
Average loading (amps):	635	400	315	5	20

Proposed New Single 230 kV and Existing 115kV Lines - Summer 2018 based on 2014 Load Forecast (Forecasted Future Loadings):					
Line Name:	Talbot Hill-Richards Creek #1	Talbot Hill-Lakeside #2	Sammamish-Richards Creek #1	Sammamish-Rose Hill #2	Rose Hill - Lakeside #2
Voltage Level:	230 kV	115 kV	230 kV	115 kV	115 kV
Average loading (amps):	30	70	215	55	40

Email No. 4

Date/Time:

October 30, 2015 - 3:17 PM

From: Bradley Strauch

To: Mark Johnson; Jens Nedrud

Subject: E2-Questions for PSE

From: Strauch, Bradley R <bradley.strauch@pse.com>
Sent: Friday, October 30, 2015 3:17 PM
To: Mark Johnson; Nedrud, Jens V
Cc: records@energizeeastsideeis.org; Reema Shakra; Kathy Fendt; Michael Paine; Steendahl, Denise
Subject: RE: E2 - questions for PSE

In the project area, PSE would most likely use drilled pier foundations rather than caissons. PSE anticipates that the poles could be installed either as direct embed (without foundations) or placed on drilled pier foundations. Poles installed as direct embed would be between 10 and 15 feet deep. Drilled pier foundations are constructed using an auger and would be likely be between 15 and 40 feet in depth, unless in the rare situation (poor soils) they would have to be deeper.

Brad

From: Mark Johnson [mailto:MJohnson@esassoc.com]
Sent: Friday, October 30, 2015 2:57 PM
To: Strauch, Bradley R; Nedrud, Jens V
Cc: records@energizeeastsideeis.org; Reema Shakra; Kathy Fendt; Michael Paine; Steendahl, Denise
Subject: RE: E2 - questions for PSE

Thanks for these prompt answers.

I have one more detail to ask about- On caisson foundations, is there a way we can state a range of depths they would go? Our noise and vibration specialist has experience with them going as deep as 35 feet, but I assume it varies with soil types and pole heights and types. Can you give us a reasonable range?

- Mark J

From: Strauch, Bradley R [mailto:bradley.strauch@pse.com]
Sent: Friday, October 30, 2015 12:57 PM
To: Mark Johnson; Nedrud, Jens V
Cc: records@energizeeastsideeis.org; Reema Shakra; Kathy Fendt; Michael Paine; Steendahl, Denise
Subject: RE: E2 - questions for PSE

Attached are the responses to the last set of questions. Let us know if you need anything else.

Thanks,

Brad Strauch
Sr. Land Planner/Environmental Scientist
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From: Mark Johnson [mailto:MJohnson@esassoc.com]
Sent: Friday, October 30, 2015 10:11 AM
To: Strauch, Bradley R; Nedrud, Jens V
Cc: records@energizeeastsideeis.org; Reema Shakra; Kathy Fendt; Michael Paine
Subject: RE: E2 - questions for PSE

Two more questions that we would like your answers on:

4. Are there other types of electrical lines, besides HPFF, that contain hazardous materials (i.e. SCFF) in the project area?
5. How many gigawatt hours per year (gWh/yr) of electricity do customers in the Eastside service area consume?

- Mark J

From: Mark Johnson
Sent: Thursday, October 29, 2015 4:14 PM
To: Brad Strauch; Nedrud, Jens V
Cc: records@energizeeastsideeis.org; Reema Shakra; Kathy Fendt; Michael Paine
Subject: E2 - questions for PSE

Brad and Jens
Thanks for meeting with me by phone yesterday to answer questions we had for PSE. Below are two questions we discussed that you said you would like to get back to us on.

1. About how long would construction of Alt 3 (new 115 kV lines and transformers) take?
2. The maximum capacity available using this option as presently configured is approximately _____, which does not meet PSE's stated need of _____ MW.

For the Lake Sammamish issue I wanted to run this past you now that I have the weight concern clarified.

3. For elimination of the Lake Sammamish submerged option, we concluded the following based on the reports you have provided:
    - Submerged cables are typically delivered to a site by ship or barge
    - Large barges cannot access Lake Sammamish due to the weir at the outlet
    - Weight limits on highways would limit the length of cable reels to 1100 feet, requiring 34 splices to reach the length of the lake
    - Splicing underwater increases risk of cable failure, while splices on land require construction of a vault at each splice
    - Highway transport may also be limited due to the 14-foot reel diameter
    - Given these constraints, placing a cable in Lake Sammamish does not appear to be a viable option.

Mark S Johnson
Director
ESA | Northwest Community Development
5309 Shilshole Avenue NW, Suite 200
Seattle, WA 98107

Email No. 5

Date/Time:

November 3, 2015 – 12:28 PM

From: Bradley Strauch

To: Mark Johnson

Subject: E2-N-1, ect

From:	Strauch, Bradley R <bradley.strauch@pse.com>
Sent:	Tuesday, November 03, 2015 12:28 PM
To:	Mark Johnson
Cc:	Nedrud, Jens V; records@energizeeastsideeis.org; Michael Paine; Reema Shakra; Kathy Fendt; Steendahl, Denise
Subject:	RE: E2- N-1, etc
Attachments:	EIS response 11-02-15 .docx
Follow Up Flag:	Follow up
Flag Status:	Completed

See the attached document. If you have any questions, please let me know.

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From: Mark Johnson [mailto:MJohnson@esassoc.com]
Sent: Monday, November 02, 2015 2:13 PM
To: Strauch, Bradley R
Cc: Nedrud, Jens V; records@energizeeastsideeis.org; Michael Paine; Reema Shakra; Kathy Fendt
Subject: E2- N-1, etc

As we discussed, I have been trying to clarify the meaning and significance of the N-0, N-1, N-1-1, and N-2 conditions for a lay reader. Can you help us fill in the blanks in the statement below?

The PSE system includes approximately XXX components that are included in its system model. Not all of these components affect the systems on the Eastside, but many components that are outside of the Eastside do affect how and where power flows into the Eastside. When everything is operating normally, the system is said to be in an N-0 state. An N-1 outage condition can occur at any time when a single element trips off line. This occurs when a problem is detected or because some damage has occurred. It can also be a result of routine maintenance when a system component must be taken out of service, even though if possible, routine maintenance would not be scheduled during peak load periods. In a typical year, the PSE system operates in an N-1 condition about XXX times per year, and persists for approximately XXX percent of the time. An N-1-1 outage condition is a N-1 outage followed by a period of time to manually adjust the system to a secure state, followed by a second N-1 outage. This occurs when a problem is detected or some damage occurs followed by an additional problem or damage event. However, it can also be a result of routine maintenance when a system component must be taken out of service, and the second N-1 outage occurs unexpectedly. In a typical year, the PSE system operates in an N-1-1 condition occurs about XXX times per year, and persists for approximately XXX percent of the time. An N-2 outage is when a single event trips multiple facilities, such as certain instances where all the breakers in a substation trip off line leaving several circuits without power, or a problem occurring that effects both circuits of a double-circuit transmission line (i.e. two transmission circuits located on one structure). This occurs when a problem is detected, or some sort of damage has occurred. It can also be a result of routine maintenance when multiple system components must be taken out of service. However, if at all possible, routine

maintenance avoids multiple elements, and if necessary, would most likely not be scheduled during peak load periods. In a typical year, the PSE system operates in an N-2 condition occurs about XXX times per year, and persists for approximately XXX percent of the time.

Somewhat related is the need to talk about the weather conditions that are modeled. I realize that I may not have the exact right time parameter here, but here is generally what I am looking to say:

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

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EIS Response 11/2/2015

The PSE bulk electric transmission system includes approximately 2100 components[1] that are included in its system model. Not all of these components affect the systems on the Eastside, but many components that are outside of the Eastside do affect how and where power flows into the Eastside. When everything is operating normally, the system is said to be in an N-0 state. An N-1 outage condition can occur at any time when a single element trips off line. This occurs when a problem is detected or because some damage has occurred. It can also be a result of routine maintenance when a system component must be taken out of service, even though if possible, routine maintenance would not be scheduled during peak load periods or during bad weather. In a typical year, the PSE system operates in an N-1 condition about 350-360 days per year (almost every day), and persists for approximately 60 percent of the time[2].

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

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

~~Somewhat related is the need to talk about the weather conditions that are modeled. I realize that I may not have the exact right time parameter here, but here is generally what I am looking to say:~~

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

[2] These are estimates as PSE does not track outages in this format.

[3] This duration is an average and storm events can run much longer than 12 hours.

The ~~extreme~~ normal peak **weather events that PSE uses in its model to test its system are extended periods of either cold** winter **temperatures or high**~~er than normal~~ summer **temperatures that have a 50 percent likelihood of occurring in a given year.** Extreme winter peak is studied for a 1-in-20 winter; however, this extreme data is not used to justify Energize Eastside. **For winter, this means a temperature of 23 degrees Fahrenheit or lower** ~~for at least XXX hours~~at the time of the system peak**. For summer, this means a temperature of 86 degrees Fahrenheit or higher** ~~for at least~~ at the time of the system peak~~XXX hours~~**.**

Email No. 6

Date/Time:

November 25, 2015 - 1:29 PM

From: Bradley Strauch

To: HBedwell@bellevuewa.gov

Subject: E2 Memo Re ch 1_2 Phase I DEIS

From: Strauch, Bradley R <bradley.strauch@pse.com>
Sent: Wednesday, November 25, 2015 1:29 PM
To: HBedwell@bellevuewa.gov
Cc: Mark Johnson; CHelland@bellevuewa.gov; records@energizeeastsideeis.org; Steendahl, Denise
Subject: RE: E2 Memo Re ch 1_2 Phase I DEIS
Attachments: CHAPTER 1.EDITS_PSE.docx; CHAPTER 2_EDITS_PSE.docx

Heidi,

Attached are PSE's review comments for chapters 1 and 2 of the Phase 1 PDEIS. There are three values in Chapter 2, sections 2.3.3.1 and 2.3.3.2, that we still need to confirm. We expect these to be verified by Monday (Nov. 30).

I apologize for the document formatting issues, but we converted the PDFs to Word in order facilitate tracking the edits. If you have any questions, please let us know. Thank you for the opportunity to review these sections for technical accuracy.

Sincerely,

Brad Strauch
Sr. Land Planner/Environmental Scientist
PUGET SOUND ENERGY
P.O. Box 97034, PSE-09N
Bellevue, WA 98009-9734
Office: 425-456-2556
Fax: 425-462-3233
Cell: 425-214-6250

-----Original Message-----
From: HBedwell@bellevuewa.gov [mailto:HBedwell@bellevuewa.gov]
Sent: Wednesday, November 11, 2015 8:05 AM
To: Strauch, Bradley R
Cc: mjohnson@esassoc.com; CHelland@bellevuewa.gov; records@energizeeastsideeis.org
Subject: E2 Memo Re ch 1_2 Phase I DEIS

Hi Brad,
Please refer to the attached memo and documents.
Let me know if you have any questions.

Heidi Bedwell

CHAPTER 1. INTRODUCTION AND SUMMARY

The City of Bellevue and its partner Eastside Cities are jointly conducting a phased environmental review process under the State Environmental Policy Act (SEPA) for the Energize Eastside Project proposed by Puget Sound Energy. This first phase assesses the comprehensive range of impacts and implications associated with broad options for addressing the applicant's objectives, in a non-project or "programmatic" Environmental Impact Statement (EIS). The second phase of this EIS process will assess project-level alternatives, as described in Section 1.5 below. This chapter provides an overview of the project and a summary of the findings of the Phase 1 Draft EIS.

1.1 WHAT IS THE PROJECT THAT IS BEING EVALUATED IN THIS DRAFT EIS?

PSE is proposing to construct and operate a ~~major~~ new 230 kV to 115 kV transformer served by approximately 18 miles of new high-capacity electric transmission lines (230 thousand volts [kilovolts, or kV]) extending from Renton to Redmond. The proposed transformer would be placed at a substation site near the center of the Eastside, an area of King County, Washington, roughly defined as extending from Renton in the south to Redmond in the north, and between Lake Washington and Lake Sammamish. Electrical power would be transmitted to this substation and the voltage lowered, or "stepped down" (transformed), from 230 kV to 115 kV for distribution to local customers.

Comment [BRS1]: "Major" is subjective

Comment [BRS2]: Add "site" as all three 230kV site options are undeveloped.

This set of facilities is proposed in order to address a deficiency in electrical transmission capacity during peak periods that has been identified by PSE through its system planning process. This deficiency is expected to arise as a result of anticipated population and employment growth on the Eastside, and it is expected to negatively affect service reliability for Eastside customers within the next few years. The project would improve reliability[1] for Eastside communities ~~by creating a more redundant[1] system and~~ and would supply the needed electrical capacity for anticipated growth and development on the Eastside.

Based on federally mandated planning standards, PSE's analysis found that the existing ~~115 kV~~ transmission system is at risk of placing Eastside customers and/or the regional power grid at risk of power outages or system damage during peak power events ~~such as~~ for ~~extreme~~ cold or hot weather. The analysis concluded that a 230 kV line (as opposed to other voltages higher than 115 kV lines) is needed because 230 kV is the next highest voltage line that PSE could feasibly install and operate consistent with the regional grid system. This Phase 1 Draft EIS evaluates the proposed 230 kV improvements and alternatives to PSE's proposal as described in more detail in Chapter 2.

Comment [DS3]: "Extreme" has a different technical meaning. We study under normal hot and cold conditions, not extreme.

1.2 WHY IS THIS EIS BEING PREPARED?

Through discussions between potentially affected jurisdictions and PSE, it was determined that the proposal is likely to have significant adverse environmental impacts. Pursuant to SEPA, a Threshold Determination of Significance was issued as outlined in the Washington Administrative Code (WAC) 197-11-360 on April 30, 2015.

To address the potential for significant environmental impacts, PSE submitted an application for processing of an EIS with the City of Bellevue. As the largest and potentially most affected city, the City of Bellevue agreed with the other potentially affected jurisdictions to take the role of lead agency, consistent with WAC 197-11-144. The City has directed preparation of the EIS, and the participating jurisdictions including the Cities of Kirkland,

Comment [BRS4]: Shouldn't this be 197-11-924? Subsection 144 does not exist.

[1] Constructing the 230 kV transmission line and installing a new transformer would allow PSE to better operate and maintain its system. PSE plans for a reasonably redundant system that allows PSE to take equipment or lines offline for maintenance and avoid power outages should accidents (e.g., weather or security incidents) damage lines or equipment.

Newcastle, Redmond, and Renton have reviewed the evaluations.

This Phase 1 Draft EIS is the first phase of a two-phase Draft EIS process being employed to evaluate the potential for significant environmental impacts (see Section 1.5.1 for an explanation about the Phase 1 Draft EIS and the Phase 2 Draft EIS). The Phase 1 Draft EIS broadly evaluates the general impacts and implications associated with the options available to address PSE's identified objectives for the project. The evaluations conducted during Phase 1 will be used to narrow the range of alternatives for consideration in the Phase 2 Draft EIS. The Phase 2 Draft EIS will be a project-level evaluation, describing impacts at a site specific and project-specific level. This approach is consistent with the requirements for Phased Review outlined in WAC 197-11-060 (5)(c).

1.3 WHAT IS THE PURPOSE AND NEED FOR THE ENERGIZE EASTSIDE PROJECT?

PSE has determined that there is a need to construct a new 230 kV bulk electrical transmission line~~corridor~~ and associated electrical substations on the east side of Lake Washington to supply future electrical capacity and improve the reliability of the Eastside's electrical grid. To better understand PSE's project proposal, the EIS project team has obtained clearance to review internal utility planning and operations information used by PSE in developing the Energize Eastside Project proposal. Because of security concerns, this information is released only to individuals with approved security clearance and can meet other evaluation factors[2].

The EIS project team, represented by Stantec (an electrical system planning and engineering subconsultant 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. Stantec prepared a memorandum evaluating the stated need for the project, and confirming that PSE's Needs Assessment was conducted in accordance with industry standards for utility planning (Stantec, 2015). See Appendix A for more information.

As outlined in WAC 197-11-060 (3)(a), it is the responsibility of the lead agency to make certain that the proposal that is the subject of environmental review is properly defined. The process of defining the proposal includes an objective understanding of the need for the project, to enable a thorough understanding of the project's objectives (see Chapter 2, Section 2.2) and technical requirements, and in order to accurately identify feasible and reasonable project alternatives for consideration in the EIS. As noted in WAC 197-11-060(3)(a)(iii), proposals should be described in ways that encourage considering and comparing alternatives, and agencies are encouraged to describe proposals in terms of objectives rather than preferred solutions. An understanding of the need for the project helps in clarifying the objectives that have been used to develop the broad alternatives.

This EIS will not be used to reject or validate the need for the proposal. Rather, the EIS is intended to identify and disclose potential significant adverse environmental impacts associated with alternatives identified to meet PSE's objectives, and to examine alternatives that could meet those objectives at a lower environmental cost.

The transmission capacity deficiency on the Eastside that PSE has identified is based on a number of factors. It arises from growing population and employment, changing consumption patterns associated with larger buildings, more air-conditioned space, changes in consumer behavior, and a changing regulatory structure that requires a higher level of reliability than was required in the past. The regulatory changes that underlie the heightened concerns about reliability trace back to an August 2003 blackout in the Midwestern and Northeastern portions of North America that affected 55 million customers. PSE has concluded that the most effective and cost-efficient solution to meet its objectives is to site a new 230 kV

[2] http://www.oatioasis.com/PSEI/PSEIdocs/CEII_Procedures_(07-11-07).pdf

transformer in the center of the Eastside, which would be fed by new 230 kV transmission lines from the north and south (Stantec, 2015).

The population of the Eastside is expected to grow at a rate of approximately 1.2 percent annually over the next decade, and employment is expected to grow at an annual rate of approximately 2.1 percent, a projection based on internal forecasting conducted by PSE. This forecast is based on the assumption that economic activity has a significant effect on energy demand. PSE relies on Moody's Analytics U.S. Macroeconomic Forecast, a long-term forecast for the U.S. economy, with adjustments for PSE's service territory that use a system of econometric equations that relate the national to regional conditions. Local economic data are provided by the Washington State Employment Security Department, U.S. Bureau of Labor Statistics and Bureau of Economic Analysis, and local organizations such as the Washington Builders Association. Demographic data are based on U.S. Census information and the Puget Sound Regional Council (Gentile et al., 2015).

Given the nature of expected development, PSE had projected that electrical demand will grow at a rate of 2.4 percent annually. Without adding at least 74 megawatts (MW) of transmission capacity for 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 (i.e., forced power outages) (Stantec, 2015). The 74 MW would only marginally meet the demand through 2018.

Based on these projections, load demand could increase to a point where, if adverse weather conditions occur and one or more components of the system are not operating for any reason, load shedding could be required in order to protect the Eastside area and the rest of the regional grid. This is because, 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 such as load shedding may be needed in order to keep the system intact within the Eastside service area and beyond. 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 (Stantec, 2015).

The load area in question is situated between two existing sources of bulk electrical power: the Sammamish substation on the north end (Redmond/Kirkland area) and the Talbot Hill substation on the south end (Renton area). These two sites are the closest substations that bring 230 kV power supply to the Eastside, and therefore supply power to support most of this geographic 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. Because of the configuration and limited capacity of the transmission system within the Eastside, a direct change in electrical demand for power flowing through these two substations, or a change in power being supplied to 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 (Stantec, 2015).

1.4 HOW DOES PUGET SOUND ENERGY'S ELECTRICAL SYSTEM WORK?

PSE serves approximately 1.1 million customers with electricity in a 4,500-square-mile service area (PSE, 2013a). This service area includes the study areas (Alternatives 1, 2, and 3 as depicted on Figures 2-4, 2-5, and 2-6 in Chapter 2) and portions of King County north and south of the study areas. The Eastside represents approximately 14 percent of PSE's total electrical load. PSE is part of a western regional system, through which electricity is produced elsewhere and transported to the Eastside along high-voltage transmission lines. As electricity nears end users, the voltage is reduced (using transformers) and redistributed through transmission substations and distribution substations.

Power is carried on major, high-voltage transmission lines (230 kV and greater) from generating facilities to the Eastside via the Sammamish substation in Redmond and Talbot Hill substation in Renton. ~~Portions of the Eastside are also served by the Lake Tradition substation in Issaquah.~~ From these substations, voltage is reduced to 115 kV and distributed to numerous Eastside distribution substations (PSE, 2013b). See Figure 16-1 in Chapter 16 for a map that shows PSE's existing electrical system on the Eastside and vicinity. The Energize Eastside Project is intended to address an identified deficiency in the capacity of PSE's transmission system. It does not address the sources of generation, which at present are primarily located outside of the Eastside area.

Comment [BRS5]: Currently, there is no transformation at Lake Tradition, it is only a switching station.

PSE's electric delivery system is regulated by several state and federal agencies, including the U.S. Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC), ~~ColumbiaGrid,~~ Western Electricity Coordinating Council (WECC), and Washington Utilities and Transportation Commission (UTC) (see Figure 1-1 and Table 1-1). PSE cooperates and supports ColumbiaGrid in their regional planning processes.

Comment [DS6]: PSE is not regulated by ColumbiaGrid. We partner with them to comply with our regional planning obligations.

Figure 1-1. Regulatory and Planning Framework for PSE

Table 1-1. Regulatory Agencies Governing PSE

U.S. Federal Energy Regulatory Commission (FERC)	FERC regulates interstate transmission of electricity, natural gas, and oil, as well as Liquefied Natural Gas (LNG) terminals interstate natural gas pipelines, and hydropower projects. Under the non-discriminatory open access transmission tariff (18 CFR 35.28), FERC requires any public utility (which includes PSE) that owns, controls, or operates facilities used for transmission of electric energy in interstate commerce to provide open access transmission service comparable to that provided by transmission owners (such as PSE) to themselves.
North American Electric Reliability Corporation (NERC)	NERC is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the bulk power system in North America, as certified by FERC. NERC develops and enforces Reliability Standards and annually assesses seasonal and long-term reliability. PSE is required to meet the Reliability Standards and is subject to fines if noncompliant.
Western Electricity Coordinating Council (WECC)	WECC is a Utah nonprofit corporation with the mission to foster and promote reliability and efficient coordination in the Western Interconnection, which includes much of western North America. The PSE service area is in the WECC region. WECC develops and implements Regional Reliability Standards and WECC Regional Criteria for the Western Interconnection. PSE is part of the Western Interconnection and is obligated to meet the Regional Reliability Standards.
ColumbiaGrid	ColumbiaGrid was formed to: improve reliability of the transmission grid

	and efficiency in its use; provide cost-effective transmission planning and expansion; develop and facilitate the implementation of solutions relating to improved use and expansion of the interconnected Northwest transmission system; and support effective market monitoring within the Northwest and within the Western Interconnection while considering environmental concerns, regional interests, and cost-effectiveness. As a signatory to ColumbiaGrid, PSE is obligated to meet the objectives of operating a reliable electric grid.
Washington Utilities and Transportation Commission (UTC)	The UTC requires that PSE make its electric service available to all residents and businesses within its service area, and that the service must be delivered in a safe and reliable manner. This is known as the "obligation~~duty~~ to serve" and is codified in Washington state law. This means that PSE shall operate a system that is safe and delivers reliable power, thus minimizing interruptions and outages. The UTC has the authority to levy fines against the company for failure to comply with regulatory requirements.

The UTC requires providers of electricity to provide service on demand in support of growth that occurs in their service areas. PSE conducts an ongoing capacity planning process to ensure its power supply and infrastructure are adequate to meet anticipated future needs (PSE, 2013a). The Integrated Resource Plan is PSE's strategic plan for securing reliable and cost-effective energy resources (PSE, 2013a). PSE filed its most recent Integrated Resource Plan with the UTC in May 2013. PSE develops both short-range and long-range infrastructure plans based upon economic, population, and load growth projections, as well as information from large customers and government stakeholders. The plan is reviewed annually and is periodically updated. (An update to PSE's Integrated Resource Plan is underway, and a draft is available for review on PSE's website.)

1.5 HOW IS THE SEPA REVIEW BEING CONDUCTED FOR THIS PROJECT?

1.5.1 Phase 1 and Phase 2 EIS

The Eastside Cities (Bellevue, Kirkland, Newcastle, Redmond, and Renton), ~~supported by the EIS consultant and in collaboration with PSE (applicant),~~ determined that a Phased EIS (WAC 197-11-060(5)), supported by the EIS consultant and in collaboration with PSE (applicant), would be the best approach to adequately evaluate the proposal. The first phase, for which this Draft EIS has been prepared, programmatically evaluates the potential environmental impacts of various alternatives to be considered for addressing the identified project need. This Phase 1 Draft EIS broadly describes the types of impacts that the alternatives could cause and mitigation that would be available to minimize or avoid such impacts. This broad evaluation is intended to provide decision-makers and community members from the affected jurisdictions with a better understanding of what constructing and operating the alternative methods would mean to the community and how to best evaluate the environmental impacts of more detailed alternatives in Phase 2.

Following release of the Phase 1 Draft EIS, comments will be reviewed and responded to, in a Phase 1 Draft EIS comment summary. These comments will be used to inform the alternatives carried forward into the Phase 2 Draft EIS, which will include additional detail on the proposed project alternatives.

Comment [BRS7]: The IRP is updated biennially.

The Phase 1 Draft EIS generally does not analyze impacts associated with specific development at specified geographic locations. The Phase 2 Draft EIS will include project level alternatives based on more defined geographic locations and a more detailed analysis of potential environmental impacts. Figure 1-1 illustrates the overall process for preparing the two phases of the Draft EIS, followed by a Final EIS that responds to comments on the Draft EIS.

The Phase 1 Draft EIS and Phase 2 Draft EIS together are intended to provide a comprehensive analysis of the project and alternatives. The Phase 2 Draft EIS will be a supplement to the Phase 1 Draft EIS as described in WAC 197-11-405(4), and as part of a phased EIS process per WAC 197-11-405(5).

Comment [BRS8]: Shouldn't this be WAC 197-11-620?

Figure 1-2. Environmental Impact Statement Process

1.6 HOW WAS THIS EIS DEVELOPED?

The EIS process was developed by the City of Bellevue, working closely with its partner Eastside Cities and its consultants. As previously noted, the proposal has been developed by PSE, a private entity; therefore, PSE developed the project objectives and the major alternatives. The City and its team refined the Phase 1 alternatives to meet SEPA requirements, including development of a No Action Alternative. Figure 1-1 illustrates the process being undertaken to complete the EIS process. The following major steps were taken to develop the Phase 1 EIS:

1. Programmatic alternatives were defined with input by the EIS consultant team, PSE, City of Bellevue, and the other Eastside Cities. The alternatives reflect the 19 project criteria developed by PSE (described in detail in Section 2.2 of Chapter 2). ~~However, n~~Not all alternatives fully meet all of PSE's objectives; however, some did reasonably approximate those objectives. ~~[confusing; the EIS only evaluates alternatives that meet the objectives, right?]~~. The Phase 1 Draft EIS includes three action alternatives and the No Action Alternative. These alternatives were carried forward in Phase 1 EIS scoping, which commenced in April 2015.
2. Phase 1 EIS scoping was conducted to assist in identifying technically viable alternatives that address PSE's reported deficiency in electrical transmission capacity. Scoping comments were requested to focus on identification of viable alternatives and associated impacts. Five public meetings were held in the affected jurisdictions, along with opportunities to provide comments online. More than 400 comments in the form of website forms, emails, oral testimony, and letters were received during scoping, as summarized in the *Phase 1 Draft EIS Scoping Summary and Final Alternatives* (City of Bellevue, 2015).
3. As a result of scoping, the alternatives were expanded and refined. The EIS team reviewed all alternatives proposed during scoping, made a technical review of the efficacy of the proposed alternatives, and screened the alternatives against PSE's criteria for an effective solution as listed in PSE's 2015 *Supplemental Solutions Report.* Staff representing each of the cooperating Cities discussed the findings, and a final set of alternatives was established by agreement among the Cities and PSE.
4. The EIS consultant team analyzed potential environmental impacts consistent with the methods outlined in each chapter of the Draft EIS. Input received during scoping was used to refine the environmental analyses, including methods used, area of study, and other elements.
5. The City of Bellevue and the other Eastside Cities reviewed drafts prepared by the EIS consultant team and provided comments for EIS team response. Following review by the Bellevue and the Eastside Cities, portions of chapters 1 and 2 of the internal review Phase 1 Draft EIS was sent to PSE for review of technical accuracy. The City of Bellevue, as SEPA lead agency, had final review of the Phase 1 Draft EIS prior to publication.

1.7 HOW HAS PUBLIC INPUT BEEN INCORPORATED INTO THE EIS PROCESS?

As described above, the scope of this EIS has incorporated public comment received through website forms, emails, oral testimony, and letters. Comments regarding the need for the project helped to refine how the project objectives were defined. Comments regarding the alternatives were evaluated and resulted in changes to the alternatives proposed in the initial Scoping Notice published in April 2015. Comments regarding potential impacts were catalogued and evaluated by the lead agency to determine which impacts could potentially be significant. For some topics, even though significant impacts are not anticipated, there is sufficient controversy about potential impacts that the topics are included in the EIS. The results of the scoping process were summarized in the *Phase 1 Draft EIS Scoping Summary and Final Alternatives* (City of Bellevue, 2015).

1.8 WHAT ARE THE APPLICANT'S OBJECTIVES FOR THE ENERGIZE EASTSIDE PROJECT AND HOW WERE THEY USED FOR THIS DRAFT EIS?

The purpose and need for the project, summarized in Section 1.3, helped to define PSE's objectives for the project, which are as follows:

- Address PSE's identified transmission capacity deficiency;
- Find a solution that can feasibly be implemented before system reliability is impaired;
- Be of reasonable project cost~~cost-effective~~;
- Meet federal, state, and local regulatory requirements; and
- Address PSE's electrical and non-electrical criteria for the project (described in further detail in Chapter 2).

1.9 WHAT ALTERNATIVES ARE EVALUATED IN THE PHASE 1 DRAFT EIS?

Section 2.3 in Chapter 2 describes the process used to develop the alternatives included in the Phase 1 Draft EIS. The EIS evaluates a No Action Alternative and three action alternatives, summarized below.

1.9.1 No Action Alternative

As required by SEPA, the No Action Alternative must be evaluated in an EIS, as a baseline against which the action alternatives can be gauged. The No Action Alternative includes the following:

- Ongoing maintenance that PSE can do without requiring state or local approvals;
- No new 230 kV transmission lines, substations, or energy generation or storage facility; and
- No change to conservation efforts as described in PSE's Integrated Resource Plan.

1.9.2 Alternative 1: New Substation and 230 kV Transmission Lines

This alternative includes installing a new transformer that would transform 230 kV bulk power to 115 kV. This new transformer would require either expansion of an existing substation on the Eastside or construction of a new substation. It would also need to be fed by new 230 kV power lines. The Phase 1 Draft EIS considers a range of 230 kV transmission options to serve the Eastside. The key elements of this alternative include the following:

- New ~~or expanded~~ substation at ~~or near~~ Vernell or~~,~~ Westminster, or a 230 kV substation near the existing 115 kV Lakeside substation~~s~~. A new substation adjacent to the Lakeside substation would be known as Richards Creek substation; however, for simplicity, this site will be referred to as Lakeside.
- New 230 kV transmission line or an upgrade of an existing 230 kV transmission line from Redmond to Renton, located between Lake Washington and Lake Sammamish, including the following possible options:
  A. Use of overhead lines in new or existing right-of-way corridors;
  B. Use of Seattle City Light's 230 kV transmission line corridor along with construction of ~~a~~ new ~~115 kV~~ 230 kV lines looping the system into both the Sammamish and Lakeside substations;

Comment [BRS9]: Reformat – no bullet for this sentence.

Comment [BRS10]: This seems like an appropriate place to introduce the new name. It may be easier to keep referring the site to as Lakeside.

C. Use of underground lines;
D. Use of submerged lines.

- No change to conservation efforts as described in PSE's Integrated Resource Plan.

1.9.3 Alternative 2: Integrated Resource Approach

A combination of methods to meet the projected need and PSE's stated electrical criteria would be used such as the following:

- Energy efficiency (e.g., promoting use of LED lightbulbs rather than incandescent, more efficient appliances, and updated windows and insulation);
- Demand response (e.g., installing specialized devices to control customer electrical usage and help manage peak uses);
- Distributed generation (e.g., promoting use various small scale energy generation equipment tied to the PSE system);
- Energy storage using large-scale battery systems;
- Single-cycle generation facilities of approximately 20 MW size, located at some PSE substations within the Eastside and operated as needed during peak demand periods. However, it should be noted that new generation facilities could be used at any time and not restricted to peak demand periods.

1.9.4 Alternative 3: New 115 kV Lines and Transformers

This alternative includes the following changes to the PSE transmission system:

- A new 230 to 115 kV transformer at Lake Tradition substation;
- ~~A l~~Loop in the BPA Maple Valley-Sammamish 230 kV line to Lake Tradition substation;
- A third 230 to 115 kV transformer at Sammamish substation;
- A third 230 to 115 kV transformer at Talbot Hill substation;
- Three new 115 kV lines at Lake Tradition substation;
- Two new 115 kV lines at Sammamish substation; and
- Two new 115 kV lines at Talbot Hill substation.

The seven additional 115 kV lines would total approximately 60 miles in length. There would be no change to conservation efforts as described in PSE's Integrated Resource Plan.

1.13 WHAT HAPPENS NEXT IN THE ENERGIZE EASTSIDE EIS PROCESS?

The Notice of Availability of this Phase 1 Draft EIS includes the timeframe for public comment on the Draft EIS, including times and locations for public meetings to take comment, and the addresses where comments can be submitted. Once public comments have been received, the Eastside Cities will issue a Scoping Notice for the Phase 2 Draft EIS. Scoping meetings will be held and comments accepted on the project-level analysis that will be prepared in the Phase 2 Draft EIS. Comments received on the Phase 1 Draft EIS and on the scope of the Phase 2 Draft EIS will be summarized and made available to the public. Then the Phase 2 Draft EIS will be prepared.

After publication of the Phase 2 Draft EIS, public meetings will be held to take comments on that document. The Final EIS will include responses to comments on the Phase 1 and Phase 2 Draft EIS documents, as well as any additional analysis that may be required to provide a thorough project-level environmental review for the Energize Eastside Project.

CHAPTER 2. PROJECT ALTERNATIVES

2.1 WHAT DOES THIS CHAPTER COVER?

This chapter provides a description of project alternatives evaluated in the Draft Environmental Impact Statement (EIS). The alternatives described in this chapter were developed based on discussions between the Cities, the EIS consultant team, and Puget Sound Energy (PSE). This chapter also identifies alternatives considered but not evaluated in the Draft EIS because they did not meet PSE's project objectives (see Section 2.2). As required by the State Environmental Policy Act (SEPA), benefits and disadvantages of delaying PSE's project are described at the end of this chapter.

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

Under SEPA, alternatives evaluated in an EIS must feasibly meet the project objectives. The Energize Eastside Project is a private project proposal; therefore, the applicant (PSE) is responsible for developing the objectives of the proposal. The objectives must be defined in a manner that does not preclude feasible alternatives that would have lower environmental costs.

As described in Chapter 1, the purpose of the project is to address a transmission capacity deficiency on the Eastside that PSE expects will develop in the near future. The transmission capacity deficiency PSE has identified is a product of the complex system that PSE uses to supply power to the Eastside and other communities it serves, and the regulations PSE must follow as a utility provider making use of the regional electrical grid. As such, the criteria for what constitutes a viable solution are correspondingly complex.

The following is a list of project criteria from PSE's *Supplemental Eastside Solutions Study Report* (May, 2015) (Gentile et al., 2015). PSE's criteria are based on regulations for utilities and prudent, safe industry practices. They include 15 electrical criteria and 4 non-electrical criteria, as follows:

Electrical Criteria

1. Applicable transmission planning standards and guidelines, including mandatory North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) standards (e.g., NERC TPL-001-4 and WECC TPL-001-WECC-CRT-2);
2. Within study period (2015– 2024);
3. Less than or equal to 95 percent of emergency limits for lines;
4. Less than or equal to 90 percent emergency limit for transformers;

5. Normal winter load forecast with 100 percent and 75 percent conservation;
6. Normal summer load forecast with 100 percent conservation;
7. Adjust regional flows and generation to stress cases similar to annual transmission planning assessment;
8. Take into account future transmission system improvement projects that are expected to be in service within the study period;
9. Minimal or no re-dispatching of generation;
10. No load shedding;
11. No new Remedial Action Schemes;
12. No Corrective Action Plans;
13. Must address all relevant PSE equipment violations;
14. Must not cause any adverse impacts to the reliability or operating characteristic of PSE's or surrounding systems; and
15. Must meet performance criteria listed above for 10 or more years after construction with up to 100 percent of the emergency limit for lines or transformers.

Non-electrical Criteria

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

Collectively, these criteria were considered the fullest expression of PSE's objectives in developing solutions for the Energize Eastside Project. Therefore, these criteria were used to identify reasonable alternatives for consideration in this EIS.

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

2.2.1 Electrical Criteria

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

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

Comment [DS1]: To account for the fact that categories A, B & C no longer exist (TPL-004-1) and have been replaced with new categories (TPL 001-4).

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

This refers to system performance with all system components operating normally. The system must perform without violations of thermal and voltage limits with all systems operating and no contingencies occurring.

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

This refers to system performance with one contingency in the system. A contingency refers to a component that is not operating normally and may be turned off in limited operation, either as a result of an emergency or as part of scheduled maintenance or system improvements. The system must perform without violations of thermal and voltage limits with one contingency occurring.

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

This refers to system performance with two contingencies in the system. This could be due to an emergency, as part of scheduled maintenance or system improvements, or a combination. The system must perform without violations of thermal and voltage limits with two contingencies occurring.

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

See criteria 2.2.1.11 and 2.2~~1~~.1.12 below.

2.2.1.1.5 Substation Planning and Security Guidelines

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

2.2.1.2 Within study period (2015– 2024)

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

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

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

PSE's operating practice is to shift or shed load or dispatch generation to avoid reaching an emergency limit. PSE utilizes 95 percent of the emergency limit as an indication of when PSE needs to start the process to study and upgrade the system to prevent violations of mandatory performance requirements and equipment loss of life. All PSE transmission lines of any voltage must remain equal to or below 95 percent of the emergency line-loading limit over the study period in order for a viable alternative to become a potential solution. This includes all periods of the year whether the system is operating under normal or abnormal system configurations, or during light load or peak load conditions. The system operator receives an alarm when the transmission line reaches 95 percent of its emergency limit.

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

As discussed above, PSE has two thermal operating limits: normal and emergency. If there is a violation of the emergency limit in a transformer, it may overheat, causing a breakdown in internal insulation and leading to a transformer failure or reducing its operational life. Substation transformers are filled with oil to facilitate cooling and insulation. However, if the transformer overheats, the oil may catch fire or explode, which is a serious safety concern. PSE's operating practice is to shift or shed load or dispatch generation to avoid reaching an emergency limit. PSE uses a measure of 90 percent of the emergency limit for transformers as an indication of when PSE needs to start the process to study and upgrade the system to prevent violations of mandatory performance requirements and equipment loss of life. All 230 to 115 kV PSE transformers ~~of any voltage~~ must remain equal to or below 90 percent of the emergency loading limit over the study period in order for a viable alternative to become a potential solution. This includes all periods of the year, whether the system is operating under normal or abnormal system configurations, or during light load or peak load conditions. The system operator receives an alarm when the ~~transmission line~~ 230 to 115 kV transformer ~~reaches~~ reaches its normal ~~90 percent of its emergency~~ limit.

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

A normal winter load forecast represents a snapshot in time reflecting the highest expected load in winter for the given year of the forecast. The peak load is calculated for an average winter with a 1 in 2 chance of occurring (two year winter weather event). This would not be considered an average load, but a peak load. The peak load is used to ensure that the system can withstand the highest estimated loading under all system configurations and still reliably serve customers. A 100 percent conservation level is the amount of reduction in load that PSE estimated could reasonably be attained through energy efficiency, demand response, and distributed generation. The 75 percent conservation level is the estimated amount of reduction in load multiplied by 0.75 to account for the possibility of achieving only 75 percent of the projected conservation, or attaining actual conservation in locations or magnitudes inconsistent with the study model assumptions. Perfect precision cannot be attained without completely accurate data, and the 75 percent conservation level serves as a gauge to help planners understand the ramifications if the model does not precisely mimic a real-world scenario. The normal winter forecast with 100 percent conservation is the peak load forecast for winter minus the 100 percent conservation load amount for winter, and it is the peak expected load used in the study for winter conditions.

Load forecasts and conservation levels (reduction in load) are evaluated in detail in PSE's most recent Needs Assessment report and are based on several parameters, such as historical metering data and population statistics. Refer to the *Supplemental Eastside Needs Assessment Report* dated April 2015 by PSE and Quanta Technology for detailed information.

2.2.1.6 Normal summer load forecast with 100 percent conservation

One major difference between summer and winter peak loads is the different demand levels and use patterns associated with winter heating versus summer cooling. The 100 percent conservation level used in summer is different from the amount of reduction used for a 100 percent winter conservation level. The normal summer forecast with 100 percent conservation is the peak load forecast for summer minus the 100 percent conservation load amount for summer, and it is the peak expected load to be used in the study for summer conditions. The 75 percent conservation level was not evaluated for summer.

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

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

Comment [BRS2]: Cannot adjust flows and generation independently. The snapshots adjust regional flows and generation levels to see how it performs

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

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

The transmission system is constantly evaluated by each utility and the regional entities that unite them to ensure its performance and ability to provide electric power to customers. Each utility and regional agency proposes improvements as needed, such as the 230 kV transformer and transmission line PSE has proposed. When a project has been ~~approved~~ identified by a utility~~for construction~~, it is the utility or regional authority's responsibility to accurately report the change to WECC so that it can be reflected in the future load flow models that WECC prepares. It is important to know not only the extent of the project, but also when it will be placed in service. One of WECC's responsibilities is to gather this information and prepare the models. However, it is PSE's or the other utility planner's responsibility to make sure that the models they use are correct and to add facilities proposed after the WECC cases are built.

For instance, a Heavy Summer 2020 model was prepared by WECC, but PSE needed to model not only 2020 but also the summer of 2018. Therefore, the planner must make sure the loads are corrected for 2 years earlier, and any projects that may be included by 2020 may not be complete in 2018 and therefore must be removed. The same is true in the other direction. For example, if a WECC Heavy Summer 2020 model is to be used for 2022, the model must reflect any additional projects expected to be in service after 2020 that may not be reflected in the WECC 2020 model.

2.2.1.9 Minimal or no re-dispatching of generation

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

2.2.1.10 No load shedding

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

PSE does not use load shedding as a solution to meet mandatory performance requirements. While NERC and WECC allow dropping load for certain contingencies, intentionally dropping firm load for an N-1-1 or N-2 contingency to meet federal planning requirements is not a practice that PSE endorses.

2.2.1.11 No new Remedial Action Schemes

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

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

A RAS is normally administered automatically to control regional issues in the power system.

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

2.2.1.12 No Corrective Action Plans

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

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

2.2.1.13 Must address all relevant PSE equipment violations

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

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

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

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

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

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

2.2.2 Non-electrical Criteria

2.2.2.1 Environmentally acceptable to PSE and communities

For PSE, *environmentally acceptable* means a solution that, through the environmental review process, would be found to minimize, to the extent practicable, the environmental impacts on the affected communities.

2.2.2.2 Constructible by winter of 2017-2018

PSE studies show that Eastside customer demand will reach a point when the Eastside's electric transmission system capacity could experience a deficiency as early as winter 2017-2018. To be a viable solution, a project must be completed and in service by the identified target need date. For example, PSE's current schedule for the proposed 230 kV transformer and transmission line installation targets construction to begin in 2017, with project completion in 2018. Any delay in the schedule would push the in-service date beyond the 2018 timeframe, which would increase PSE's reliance on the use of CAPs and load shedding. For example, some specialized equipment can take up to 3 years to procure. Therefore, PSE would not be able to meet the target in-service date. Alternatives must be reviewed to ensure they are reasonably constructible by the 2018 in-service target date.

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

To PSE, *proven technology* has successfully operated with acceptable performance and reliability within a set of predefined criteria. Proven technology has a documented track record for a defined environment, meaning there are multiple examples of installations with a history of reliable operations. Such documentation shall provide confidence in the technology from practical operations, with respect to the ability of the technology to meet the specified requirements (API SPEC 17 E, 2010).

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

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

2.2.2.4 Reasonable project cost

PSE has a legal obligation~~duty~~ to deliver safe, dependable power, and the obligation to do so at a reasonable cost. PSE continually balances these obligations in determining the best solutions to solve problems facing the electric system. PSE's regulator, the Washington Utilities and Transportation Commission (UTC), also has an obligation to review all PSE projects to determine if the solution is reasonable and prudent. After a project is complete and before the costs are allowed to be placed into the rate base, PSE must prove to the UTC that the cost to build a project is prudent and reasonable to ratepayers. This means PSE must research and compare costs and benefits of multiple alternatives that can accomplish the desired objectives. This is not a simple lowest project cost test; it is a holistic review and analysis of factors such as projected duration of solution, risk to the electric system associated with the type of solution (e.g., is the solution an untested technology), and impacts to the community, as well as the dollar cost of the project.

2.2.3 Understanding PSE's Model Assumptions

To understand the nature of the issue that PSE is proposing to address with the Energize Eastside project, it is helpful to know about the frequency of the conditions that produce the transmission capacity deficiency they have identified. This includes an understanding of how often there are equipment outages that affect the transmission system, and how often the weather conditions occur that produce the peak loads they are trying to address.

The PSE bulk electric transmission system includes approximately 2100 components[1] that are included in its system model. Not all of these components affect the systems on the Eastside, but many components that are outside of the Eastside do affect how and where power flows into the Eastside. When everything is operating normally, the system is said to be in an N-0 state. An N-1 outage condition can occur at any time when a single element trips or is taken off line. This occurs when a problem is detected or because some damage has occurred. It can also be a result of routine maintenance when a system component must be taken out of service, even though if possible, routine maintenance would not be scheduled during peak load periods or during bad weather. In a typical year, the PSE system operates in an N-1 condition about 350-360 days per year (almost every day), and persists for approximately 60 percent of the time[2].

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

An N-2 outage is when a single event trips multiple facilities, such as certain instances where all the breakers in a substation trip off line leaving several circuits without power, or a

[1] Transmission system elements include transmission lines 115 kV and above, transformers whose low side is 115 kV or above, generators connected to transmission, generator step up transformers, reactive devices connected to transmission, substation bus sections at 115 kV and above, and circuit breakers at 115 kV and above.
[2] These are estimates as PSE does not track outages in this format.
[3] This duration is an average and storm events can run much longer than 12 hours.

problem occurs that affects both circuits of a double-circuit transmission line (i.e. two transmission circuits located on one structure). This occurs when a problem is detected, or some sort of damage has occurred. It can also be a result of routine maintenance when multiple system components must be taken out of service. However, if at all possible, routine maintenance avoids multiple elements, and if necessary, would most likely not be scheduled during peak load periods or poor weather. In a typical year, the PSE system operates in an N-2 condition occurs about 10-20 times, and persists for approximately 4-12 hours, or less than 1 percent of the year[2].

The normal peak weather events that PSE uses in its model to test its system are extended periods of either cold winter temperatures or high summer temperatures that have a 50 percent likelihood of occurring in a given year. Extreme winter peak is studied for a 1-in-20 winter; however, this extreme data is not used to justify Energize Eastside. For winter, this means a temperature of 23 degrees Fahrenheit or lower at the time of the system peak. For summer, this means a temperature of 86 degrees Fahrenheit or higher at the time of the system peak.

2.3 PROJECT ALTERNATIVES

This Phase 1 Draft EIS evaluates PSE's proposed Energize Eastside Project, a 230 kV overhead line, a No Action Alternative (as required by SEPA), and two other "action alternatives." These alternatives were developed by the Cities in cooperation with PSE, to provide options that meet some or all of PSE objectives for the project at a lower environmental cost. The **No Action Alternative** provides a benchmark against which the proposed project and other action alternatives can be compared. **Alternative 1** includes the 230 kV overhead lines but also includes options for locations, including underground and underwater options. **Alternative 2** includes a variety of solutions that would require very limited new transmission lines and that would need to be implemented in combination in order to meet the project objectives. **Alternative 3** would involve installing enough 115 kV lines and transformers to address the project objectives without building 230 kV lines. Each alternative is described in more detail below.

2.3.1 No Action Alternative

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

~~Population forecasts prepared by Quanta and compiled by PSE and B~~based on U.S. Census and Puget Sound Regional Council population forecast data, PSE's analysis concluded ~~have indicated~~ that the population in ~~the~~ 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 2.6 percent per year, resulting in additional electrical demand. If electrical load growth occurs as PSE has projected, PSE's system would likely experience loads on the Eastside that would place the local and regional system at risk of damage if no system modifications are made. To address this risk in the near term, PSE would use Corrective Action Plans (CAPs) (described above in PSE's criteria for the project), which are a series of operational steps used to prevent system overloads or large-scale loss of customers' power. CAPs generally involve shutting off or reducing load on overloaded equipment and rerouting the load to other equipment. The CAPs are seen as temporary measures used to keep the entire system operating, but they can place large numbers of customers at risk of a power outage if anything else on the system begins to fail.

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

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

For the Eastside in 2024, PSE projected that proposed conservation measures would address approximately 110 MW of peak usage period, leaving a remaining Eastside load of 764 MW needing to be served during projected peak periods. The conservation measures would address approximately 13 percent of the peak load. PSE currently conserves approximately 21 MW, or 3 percent of the Eastside baseline peak load. Systemwide, PSE currently is estimated to achieve~~s~~ system peak conservation of approximately 91 MW or approximately 1.8 percent of the system peak of 4,803 MW in 2014 through 2015.

To achieve its electrical conservation goals, t~~T~~he types of conservation measures PSE expects to ~~implement~~ incentivize ~~to achieve its electrical conservation goals~~ include the following:

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

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

As appropriate, conductor replacement on existing lines could occur under the No Action Alternative. These improvements would not increase overall system capacity, because capacity issues driving this project are typically associated with transformer overloads rather than conductor overloads.

Comment [BRS3]: PSE did not have access to Appendix A; therefore, we cannot confirm the accuracy of the referenced information

PSE would continue the current practice of using advanced systems, such as Conservation Voltage Reduction, to improve system efficiency and reduce overall loading. There are no currently known new technologies that PSE would employ that could substantially affect the transmission capacity deficiency on the Eastside. Under the No Action Alternative, PSE would not be precluded from seeking out new technologies, however.

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

Under this alternative, PSE would install a new transformer somewhere near the center of the Eastside to convert 230 kV bulk power to 115 kV to feed the Eastside distribution system. The new transformer would be installed at or near one of three properties that are either adjacent to existing substations or have been purchased by PSE for future substations. Potential locations could be adjacent to the existing Lakeside substation (where PSE would need to purchase additional land), or at one of two possible substation sites referred to as Westminster and Vernell, all within Bellevue city limits (Figure 2-2). These sites are located where multiple 115 kV lines come together, providing the most efficient power injection to the system. The property adjacent to the existing Lakeside 115 kV substation presents the most effective location from a system-wide perspective because of its immediate proximity to the existing 115 kV substation and the multiple existing 115 kV lines. Both the Westminster and Vernell sites would require the addition of one or more new 115 kV lines. At any of these sites, development of a new 230 kV substation yard would be required to accommodate the new transformer and supporting equipment.

To supply the new transformer, two new 230 kV transmission lines would be constructed to bring power from existing 230 kV sources. PSE's Talbot Hill substation in Renton and Sammamish substation in Redmond are the closest existing 230 kV sources to the center of the Eastside, and are considered the southern and northern termini of this alternative. ~~While PSE's preferred location could be in one of its existing transmission easements or rights-of-way, T~~the Phase 1 Draft EIS considers that transmission lines could be placed in existing or new corridors, including adjacent to roads or highways.

Seattle City Light (SCL) has a 230 kV transmission line that traverses the Eastside and is a potential power source. PSE has explored the idea of using the SCL line as an option; however, SCL stated that it needs this line to serve its customers (Gentile et al., 2014). The SCL facility is not under PSE ownership and currently does not have the capacity to meet PSEs' identified need for the Energize Eastside Project. Tying into this source is one option that PSE could pursue to supply the new transformer. ~~PSE is continuing to coordinate with SCL regarding the potential use of this line.~~

The present emergency ratings of the SCL lines are 426 megavolt amperes (MVA) in the summer and 526 MVA in the winter. In order for PSE to utilize these lines as the source for an additional 230 kV transformer on the Eastside, the present ratings are insufficient. If lines were upgraded by replacing only the conductor, then the assumed ratings for the reconductored lines are 692 MVA in the summer and 771 MVA in the winter. This would not be adequate to meet both SCL's needs and PSE' project objectives (PSE 2015x, personal communication). Therefore, if SCL were to grant use of this line, PSE would need to both tie into it and upgrade it. The next incremental increase in capacity would be to rebuild the SCL lines (replace structures and conductors), which could provide a line capacity of approximately 1,139 MVA in the summer and 1,366 MVA in the winter. The rebuild is anticipated to provide sufficient capacity for a period of less than 10 years.

2.3.2.1 General Transmission Line Options

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

Solutions considered part of this alternative include “single circuit” lines as well as solutions that would allow for addition of a second 230 kV circuit on the same poles or in the same underground or underwater facility. In the near term, one of the existing 115 kV lines between the Lakeside substation and the Talbot Hill substation ~~would~~may need to be ~~replaced~~ rebuilt with a ~~line that provides a~~ higher capacity conductor. There would be little difference between a high capacity 115 kV line and a 230 kV line. While there is not an immediate need for a second 230 kV circuit, in some situations, there may be~~are~~ cost efficiencies to~~with~~ installing a second ~~double- circuit~~ transmission facility in the same corridor as the 230 kV line. ~~ies that~~ PSE considers this an important factor~~considers important~~ in its efforts to identify the least costly infrastructure to serve its customers. An additional wire would be installed on top of the new poles for lightning protection. Any existing fiber-optic cable would need to be transferred to the new poles.

A single circuit transmission line includes three conductors (wires). A double circuit includes six conductors.

The types of lines being considered for Alternative 1 have been categorized into four options as follows: **Option A**—new overhead transmission lines; **Option B** –use existing SCL overhead transmission lines; **Option C** –underground transmission lines; and **Option D** –underwater transmission lines. These options are described below.

2.3.2.2 Option A: New Overhead Transmission Lines

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

2.3.2.2.1 Transmission Overhead Line Locations

The study area for Alternative 1 (Figure 2-4) shows the extent of the area where installing a new 230 kV transformer and transmission line would be used to meet PSE’s project objectives. Within this area, overhead lines could be constructed anywhere. PSE policy is to use its existing easements or rights-of-way wherever possible, but road and other utility right-of-way corridors (such as city streets, state and interstate highways, and some sections of the SCL corridor) are also possible locations. PSE could need to obtain new right-of-way to extend the transmission lines to a desired substation, or to avoid an area of potential impact elsewhere. Additionally, relocation of existing distribution or 115 kV lines may be needed in order to accommodate the new 230 kV line.

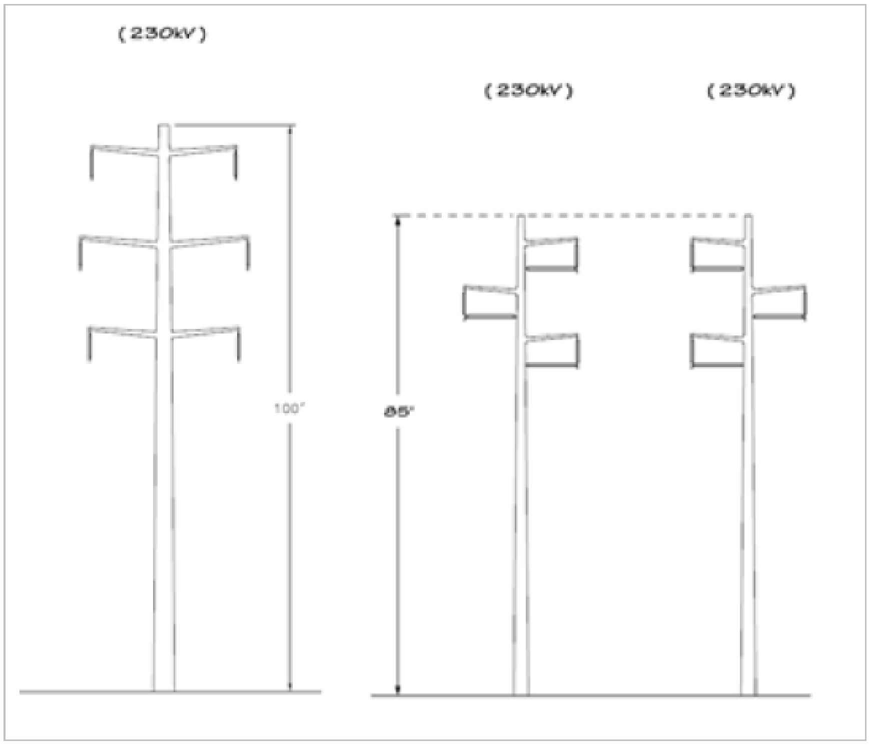
Specific pole locations would be determined based on site engineering. Pole locations would generally be based on tensioning needs for the wire (including where turns are needed along the route), underground obstacles at pole foundation locations, topography, and allowable structural heights, all while attempting to use as few poles as possible.

2.3.2.2.2 Pole Types and Heights for Overhead Lines

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

In order to meet National Electric Safety Code (NESC) and FERC/NERC requirements to prevent contact, adequate clearances must be maintained between each conductor, the ground, adjacent buildings, and trees. Pole height therefore would vary depending on the number of circuits, the arrangement of the circuits on the poles, topography, and surrounding land cover. Figure 2-1 shows the typical range of pole dimensions. Generally, ~~for a double-circuit system,~~ pole heights would range from 85 to 100 feet. In special cases, such as crossing a ravine or highway, pole heights could be shorter or taller.

Figure 2-1. Potential Pole Dimensions



2.3.2.2.3 Overhead Line Installation

The methods used to install the poles will depend on the type of pole used and both its physical and operational location. Poles can be directly embedded in the ground or utilize an anchor bolt cage, which is a drilled pier foundation that involves setting the anchor bolt cage in a poured column of concrete. Poles are set and anchored to the foundations. Once the pole is set in place, the transmission wire would be installed. The wire-stringing operation requires equipment at each end of the section being strung. Wire would be pulled between these temporary pulling sites through pulleys at each structure. These pulling sites would be set up at various intervals along the right-of-way, typically 1 to 3 miles apart. Specific pulling sites would be determined close to the time the stringing activity takes place. Once the wire is strung, the stringing blocks (i.e., guide rollers) would be removed and the wire clipped into its final hardware attachment.

2.3.2.2.4 New Transformer

PSE currently owns three properties that have been designated as locations for future substations in the central portion of the Eastside that could potentially serve the project objectives with a new 230 kV to 115 kV transformer. The substation yard would need to be large enough to accommodate the new transformer and associated electrical equipment such as circuit breakers, bus, and connections to the new transmission lines. The gravel yard would include the necessary foundations, access ways, stormwater drainage, and security fencing (typically 8-foot-tall chainlink, but other types of fencing may be used). In order to accommodate a new transformer and associated equipment, acquisition of property adjacent to the substation site could be required.

Oversize trucks would be used to transport the transformers. Use of oversize trucks would be restricted to hours that would reduce traffic impacts. Unloading and placing the transformer is typically done by crane. Depending on site access and configuration, these activities could require temporary street closures and detours.

2.3.2.3 Option B: Use Existing 230 kV Overhead Transmission Lines

Option B makes use of existing overhead transmission lines such as the SCL 230 kV overhead transmission line (see Figure 2-2). System operational studies by PSE have shown that this would require ~~a~~ significant modifications ~~complete rebuild~~ of the SCL lines, including replacing most of the existing structures and all conductors, to meet the rating for the necessary capacity. This option includes ~~rebuilding and re-conductoring~~ both of the SCL SnoKing-Maple Valley 230 kV transmission lines. It would also require connecting ~~one double circuit~~ two 230 kV lines to a new transmission substation (to be called Richards Creek if located adjacent to Lakeside substation) and connecting another two 230 kV lines ~~double circuit 230 kV line~~ to the Sammamish substation. The SCL lines may be difficult to take out of service; therefore, the replacement line may need to be constructed adjacent to the existing line and placed into service prior to removing the existing structures and conductor. ~~PSE is continuing to discuss the feasibility of this option with SCL.~~

Comment [BRS4]: See comment in Chapter 1. If using the new name, then suggest placing it on the Maps.

2.3.2.4 Option C: Underground Transmission Lines

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

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

The types of development and terrain to be crossed are important considerations in the design and construction methods used. Most underground installations are open-cut trench construction, with trench depth determined by future use of the area, location of other utilities, obstructions, and other factors. Additional excavation is done to construct access and splice vaults. Construction typically involves excavators, concrete trucks, tractor trailers, cranes, and cable reel trucks. Construction techniques for underground transmission lines largely depend upon the type of terrain and surface conditions:

- Flat terrain – Typically a temporary road is constructed along the full length of the trenching operation to provide the necessary construction access.

- Rolling hills – Where slopes are not extreme (less than 10 percent), open trench construction is typically used. Extreme slopes can limit access for construction equipment. In some cases access roads are cut into the hill or switchbacks are used to climb steeper slopes. Horizontal directional drilling (HDD) or trenchless construction can sometimes be utilized to cross a series of hills.
- Rock - If bedrock is encountered, explosives may be used to ensure adequate trench depths.
- Wetlands – While open cutting can sometimes be used to cross wetlands, there are significant environmental controls typically applied to the process. In some cases, HDD can be used to span a wetland area.
- Other obstructions – There are other situations where open trenching is not practical. This includes crossing of streams, rivers, waterways, highways, railroad tracks, and other situations where open cutting is not allowed or practical. Various trenchless techniques or routing changes may be needed in these cases.

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

2.3.2.5 Option D: Underwater Transmission Lines

Option D involves constructing an underwater transmission line in Lake Washington. Underwater cable could be installed in ~~either~~ Lake Washington provided that the appropriate equipment and materials could be transported to the water body. (The possibility of using Lake Sammamish was also considered, but technical limitations would preclude use of that route. See Section 2.5 for discussion of alternatives considered but not included.) Overland connections required to connect a submerged line to the Sammamish and Talbot Hill substations, and to a new transformer near the center of the Eastside area as described above for all Options under Alternative 1.

For the Phase 1 Draft EIS, a study area was selected that assumes cables could be installed within 1,000 feet of the western shoreline of Lake Washington from Kirkland to Renton, and includes the entire channel between Mercer Island and the eastern shore of Lake Washington.

The underwater line would need to cross existing submarine cables in Lake Washington, requiring adequate spacing. Appropriate design steps would need to be taken to protect both existing and new cable systems.

PSE commissioned Power Engineers to prepare a report on an underwater option in one segment of Lake Washington, which provides a number of details about what this option would entail (Power Engineers, 2015). The underwater cable system would likely be composed of three to six conductors spaced at least 16.5 feet apart from one another. Because of system demands, it was assumed that six cables would be needed. These cables could be buried 3 to 5 feet below the lake bottom, although in some areas that are deep enough to avoid potential conflicts with deep draft vessels, cables may be laid directly on the lake bottom. Shore landings would be constructed using open-cut trenching, sheet piling, and dredging. Trenchless installation is possible but requires larger cable sizes and higher costs. Installation would require special vessels to dredge trenches in the lake bottom and lay cable (Power Engineers, 2015). Because of the limitations on the size of vessels capable of passing under the I-90 floating bridge, multiple passes with a smaller vessel may be required for the complete installation of the cable system. Truck delivery is considered infeasible because the longest cable segment that could be transported by truck is approximately 1,100 feet, due to highway weight limits.

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

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

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

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

Additional information about laying submarine cable in Lake Washington can be found in the *Eastside 230 kV Project Lake Washington Submarine Cable Alternative Feasibility Report* prepared for PSE (Power Engineers, 2015).

2.3.2.6 Conservation

Under Alternative 1, PSE would continue the conservation efforts called out in its Integrated Resource Plan, as described in the No Action Alternative. As such, this alternative is expected to result in the same levels of conservation as the No Action Alternative.

2.3.3 Alternative 2: Integrated Resource Approach

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

In order for conservation to meet the project objectives for the Energize Eastside Project, the amount of conservation accomplished would need to be approximately four times the conservation level that PSE currently plans to achieve in the Eastside area. By the winter of 2017-2018, PSE would need to accomplish an additional 163 MW of conservation beyond the currently planned 50 MW of conservation within the Eastside (total need of 213 MW of conservation within the Eastside). By winter 2024, the amount of conservation within the Eastside needed to meet the project objectives would be 324 MW, which is 214 MW more than the 110 MW currently planned for that area. If growth continues as predicted, additional conservation or a system upgrade would be necessary to reliably serve the area beyond 2024.

For comparison, PSE's current plan for the entire PSE system is to implement 832 MW of conservation by 2024, with the Eastside representing approximately 14 percent of the total load for the PSE system, and therefore 14 percent of the total projected conservation. Additional study would be needed to determine if the amount of additional conservation needed is technically achievable.

Comment [BRS5]: This value should be checked as our number is 852 MW by 2024.

Because Alternative 2 is based on the assumption that just enough conservation and new energy supply will be accomplished within the Eastside each year to avoid needing additional transmission capacity, it results in the need for closer monitoring and management. This alternative could address the project need but results in uncertainty about how much infrastructure will be provided and how much additional will be needed. Under that assumption, at the end of the 10-year target period, additional measures or facilities would be required to address future growth. The approach could be continued conservation efforts, but because of stricter building codes already in place and the acceleration of retrofitting assumed under this alternative, the availability of additional capacity for conservation is uncertain. If conservation cannot address identified capacity needs, additional transmission or generation infrastructure could be required.

Alternative 2 assumes a mix of measures to accomplish conservation savings. In order to fully address the identified capacity need, Alternative 2 would include a combination of energy storage units, demand response devices, distributed generation, and energy efficiency improvements. These measures are described below. Table 2-1 summarizes a theoretical mix of measures and anticipated energy conservation for each component. This table is provided for illustrative purposes, so that a reader can understand the approximate magnitude of the effort required to meet the project need. The actual mix would depend on the success of each component in being adopted. Some, like energy storage, could be built by PSE, while others require voluntary participation by customers.

Table 2-1. Energy Conservation Estimates for Components of Alternative 2

Alternative 2 Component	Energy conserved or generated beyond the conservation included in the No Action Alternative	Comments
Energy efficiency	42 MW	Based on tripling the 2033 level from the Integrated Resource Plan
Demand response	32 MW	Based on tripling expected adoption by 2024
Distributed generation	100 MW	Based on tripling the 2033 level from the Integrated Resource Plan
Energy storage	121 MW	Based on minimum to eliminate emergency overloads estimated by Strategen (2015)
Peak power generators	60 MW	Assumes new 20 MW single-cycle gas fired generators at three existing substations within the Eastside

2.3.3.1 Energy Efficiency Component

The energy efficiency measures under Alternative 2 would be the same as those described for the No Action Alternative, such as replacing older, inefficient appliances and lighting, and adding insulation and weatherproofing. However, to meet the project objectives for Energize Eastside, these efforts would need to be substantially accelerated and expanded on the Eastside. The potential for additional energy efficiency on the Eastside is not currently known and would require additional evaluation. Stricter building energy code standards could accomplish part of the project objective but are not within the control of PSE. Therefore, they are not considered part of this alternative, but could be considered by affected jurisdictions as a means to help ensure the success of this alternative. Additional promotion and incentives would be ~~implemented~~ necessary to encourage ~~additional~~ this higher level of conservation. For the Phase 1 Draft EIS analysis, it was assumed that current conservation programs could be accelerated such that the energy efficiency planned for the Eastside through 2033 could be tripled and accomplished by 2024 (Table 2-1). This analysis assumes PSE would need to accomplish approximately 42 MW of additional energy efficiency just within the Eastside by 2024. For comparison, the Integrated Resource Plan predicts approximately 14 MW of energy efficiency gains on the Eastside from 2024 to 2033, and 100 MW of additional energy efficiency during that period systemwide.

Comment [BRS6]: We still are working on confirming this value and are targeting Monday (Nov. 30) for verification.

2.3.3.2 Demand Response Component

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

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

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

Comment [BRS7]: We still are working on confirming this value and are targeting Monday (Nov. 30) for verification.

Comment [BRS8]: We still are working on confirming this value and are targeting Monday (Nov. 30) for verification.

2.3.3.3 Distributed Generation Component

Distributed generation involves generating power on-site. Distributed generation reduces costs and interdependencies associated with transmission and distribution and can shift control to the consumer. On-site energy generation can include solar photovoltaic systems, gas turbines, anaerobic digesters, reciprocating engines (e.g. diesel generators), microturbines, fuel cells, small hydro, and wind turbines.

In order to address the Eastside transmission deficiency with distributed generation alone, approximately 300 to 400 MW of capacity would be needed by 2024 depending on the geographic location of the~~distribution of the~~ generation. For comparison, a typical 6 kW rooftop solar photovoltaic system generates 6,000 kWh per year, and a typical customer- based wind turbine generates 300 kWh (1 MW = 1,000 kW). Currently, wind turbines on the Eastside are limited to two small-scale (approximately 1 MW) turbines, due to a lack of consistent wind resources. Typically, winter peak system loading occurs in the morning and evening, when solar is less effective because of the shorter daylight hours. Solar could help reduce summer peak loads but because additional capacity would still be needed for winter, the use of solar generation to address the transmission capacity deficiency would need to be matched by winter generation capacity and therefore would be redundant. For the Phase 1 evaluation, it was assumed that solar power and wind would contribute minimally to addressing the identified capacity deficiency by 2024. Because there are no identified locations on the Eastside where small hydroelectric facilities would be feasible, it was assumed that small-scale hydroelectric would not contribute to addressing capacity. Therefore, distributed generation facilities would consist primarily of gas turbines, anaerobic digesters, reciprocating engines, microturbines, and fuel cells.

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

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

2.3.3.4 Energy Storage Component

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

- An energy storage system with power and energy storage ratings comparable to the Baseline Configuration (large enough to reduce normal overloads) has not yet been installed anywhere in the world.
- 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.
- 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.
- Summer requirements were not evaluated because the limitations identified during the winter study indicated that energy storage would not be a feasible stand-alone alternative.

For these reasons, energy storage was considered a partial solution that would be implemented together with other demand-side reduction strategies. This analysis considers a facility capable of storing 121 MW, which would be adequate to eliminate emergency overloads. This would require a site of approximately 6 acres and would need to be close to the center of the Eastside, ideally adjacent to an existing substation.

2.3.3.1 Peak Generation Plant Component

This component would involve installing 20 MW generators at substations within the Eastside. These could be any type of generator but the most likely type would be a simple-cycle gas-fired generator. These systems burn natural gas to turn a turbine that powers a generator. They can be combined with heat recovery units to improve overall efficiency.

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

2.3.4 Alternative 3: New 115 kV Lines and Transformers

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

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

Table 2-2. Substation Modifications Required for Alternative 3

Substation	New 230/115 kV Transformer Required	New 115 kV Line Connections Required to:	Fits in Existing Substation Footprint	Notes
Sammamish	Install 3rd 230/115kV Transformer	Ardmore and Clyde Hill	No	Would need to expand the substation footprint by approximately 10 to 20%.
Lakeside 115 kV		Pickering and Talbot Hill	No	Requires substation yard expansion to fit additional buswork. Would not likely need to buy property, but would need to extend approximately 10 to 20% of the existing fence footprint.
Lake Tradition	Install 1st 230/115kV Transformer	Novelty Hill and Berrydale	Yes	Requires existing BPA 230 kV line to be extended to bring 230 kV to Lake Tradition substation.
Talbot Hill	Install 3rd 230/115kV Transformer	Lakeside and Hazelwood	No	Only enough space for one 115 kV line bay and three would be needed. Would need to expand the yard by approximately 5to 10%.
Ardmore		Sammamish	Yes	Requires fourth line; should fit within the existing substation footprint.
Clyde Hill		Sammamish	No	Requires reconfiguring the substation. Preliminary rebuild designs have the substation increasing about 50 to 60% larger than existing yard.
Pickering		Lakeside 115 kV	Yes	
Berrydale		Lake Tradition	Yes	
Novelty Hill		Lake Tradition	Yes	
Hazelwood		Talbot Hill	No	Requires rebuilding the substation. A preliminary layout has the substation increasing about 200% larger than the existing yard. Additional property potentially needed.

Source: PSE

The exact number and locations of lines have not been determined, but the diagram provided by PSE (Figure 2-3) provides a conceptual layout of where new 115 kV lines would be required. A complete routing study would be done to evaluate the feasibility of any potential route. It is assumed that these lines would follow existing utility or road rights-of-way, and would either replace or be co-located with existing transmission and distribution lines wherever possible. This represents approximately 60 miles of new 115 kV lines. It is assumed these lines would be overhead lines. Additionally, an existing BPA 230 kV line would have to be extended to bring 230 kV to the Lake Tradition substation.

For a typical single circuit 115 kV system, with~~out any~~ distribution lines on the same poles, pole heights would generally vary from 60 feet to 75 feet depending on span length, structure configuration, and topography. However, in some instances taller poles may be required to span obstacles, meet right-of-way constraints, and topography. ~~In some locations, co-location with distribution lines would be necessary or desirable, and pole heights would likely be xxx feet taller.~~ If co-location is required with existing 115 kV lines (a very likely scenario, creating a double circuit), then pole heights would mostly likely need to be up to 30 feet to 40~~xxx~~ feet taller in order to meet NESC requirements and right-of-way constraints.~~.~~

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

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

Under Alternative 3, PSE would continue the conservation efforts called out in its Integrated Resource Plan, as described in the No Action Alternative. As such, this alternative is expected to result in the same levels of conservation as the No Action Alternative.

Kirkland

Sammamish

Redmond

Novelty Hill

Yarrow Point

Hunts Point

Clyde Hill

Ardmore

Clyde Hill

Medina

Bellevue

Lake Sammamish

Sammamish

Lake Washington

Beaux Arts

Lakeside

Mercer Island

Pickering

Newcastle

Issaquah

Lake Tradition

Existing Substa ions

New 230 kV/115 kV Transformers

Water bodies

New 115 kV Transmission Lines

Roadway

City Limits

Unincorporated King County

Ta bot Hill

Renton

0 2

Miles

U:\GIS\GIS\Projects\14xxxx\D140548_EastsidePSETransmisisonCoor\MXD\Alt3Substation_New115kV_location.mxd

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

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

Energize Eastside EIS 140548

Figure 2-3

Alternative 3 - New 115 kV Lines and Transformers

2.4 WHICH AREAS WERE STUDIED?

The study areas for each alternative are outlined in Figures 2-4, 2-5, and 2-6 and correspond to the areas where the project components would be constructed and operated.

The Alternative 1 study area includes portions of Renton, Newcastle, Bellevue, Kirkland, and Redmond and unincorporated King County. Alternative 1 assumes in-water work within a portion of Lake Washington, including in-water areas along the shorelines of Mercer Island, Beaux Arts Village, Medina, Hunts Point, and Yarrow Point.

The Alternative 2 study area excludes in-water work, but includes potential project activity anywhere from the east side of Lake Washington to west side of Lake Sammamish.

The Alternative 3 study area includes the same western boundary as Alternative 2 but extends eastward beyond Lake Sammamish and into the foothills of the Cascade Mountains. Portions of Sammamish and Issaquah are within the Alternative 3 study area.

The No Action Alternative is assumed to be consistent with the Alternative 3 study area. The alternatives are located collectively within the following public land survey system townships and ranges: T25N / R6E, T25N / R5E, T24N / R6E, T24N / R5E, and T23N / R5~~6~~E.

Comment [BRS9]: R5E is where Talbot Hill substation is located.

Sammamish

Novelty Hill

Kirkland

Redmond

Yarrow Point

Hunts Point

Vernell

Westminster

Clyde Hill

Medina

Bellevue

Lake Sammamish

Sammamish

Lake Washington

Beaux Arts

Lakeside

Mercer Island

Newcastle

Issaquah

Lake Tradition

Alternative 1 (landside)

Alternative 1 (waterside)

Proposed Substation

Substation

Roadway

Water bodies

City Limit

Unincorporated King County

Talbot Hill

Renton

0 2

Miles

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

U:\GIS\GIS\Projects\14xxxx\D140548_EastsidePSETransmisisonCoor\MXD\Alternative_1.mxd

energize EASTSIDE EIS

SOURCE: King County 2015; ESA 2015; WA Ecology 2014

Energize Eastside EIS 140548

Figure 2-30

Sammamish

Novelty Hill

Kirkland

Redmond

Yarrow Point

Hunts Point

Clyde Hill

Medina

Bellevue

Lake Sammamish

Sammamish

Lake Washington

Beaux Arts

Lakeside

Mercer Island

Newcastle

Issaquah

Lake Tradition

Talbot Hill

Renton

Alternative 2

Substation

Roadway

Water bodies

City Limit

Unincorporated King County

0 2

Miles

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

U:\GIS\GIS\Projects\14xxxx\D140548_EastsidePSETransmisisonCoor\MXD\Alternatives.mxd

SOURCE: King County 2015; ESA 2015; WA Ecology 2014

Energize Eastside EIS 140548

Figure 2-5

Alternative 2 Study Area

Sammamish

Novelty Hill

Kirkland

Redmond

Yarrow Point

Hunts Point

Clyde Hill

Medina

Bellevue

Lake Sammamish

Sammamish

Lake Washington

Beaux Arts

Lakeside

Mercer Island

Newcastle

Issaquah

Lake Tradition

Talbot Hill

Renton

Alternative 3

Substation

Roadway

Water bodies

City Limit

Unincorporated King County

0 2

Miles

U:\GIS\GIS\Projects\14xxxx\D140548_EastsidePSETransmisisonCoon\MXD\Alternatives.mxd

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

SOURCE: King County 2015; ESA 2015; WA Ecology 2014

Energize Eastside EIS 140548

Figure 2-6

Alternative 3 Study Area

2.5 ALTERNATIVES CONSIDERED BUT NOT INCLUDED

The following alternatives were identified through scoping but will not be included for analysis in the Phase 1 Draft EIS.

2.5.1 Use Existing BPA High-Power Transmission Line

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

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

- All of these solutions were found to overload either transmission lines or transformers and therefore would not meet PSE's stated project objectives. See *Eastside Transmission Solutions Report*, October 2013 (updated February 2014), Tables 4.1 and 4.2, and Sections 4.6.3, 4.6.6, 4.6.8, 5.1.1, and 5.1.2 for more information (Gentile et al., 2014).

SOURCE: King County 2015; ESA 2015; WA Ecology 2014

Figure 2-8
Alternative 3 Study Area

2.5.2 Upgrade/Adjust Existing Electrical System

Several changes and adjustments to the electrical transmission system were proposed as potential solutions. Several related to discontinuing the flow of electricity through the Eastside to Canada during peak demand periods. These were described in comments during renegotiation of the Columbia River Treaty (which relates to river flows and electrical supply across the U.S. - Canada border), diverting power flowing from the south toward Canada to other transmission lines, or simply cutting off power flow to Canada altogether. Other suggested solutions include converting an existing alternating current (AC) line to a direct current (DC) power line, using “self-healing” lines, and changing conductor types and sizes.

Disconnecting the system from the region or not providing power to the rest of the region during peak periods is not included as an alternative because it was not considered viable for the following reasons:

- PSE has statutory and regulatory obligations that come with being interconnected to the electric grid and that cannot be violated without penalties. Those obligations are with the FERC, NERC, WECC, ~~ColumbiaGrid,~~ and UTC.
- This solution would also compromise PSE’s ability to supply power and maintain reliability in an efficient and cost-effective manner; the generation that is owned and contracted for by PSE is generally outside PSE’s service area and requires transmission lines to transport that power to PSE’s service area. The diversity of the generation mixture provides security in the event that one kind of generation becomes limited (e.g., hydroelectricity in a year with low snowmelt or rainfall). Being part of the regional grid allows the dispatch of the least costly generating units within the interconnected area, providing an overall cost savings to PSE customers. Planned outages of generating and transmission facilities for maintenance can be better coordinated so that overall cost and reliability for the interconnected network is more efficient. Being interconnected also allows economies of scale for both transmission and generation facilities. Finally, this solution could reduce the supply of power to the Eastside, necessitating additional conservation, generation, or storage beyond that considered in the other alternatives in the EIS.
- Disconnecting the north and south sections of the route at a central Bellevue substation to prevent non-Eastside load from being carried on this line during peak periods of demand on the Eastside would deprive the Eastside of power supply needed during these periods. Separating the system in central Bellevue from the region at grid would also not meet FERC mandatory reliability standards. This could be a CAP, which is temporary in nature and not a long-term solution, and does not bring a new source or new generation into the deficiency area.
- Relying on BPA projects would not deliver the appropriate amount of power to the Eastside area because the BPA sources are outside the deficiency area and would address only wider regional problems, leaving a deficiency on the Eastside (see Section 2.5.1).
- Renegotiating the Columbia River Treaty is outside the purview of PSE and the Eastside Cities and would not help solve the problem as described previously.

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

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

2.5.3 Generation Facilities

Adding a generation facility or group of facilities is not included as an alternative. To be effective, PSE found that the facilities would have to be located near the center of the Eastside area, such as near the Lakeside substation. Any such facility would likely have to be natural gas-fired to be capable of producing power reliably whenever it is needed. PSE determined that at least 300 MW of power generating capacity would be needed and the most cost- effective way to generate that amount of power would be in a single plant. In its 2013 Solutions Report, PSE found that small distributed generation and energy storage would have little impact on the problem (Gentile et al., 2014) ~~unless a large number were developed as described in the Integrated Resource Approach Alternative (Gentile et al., 2014)~~. Generation facilities at the 300 MW size would require a natural gas and water infrastructure that is presently unavailable, and providing this infrastructure would likely entail significant environmental impacts. Facilities of this type typically are large noise generators. In addition, the increased usage of natural gas-fired plants over time would have difficulty meeting clean air regulations. Even if it were economically feasible to create multiple smaller facilities, they would need to be clustered close to the center of the Eastside and would likely impose similar or even greater impacts than a single plant. This alternative is not included because the Cities determined that it does not meet SEPA requirements to provide a reasonable alternative that could feasibly attain or approximate a proposal's objectives at a lower environmental cost or decreased level of environmental degradation (WAC 197-11-440(5)(b)).

Backup generators could potentially be used to reduce peak demand, thereby solvinge the capacity issue~~peak demand~~; however, PSE did not find enough existing generators or owners willing to connect to the network to meet the project objectives. PSE cannot compel owners of generators to connect to a network. In addition, increased usage of diesel generators would not meet present clean air regulations, and such facilities often have considerable noise impacts. This alternative is not included because it does not meet PSE's performance criteria of serving 10 years or more after construction, and being environmentally acceptable to PSE and communities.

The Westside Peaking System is located outside the deficiency area and would require transmission to adequately deliver power to the load area. This alternative is not included because it would not address the deficiency on the Eastside.

Comment [BRS10]: We are not sure what this is referring to.

2.5.4 Submerged 230 kV Transmission Line in Lake Sammamish

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

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

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

2.5.5 Other Approaches

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

A combination of alternatives would not address the transmission capacity deficiency during peak periods that has been identified by PSE. Solving the Eastside deficiency requires a reliable alternative composed of one or both of the following:

- A new high-voltage energy source (new transmission line) from the outside brought into the deficiency area connected to a new transformer.
- A new generation source or energy storage of sufficient size and duration installed within the deficiency area.

Comment [BRS11]: This was unclear to us, so some changes are suggested. If these do not reflect your intent, please let us know.

Comment [BRS12]: This sections feels a bit out of place.

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

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

2.6 BENEFITS AND DISADVANTAGES OF DELAYING THE PROPOSAL

Email No. 7

Date/Time:

December 28, 2015 – 12:03 PM

From: Bradley Strauch

To: Mark Johnson

Subject: E2-Pole and load configuration assumptions -1

From: Strauch, Bradley R <bradley.strauch@pse.com>
Sent: Monday, December 28, 2015 12:03 PM
To: Mark Johnson
Cc: Reema Shakra; Kathy Fendt; Steendahl, Denise; records@energizeeastsideeis.org
Subject: RE: E2- Pole and load configuration assumptions

Mark,

Yes, those would be single circuit, like the ones in the figure. On the existing corridor, they would likely be on two single structures as shown on the figure (noted as "Single Circuit Pole"). One 230kV and one high capacity 115kV circuit (3 conductors each with a communication/shield wire.), both built to 230 kV configuration standards. The shield wire would likely be at the top of the structure.

The two lines could be built on one structure, but those would be taller (~100 ft) in order to meet the necessary electrical clearance (noted as "Double Circuit Pole" on your figure.

Brad

From: Mark Johnson [mailto:MJohnson@esassoc.com]
Sent: Monday, December 28, 2015 11:53 AM
To: Strauch, Bradley R
Cc: Reema Shakra; Kathy Fendt; Steendahl, Denise; records@energizeeastsideeis.org
Subject: RE: E2- Pole and load configuration assumptions

Thanks, Brad. To be clear about the 85 foot poles, would those be single circuit poles like the pair of poles shown in the figure? (It has been a little confusing to tell folks what to expect- two poles or one, what height, how many wires?)

- Mark J

From: Strauch, Bradley R [mailto:bradley.strauch@pse.com]
Sent: Monday, December 28, 2015 11:47 AM
To: Mark Johnson
Cc: Reema Shakra; Kathy Fendt; Heidi Bedwell; records@energizeeastsideeis.org; Chris Hooper (chrishooper@enertech.net);
Subject: RE: E2- Pole and load configuration assumptions

Mark,

We are pulling together the information you have requested.

Regarding our discussion about pole heights, specifically in the Newcastle area, the actual pole heights, in Newcastle, range from 49 feet to 65.5 feet (avg. 56.4 ft) above ground for the Talbot – Lakeside #1 line and 46 to 69 feet (Avg. 55.6 ft) for the Talbot – Lakeside #2 line. For analysis purposes, you can expect that the typical height for the structures that could be used to rebuild the exiting 115kV line to 230kV, would likely be around 20 to 30 feet taller than the existing structures. This is dependent upon the configuration, topography, span length, etc…

We do expect that the typical pole heights for the 230kV line will be around 85 feet.

Brad

From: Mark Johnson [mailto:MJohnson@esassoc.com]
Sent: Thursday, December 24, 2015 4:40 PM
To: Strauch, Bradley R
Cc: Reema Shakra; Kathy Fendt; Heidi Bedwell; records@energizeeastsideeis.org; Chris Hooper (chrishooper@enertech.net)
Subject: E2- Pole and load configuration assumptions

Brad,
Per out conversation, here are some details we'd like to track down to firm up our EMF analysis.

For 230 kV, what is the expected average load in 2024? And what is the expected peak load?

For overhead lines:
Pole height: assumption: 85 feet (average) Configuration is assumed to be as shown on the attached figure (the 85 foot poles) [please confirm]
What is the expected minimum conductor ground clearance (height to ground) at midspan?
What is the expected horizontal and vertical phase spacing of the conductors?
What is the distance between the two poles?

If the double circuit poles being considered, please provide equivalent information for those.

For underground, we would assume:
Typical: 5 feet below ground surface to the top of the pipe [please confirm]
Double circuit 230 kV XLPE cable, using two cables per phase
Would all of the phases bundled together within a common pipe, or are individual phases bundled within individual pipes with spacing between pipes, etc.?
(If we don't have these details, we will assume a worst case arrangement.)

Merry Christmas. We are working next week so feel free to call or write back if you have questions.

Mark S Johnson
Director
ESA | Northwest Community Development
5309 Shilshole Avenue NW, Suite 200
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206.789.9658 main
206.576.3750 direct | 206.550.0723 cell
mjohnson@esassoc.com | www.esassoc.com
Follow us on Facebook | Twitter | LinkedIn

Email No. 8

Date/Time:

December 28, 2015 – 2:29 PM

From: Bradley Strauch

To: Mark Johnson

Subject: E2-Pole and load configuration assumptions -2

From:	Strauch, Bradley R <bradley.strauch@pse.com>
Sent:	Monday, December 28, 2015 2:29 PM
To:	Mark Johnson
Cc:	Reema Shakra; Kathy Fendt; Heidi Bedwell; records@energizeeastsideeis.org; Chris Hooper (chrishooper@enertech.net); Steendahl, Denise
Subject:	RE: E2- Pole and load configuration assumptions
Attachments:	Page 40 PSE UG FeasibilityStudy.pdf

Mark,

Here is some of the additional information you requested.

For 85-foot poles, under emergency conditions, when the conductor is at its maximum operating temperate and therefore, the most (or lowest) sag, a minimum of 28 feet of ground clearance will be maintained. In some circumstances, additional clearance may be required (e.g., Highway crossings may require more clearance). Vertical spacing between the conductors located on the same side of the structure will be 16 feet. The horizontal spacing between conductors on either side of the structure will be approximately 20 feet. Distance between structures is typically between 500 and 700 feet.

For 100-foot pole, under emergency conditions, when the conductor is at its maximum operating temperature and lowest sag, a minimum of 28 feet of ground clearance will be maintained. In some circumstances, additional clearance may be required (e.g., Highway crossings may require more clearance). Vertical spacing between the conductors on the same side of the pole will be 16 feet. The horizontal spacing between conductors on either side of the pole will be approximately 33 feet. Typical distance between poles is approximately 500-700 feet.

Regarding underground configurations, a minimum of 3 feet between the ground surface and top of the duct bank is maintained. Additional details can be found in the Power Engineer's Underground Feasibility Study (March 2014)(Page 40 is attached).

Brad

From: Mark Johnson [mailto:MJohnson@esassoc.com]
Sent: Thursday, December 24, 2015 4:40 PM
To: Strauch, Bradley R
Cc: Reema Shakra; Kathy Fendt; Heidi Bedwell; records@energizeeastsideeis.org; Chris Hooper (chrishooper@enertech.net)
Subject: E2- Pole and load configuration assumptions

Brad,
Per out conversation, here are some details we'd like to track down to firm up our EMF analysis.

For 230 kV, what is the expected average load in 2024? And what is the expected peak load?

For overhead lines:
Pole height: assumption: 85 feet (average) Configuration is assumed to be as shown on the attached figure (the 85 foot poles) [please confirm]
What is the expected minimum conductor ground clearance (height to ground) at midspan?
What is the expected horizontal and vertical phase spacing of the conductors?
What is the distance between the two poles?

If the double circuit poles being considered, please provide equivalent information for those.

For underground, we would assume:
Typical: 5 feet below ground surface to the top of the pipe [please confirm]
Double circuit 230 kV XLPE cable, using two cables per phase
Would all of the phases bundled together within a common pipe, or are individual phases bundled within individual pipes with spacing between pipes, etc.?
(If we don't have these details, we will assume a worst case arrangement.)

Merry Christmas. We are working next week so feel free to call or write back if you have questions.

Mark S Johnson
Director
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206.576.3750 direct | 206.550.0723 cell
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Follow us on Facebook | Twitter | LinkedIn

3.5 XLPE Cable System Design

3.5.1 System Description

Open Trench
For open trench underground construction, the cable system would consist of a double circuit 230 kV XLPE cable, using two cables per phase to meet loading requirements, installed in a 2'-3" x 4'-0" concrete encased duct bank. The duct bank would consist of multiple conduits to carry the transmission line cables and grounding cables. The concrete duct bank would have a compressive strength of 3000 psi and be installed at a depth to provide a minimum of thirty-six inches (36") of cover. The conduit details within the duct bank are as follows:

- Eight (8) eight inch (8") schedule 40 PVC conduits used for the transmission line cable per circuit. Initially, six out of the eight 8" conduits would have cable installed, allowing for two spare conduits.
- One (1) two inch (2") schedule 40 PVC conduit installed for ground continuity cable per circuit.
- One (1) two inch (2") schedule 40 PVC conduit installed for communication cable per circuit.

The final duct bank size and layout would be determined during final design based on PSE's final design criteria. Factors to be considered are electrical requirements, heat dissipation, minimal burial depths, existing facility/utility locations and cable installation requirements. Figure 3-11 shows a typical trench detail and installation cross section.

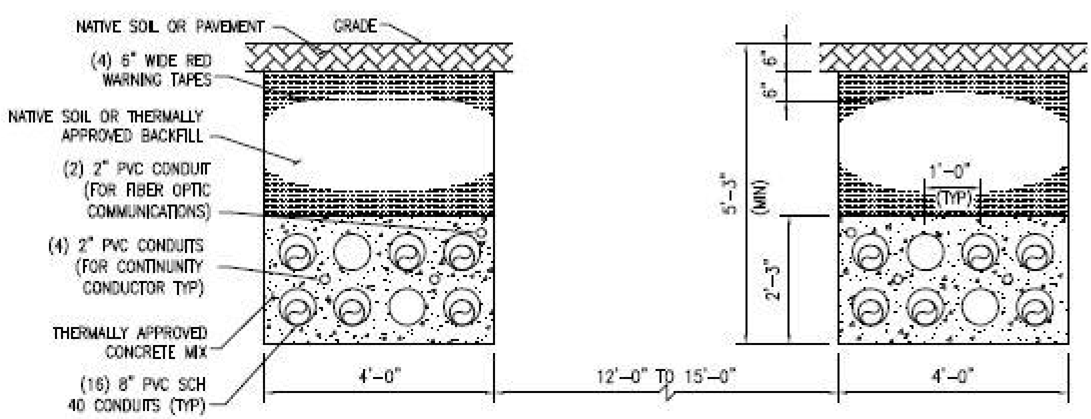

Figure 3-11 XLPE Typical Trench Detail

Trenchless
Two possible trenchless methods for crossing difficult terrain are the horizontal directional drilling method and also the jack and bore (J&B) method. These methods require a transition from the open trench installation to the desired trenchless arrangement. Figure 3-12 and 3-13 show the proposed HDD and J&B conduit arrangements. The bored designs would contain high density polyethylene conduits that are joined by fusion welding to allow for the tensions seen while the conduits are pulled into a borehole. The parameters for these HDD designs are as follows:

- Four horizontal directional drills, utilizing a 25-inch diameter bundle. Each HDD contains one three-phase set of cable ducts and one spare duct for the 230 kV double circuit transmission lines.
- A minimum spacing between drills of 15 feet to minimize mutual heating effects during operation.

Email No. 9

Date/Time:

December 29, 2015 – 3:00 PM

From: Bradley Strauch

To: Mark Johnson

Subject: E2-Pole and load configuration assumptions -3

From: Strauch, Bradley R <bradley.strauch@pse.com>
Sent: Tuesday, December 29, 2015 3:00 PM
To: Mark Johnson
Cc: Reema Shakra; Kathy Fendt; Heidi Bedwell; records@energizeeastsideeis.org; Chris Hooper (chrishooper@enertech.net); Steendahl, Denise
Subject: RE: E2- Pole and load configuration assumptions

Mark,

Below are some general estimated 230kV line loadings for 2024. These are only estimates.

Winter 2023-24 Estimated Future Loading

Talbot Hill – Richards Creek: Average Loading (amps) – 650
Peak Loading (Max 1 hour) – 1300

Sammamish – Richards Creek Average Loading (amps) – 320
Peak Loading (Max 1 hour) – 645

Summer 2024 Estimated Future Loading

Talbot Hill – Richards Creek: Average Loading (amps) – 90
Peak Loading (Max 1 hour) – 160

Sammamish – Richards Creek Average Loading (amps) – 190
Peak Loading (Max 1 hour) – 345

From: Mark Johnson [mailto:MJohnson@esassoc.com]
Sent: Monday, December 28, 2015 2:33 PM
To: Strauch, Bradley R
Cc: Reema Shakra; Kathy Fendt; Heidi Bedwell; records@energizeeastsideeis.org; Chris Hooper (chrishooper@enertech.net); Steendahl, Denise
Subject: RE: E2- Pole and load configuration assumptions

Thanks, Brad. Do you think you'll be able to track down load information today? That question again:

For 230 kV, what is the expected average load in 2024? And what is the expected peak load?

- Mark J

From: Strauch, Bradley R [mailto:bradley.strauch@pse.com]
Sent: Monday, December 28, 2015 2:29 PM
To: Mark Johnson
Cc: Reema Shakra; Kathy Fendt; Heidi Bedwell; records@energizeeastsideeis.org; Chris Hooper (chrishooper@enertech.net); Steendahl, Denise
Subject: RE: E2- Pole and load configuration assumptions

Mark,

Here is some of the additional information you requested.

For 85-foot poles, under emergency conditions, when the conductor is at its maximum operating temperate and therefore, the most (or lowest) sag, a minimum of 28 feet of ground clearance will be maintained. In some circumstances, additional clearance may be required (e.g., Highway crossings may require more clearance). Vertical spacing between the conductors located on the same side of the structure will be 16 feet. The horizontal spacing between conductors on either side of the structure will be approximately 20 feet. Distance between structures is typically between 500 and 700 feet.

For 100-foot pole, under emergency conditions, when the conductor is at its maximum operating temperature and lowest sag, a minimum of 28 feet of ground clearance will be maintained. In some circumstances, additional clearance may be required (e.g., Highway crossings may require more clearance). Vertical spacing between the conductors on the same side of the pole will be 16 feet. The horizontal spacing between conductors on either side of the pole will be approximately 33 feet. Typical distance between poles is approximately 500-700 feet.

Regarding underground configurations, a minimum of 3 feet between the ground surface and top of the duct bank is maintained. Additional details can be found in the Power Engineer's Underground Feasibility Study (March 2014)(Page 40 is attached).

Brad

From: Mark Johnson [mailto:MJohnson@esassoc.com]
Sent: Thursday, December 24, 2015 4:40 PM
To: Strauch, Bradley R
Cc: Reema Shakra; Kathy Fendt; Heidi Bedwell; records@energizeeastsideeis.org; Chris Hooper (chrishooper@enertech.net)
Subject: E2- Pole and load configuration assumptions

Brad,
Per out conversation, here are some details we'd like to track down to firm up our EMF analysis.

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Pole height: assumption: 85 feet (average) Configuration is assumed to be as shown on the attached figure (the 85 foot poles) [please confirm]
What is the expected minimum conductor ground clearance (height to ground) at midspan?
What is the expected horizontal and vertical phase spacing of the conductors?
What is the distance between the two poles?

If the double circuit poles being considered, please provide equivalent information for those.

For underground, we would assume:
Typical: 5 feet below ground surface to the top of the pipe [please confirm]
Double circuit 230 kV XLPE cable, using two cables per phase
Would all of the phases bundled together within a common pipe, or are individual phases bundled within individual pipes with spacing between pipes, etc.?
(If we don't have these details, we will assume a worst case arrangement.)

Merry Christmas. We are working next week so feel free to call or write back if you have questions.

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