Independent Technical Analysis
of
Energize Eastside

for the

City of Bellevue, WA

April 28, 2015
Version 1.3

Prepared by
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Table of Contents

1. Executive Summary

Utility System Efficiencies, Inc. (USE) was engaged by the City of Bellevue in December 2014 to conduct an independent technical analysis of the purpose, need, and timing of the Energize Eastside project. Energize Eastside (EE) is Puget Sound Energy's (PSE's) proposed project to build a new electric substation and new higher–capacity (230 kilovolt) electric transmission lines in the East King County area, which encompasses Bellevue, Clyde Hill, Medina, Mercer Island, Newcastle, the towns of Yarrow Point, Hunts Point, and Beaux Arts, and portions of Kirkland, Redmond, and Renton (the Eastside). The transmission lines would extend from an existing substation in Redmond to one in Renton (See Figure 3.1).

The goals of the technical analysis were to determine:

- Is there a need for this project to address growth in Bellevue? In answering this question, the analysis included determining if PSE's load forecast is reasonable, and if their studied contingencies were reasonable. Here, reasonable is defined as just, rational, appropriate, ordinary, or usual in the circumstances.[1] If the actions or data are consistent with industry practice, it is deemed reasonable.
- Is the EE project needed to address the reliability of the electric grid on the Eastside? This question assesses the purpose of the project and its timing. In other words, is the need a local issue?
- Is there a need for the project to address regional flows, with imports/exports to Canada (ColumbiaGrid[2])? This question is examined in Appendix B, Optional Technical Analysis.

This independent technical analysis (ITA) included reviewing EE documentation, examining the forecast and growth assumptions, reviewing historical demand (MW load) of the area, reviewing weather volatility, and assessing potential variability from the forecast assumptions used in the EE study. The ITA reviewed PSE's forecasting methodology, the major elements that made up the forecast, and decisions made in the forecasting procedure (including choices on what elements or variables to include). The ITA compared PSE's forecast variables with typical industry forecast variables. The ITA also looked at the assumptions that PSE used in electrically modeling the Energize Eastside area, including generation assumptions, local loads, and regional flows. The ITA reviewed PSE's powerflow cases[3] to determine whether the modeling in the cases was consistent with the forecast, and whether the outage scenarios resulted in PSE's identified transmission deficiency.

The optional technical analysis (OTA) at Appendix B examined several hypothetical scenarios, called sensitivity studies. The OTA looked at the effect of a) reducing load growth in the Eastside area, b) reducing load growth in King County while keeping the Eastside growth the same, c) increasing Puget Sound area generation, and d) reducing the Northern Intertie[4] flow to zero (no transfers to Canada). Reduced Northern Intertie flow was examined only to assess the relative impact of local need

[1] http://www.nolo.com/dictionary/reasonable-term.html
[2] ColumbiaGrid (single word) is a regional transmission planning organization with a footprint encompassing Oregon, Washington, parts of Idaho and Montana.
[3] powerflow case: Computer model of the electric grid representing a snapshot in time with a specific scenario of electric load, generation, and equipment, including what is in service and what isn't.
[4] Northern Intertie - transmission interconnection between Washington and British Columbia (also called Path 3.)

versus regional need and does not reflect a realistic planning scenario. The OTA also looked at the impact of an Extreme Winter forecast.

A key purpose of the ITA and the OTA was to provide an increased level of *understanding* of the purpose, need and timing of the EE project to the City Council and community stakeholders. Over the course of the project, dozens of questions were received from various stakeholders. City staff filtered stakeholder comment through the Task's scope, and submitted the need related questions to USE (Other comments as appropriate were directed to the Environmental Impact Statement (EIS) process, the Integrated Resource Plan[5] (IRP) process, etc.). A Q & A discussion is included at the end of each section of the ITA. All questions analyzed are also set forth in Appendix D.

Disclaimer: This report seeks to describe the findings in terms that a non-expert can understand. Thus, some descriptions or definitions may not be exact, in an effort to make the general concept clear. However, some questions received required a higher level of technical detail. Again, the effort was made to simplify the explanations while still providing a helpful response. A glossary is provided in Appendix A.

Results:

IS THERE A NEED FOR THIS PROJECT TO ADDRESS GROWTH IN BELLEVUE? YES.

The ITA examined the forecasting methodology used by PSE in its 2014 forecast, completed in February 2015. The 2014 forecast methodology provided improved visibility of where growth was occurring within PSE's service area. The PSE forecast shows a growing peak load demand[6] of 2.4% per year for years 2014 – 2024.

The typical utility industry forecast is composed of 1) weather normalization[7], 2) economic and demographic data, 3) application of end-use data[8] including conservation and efficiency measures, and 4) adjustment for large specific load additions (such as for a new building).

The ITA concludes that PSE has followed industry practice in forecasting its demand load, incorporating the four major components of forecasting:

- PSE incorporated weather normalizing. The variables used in the weather normalizing process were typical based on industry practice.
- PSE used typical data set elements and multiple data sources for its economic/demographic data as shown in Table 6.1, acquiring data at the county level, and for the Eastside area at the census track level, in order to differentiate growth rates within the service territory. Data on jobs and

[5] Integrated Resource Plan - A comprehensive and long-range road map for meeting the utility's objective of providing reliable and least-cost electric service to its customers while addressing applicable environmental, conservation and renewable energy requirements. A process used by utility companies to determine the mix of Supply-Side Resources and Demand-Side Resources that will meet electricity demand at the lowest cost. The IRP is often developed with input from various stakeholder groups.
[6] MW demand
[7] Weather normalization is a process that adjusts actual energy (MWh) or demand (peak MW) values to what would have happened under normal weather conditions. Normal weather conditions are expected on a 50 percent probability basis (i.e., there is a 50 percent probability that the actual peak realized will be either under or over the projected peak).
[8] End-use: How is the electricity being used? What appliances are used? What efficiency measures are employed? What load can be controlled or interrupted? Utilities and cities can influence electric end-use through Demand-Side Management technologies and practices, city code changes, efficiency programs or incentives, awareness campaigns, et cetera. The end-use data is generally limited to new DSR measures. Historical end-use data is generally not captured due to the difficulty in acquiring it (surveys, etc.).

employment in the Eastside region were obtained by PSE from the Puget Sound Regional Council and the WA State Office of Financial Management, and included census tract level analysis. PSE employed regression analysis[9] at this step, an industry standard computer analysis technique, to determine the forecast before new conservation measures and block load adjustments. (The computerized regression analysis was not analyzed as part of this study, but the technique is a computerized estimation of the best fit of the variables to the given data.)

- PSE acquired/developed significant end-use data via their IRP process, including over four thousand Demand Side Resources (DSR) measures, incorporated National and State requirements on conservation and RPS, and optimized the achievable, technical measures with a resultant 100% Conservation scenario which projects 135 MW of winter peak DSR by 2031.
- PSE gathered block load data (major projects) and utilized short-term forecast adjustments (1-year ramp in based on certificates of occupancy and 2-year ramp-out) to account for the impact on demand.

No forecast is perfect, but by following industry practice, the ITA concludes that PSE used reasonable methods to develop the forecast. PSE's resultant forecast shows the Eastside area growing at a higher level than at the county and system level, and these growth rates are based on the data it received.

PSE is applying the Northwest US practice (as does Seattle City Light (SCL)) of basing projects on a normal 50/50 forecast (actual load will be more than forecast half the time, and less than forecast half the time). This 50/50 forecast is less conservative than scenarios utilized by many other electric utilities elsewhere in the country. Basing projects on an adverse weather scenario is more conservative, but seeks to ensure that the lights stay on given the adverse weather event.

IS THE EE PROJECT NEEDED TO ADDRESS THE RELIABILITY OF THE ELECTRIC GRID ON THE EASTSIDE? YES.

Although the new 2014 forecast resulted in an 11 MW decrease in the Eastside area's 2017/18 winter forecast, the reduced loading still resulted in several overloaded transmission elements in winter 2017/2018, which drive the project need.

Although the corrective action plan (CAP) required in the 2017/18 winter to avoid facility overload doesn't require dropping load (turning off customers' power), by winter 2019/20 approximately 63,200 customers are at risk of losing power. In addition, by summer 2018, studies show that customers will be at risk of outages and load shedding[10] due to CAPs used to mitigate transmission overloads. Despite the possibility of an in-service date shift to summer 2018 from winter 2017/18, balancing a six month delay in a complex and multi-year EIS process (which can have its own delays) against the risk of an adverse winter and less realized conservation (which could increase 2017/18 winter loading to a point where customers are at risk of load

[9] Regression analysis is a statistical process for estimating the relationships among variables. It seeks to determine the strength of the relationship between one dependent variable (usually denoted by Y) and a series of other changing variables (known as independent variables). It is also known also as curve fitting or line fitting because a regression analysis equation can be used in fitting a curve or line to data points. It includes many techniques for modeling and analyzing variables.

[10] Load shedding - An intentional electrical power shutdown to a portion of the system (customers experience an outage) to protect the network from a greater impact or from potential damage.

shedding), suggests it is reasonable to maintain the schedule for the existing project in-service date.

Several hypothetical scenarios were studied as part of the Optional Technical Analysis (OTA). Each one showed overloads in the 2017/18 timeframe, indicating project need in order for PSE to meet federal regulatory requirements for system reliability. The OTA results showed that reducing the Eastside area growth from 2.4% to 1.5% per year in the period from winter 2013/14 to winter 2017/18 still resulted in project need. Reducing PSE's King County growth while keeping the Eastside growth the same similarly resulted in a project need. Turning on additional generation in the Puget Sound area also resulted in a project need. (See Appendix B.)

IS THE PROJECT NEEDED TO ADDRESS REGIONAL GRID POWER FLOWS, SPECIFICALLY POWER FLOWS ON THE NORTHERN INTERTIE (TO AND FROM CANADA)? The project is necessary to address local need.

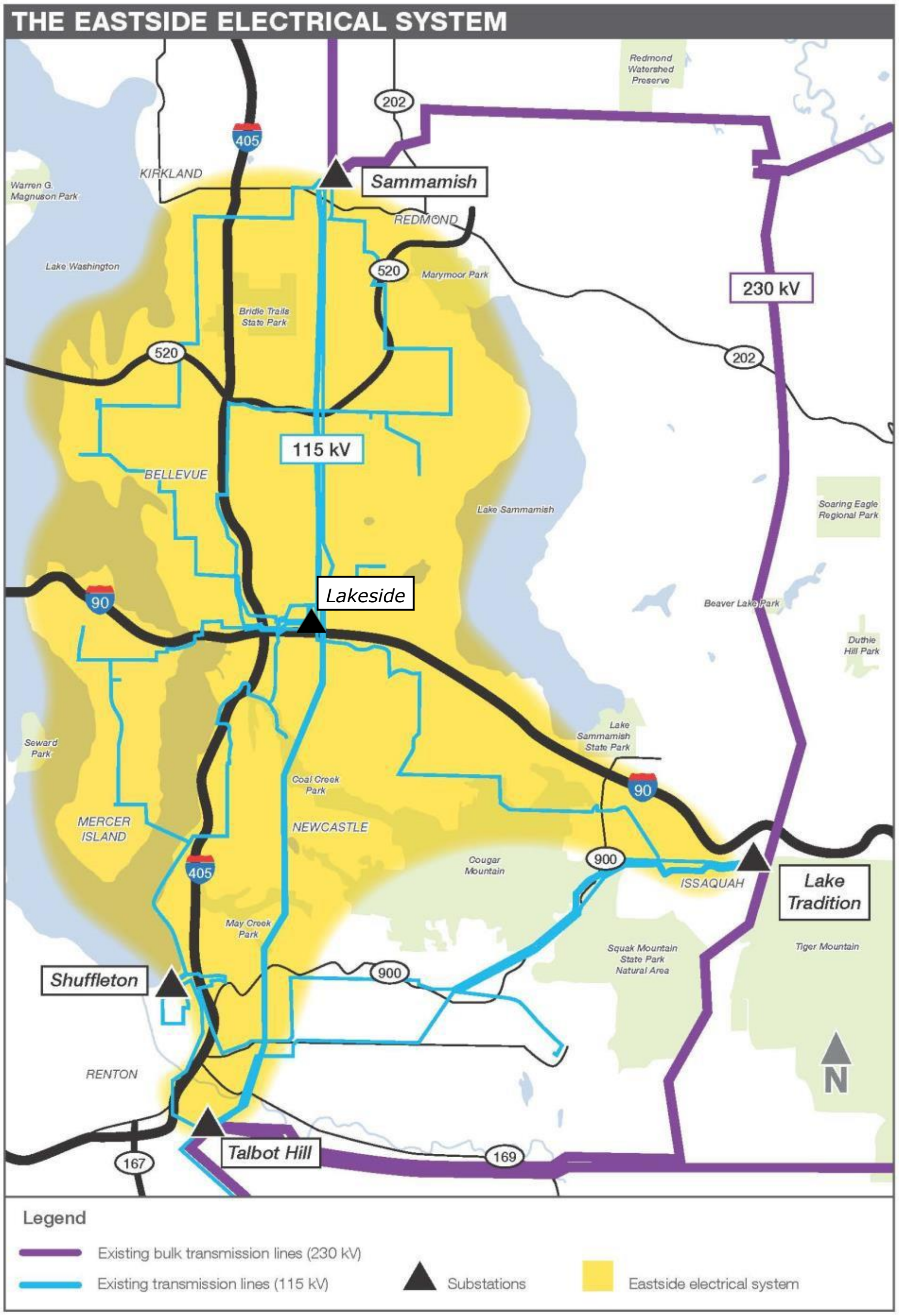
The Optional Technical Analysis examined this issue by reducing the Northern Intertie[11] flow to zero (no transfers to Canada). Although this scenario is not actually possible due to extant treaties, it was modeled to provide data on the drivers for the EE project, to examine if regional requirements might be driving the need. The results showed that in winter 2017/18, even with the Northern Intertie adjusted to zero flow, the Talbot Hill 230/115 kV transformer #2 would still be overloaded by several contingencies (several different outage scenarios). Again, the projected overloads indicate a project need at the local level to meet reliability regulations. (See Appendix B for more details.)

[11] Northern Intertie - transmission interconnection between Washington and British Columbia (Also called Path 3.)

2. Eastside Area

The Eastside area is highlighted in yellow below, and was defined electrically as the area served by the 115 kV transmission lines that connect with the Lakeside Transmission Substation. Geographically it is bounded by Lake Washington and Lake Sammamish. The area is also north of PSE's Talbot Hill Substation and south of PSE's Sammamish Substation.

Figure 3.1: Eastside Area (Figure provided by PSE)



3. 2013 Eastside Needs Assessment Report

This section is included in the ITA report because PSE's 2013 Needs Assessment report is public whereas there is no updated PSE report documenting the 2014 forecast results as of the date of this writing.

The "Eastside Needs Assessment Report", published in October 2013 by PSE, focused on the central King County portion of PSE's service territory. It was based on PSE's corporate forecast which was published in June 2012. The study determined that there was a transmission capacity deficiency in the Eastside area that would develop by the winter of 2017/2018.

Key Assumptions in PSE's 2013 Study:

- System load levels used the PSE corporate forecast published in June 2012.
- Area forecasts were adjusted by substation to account for expected community developments as identified by PSE customer relations and distribution planning staff.
- Generation dispatch patterns reflected reasonably stressed conditions to account for generation outages as well as expected power transfers from PSE to its interconnected neighbors.
- Winter peak Northern Intertie transfers were 1,500 MW exported to Canada.
- Summer peak westside Northern Intertie transfers were 2,850 MW imported from Canada.

Per PSE's 2013 study report, specific areas of concern for the 2017/2018 winter are shown in Table 4.1 below. The table lists the overloaded elements within each category of contingency.

Each of the three contingency types (N-1, N-1-1, and N-2) shown below are part of the required study process and are defined in the report glossary.

Table 4.1: PSE's 2013 Study Report: 2017/2018 Overloaded Elements

	2017/2018 Normal Winter (23° F) 100% Conservation		
	Type of Contingency		
Transmission Line or Transformer	N-1	N-1-1	N-2
Talbot Hill - Lakeside #1 115 kV line		OL	OL
Talbot Hill - Lakeside #2 115 kV line		OL	OL
Talbot Hill 230-115 kV transformer #1		OL	
Talbot Hill 230-115 kV transformer #2		OL	
Talbot Hill-Boeing Renton-Shuffleton 115 kV line		OL	
Shuffleton – O'Brien 115 kV line			
Shuffleton – Lakeside 115 kV line			

OL = Overload of Emergency Rating.

PSE's 2013 Needs Assessment report drove many need-related Stakeholder questions about the forecast, the weather scenarios, the regional scenarios, exports and imports to Canada, the outage contingencies studied and whether they were needed, the probability of having the issues, etc. PSE develops a new forecast every two years, and in February 2015, PSE completed their new forecast with actuals through 2014. They have since restudied the situation with the new forecast. The remainder of this ITA report will relate the questions received to the new forecast and the new results.

4. Energy versus Demand

Forecasts are developed for both energy and demand. A useful analogy is to compare energy to a car odometer and demand to a car speedometer.

- Energy (kWh) is analogous to an odometer reading, which is a cumulative measure of total miles traveled over time. Energy is a cumulative measure of total power produced or consumed over time.

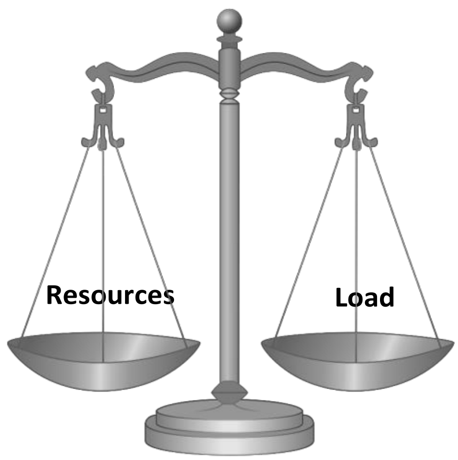
Demand (kW) is analogous to a speedometer reading, which shows a snapshot of the speed at a precise moment. Demand is a snapshot of power required or power used. Peak demand is the highest demand that will be required at any particular moment during a period of time. An odometer doesn't indicate how fast someone drives, but does indicate how much driving has been done. Similarly, an energy forecast (kWh) indicates increases or decreases in the use of electricity, but doesn't indicate peak usage (kW).

Bellevue's Resource Conservation Manager (RCM) program stats on declining energy use are reflecting a decline in the average use per customer. The DSM programs, solar, etc. are showing success with this decline. But, that is one piece of the story - the energy piece on a per customer basis. The number of customers continues to increase, and the aggregate peak usage (peak demand), is continuing to increase. Growth in peak demand drives the size and amount of infrastructure required and drives the issue of grid reliability.

5. Typical Electric Forecast Elements

The typical utility industry forecast is composed of four main parts which will each be further explained later in this section: 1) adjustment for weather, 2) economic and demographic data, 3) application of end-use data, including energy efficiency and conservation effects, and 4) adjustment for large specific load additions (such as for a new building).

Resource planning is a related activity which provides direction on some of the forecasting elements. Resource planning (ensuring there are sufficient generation and conservation/efficiency resources to serve the customer load) requires a load forecast to know how much load one must serve. The resources must balance the load.



National Level

There are NERC Reliability Standards which pertain to the collection of data necessary to analyze the resource needs to serve peak demand while maintaining a sufficient margin to address operating events. One Standard (NERC MOD-021-1) requires that "forecasts shall each clearly document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demands, and Direct Control Load Management) are addressed." Another Standard (NERC MOD-019-0.1) requires "forecasts of interruptible demands and Direct Control Load Management (DCLM) data".

State Level

There are state requirements for resource planning, which identifies generation resources and conservation/efficiency measures to serve the customer load. State Law (RCW 19.280.030), identifies the requirements of a resource plan, and states that the integrated resource plan must include:

> "(1)(a) A range of forecasts, for at least the next ten years or longer, of projected customer demand which takes into account econometric data[12] and customer usage;"

[12] Econometrics is the application of mathematics and statistical methods to economics. The data to which it is applied is called econometric data. Econometrics tests hypotheses and forecasts future trends by applying statistical and mathematical theories to economics. It's concerned with setting up mathematical models and testing the validity of economic relationships to measure the strengths of various influences.

> "(1) (b) An assessment of commercially available conservation and efficiency resources. Such assessment may include, as appropriate, high efficiency cogeneration, demand response and load management programs, and currently employed and new policies and programs needed to obtain the conservation and efficiency resources;"

Item 1(a) above requires econometric and end-use data in the forecast. Item 1(b) requires that the forecast account for conservation and efficiency resources. Both are industry practices.

Resources consist of Supply-Side Resources (conventional generation plants, renewables, etc.) and Demand-Side Resources (resources that reduce the demand (load)).

5.1. Simplified Description of the Forecasting Procedure

1) WEATHER NORMALIZING.

The North American Electric Reliability Corporation (NERC[13]) provides direction at the national level for normalizing the demand (MW) forecast to account for weather impact.

> "The fundamental test for determining the adequacy of the Bulk Electric Power System (BEPS) is to determine the amount of resources and the certainty of these resources to be available to serve peak demand while maintaining a sufficient margin to address operating events. This test requires the collection and aggregation of demand forecasts on a normalized basis. This is defined as a forecast that has been adjusted to reflect normal weather conditions and is expected on a 50 percent probability basis, also known as a 50/50 forecast (i.e., there is a 50 percent probability that the actual peak realized will be either under or over the projected peak). This forecast can then be used to test against more extreme conditions." [14]

Normalizing the forecast seeks to remove the variation in load due to weather related factors including the temperature at the time of the peak, the temperature on the days prior to the peak, whether the peak occurred on a weekend, a weekday, a holiday, etc. Reactions to these variables vary throughout the United States, yet for a localized area there will be a typical reaction that can be calculated. These are addressed when normalizing the forecast. For example, many office buildings use less power on the weekend or on a holiday. Moreover, some residential customers will put up with a short cold or hot spell, but if it lasts "too long", they will be more likely to increase their use of heating or air conditioning.

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[13] NERC: North American Electric Reliability Corporation. NERC is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards as one of its duties. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico.

[14] NERC, Normalizing "NERC | MOD C White Paper | April 24, 2014", page 5 http://www.nerc.com/pa/Stand/Project%20201004%20Demand%20Data%20MOD%20C/MOD_C_White_Paper_Redline_20140424.pdf

In addition to calculating the normalized peaks, industry also typically calculates an adverse or extreme peak. Many utilities utilize a 90/10 forecast[15] to justify projects, some use an 80/20 forecast to justify projects. Utilities in the Northwest area of the United States typically base their projects on the normal (50/50) forecast, although they develop a 95/05 forecast (1-in-20) for reference.

A typical industry source for the weather data is a National Oceanic and Atmospheric Administration (NOAA) weather station. Some utilities may have their own weather recording data.

Stakeholder Questions on weather adjustment

Q1.Please explain weather adjustment. Is it reasonable/appropriate?

- A *Please see the above discussion.*
- A *Weather adjustment is reasonable and appropriate, and is required by NERC.*

2) DEVELOP A MATHEMATICAL RELATIONSHIP (EQUATION) BETWEEN A) THE ECONOMIC AND DEMOGRAPHIC DATA AND B) EITHER ENERGY USAGE (KWH) OR ELECTRIC DEMAND (KW).

For each customer class (e.g. industrial, commercial and residential), estimate the relationship between electricity consumption (usage) or demand, and the major variables that affect it (e.g. population, price, economic growth, etc.). This relationship is usually developed first, without accounting for new Demand-Side Resources (DSR), in order to show the effect of the DSR on the forecast.

Econometrics utilizes multiple sources of data. Table 5.1 lists examples of data sets that may be used in the econometric modeling.

Table 5.1: Examples of Data Used in Econometric Models

Example Data Sets used in Econometrics
Household Size
Population
Customer Count by Customer Class
Employment (Manufacturing, Non-Manufacturing, by NAICS Code[16], etc.)
GDP (Gross Domestic Product)
GMP (Gross Metropolitan Product) – a measure of the size of the economy of a metropolitan
Personal Income

[15] 90/10 forecast: 90% probability that the weather will be less severe and a 10% probability that the weather will be more severe. This is also called a 1-in-10 forecast.

[16] NAICS - The North American Industry Classification System (NAICS) is the standard used by Federal statistical agencies in classifying business establishments for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. business economy (Source: Census.gov)

3) Account for end-use data including energy efficiency and conservation effects (Typically from an Integrated Resource Plan (IRP))

End-Use Analysis projects the quantity and use of electricity-using equipment (or a subset of them) to make a forecast or to revise one. *End-use analysis is responsive to consumer changes in kinds of equipment and allows analysis of conservation programs, energy efficiency improvements, building code modifications, increase in household electronics or typical housing square footage, etc. It breaks the data into user sectors and needs an extensive inventory of data. It readily reflects changes in the factors that influence consumption, but requires detailed assumptions on the use going forward.*

Utilities and cities can influence electric end-use through Demand-Side Management technologies and practices, city code changes, efficiency programs or incentives, awareness campaigns, et cetera. Example end-use programs are listed below.

- Residential mass market lighting and appliances
- Residential HVAC replacement
- Residential new construction
- Residential retrofits
- Commercial/Industrial lighting, equipment, HVAC
- Customized programs for larger customers
- Demand Response incentive/enabling programs
- Pricing—interruptible, time of use pricing, real time pricing

Demand-Side Management (DSM) can be broken into two components: energy efficiency and Demand Response. Energy efficiency attempts to permanently reduce the demand for energy in intervals ranging from seasons to years and concentrates on end-use energy solutions. Demand Response is designed to change on-site demand for energy in intervals from minutes to hours, targeting the lowering of electric demand/energy use during peak periods by transmitting changes in prices, load control signals or other incentives to end-users to reflect existing production and delivery costs.

When end-use factors are taken into account in the forecast, there will be multiple variables representing different elements of end-use. Some may offset others. For example, the U.S. Department of Energy noted that "Homes built between 2000 and 2005 used 14% less energy per square foot than homes built in the 1980s and 40% less energy per square foot than homes built before 1950. However, larger home sizes have offset these efficiency improvements."[17]

When utilized, the IRP process is where the end-use data is analyzed. The IRP is a comprehensive and long-range road map and is where a utility examines both Supply-Side and Demand-Side options with the objective of providing reliable and least-cost electric service to its customers while addressing applicable environmental, conservation and renewable energy requirements. Because energy efficiency is generally a low-cost resource, the IRP tends to incorporate energy efficiency as a utility system resource and reduce the need for additional Supply-Side resources.

The end-use data is generally limited to new DSR measures. Historical end-use data is not usually captured due to the difficulty in acquiring it.

[17] "Buildings Energy Data Book", US Department of Energy

4) <u>ADJUST FOR BLOCK LOADS (MAJOR LOAD ADDITIONS)</u>

Known large load additions would be added to or removed from the forecasted load. This could include new large commercial buildings, major customers leaving the area, etc.

The above forecast discussion represents the system forecast, referring to the forecast for the utility's entire service area. A system forecast may be broken into sub-areas at the utility's discretion, or separate forecasts may be developed for sub-areas. Various scenarios may be modeled, to examine higher or lower conservation levels, adverse weather, et cetera.

5.2. Utilizing the System Forecast in Powerflow Cases

In order to conduct studies on the transmission system, the substation loads are calibrated to the system forecast. Once calibrated, the substation loads are modeled in the transmission planning cases for study. Multiple seasons and years may be studied.

6. PSE's Forecast Methodology

PSE updates their load forecasts every two years. In early February 2015, PSE completed their 2014 forecast which included historical data through 2014, and thus included the summer 2014 peak and the winter 2013/2014 peak. This new forecast was based on a new methodology. PSE shifted from a predominately system-wide view to a county by county examination. Particular focus was placed on King County, where the Eastside study area was further separated out from King County using census tract data to develop a separate Eastside forecast. This new forecast methodology provided improved visibility of where growth was occurring and where it wasn't. Consequently, after conferring with the City, USE decided to wait for the new forecast, with its improved visibility of the Eastside area, as well as its more recent actual load information.

The review of PSE's forecast methodology in this report is specific to PSE's 2014 forecast.

6.1. Weather Adjustment (Weather Normalizing)

PSE's 2014 system forecast incorporated weather normalizing consistent with industry practice.

PSE's weather normalizing process tests the following major variables via regression analysis. The regression analysis process selects out the variables that result in the best fit to the data.

- ☐ Peak hourly load for the month
- ☐ Maximum hourly load on each of the three days prior to the peak day
- ☐ Minimum and maximum temperature on the peak day
- ☐ The minimum temperature on each of the three days prior to the peak day
- ☐ The average temperature on the peak day
- ☐ The average temperature on each of the three days prior to the peak day
- ☐ Temperature 1, 2, and 3 hours before the peak
- ☐ Temperature at the peak hour
- ☐ Total monthly load
- ☐ Average monthly temperature
- ☐ The season the peak occurred in
- ☐ Whether the average temperature on the peak day, or the day before, fell below a certain threshold (cold snap variables)
- Whether it is an El Niño
- ☐ Day of the week

The factors PSE uses to normalize the effect of weather are quite typical for electric forecasting. Some utilities use humidity as a variable, PSE does not. PSE stated it did not consider humidity a significant factor. Realistically, humidity is less likely to be a factor in the winter. Heating the cold air lowers the relative humidity[18], so it feels dryer.

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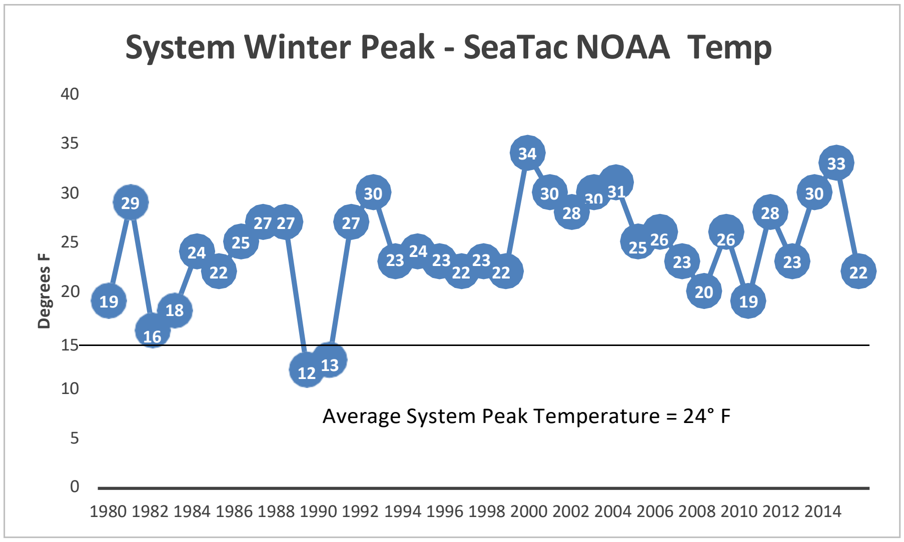
[18] Relative humidity is the amount of water vapor present in air. It is expressed as a percentage of the amount needed for saturation at the same temperature. Thus relative humidity varies with temperature.

PSE utilizes the SeaTac NOAA weather station for weather data. Figure 6.1 shows the historic winter system peak[19] actual temperatures through winter 2013/2014.

Figure 6.1: Historical Temperature Data



PSE has defined their winter season as November 1 – February 28, and the normal temperature at which PSE's winter load peaks is 23° F (normal peak load temperature). PSE also defines an extreme winter peak load that has a probability of occurring once every twenty years and occurs at a temperature of 13° F. Although PSE develops the extreme winter forecast and models the effect, they only use it as an indicator of future deficiencies. PSE does not use the extreme winter forecast to justify transmission projects, they only use the normal forecast to justify projects. (Utilities in the Northwest area, including Seattle City Light (SCL), use the normal forecast for justifying projects. Many utilities outside this area use an adverse forecast to justify projects.)

<u>Comments:</u>

PSE uses a normal peak load temperature of 23° F. The average winter peak load temperature since 2008 is 24°F, though examining a longer span of time may show that it is 23° F. It is likely that a 1° shift upwards in temperature would reduce the normal winter forecast, but it may not be significant. One could say the normal forecast is a bit conservative. On the other hand, PSE does not use any type of adverse weather (anything worse than a 50/50 forecast) to justify a project. Many utilities design their system based on adverse weather, such as a 90/10 or 80/20 scenario where the forecast is exceeded 10% or 20% of the time. Per the Western Electricity Coordinating Council (WECC) Data Collection Manual (2014), NERC has requested that each Balancing Authority provide a 90/10 forecast. In NERC's 2014-2015 Winter Reliability Assessment, it recommends that scenarios should be assessed that reflect severe winter conditions, such as a "… higher-than-normal peak load (e.g. 90/10 forecast)." PSE does study a 95/5 (1 in 20) extreme winter, but does not use it to justify projects

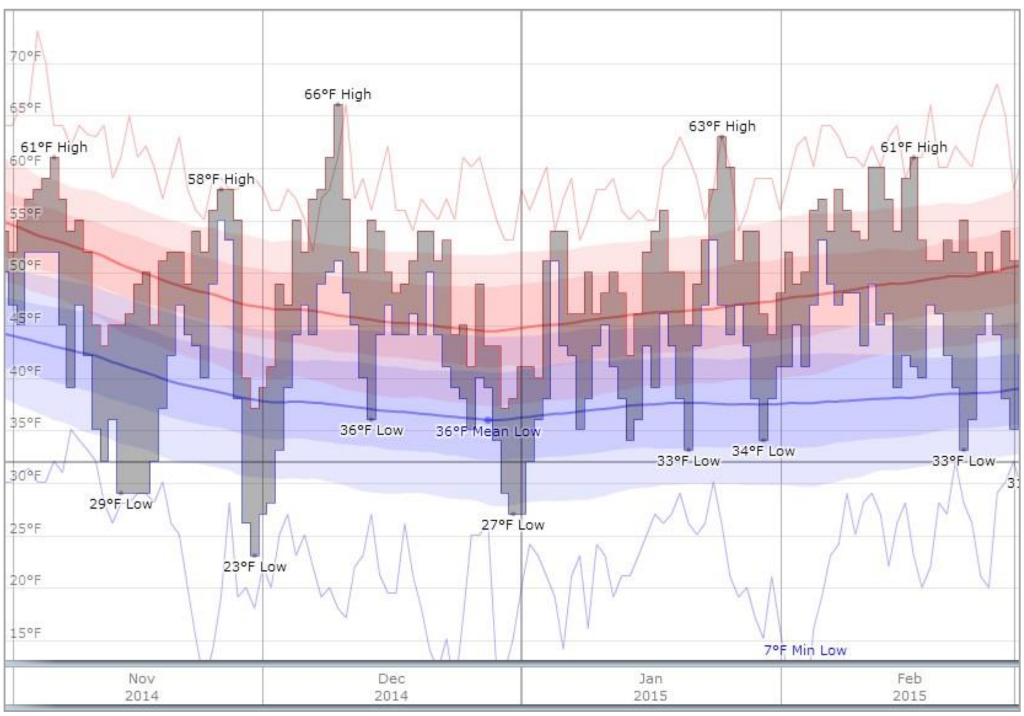
PSE uses one weather station for their service area. Some utilities use more than one weather station to reflect significant weather differences in their service territory.

[19] A system peak refers to the peak demand. In winter, this would be driven by low temperatures.

PSE feels there is not enough weather variation within their service territory to require using more than one weather station. In addition, they expressed concern that the while the SeaTac weather station is very reliable, not all the weather stations are maintained as well and there might be data reliability issues.

Although the 2014/2015 winter peak period ended February 28th, the winter peak data is not yet available. The data verification and normalizing process is not complete and typically occurs mid-year, but it is known that the 2014/15 winter peak was an unusually warm one. Figure 6.2 is taken from Weatherspark.com, and simply shows the highs and lows for each day during the winter season. The very lowest temperature for the entire season was 23°F on November 30th at 2am, per Weatherspark.com. PSE's winter peak (demand) typically occurs either in the morning between 7am and 9am or in the late afternoon/early evening between 4:30pm and 7pm. In either case the winter system peak would have occurred at a warmer temperature. Does this drive any change? At this point, no. It is expected that actual temperatures will not be the same as the defined "normal" temperature. A single data point is unlikely to change a trend. When PSE revises their forecast in two years, they will have two more data points and will recheck the trends through a new regression analysis.

Figure 6.2: Historical Temperature Data 2014/15 Winter Season – Weatherspark.com



6.2. *PSE's Econometric Modeling*

PSE incorporates economic and demographic data into their forecast, subdivided by customer class, using typical data set elements. See Table 6.1 for the sources of data used in their model.

Table 6.1: Data used in PSE's Economic/Demographic Model

Data Set	Historical Data Frequency	Source of Historical Data	Source of Forecasted Data
County Level Employment			
Labor Force, Employment, Unemployment Rate	Quarterly	US Bureau of Labor Statistics (BLS)	PSE's Economic/Demographic Model
Total Non-Farm Employment Goods Producing & Service Providing Sectors	Monthly	WA State Employment Security Department (ESD), using data from Quarterly Census of Employment & Wages	
County Level Personal Income			
Personal Income, Wages and Salaries	Yearly	US Bureau of Economic Analysis (BEA)	PSE's Economic/Demographic Model
County Level Population and Households			
Population (thousands)	Yearly	US BEA/ WA State Office of Financial Management (OFM)	PSE's Economic/Demographic Model
Households, Single-family & Multi-Family (thousands.)	Annual forecasts	US Census	
Household size, Single- and Multi-family (number)	Quarterly	Building Industry Association of Washington	
Eastside Area by Census Tracts			
Population	Yearly	WA State Office of Financial Management (OFM), 9/28/14	PSRC data, April 2014
Employment	Yearly	PSRC, June 2014	PSRC data, April 2014
US Level Macroeconomy			
GDP ($ x Billions, in year 2000 $), Industrial Production Index	Quarterly	Moody's	Moody's
Employment (mils.), Unemployment Rate (%)			
Personal Income ($ x Billions) Wages & salary disbursements, Other Income			
CPI (82-84=1.00[20]), consumer expenditures deflator (2000=1.0)			
Housing Starts (millions)			
Population (millions)			
T-bill rate, 3 months (%), Conventional mortgage rage (%)			

The Puget Sound Regional Council (PSRC) intends for the City of Bellevue to be a hub for regional growth. In their Vision 2040 Regional Growth Strategy report, PSRC designated five Metropolitan Cities to serve as the focal point for accommodating population and employment growth. These are Bellevue, Bremerton, Everett, Seattle, and Tacoma. The strategy is for the Metropolitan Cities "… to accommodate 32 percent of regional population growth and 42 percent of regional employment growth by the year 2040." It was also noted that it would be in the spirit of the strategy for them to accommodate an even higher percentage.

In addition, the City of Bellevue provided the following information on expected population and employment growth. "Currently there are an estimated 11,000 residents living in Downtown, and that number is expected to grow to 19,000 by 2030. Currently there are about 45,000 jobs within Downtown and that number is expected to increase to 70,300 by 2030."

Given the above, one could expect a higher growth in the Eastside area than in some of the other areas served by PSE.

[20] The average of the 1982-1984 data is set to 1.00

The following graphs display the historic and forecasted data for population, employment, and customer count, provided by PSE. Data is shown for the PSE service territory, PSE's portion of King County, and Eastside. The graphs for Eastside were developed from data sets at the census tract level. Graphs for these data sets are provided for comparison of growth rates between Eastside, King County and the PSE service territory.

The historic graph data for the PSE system goes back to 2000, and includes Jefferson County up until March 2013. The historic graph data for King County and Eastside only goes back to 2006. The Eastside customer count graphs are missing the actual data for year-end 2013; PSE recently updated their billing system with a new IT company, and not all of their customer reports were available at the time of the 2014 forecast.

Because the system graph data goes back to 2000, it shows the trend prior to the recession. The King County and Eastside graph data only goes back to 2006, so the historical trend is obscured by the recession.

Employment and population are increasing. (Data provided by PSE. See Table 6.1 for original data sources.)

Figure 6.3: Population and Employment - PSE Service Territory

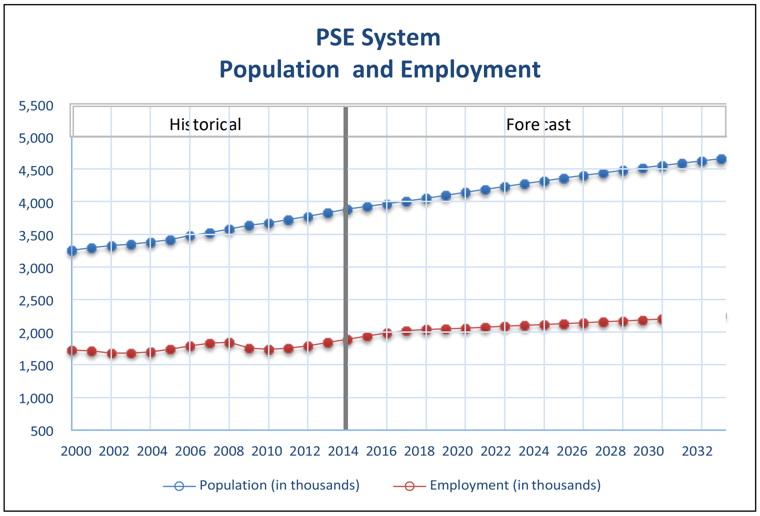


Figure 6.4: Population and Employment – King County

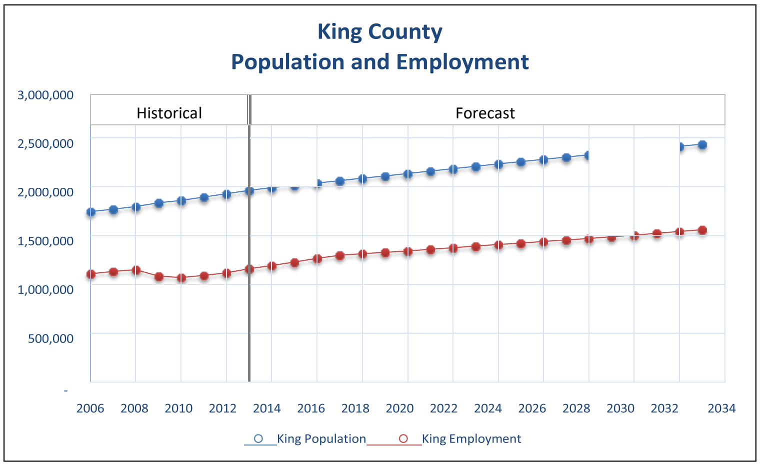
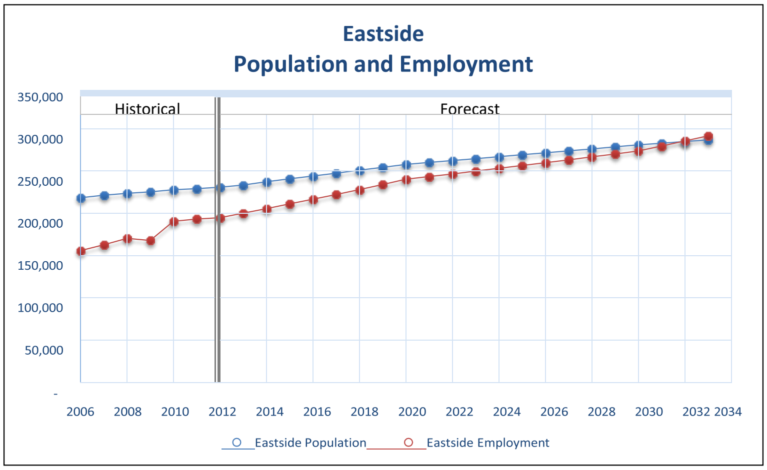
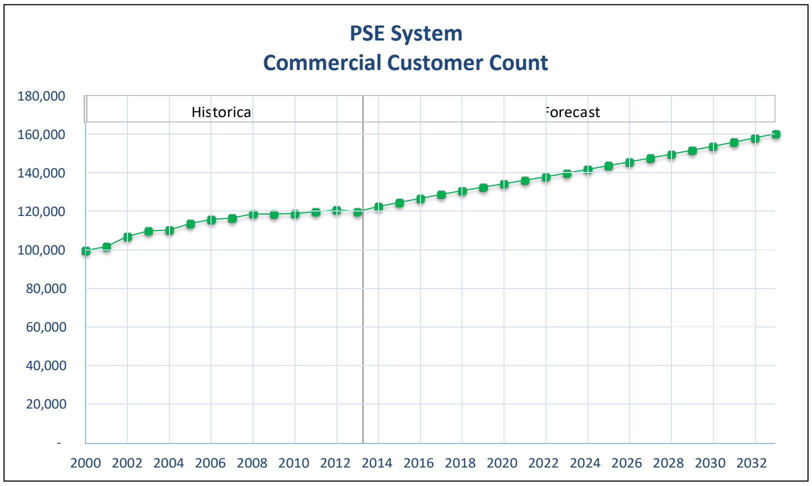


Figure 6.5: Population and Employment – Eastside



Forecasts for the commercial customer counts are increasing.

Figure 6.6: Commercial Customer Count - PSE Service Territory



The PSE system data goes back to 2000 and shows the trend prior to the recession. The King County and Eastside data only goes back to 2006, so the historical trend is obscured by the recession.

Figure 6.7: Commercial Customer Count – King County

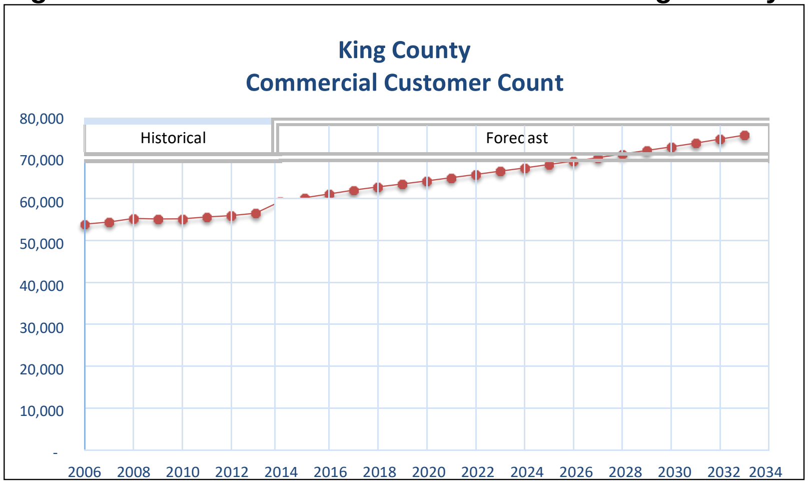
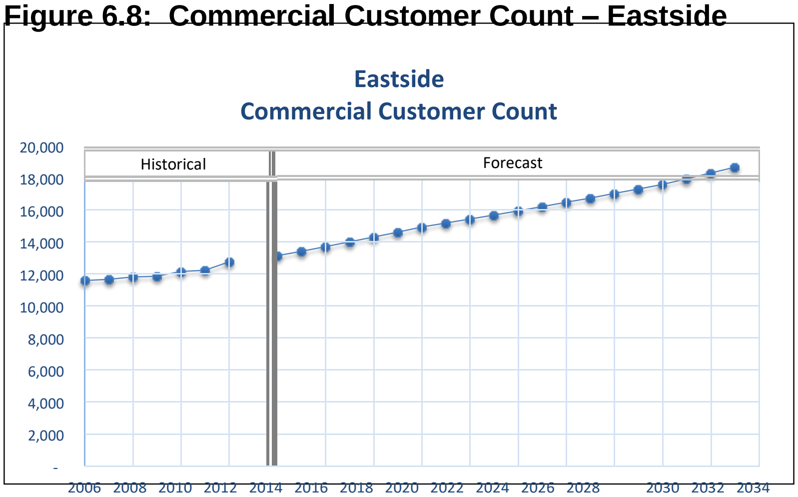
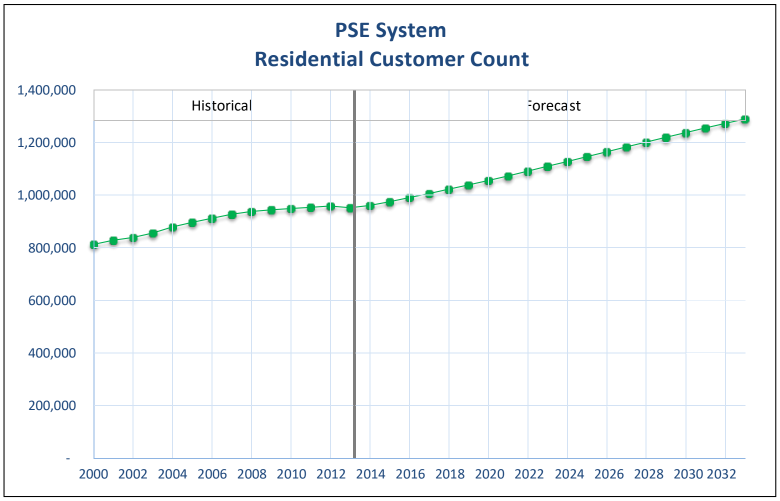


Figure 6.8: Commercial Customer Count – Eastside



Forecasts for the residential customer counts are increasing.

Figure 6.9: Residential Customer Count - PSE Service Territory



The PSE system data goes back to 2000 and shows the trend prior to the recession. The King County and Eastside data only goes back to 2006, so the historical trend is obscured by the recession.

Figure 6.10: Residential Customer Count – King County

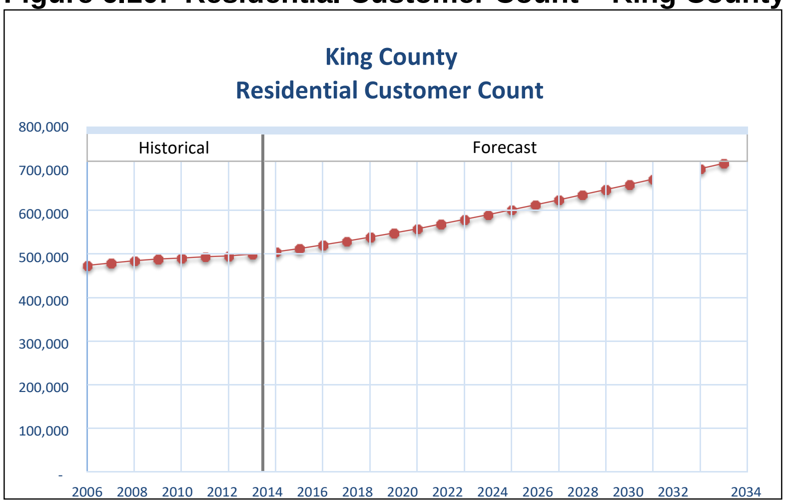
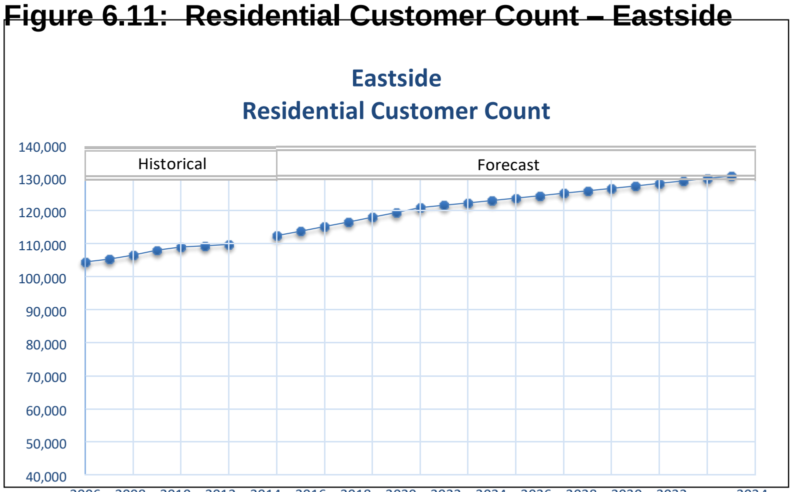


Figure 6.11: Residential Customer Count – Eastside



The industrial customer count is continuing to decline as more industrial customers move out of the area and more commercial moves in.

Industrial customers include warehousing.

Figure 6.12: Industrial Customer Count - PSE Service Territory

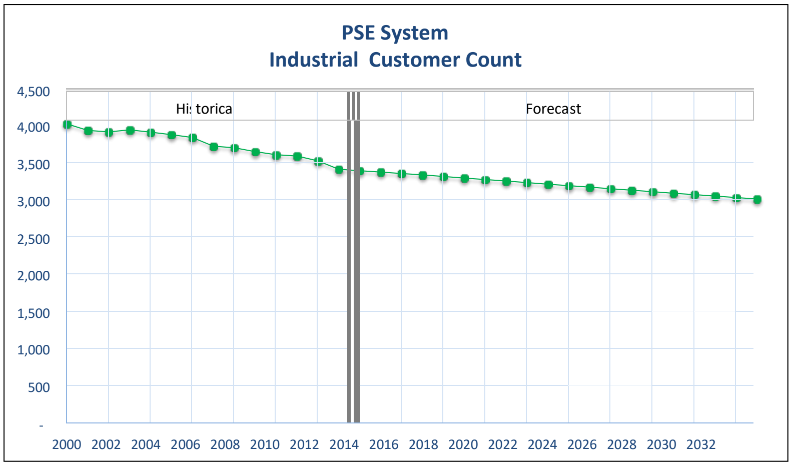


Figure 6.13: Industrial Customer Count – King County

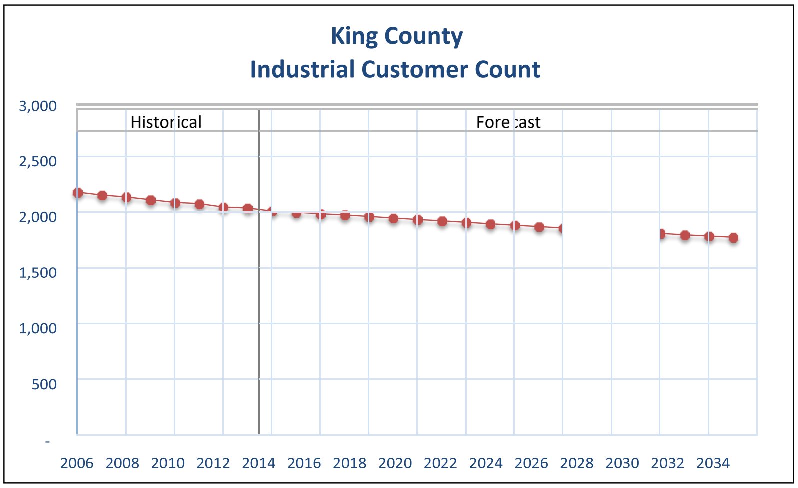
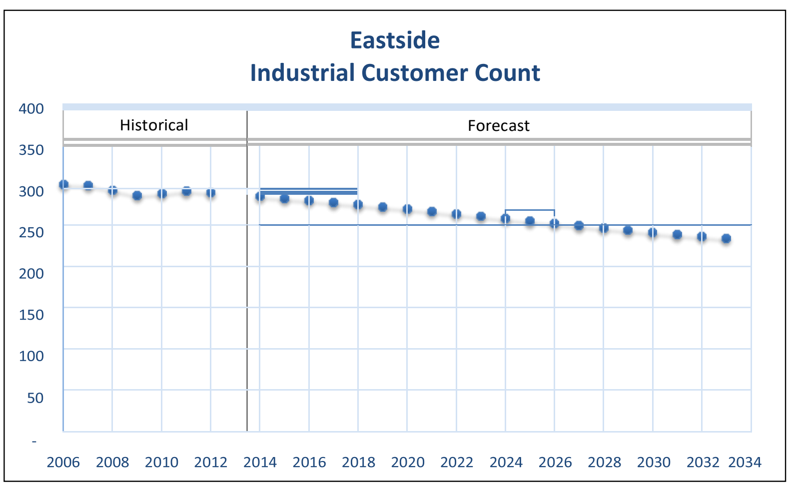


Figure 6.14: Industrial Customer Count – Eastside



6.3. End-Use Data, Including Demand-Side Response and Energy Efficiency

End-use data is evaluated in Integrated Resource Planning. The IRP is where a utility examines both Supply-Side and Demand-Side options with the objective of providing reliable and least-cost electric service to its customers while addressing applicable environmental, conservation and renewable energy requirements. Because energy efficiency is generally a low-cost resource, the IRP tends to incorporate energy efficiency as a utility system resource and reduce the need for additional Supply-Side resources.

Washington State's Renewable Portfolio Standard (RPS) law requires conservation potential be developed using Northwest Power & Conservation Council (NWPCC) methodology, and conservation targets are based on IRP with penalties for not achieving them. It requires PSE to meet specific percentages of its load with renewable resources or renewable energy credits (RECs) by specific dates.

The Energy Independence and Security Act (EISA, 2007) provides for minimum federal standards for lighting and other appliances beginning in 2012. It also sets standards for increasing the production of clean renewable fuels, increasing the efficiency of buildings and vehicles, and more.

PSE commissioned The Cadmus Group, Inc. (Cadmus) to conduct an independent study of Demand-Side Resources (DSR) in the PSE service territory as part of its biennial integrated resource planning (IRP) process. The study considered energy efficiency, fuel conversion, Demand Response, and distributed generation, totaling over four thousand measures. PSE also considered distribution efficiency. The achievable, technically feasibly Demand-Side measures were combined into bundles[21] based on levelized cost[22] for inclusion in the generation optimization analysis. The optimization model developed and tested different portfolios, combining Supply-Side Resources with Demand-Side bundles, to find the lowest cost combination of resources that: a) met capacity need; b) met renewable resources/RECs need; and c) included as much conservation as was cost effective. (Once the capacity and renewable resources/RECs needs are met, the decision to include additional conservation bundles is simply whether that next bundle of measures increases the cost or decreases it.) The final set of cost effective measures is identified as the "100% conservation" set. By 2033, the 100% conservation scenario is projected to reduce PSE's winter system peak by 1226 MW, 209 MW from the EISA programs and 1017 MW from all the other Demand-Side Resources. Only new opportunities are captured.

The table below breaks out the 100% conservation DSR at the King County and Eastside area level. The MW column shows the impact (reduction) to the demand forecast. For the Eastside area, 51 MW of peak DSR is projected by 2017, and 135 MW by 2031. These reductions are incorporated into the 100% Conservation forecast, which is what is being reviewed in this report.

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[21] All the bundles are cost bundles, with the exception of a standards bundle (expected effects of codes and standards such as EISA) and a distribution efficiency bundle. An example bundle is the set of measures that cost between $28/MWh and $55/MWh.

[22] Levelized Cost - An economic assessment of the cost to build and operate a power-generating asset over its lifetime divided by the total power output of the asset over that lifetime. It is also used to compare different methods of electricity generation in cost terms on a comparable basis.

Table 6.2: Cumulative DSR Impact (2013 IRP)

King County			Eastside Area		
year	Annual DSR (MWh)	Peak DSR (MW)	year	Annual DSR (MWh)	Peak DSR (MW)
2014	112,730	45	2014	94,667	21
2015	348,463	88	2015	152,559	31
2016	557,863	131	2016	207,980	41
2017	756,295	171	2017	262,563	51
2018	951,360	213	2018	317,493	61
2019	1,147,137	246	2019	386,767	74
2020	1,393,906	309	2020	464,427	86
2021	1,668,547	350	2021	529,013	96
2022	1,902,423	387	2022	585,484	107
2023	2,112,925	421	2023	629,201	110
2024	2,274,243	432	2024	650,086	113
2025	2,351,296	444	2025	672,152	116
2026	2,431,870	457	2026	693,168	120
2027	2,508,352	471	2027	715,397	123
2028	2,589,821	483	2028	734,411	127
2029	2,658,889	494	2029	754,139	130
2030	2,731,640	505	2030	771,869	134
2031	2,798,219	517	2031	793,300	135
2032	2,875,530	532			
2033	2,931,133	533			

Source: PSE

Stakeholder Questions on Demand-Side Response:

Q2. What is the effect of the LED street light program on load?

- A *The Eastside load is forecasted at 641 MW under normal conditions (Winter 15/16). The funded street light conversion program would reduce this load by 282 kW and the full conversion would reduce the load by 798 kW. On a percentage basis, the funded conversion would reduce Eastside load by 0.044% and the full conversion would reduce Eastside load by 0.12%. Though not evaluated in the 2013 IRP and thus not part of the 100% conservation measures, there will be limited impact to the overall load in any given year.*

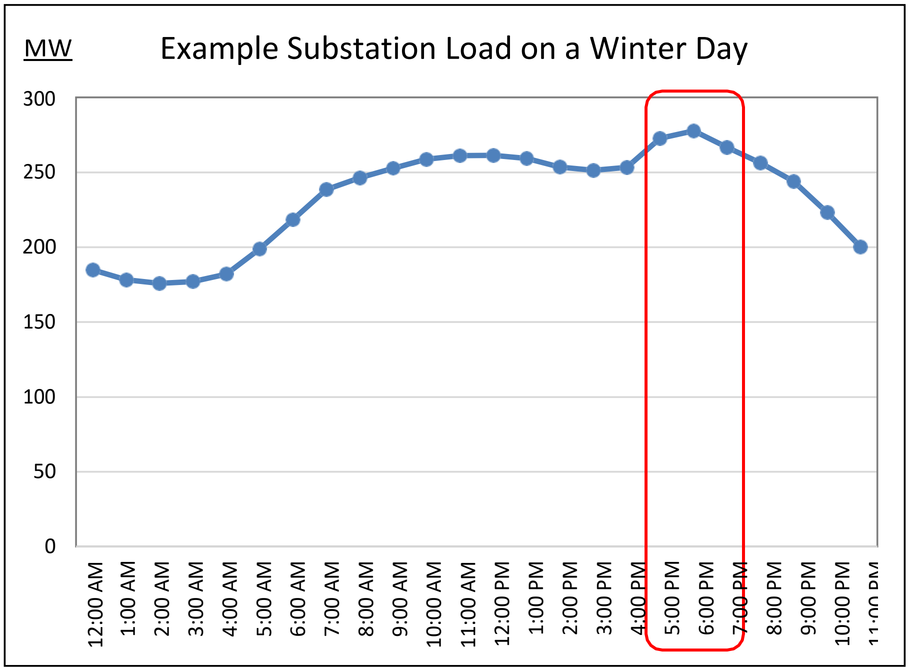
Q3. Does the load forecast take into account local government actions, such as Bellevue's street light and traffic light initiatives?

- A *The LED programs were not specifically identified in the 2013 IRP. The LED technology and availability is different today than it was when the 2013 IRP study began. PSE is planning on including LED lighting in the 2015 IRP.*

Q4. What is the effect of the planned 289 kW of renewable generation (including Solarize Bellevue, the Bellevue College and the Bellevue Service Center), to the grid?

- A *The Eastside load is forecasted at 641 MW under normal conditions (Winter 15/16). The planned 289 kW of renewable generation is nameplate rating, so actual output may be 80-85% of that on a sunny day. For a summer* *peak, the Eastside load could be reduced by 0.04%. For a winter peak, solar output would be significantly less or non-existent. PSE assumes that solar will not be available for the winter peak, since the winter peak usually occurs when it is dark out. The sample graph below reflects a mixed commercial/residential area, with the peak driven by the residential load. (A substation with the peak driven by commercial load could have a different load profile (different peaking curve).)*

Figure 6.15: Sample Winter Load Profile



Q5.Is PSE using all the available Demand Response initiatives/opportunities?

A. *Available Demand Response initiatives/opportunities were evaluated as to whether they were achievable and technically feasible. Then PSE used a generation optimization tool to identify the lowest cost combination of resources that a) meet capacity need b) meet renewable resources/RECs need, and c) included as much conservation as was cost effective. (Once the capacity and renewable resources/RECs needs are met, the decision to include additional conservation bundles is simply whether that next bundle of measures increases the cost or decreases it. The IRP has the objective of providing reliable and least-cost electric service to its customers while addressing applicable environmental, conservation and renewable energy requirements. For example, Pacificorp states that the objective of the IRP is "…providing reliable and least-cost electric service to all of our customers while addressing the substantial risks and uncertainties inherent in the electric utility business." Energy Efficient West Virginia states that IRP is a process used by utility companies to determine the mix of resources that will meet electricity demand at the lowest cost.*

Q6.How does efficiency affect energy usage?

- A. *Energy efficiency elements were described above. The 2013 IRP identified 521 aMW[23] of market achievable, technically feasible electric energy-efficiency potential by the end of 2033. To gauge achievability, Cadmus relied on customer response to past PSE energy programs, the experience of other utilities offering similar programs, and the Northwest Power and Conservation Council's most recent energy efficiency potential assessment. For the 2013 IRP, PSE assumed achievable electric energy efficiency potentials of 85 percent in existing buildings and 65 percent in new construction. If this potential proves cost-effective and realizable, it would result in a 16% reduction in 2033 forecast retail sales. (Note: this is an energy usage question, not a demand (MW) question. That said, the forecast and need are based on incorporating all of the cost-effective conservation measures (100% Conservation).)*

Q7. Provide details on cost-effective energy efficiency and Demand Response (DR) elements included in the forecast, and how "cost-effective" is determined.

- A. *See Tables B-2-1, B-2-2, and B-2-3 (pages 156 – 265) of IRP Appendix N (2013) for a list of the thousands of electric measures studied. Table 13, page 20 provides a summary of the number of energy efficiency measures by customer class. The energy efficiency measures make up the majority of the DSR measures.*
- A. *Cost-effective: The short answer is that PSE has an optimization tool that ensures that the capacity needs are met, ensures that the renewable resources/RECs requirements are met, then minimizes total revenue requirements for both Supply-Side and Demand-Side. Those measures it selects are "cost effective". Longer answer: The measures are bundled into similar levelized costs and the optimization tool evaluates the measures in bundles rather than each individually, then the model determines which bundles are cost effective. See IRP Chapter 5 Figure 5-17 for the DSR bundles by cost group and Appendix N Figure 15 for the DSR supply curve. Out of an identified 1226 winter peak MW of achievable, technical potential in the PSE system (*1017 MW + 209 MW EISA), 1007 MW *were identified as cost effective.*

Q8. Do the growth projections account for increased electrical efficiency? What assumptions are made, and do these represent the low, high, or average model outputs?

- A. *Yes, the growth projections account for the cost effective efficiency measures.*
- A. *See answers to the preceding two questions.*
- A. *The forecast represents the base model.*

Q9. Concern expressed with PSE's forecast when considering energy efficiency, renewables, and Demand Response incentives.

- A. *Please see above discussion and answers.*

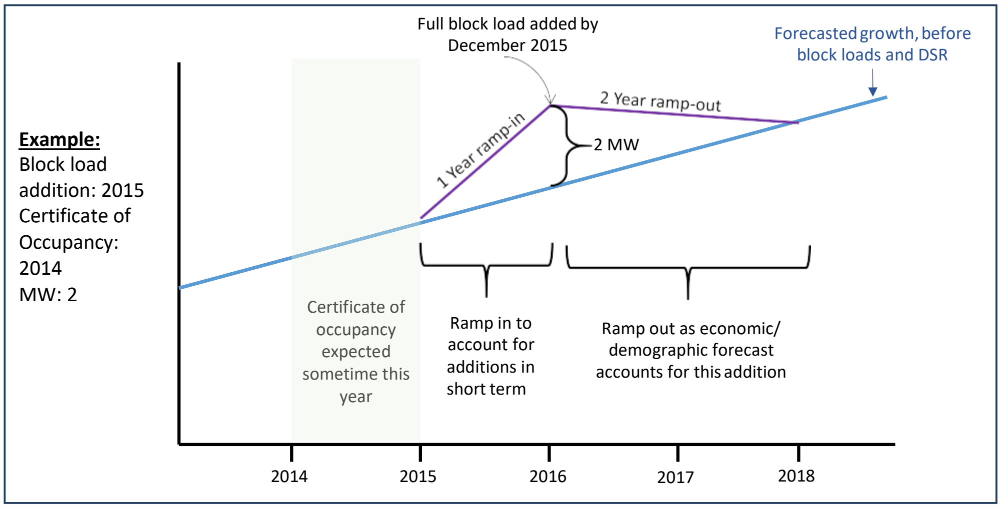
6.4. Major Loads

PSE adjusts its forecast to incorporate major load additions, also called block load additions. The adjustment is a temporary adjustment, as they assume that within a few years the growth built into the load forecast will "catch up" and include the block load additions.

[23] aMW - The average number of megawatt-hours (MWh) over a specified time period; for example, 295,650 MWh generated over the course of one year equals 810 aMW (295,650/8,760 hours). (Source: PSE's 2013 IRP Definitions)

Example: A building has a certificate of occupancy in 2014, with an expected diversified load of 2 MW. PSE will assume it takes a year for the load to fully appear and will add it to the forecast using a one year ramp-in. PSE then ramps the adjustment out over two years, assuming that the growth built into the forecast will take two years to catch up to the block load addition. The block load additions are like bumps on the forecast; they don't change the overall trend, but do create short term changes. See the figure below.

Figure 6.16: Block Load Addition Methodology (from PSE)



PSE acquires data on major load additions from cities as well as directly from developers; some of this data is considered confidential and was not shared. PSE did provide a list of over fifty Eastside Block Load projects (unnamed) with estimated MW load and the expected year when the load would be fully realized. The table below provides a summary by year of this information. The square footage and number of units are reported where known. PSE's Planning group projects a probability of occurrence of 100% for loads anticipated through 2017, 50% for loads anticipated between 2018 and 2020, and 0% for projects after 2020. This probability is multiplied by the expected load before adding into the forecast. The probability factor is a way of addressing the increasing uncertainty of projects in future years.

Table 6.3 does include the City of Bellevue Projects (individually listed in Table 6.4). The Sound Transit East Link project is included in the forecast and accounts for a small portion of the load (approximately 3.5 MW) beginning in the year 2020. Although the East Link web site indicates a 2023 in-service date, PSE's initial expectation is that a small portion of the load will be needed in 2020 and as the project grows they anticipate that Sound Transit's impact on the peak demand will increase. This particular load may be forecasted in advance of need, but it would not impact the 2017/18 HW need for the Energize Eastside project.

Table 6.3: Eastside Total Block Loads by Year

Estimated Completion Year	Assigned Probability	# of Projects	Commercial Sq Footage	# of Multi-family units	MW fully energized this year	MW added to forecast
2014	100%	3	100,000	642	4.4	4.4
2015	100%	9	n/a	1231	5.3	5.3
2016	100%	6	263,000	493	7.0	7
2017	100%	7	2,157,000	1566	25.0	25
2018	50%	4	820,362	n/a	1.0	0.5
2019	50%	6	1,989,340	n/a	21.5	10.75
2020	50%	18	1,316,000	234	16.3	8.15
2021	0%	4	2,010,000	n/a	14.8	0
2022	0%	0	0	0	0.0	0
2023	0%	0	0	0	0.0	0
2024	0%	3	928,000	n/a	8.5	0
2025 and beyond	0%	9	602,000	150	17.8	0

* Square footage and number of units are reported where known.

Table 6.4 lists the thirty-nine major projects identified on the City of Bellevue’s website, and is provided to show the significant growth expected in the City of Bellevue. Twelve of the Projects include data on the number of stories (building floors, and seven of these are planning fifteen stories or more.

Table 6.4: City of Bellevue Major Projects (website)

#	Name
Downtown - In Review	
1	Bellevue Square SE Corner Expansion
2	Washington Square Hilton garden Inn
3	Goldsmith Plaza 305
4	Bellevue Center, Phase II
5	415 Office Building
6	Rockefeller Bellevue Tower Phase I
7	Marriott AC Hotel
8	AMCUT
Downtown - Under Construction	
1	Alamo Manhattan Main Street
2	Main Street Gateway / Bellevue Gateway, LLC
3	Marriott Hotel
4	Bellevue at Main / SRM
5	Bellevue Apartments / LIHI
6	Alley 111
7	Bellevue Office Tower
8	Bellevue Park II Apartments
9	Lincoln Square Expansion
10	SOMA Phase II
Downtown - Issued Land Use & Building	
1	The Summit Building C / Bentall
2	103rd Avenue Apartments / HSL Properties
3	Bellevue Center, Phase I
4	Pacific Regent of Bellevue, Phase II
Downtown - In the Pipeline	
1	Evergreen Development Bellevue Tower
2	EROS Properties
3	Fana CBD Master Development Plan
4	Metro 112 Apartment, Phase II
5	17-102nd Avenue NE
6	Eastlink Bellevue Transit Center Station
7	10625 Main Street
8	846 108th Avenue NE
9	Habib Properties
10	Bellevue Plaza
Bel-Red - In Review	
1	Spring District Residential (Land Use Approval)
2	Spring District Office, Bldgs. 16&24 (Building Permit)
3	East Link 130th Station
Bel-Red - Under Construction	
1	GRE Phase I and Phase II
Bel-Red - In the Pipeline	
1	Aegis at Overlake
2	Sherwood Center
3	East Link 120th Station

Projects can shift, developers can change their schedule, but PSE's projected timing of the block loads falls within a realistic range based on current construction schedules and plans, with the possible exception of the East Link project in 2020. However, the East Link timing wouldn't affect the EE timing. PSE's 1-year ramp-in is based on having certificates of occupancy; as long as certificates of occupancy and visual confirmation of both construction and occupancy rates are utilized, the forecast can be updated each time with the best available information. In addition, some of the block load project information is still limited and doesn't provide a complete picture of the electric load requirements, so assumptions must be made. These situations are also typical and another reason for the need to regularly update block load information which is a typical industry practice. In summary, PSE's block load data appears to fall within a realistic range. Construction is happening. Developers have indicated interest in future projects. Also, PSE applies a probability factor to the estimated loads to try to address the uncertainty of projects with later in-service dates, and all the forecasted impacts of the block loads on the forecast are only temporary bumps, and are ramped out of the forecast so that they don't affect the overall growth trend.

Stakeholder Questions on Major Projects

Q10. Is development like Bellevue's Spring District factored in? Are there numbers that account for the impact of individual projects in downtown Bellevue? What numbers are used to predict the load impact for these projects?

A. *Yes. See Table 6.3 for the summary.*

Q11. A scenario was posed that data centers were consolidating and moving out of the Eastside area, and a question was asked whether PSE had accounted for that in their forecast.

A. *PSE does account for large loads leaving the system or moving from one substation to another, but is not aware of any major changes in data centers. Data centers can be relatively small or quite large. Per PSE, the large data centers generally locate outside the PSE service area, where it is cheaper. PSE's planners have seen no indication of large data center changes. A short, independent web search did not turn up any large data center moves out of the Eastside area.*

6.5. PSE's Forecast

Figures 6.17 – 6.21 depict energy and demand (MWh and MW) forecasts, and growth rates. The peak forecast is affected by conservation programs, and all the graphs assume 100% conservation and a normal winter. PSE's conservation programs are heavily weighted toward the first 10 years of the forecast (2014-2023), with less aggressive conservation occurring in the second 10 years of the forecast (2024-2033). This can result in a slower growth rate in the load forecast for the first 10 years.

PSE reached several key conclusions in comparing the new 2014 forecast (F14) with the prior 2012 forecast (F12), which affects some of the information that PSE had publicly shared showing demand and need for the project. PSE's F14 system forecast assumed a more gradual recovery of the US economy from recession than the prior F12 forecast. The F14 system forecast also used an updated US population growth forecast from the US Bureau of Census which is lower than what was used in F12.

In addition, customer growth and customer counts in the F14 system forecast are lower than in F12 because of slower housing recovery. Finally, peak load growth and peak load levels at the system and King County level are also projected to be lower in F14 versus F12.

The Eastside area is where the load projections increased. Eastside peak loads in the new forecast, based on PSRC's population and employment growth forecasts, are projected to grow by 2.4% per year[24] in the next 10 years driven by growth in commercial sector and high density residential sector.

Although the F14 forecasted Eastside growth rate increased over the 2012 forecast (F12), the resultant F14 forecast for Eastside reduced the projected 2017/18 normal winter loading by 11 MW. The new F14 forecast, based on census tract level demographic data for the Eastside area, had normalized actual peak loads for winter 2012/13 and 2013/14 which were less than the forecasted peak loads from the F12 forecast, which in turn resulted in lower forecasted peaks for winter 2017/18. Section 8 of the report discusses the impact on the Energize Eastside project need.

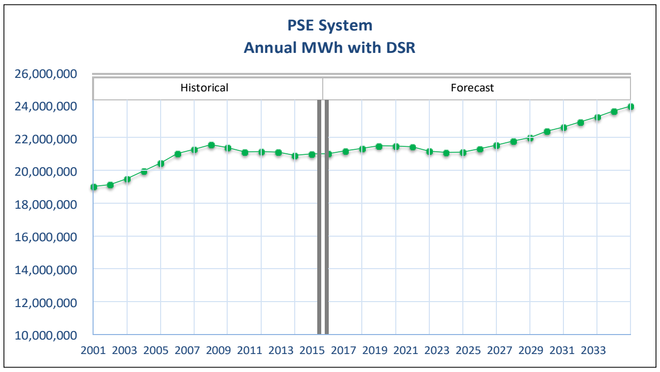
Table 6.5: PSE's Eastside 2017/18 Forecast Comparison

Forecast Development Year	2017/18 Winter Peak
2012	699 MW
2014	688 MW

Figures 6.17 – 6.20 show MWh and MW forecasts for the PSE system, King County, and the Eastside area. The EE project need is based on the MW graph for Eastside. The MWh forecasts do not drive the need, but are shown because of the number of Stakeholder questions received and the uncertainty and/or misconception of what MWh indicate. The MWh forecasts show *usage*, like the odometer, not *peak.* They reflect growth and conservation, but are not directly tied to the peak. The typical behavior or response of a household may be different on the one or two very cold days in a year, as one is getting ready in the morning or coming back from work to a cold house.

Figure 6.17 shows the energy forecast for the PSE system. The forecasted dip in energy is due in part to the aggressive conservation programs that are weighted toward the first 10 years of the forecast (2014-2023). In addition, the block loads are phased in and then phased out over time. Any block loads that come in after 2017 are only given half of the MWh since these projects are less certain to be completed. After 2020 no block loads would be phased in, with a few more years of earlier block loads phasing out.

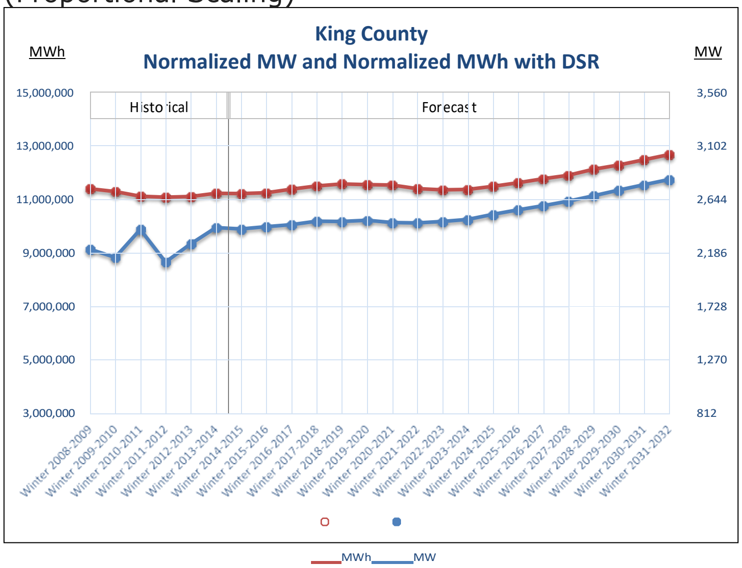
Figure 6.17: PSE's Energy Forecast (MWh) – PSE System



[24] The growth rate is a peak load growth rate and is developed through a regression analysis.

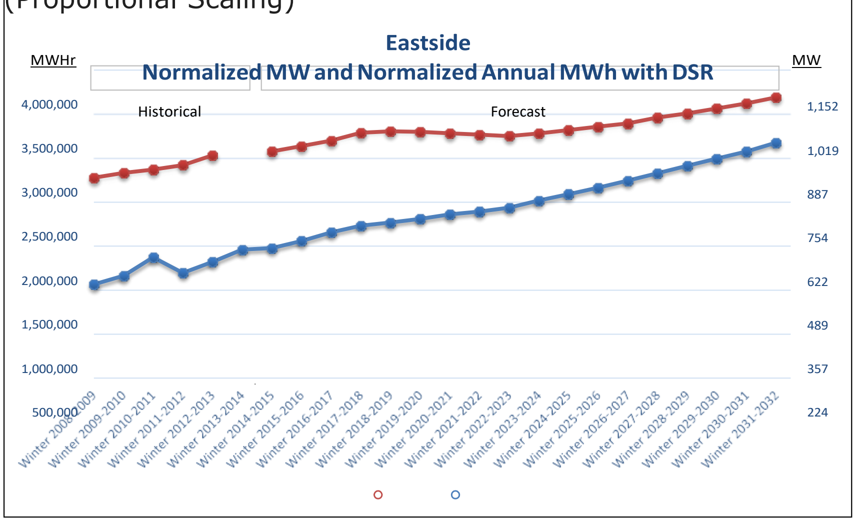
Figure 6.18 shows the energy forecast and demand forecast for King County. King County is forecasted to have a relatively flat energy and demand forecast until approximately winter 2023/2024, at which point both forecasts are increasing. The energy and demand forecasts track fairly closely in King County, but this doesn't mean the same response is expected in other areas.

Figure 6.18: PSE's Energy (MWh) and Demand (MW) Forecasts - King County (Proportional Scaling)



In the Eastside area, the energy forecast appears to show a stronger impact from conservation compared to the demand forecast. As mentioned previously, the forecasted dip in energy is due in part to the aggressive conservation programs that are weighted toward the first 10 years of the forecast (2014-2023). It is also impacted by the block loads which are phased in and then phased out over time. After 2020 no block loads would be phased in, with a few more years of earlier block loads phasing out.

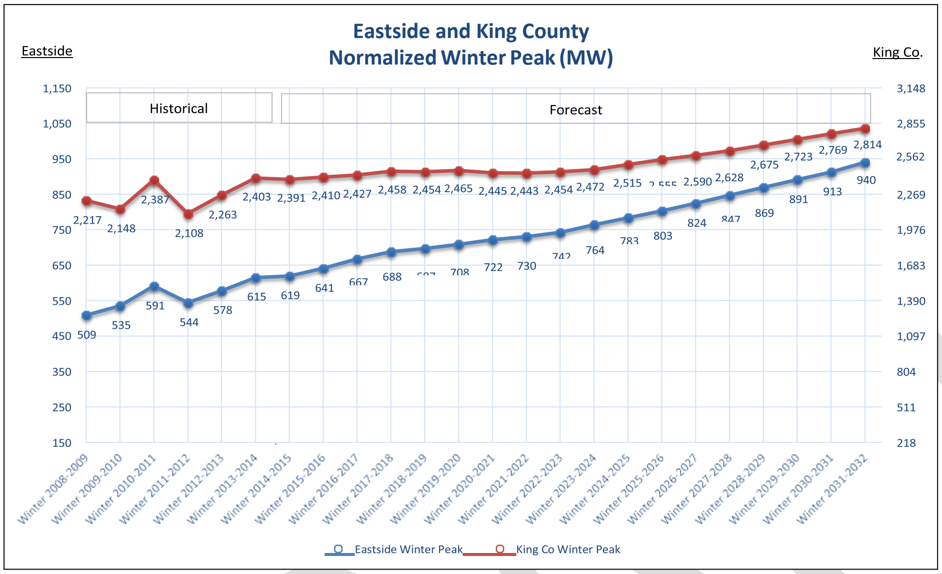
Figure 6.19: PSE's Winter Energy (MWh) and Demand (MW) Forecasts – Eastside (Proportional Scaling)



The dip is due to a cold snap that lasted several days. Per PSE their weather adjustment does not fully account for the lag effects of longer cold snaps.

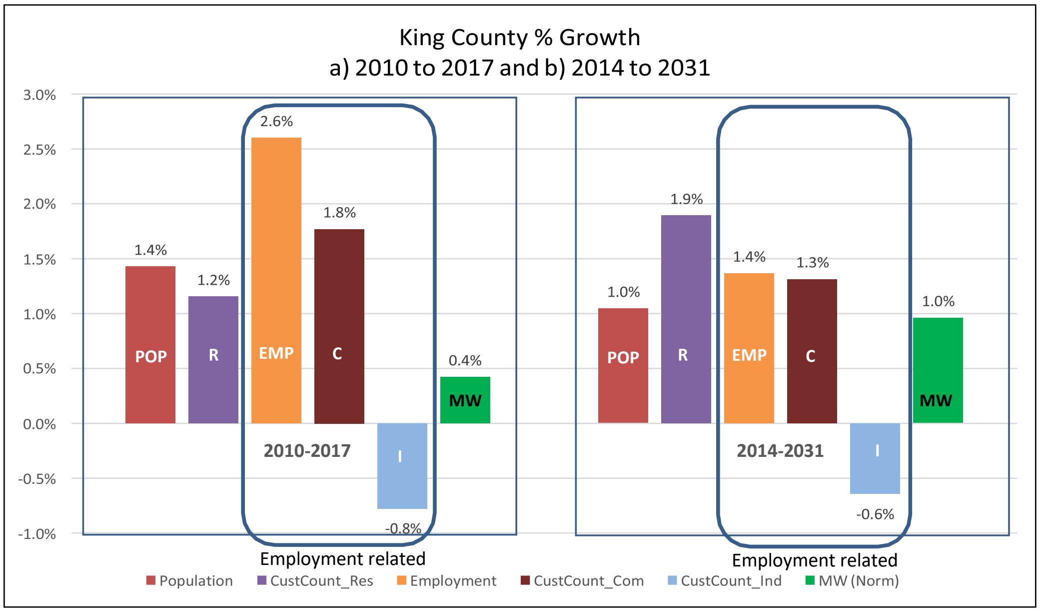
Figure 6.20 compares the Eastside and King County winter peak demand forecasts. The Eastside area is forecasted to grow at a faster rate than King County. This is in line with the Vision 2040 Regional Growth Strategy

Figure 6.20: PSE's Winter Demand Forecasts – Eastside and King County, 100% Conservation
(Proportional Scaling)



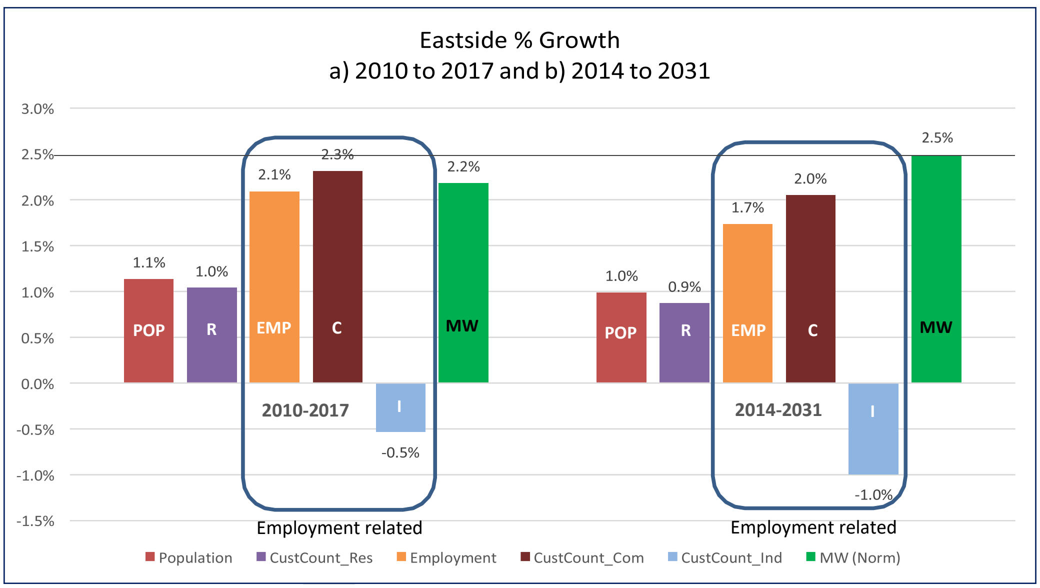
The 2014 forecast shows a 2.4% growth rate for the Eastside area from 2014-2024 and a 2.5% growth for Eastside between 2014 and 2031. In comparison, the forecast shows a 1% growth rate for King County between 2014 and 2031. The Eastside area is projected to grow significantly faster than King County as a whole, which is in line with the Vision 2040 Regional Growth Strategy report. Whether this growth will be sustained through 2031 is unknown. Note: if the growth rate is calculated from the 2010 actuals through 2017, the growth rate is 2.2% for Eastside and 0.4% for King County. See Figure 6.21 and Figure 6.22.

Figure 6.21: Growth Rates – King County



See Table 6.1 for original data sources. Numbers provided by PSE.

Figure 6.22: Growth Rates – Eastside Area



See Table 6.1 for original data sources. Numbers provided by PSE.

<u>Stakeholder Questions related to Actuals (Historical Data)</u>

Q12. What are the ACTUAL numbers for 2012, 2013 and 2014?

A. *Actual numbers for employment, population and customer count are shown in Section 6.2. Actual numbers (normalized) for MWh and MW are shown in Section 6.5.*

Q13. Please show historical loads.

A. *See preceding question.*

Q14. What is the source of the actuals?

A. *See Table 6.1*

Q15. Would like graph showing load history (back to 2000) and forecast.

A. *See Section 6.5*

Q16. Please include 2014/15 winter peak data.

A. *The data is not yet available for the 2014/15 winter peak. See Figure 6.2 and the paragraph above it.*

Q17. Please provide the unadjusted and temperature adjusted historical peaks.

A. *Temperature adjusted historical peaks are shown in Section 6.5. See the beginning of Section 5 and Section 5.1 for why unadjusted peaks are not used.*

Q18. What have been the highest actual aggregate winter peak loads on Eastside feeders and distribution lines …? How would they relate to PSE's forecast of future loads?

A. *The aggregate peaks for the Eastside area are captured in the historical data shown in Figure 6.19.*

A. *The historic loads are included in the regression analysis which results in the forecast of future loads.*

6.6. Summary Analysis of PSE's Forecasting

PSE has followed industry practice in forecasting their demand load.

- ☐ PSE included the major components of a typical system forecast: weather normalizing, use of econometric data, incorporating end-use data (including conservation and DSR measures), and making adjustments for block (major) loads.
- ☐ The variables used in the weather normalizing process were typical based on industry practice.
- ☐ PSE used typical data set elements and multiple data sources for economic/demographic data as shown in Table 6.1, acquiring data at the county level, and for the Eastside area at the census track level, in order to differentiate growth rates within its service territory.
- ☐ PSE employed regression analysis at this step, an industry standard computer analysis technique, to determine the forecast before Demand Side Resources (DSR) and block load adjustments. (The computerized regression analysis was not analyzed as part of this study, but the technique is a computerize estimation of the best fit of the variables to the given data. The equations are considered proprietary by PSE.)
- ☐ PSE acquired/developed significant end-use data via their IRP process on over four thousand DSR measures, incorporated National and State requirements on conservation and RPS, and optimized the achievable, technical measures with a resultant 100% Conservation scenario which projects 135 MW of Eastside winter peak DSR by 2031.
- ☐ PSE gathered block load data (major projects) and utilized short-term forecast adjustments (1-year ramp in based on certificates of occupancy and 2-year ramp-out) to account for the impact. The block load impact was further adjusted by applying a probability factor based on the projected block load in- service date, with 100% through 2017, 50% from 2018 to 2020, and 0% after 2020. The in-service date accuracy and the ramp-in timing of one year is harder to evaluate. Projects can shift, developers can change their schedule, but PSE's projected timing of the block loads falls within a realistic range based

on current construction schedules and plans, with the possible exception of the East Link project in 2020 which wouldn't affect the EE timing. PSE's 1-year ramp-in is based on having certificates of occupancy; as long as certificates of occupancy and visual confirmation of both construction and occupancy rates are utilized, the forecast can be updated each time with the best available information. In addition, some of the block load project information is still limited and doesn't provide a complete picture of the electric load requirements, so assumptions must be made. This is also typical and another reason for the need to regularly update block load information which is a typical industry practice. In summary, PSE's block load data appears to fall within a realistic range. Construction is happening. Developers have indicated interest in future projects. Also, PSE applies a probability factor to the estimated loads to try to address the uncertainty of projects with later in-service dates, and all the forecasted impacts of the block loads on the forecast are only temporary bumps, and are ramped out such that they don't affect the overall growth trend.

No forecast is perfect, but by following industry practice, PSE used reasonable methods to develop the forecast. PSE's resultant forecast shows the Eastside area growing at a higher level than at the county and system level, and that is based on the data PSE received.

<u>Comments on weather adjustment:</u>

PSE is applying the Northwest US practice (as does SCL) of basing projects on a normal 50/50 forecast, which by definition should be exceeded half the time, and using a 95/5 (1-in-20) extreme weather scenario for reference (but not for developing projects). Although a regional industry standard, many other US utilities base projects on an adverse weather scenario, such as a 90/10 or 80/20. Basing projects on an adverse weather scenario is more conservative, but seeks to ensure that the lights stay on given the adverse weather event. These statistically less frequent assumptions would result in a higher load forecast, and if adopted as a policy on which to base projects, would require the system to be designed to withstand it.

Based on historical temperature data, one could suggest that PSE's forecast use a normal temperature of 24°F rather than 23°F for winter normalizing (see Figure 6.1), but: a) the 24°F average is based on a relatively short span of time, and b) the forecast used to propose projects is a normal 50/50 forecast and is expected to be exceeded given an adverse weather event. If PSE were to adopt an adverse weather policy on which to base projects, then it could make sense to re-evaluate the "normal" winter peak temperature; however, since the system demand is based on the less conservative 50/50 load forecast, using 23°F for the normal temperature is a reasonable assumption because it results in a slightly higher system demand than using 24°F.

<u>*Stakeholder* Questions related to Forecast Methodology</u>

Q19. Questions on heat map. Request to create a more accurate map.

A. *USE attempted to make a replacement heat map. One can obtain usage (kWh) data at a detailed level, but that doesn't show the peak demand which drives the project need - analogy of the odometer and speedometer. USE created a map of substation peak demand, using spatial interpolation* *between the substations, but the accuracy wasn't sufficient for the granularity of detail that is desired. The substations aren't necessarily located right where the heaviest load is. USE didn't feel the result gave a sufficiently clear representation of the area load and so did not include it.*

Q20. What are the industry standards for forecasting? Compare to PSE forecast.

A. *See Sections 5 & 6 for standard industry practice.*

Q21. There appear to be no industry wide standards for the development of utility load forecasts, but there do appear to be standards for Integrated Resource Plans. RCW 19.280 State IRP, WAC 480-100-238. Clarify term "conservation" and why it is used for customer load reductions.

A. *Yes, the industry standards have concentrated on the IRP process, but within that are requirements relating to some of the forecast elements. There are typical industry practices.*

A. *100% Conservation is defined as the cost-effective, achievable, technical DSR measures. See the Section 5 introduction and Section 6.3.*

Q22. Is PSE using population growth as a parameter? If so, at what granularity are the growth projections made? In other words, are growth projections used for individual cities, or is the Eastside treated as a whole, with one forecast governing the whole area?

A. *Population is used as a parameter.*

A. *Forecasts were developed at the system level, at the county level, and for the Eastside area. The Eastside forecast was developed using census tract data.*

Q23. We would like to understand economic projections as well. Is economic growth projected for each city, or only for the whole Eastside? What numbers were used?

A. *Economic projections were made at the system level, at the county level, and for the Eastside area. Graphs were provided for some of the major elements (Section 6.2 and 6.5).*

Q24. Does the load forecast anticipate changes in regional transmission flow, such as south-north transmissions to Canada?

A. *The load forecast is based on load. Transmission flows are irrelevant to the forecast. The link between forecast and transmission flows comes from modeling the substation load data, which was correlated to the load forecast, into a powerflow case. The powerflow case is where regional flow scenarios can be modeled. (See Appendix B, Optional Technical Analysis for study results of this scenario. It showed that even with no power flowing to Canada on the Northern Intertie (which is an unrealistic hypothetical scenario but modeled to answer the local vs. regional question), there is still a project need.*

Q25. What other factors governing the regional grid is the load forecast taking into account?

A. *See preceding answer.*

Q26. Is it possible that the industry-standard methodology which PSE uses to forecast load growth has not evolved to reflect the realities of the current electricity marketplace? Are there any newer methodologies, or modifications to existing methodologies, which better reflect the realities of the modern electricity marketplace?

A. *This question is outside the scope of this study; however, the IRP process continues to get attention, and frequently includes input from stakeholders, which is where Demand-Side Resources are evaluated and feed into the forecast process.*

Q27. Is PSE's load projection reasonable? Are they the needs of Eastside or the needs or BPA, etc.? Are the loads PSE is projecting based on a farfetched combination of circumstances that are unlikely to actually happen?

A. *The load projections and need determination are based on a normal weather forecast with 100% conservation. The 2014 forecast methodology and inputs are reasonable. See Section 6.6. See Section 7 for discussion on standards.*

Q28. Is PSE's forecast based on good data, independently verified?

A. *Yes, PSE has followed industry practice in forecasting their demand load. See section 6.6.*

Q29. Why is PSE projecting load growth when their public documents (e.g. 10k) show they are selling less electricity?

A. *The referenced 10k report is based on energy, which like an odometer reading shows usage, not peak demand. As noted previously, average use behavior is not necessarily winter peak behavior; the trends don't have to match. In addition, the data in the report is not adjusted for weather. See figures in Section 6.5 for current forecasts.*

Q30. Provide justification/rational/definition for the System Capacity line on PSE's "Customer Demand Forecast".

A. *System Capacity: Occurs when the load (Eastside Area) just hits the rating limit of the critical contingency condition(s). The System Capacity line can shift depending on where load grows (if not homogenous). The contingency analysis is dictated by national standards. Using the same methodology as the 2013 report, a winter Eastside system capacity range of 688-708 MW has been identified based on the 2014 load forecast powerflow results (see Figure 8.1).*

Q31. How does PSE justify an Eastside growth rate of 1.7% to 2%?

A. *PSE used reasonable methods to develop the 2014 forecast by following industry practice (see Section 6.6). The forecast is built from the data inputs via regression analysis. The 2014 demand forecast shows a 2.4% growth rate for the Eastside area from 2014-2024 and a 2.5% growth for Eastside between 2014 and 2031. In comparison, the forecast shows a 1% growth rate for King County between 2014 and 2031. The Eastside area demand is projected to grow significantly faster than King County as a whole, which is in line with the land use* Vision 2040 Regional Growth Strategy *report. Whether the forecasted demand growth will be sustained through 2031 is unknown. Note: if the growth rate is calculated from the 2010 actuals through 2017, the growth rate is 2.2% for Eastside and 0.4% for King County. See Figure 6.18 and Figure 6.19.*

A. *Note: SCL's "demand" forecast growth of 0.5% noted in their latest IRP update is actually an energy forecast. SCL's actual demand forecast from December 2013 to December 2034 has an estimated compound annual growth rate (CAGR) of 1.2%, based on an estimated 1180 MW in December 2013 and using their IRP demand graph as reference. PSE has a CAGR of 2.4% from winter 2013/14 to winter 2031/32 based on an estimated 615 MW in winter 2013/14.*

Q32. What is the magnitude and timing of the need for EE? An updated peak load forecast is needed to resolve serious questions about the load forecast used by PSE to justify the project as now proposed.

A. *In early February 2015, PSE completed their 2014 forecast which included historical data through 2014, and thus included the summer 2014 peak and the winter 2013/2014 peak. See the top of Section 6 for discussion on the new forecast methodology.*

Q33. Please explain PSE's "Eastside Customer Demand Forecast" chart. A detailed quantitative analysis for the years is needed on this chart. There have been several credible articles stating electrical usage is not growing but is flat, even declining in the United States. This trend is apparent over several years and is due to conservation and technological changes in production, usage and storage. How does Energize Eastside explain this disparity? Also, solar energy has been increasing on the Eastside.

A. *Please see discussions in Section 6.2 on the economic and demographic data sources, the Vision 2040 Regional Growth Strategy, and Section 6.4 on Major Loads. Please see Section 4 on Energy vs. Demand and Q4 on potential impact of solar on a winter peak.*

Q34. PSE's energy use (MWh) trend and # of customer trend is similar to SCL, yet PSE's load forecast (MW) shows a significantly higher growth % than SCL. Explain. National electricity use is declining as is regional (Pacific Northwest Utilities Conference Committee (PNUCC)). Why is PSE's forecast increasing? Explain why electricity use in Bellevue is so different from other cities.

A. *Please see Q31 and Q33 answers.*

Q35. Please explain PSE's "Eastside Customer Demand Forecast" chart. Show peak demand for Bellevue. Show retail sales to customers, off-system sales and electricity delivered to transmission only customers. Concern over accuracy of trend.

A. *See preceding answer. See Figures in Section 6.5.*

A. *There are no off-system sales within the Eastside area; this would not affect the Eastside forecast. There are transmission only customers in King County outside of the Eastside area, but since the off-system sales customers are not PSE's customers, they wouldn't affect that forecast either.*

Q36. Is it true that PSE's "Eastside Customer Demand Forecast" graph is based on a hypothetical "grid-flow modeling scenario" … rare winter peak …

A. *No. It is based on normal winter weather. The hypothetical outage scenarios are part of the industry mandated contingency analysis. Please see the weather normalizing discussion in Section 5 and see Section 7 on Standards, regarding the required contingency analysis.*

7. Electric Utility Reliability Standards

7.1. EPAct 2005

On August 14, 2003, large portions of the Midwest and Northeast United States and Ontario, Canada, experienced an electric power blackout. The outage affected an area with an estimated 50 million people and 61,800 megawatts (MW) of electric load in the states of Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey and the Canadian province of Ontario. The blackout began a few minutes after 4:00 pm Eastern Daylight Time (16:00 EDT), and power was not restored for 4 days in some parts of the United States. Parts of Ontario suffered rolling blackouts for more than a week before full power was restored. Estimates of total costs in the United States range between $4 billion and $10 billion (U.S. dollars). In Canada, gross domestic product was down 0.7% that August, there was a net loss of 18.9 million work hours, and manufacturing shipments in Ontario were down $2.3 billion (Canadian dollars).[25]

Partially in response to this blackout, Section 1211 was added to the Energy Policy Act of 2005 (EPAct 2005). EPAct 2005 became law on August 8, 2005. Section 1211 of the EPAct 2005 requires that the Federal Energy Regulatory Commission (FERC) certify an Electric Reliability Organization (ERO) to establish and enforce reliability standards for the bulk-power system[26], subject to FERC review. On July 20, 2006, FERC certified the North American Electric Reliability Corporation (NERC) as the ERO for the continental U.S. under the Federal Power Act Section 215.

From the NERC website (www.nerc.com):

> "NERC is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization for North America, subject to oversight by the Federal Energy Regulatory Commission and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the bulk power system, which serves more than 334 million people."

Because of changes brought about by EPAct 2005, the NERC standards that were previously voluntary are now mandatory and all users of the Bulk Power System (BPS) must comply with these standards. There are currently 1426 requirements in 143 reliability standards either subject to enforcement or subject to future enforcement.

[25] http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf, pg. 1

[26] In this report, the terms Bulk Power System (BPS) and Bulk Electric System (BES) will be used interchangeably. While the definitions are slightly different, for the purposes of this report and for determining the need for the Energize Eastside Project, these two terms can be treated as the same.

7.2. Reliability Standards Applicable to Energize Eastside[27]

NERC Reliability Standard TPL-001-4[28] (Transmission System Planning Performance Requirements) is the Reliability Standard most relevant to the need for the Energize Eastside Project. TPL-001-4 Requirement 1 and Requirement 7 are currently subject to enforcement. Requirements 2-6 and 8 are not currently subject to enforcement but will be subject to enforcement on January 1, 2016. The enforcement date for Requirements 2-6 and 8 is before the planned in-service date of the Energize Eastside Project. Therefore, the Energize Eastside Project will be subject to the newer requirements before the project goes into service. In addition, the newer requirements are in many cases more stringent than the existing requirements. For the above reasons, this report will limit its discussion to the newer TPL-00104 Requirements and will not discuss the currently enforceable requirements of TPL-001-0.1, TPL-002-0b, TPL-003-0b, and TPL-004-0a[29].

Another Reliability Standard that can have an impact on the need for the Energize Eastside Project is FAC-008-3[30] (Facility Ratings). TPL-001-4 and FAC-008-3 are discussed in more detail below.

TPL-001-4 requires that each Planning Coordinator and Transmission Planner[31] perform an annual transmission assessment of its portion of the Bulk Electric System[32] (BES). This assessment must model, among other things, system peak load, known commitments for Firm Transmission Service and Interchange, and the planning events (contingencies) listed in Table 1 of TPL-001-4[33].

TPL-001-4 requires the development of a Corrective Action Plan (CAP)[34] whenever the transmission assessment determines that the system cannot meet the performance requirements listed in Table 1. In other words, once a performance requirement specified in TPL-001-4 cannot be met (e.g., an overload is found), a need has been determined.

FAC-008-3 is applicable to both Transmission Owners and Generation Owners[35]. FAC-008-3 requires each Transmission Owner and Generation Owner to have a facility[36]

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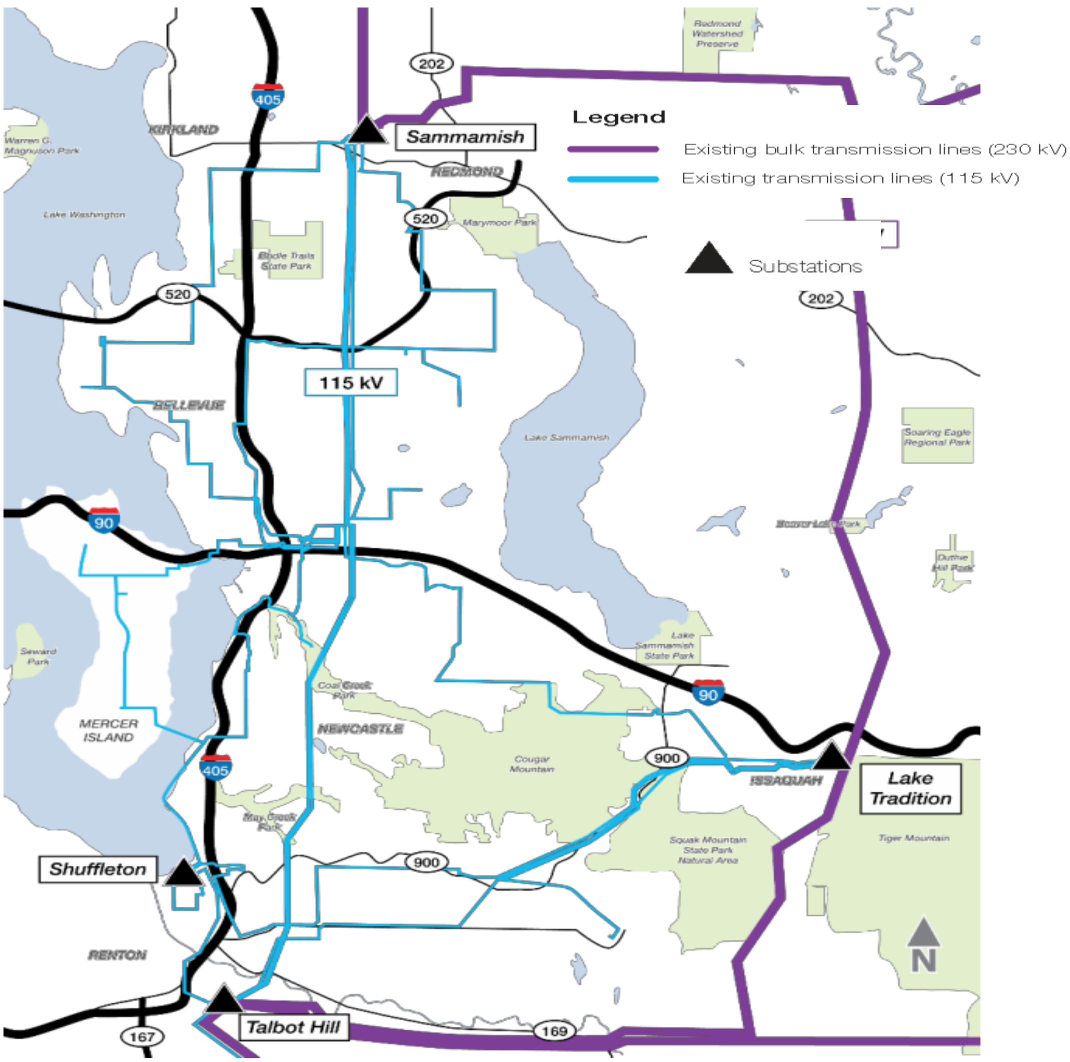
[27] capitalized terms in this section refer to terms that are defined in the NERC Glossary
[28] http://www.nerc.com/files/TPL-001-4.pdf
[29] Reliability Standards TPL-001-0.1, TPL-002-0b, TPL-003-0b, and TPL-004-0a are being replaced by TPL-001-4.
[30] http://www.nerc.com/files/FAC-008-3.pdf
[31] Puget Sound Energy is registered with NERC as both a Planning Coordinator and a Transmission Planner.
[32] The Bulk Electric System (BES) definition is fairly long and involved (see http://www.nerc.com/pa/RAPA/BES%20DL/BES%20Definition%20Approved%20by%20FERC%203-20-14.pdf), but for the purposes of this report, the BES can be considered to be all networked transmission elements with an operating voltage of 100 kV or higher. Radial facilities are generally not considered to be part of the BES even if they are operated at voltages of 100 kV or higher.
[33] Table 1 is provided in Appendix RPM-1 of this report.
[34] Corrective Action Plans as used in the TPL-001-4 Reliability Standard are not the same as the Corrective Action Plans described by PSE in the Eastside Needs Assessment Report (October 2013). In TPL-001-4, a Corrective Action Plan may include operational measures (such as switching existing facilities in or out) and/or the addition of new facilities. In the Eastside Needs Assessment Report, Corrective Action Plans only refer to operational measures.
[35] Puget Sound Energy is registered with NERC as both a Transmission Owner and a Generation Owner.
[36] A facility is a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

rating[37] methodology[38] that is consistent with manufacturer ratings, standards developed through an open process, or a practice that has been verified by testing, performance history, or engineering analysis. The intent of this Reliability Standard is to ensure that facility ratings are based upon sound engineering practices and are consistent across a utility's service area.

7.3. Critical Contingencies for the Energize Eastside Project

Figure 7.1 below is a sketch of the Eastside area transmission network[39]. The area between Sammamish and Talbot Hill is the area of where a number of overloads have been seen in planning studies.

Figure 7.1: Eastside Area Transmission Sketch



[37] A facility rating is the maximum or minimum voltage, current, frequency, or power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
[38] A facility rating methodology is a procedure that is used to establish the facility ratings for all of a utilities facilities.
[39] From the Energize Eastside website: energizeeastside.com

The specific contingencies that cause facility rating violations on specific elements of the power system are CEII[40] and cannot be disclosed in a public document. However, the general types of contingencies that cause overloads on various facilities can be disclosed. Below is a list of the general types of contingencies that are causing overloads on the PSE eastside transmission system.

- Overlapping outages of two transformers (N-1-1) (P6),
- Overlapping outages of two transmission lines (N-1-1) (P6),
- Overlapping outages of one transmission line and one transformer (N-1-1) (P6), and
- Simultaneous outage of two transmission lines (N-2) (P7).

As discussed above, the NERC TPL-001-4 Reliability Standard requires that a Corrective Action Plan (CAP) be developed whenever the system does not meet the performance requirements specified in the standard. A CAP can include: new facilities such as transmission lines; adjustments to operating procedures (such as opening a switch at the end of a transmission line); or a combination of both new facilities and operating procedures.

7.4. Normal vs. Emergency Ratings

A "*normal rating"* is the limit at which a transmission facility can operate indefinitely (i.e., 24/7/365 for the life of the project, which in some cases could be over 50 years). An "*emergency rating"* is only available for use for a short period of time and using an emergency rating usually involves a loss of usable life for the facility. This loss of usable life is caused by the increased temperatures that the facility is subject to when loaded to its emergency limit. The higher temperatures can cause insulation in transformer banks to degrade or overhead conductors to weaken and/or sag. In some cases an emergency rating may have a lifetime limit on the number of hours it can be used (e.g., 100 hours). Once that lifetime limit is reached, a facility will not be able to exceed its normal rating or it may need to be replaced. An emergency rating cannot be used for normal overloads that might occur due to load growth or a sudden increase in load due to extreme weather. Given a typical lifetime limit of 100 hours, an emergency rating would only be good for a little over 4 days under normal (non-contingency) conditions. Therefore, an emergency rating can only be used under contingency (outage/equipment failure) conditions.

In addition to the differences between normal and emergency ratings, there are typically different ratings for summer and winter conditions. Because equipment ratings are based in part on thermal limits of the equipment (as noted above) and the ambient temperatures expected during winter are less than the ambient temperatures seen during summer, normal and emergency winter ratings are almost always higher than the respective normal and emergency ratings for summer.

PSE utilizes different normal and emergency facility ratings for summer and winter conditions, consistent with industry practice.

[40] CEII - Critical Energy Infrastructure Information CEII is protected information whose release could compromise the reliability of the BES. Each individual utility decides what information they deem to be CEII. The specific contingencies that cause overloads on the elements documented in the public Energize Eastside study reports are considered to be CEII by PSE. Other utilities also consider information such as this to be CEII.

7.5. Transmission Reliability vs. Distribution Reliability

Transmission outages currently cause about 5% of the customer outage duration on PSE's system in the Energize Eastside area. The remaining 95% of the customer outage duration are caused by distribution outages (see Table 7.1) below[41]. As can be seen from Table 7.1, the City of Bellevue's transmission related customer outage performance is much better than the rest of the Energize Eastside area (less than 1% of the customer outage minutes were due to transmission outages).

2014 Total Outages					
Energize Eastside Area (includes City of Bellevue)					
	# of Outages	# of Customers Impacted	Total Customer Minutes	Customers Impacted Per Outage	Outage Minutes Per Customer Per Outage
Transmission outages	6	35,614	2,521,995	5936	11
All other outages	1182	120,074	47,481,181	102	0.33
Total outages for EE	1188	155,688	50,003,176		
Transmission outage percentage of total	0.5%	22.9%	5.0%		
City of Bellevue					
	# of Outages	# of Customers Impacted	Total Customer Minutes	Customers Impacted Per Outage	Outage Minutes Per Customer Per Outage
Transmission outages	3	18,939	224,327	6313	4
All other outages	745	61,963	29,964,379	83	0.65
Total outages for COB	748	80,902	30,188,706		
Transmission outage percentage of total	0.4%	23.4%	0.7%		

Table 7.1 also shows some additional pertinent information regarding the relative severity of transmission outages versus distribution outages. The number of customers affected by a transmission outage in this example is over 50 times greater than the number affected by a distribution outage. In addition, the outage duration per customer per outage is much longer for transmission outages than for distribution outages. This difference is one reason why transmission reliability is required to be so high. While the risk of an outage is low, the consequences of that outage can be quite large.

[41] This data from PSE indicates that the Energize Eastside area has fewer customer outage minutes due to transmission outages (as a fraction of the total outage minutes) than other utilities in the U.S.

The reason mentioned above is the same reason why the nuclear industry designs back-up systems for the reactor core cooling system with multiple layers of redundancy. Nuclear plants are typically designed with two sources of off-site (grid) power. If one source fails, the other can be used to supply the plant cooling load. In addition, just in case both off-site power sources are out, the plant has backup diesel generators that are capable of supplying the cooling system load. Just in case the primary diesel generators fail, there is a redundant set of diesel generators to step in if necessary. Then for additional protection, battery backup is provided in case the offsite grid power and both sets of diesel generators fail. The reason for this extreme level of redundancy is because even though the risk of a failure of four levels of cooling system power supply is incredibly small, the consequence of a failure is extremely large.

In addition to the Northeast blackout discussed above, two other major blackouts have occurred in the Western Interconnection in the last two decades. These two blackouts are discussed below.

On July 2, 1996 at 1424 MDT a disturbance occurred that ultimately resulted in the Western Systems Coordinating Council (WSCC) system (the Western Interconnection) separating into five unconnected load and generation subsystems. This disturbance resulted in the loss of 11,850 MW of load and affected 2 million people in the West. Customers were affected in Arizona, California, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming in the United States; Alberta and British Columbia in Canada; and Baja California Norte in Mexico. Outages lasted from a few minutes to several hours. Electric service was restored to most customers within 30 minutes, except on the Idaho Power Company (IPC) system, a portion of the Public Service Company of Colorado (PSC), and the Platte River Power Authority (PRPA) systems in Colorado, where some customers were out of service for up to six hours. On portions of the Sierra Pacific Power Company (SPP) system in northern Nevada, service restoration required up to three hours.

On August 10, 1996 a major disturbance occurred in the Western Interconnection (Western Systems Coordinating Council, WSCC) at 1548 PDT resulting in the Interconnection separating into four unconnected load and generation subsystems. Conditions prior to the disturbance were marked by high summer temperatures (near or above 100 degrees Fahrenheit) in most of the Region, by heavy exports (well within known limits) from the Pacific Northwest into California and from Canada into the Pacific Northwest, and by the loss of several 500 kV lines in Oregon. The California–Oregon Intertie (COI) (Pacific Northwest to California) north to south electricity flow was within parameters established by recent studies initiated as a result of the July 2-3, 1996 disturbance (see above). The flow on the AC system between the Pacific Northwest and California was about 4,350 MW and the flow on the Pacific DC Intertie (PDCI) (a DC system) was 2,848 MW. This disturbance resulted in the loss of over 28,000 MW of load and affected 7.5 million people in the West. Customers were affected in Arizona, California, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming in the United States; Alberta and British Columbia in Canada; and Baja California Norte in Mexico. Outages lasted from a few minutes to as long as nine hours.

Both of the above outages occurred prior to the implementation of mandatory Reliability Standards. The purpose of the mandatory Reliability Standards is to maintain the reliability of the BES and to help prevent major outages like these from happening again. As previously noted, even though the probability of outages like these is very small, the consequences of this type of outage are very large. Therefore, the Reliability Standards require the examination of contingencies that to a lay person seem to be highly unlikely.

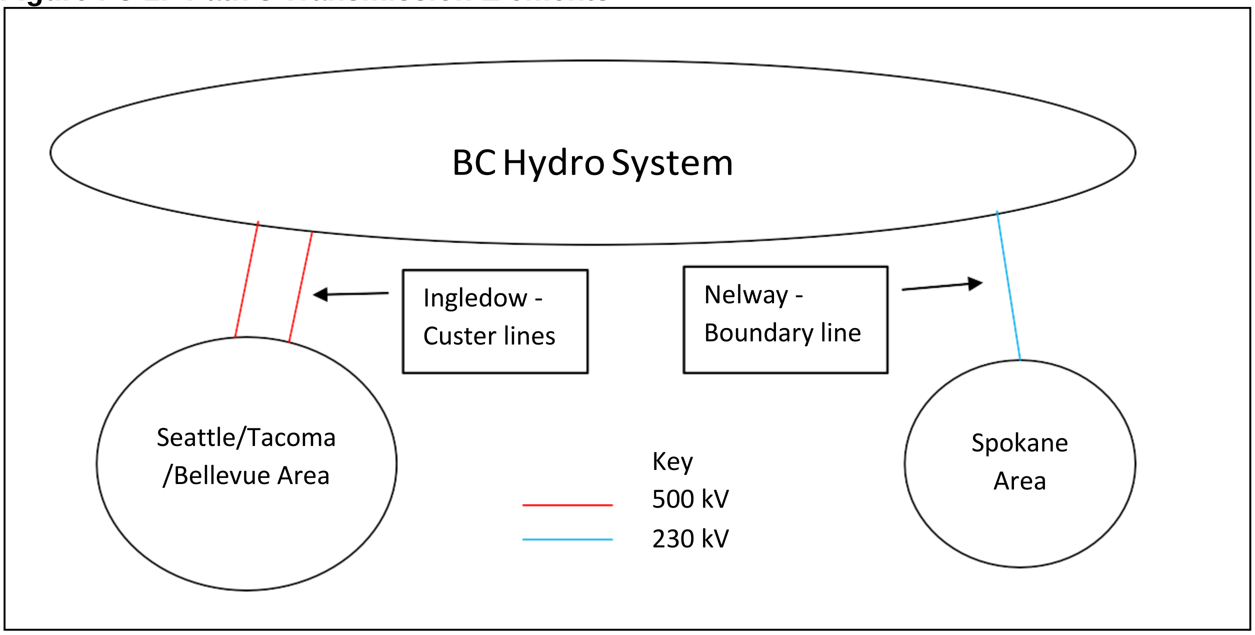
In general, the probability of a single contingency (N-1) is at least once every three years. The probability of multiple contingencies such as N-1-1 or N-2 is somewhere between once every three years and once every 30 years. (See Section 8 and Appendix B for analysis of this subject.)

7.6. Path 3 Issues

Path 3 is the transmission interconnection between Washington and British Columbia. Path 3 consists of three transmission circuits (see Figure P3-1):

1. Ingledow - Custer 500 kV #1,
2. Ingledow - Custer 500 kV #2, and
3. Nelway - Boundary 230 kV #1.

Figure P3-1: Path 3 Transmission Elements



It should be noted when discussing Path 3 that sometimes the Nelway - Boundary 230 kV line is referred to as the Path 3 eastside intertie. This term should not be confused with eastside as it is used in the context of the Energize Eastside project. The Path 3 eastside intertie is located near Spokane, WA and is over 250 miles away from the area under consideration for the Energize Eastside project.

Path 3 has a non-simultaneous rating of 3150 MW north to south and 3000 MW south to north. Known commitments for Firm Transmission Service and Interchange on Path 3 are 2300 MW north to south and 1500 MW south to north.

The planning cases PSE used to study the need for the Energize Eastside project had Path 3 flow at 3150 MW north to south in the summer base cases and 1500 MW south to north in the winter base cases.

<u>Stakeholder Questions related to Standards and Reliability</u>

Q37. 2013 Needs Assessment report, page 43. The "3d" sensitivity, modeling 2021-2022 extreme Weather with 100% conservation. Explain why this scenario, which had 845 MW predicted Eastside load, showed no overload for N-0 yet 845 MW is above PSE's "current system capacity" line in their 2013 report. Clarify what PSE's capacity line represents.

A. *PSE's capacity line is the load level at which overloads will just begin to occur under contingency situations. Because the scenario being referred to in this question is "N-0" (or no contingency), there are no overloads. The reason for there being no overloads is that up to two additional pieces of equipment are in service to carry power to the load.*

Q38. Too much transmission reliability?

A. *The requirement for transmission reliability is discussed in the section on NERC Reliability Standards. Because the Reliability Standards are mandatory, meeting these standards provides just adequate reliability.*

Q39. How are EE "need" and "reliability" related? How many outages in the next 10 years (2017-2027) are anticipated to be avoided by implementation of EE, due to transformer limitations or otherwise stressing system capacity due to local Eastside growth (excluding unpredictable weather events)?

A. *EE need is related to reliability by the requirement that when overloads occur during a planning assessment under the contingencies that are required to be run (see the discussion of TPL-001-4 in the Independent Technical Analysis), there is by definition a need. This need is not necessarily EE, but something must be done to mitigate the overloads seen in the planning assessment. The question of how many outages may be avoided by implementation of EE is not relevant to the question of need. The Reliability Standards require that a defined set of contingencies be run on the system model. If overloads or other violations are found, then a Corrective Action Plan must be produced. The fact that a Corrective Action Plan is needed demonstrates that there is a need.*

Q40. What is the probability of an N-1-1?

A. *The probability of an N-1-1 is not a factor that is considered in determining if there is a need for a project. However, typically the probability of an N-1-1 is between 0.33 and 0.033 outages per year or once in 3 years to once in 30 years.*

Q41. One of the rationales advanced by PSE for the new transmission lines was to increase the 'reliability' of PSE's transmission system and/or the reliability of PSE's "system" that supplies electricity to Bellevue and other east side communities.

A. *Energize Eastside is a project designed to mitigate overloads found in planning studies that used projected future load growth. Therefore, a better way to look at EE is that it will maintain the current reliability that exists today and prevent it from getting worse.*

Q42. Task 8 of USE's 'scope of services' states that USE will develop a formal, written evaluation of the need for PSE's Energize Eastside (EE) project, including an assessment of the " … impacts to electrical system reliability …" Please describe (or provide in the report) a schematic/line-diagram of the "electrical system" that USE evaluated to assess the "reliability" of the "electrical system"; and describe the quantitative reliability measures/metrics that were used in performing the evaluation of the impact of PSE's EE project on the "electrical system" reliability.

A. *The electrical system modeled was the entire Western Interconnection that extends from the Pacific Ocean on the west east to Colorado and from British Columbia and Alberta in the north south to Arizona and a portion of northern Mexico. The studies concentrated on the Puget Sound area, but included all facilities in the entire Western Interconnection. USE did not assess the impacts of PSE's EE project on electric system reliability. Our work scope was limited to investigating the need for EE. Therefore, we investigated the accuracy of PSE's latest load forecast (2014) and ran studies using the system model without EE in it to see if problems occurred that would require a project like EE to solve. In performing this* *investigation, we addressed the impacts of PSE's assumptions regarding load growth and regional transfers on the system without EE to determine if there was a need for a project like EE. The Optional Technical Assessment (OTA) (Appendix B) looked at the sensitivity of modified assumptions regarding load growth, westside generation levels, and regional transfers on the need for a project like EE. Determining the preferred project to mitigate the problems found in the studies of the system without EE is one of the purposes of the EIS process, but this determination is beyond the scope of the ITA and the OTA.*

Q43. Why is an N-1-1 outage scenario (rare) used to determine need?

A. *Because N-1-1 contingencies must be simulated in the planning assessments required by the mandatory NERC TPL-001-4 Reliability Standard.*

Q44. Questions about reliability, outages, contingency analysis.

A. *As noted in responses to other questions, probability of an outage is not considered in determining need using the NERC TPL-001-4 Reliability Standard. When performing a planning assessment all outages need to be simulated and if there are any overloads or other violations, then a Corrective Action Plan must be developed. What is included in this Corrective Action Plan will vary depending on the type of outage and what sort of mitigation is allowed for that outage in the TPL-001-4 Reliability Standard. However, need is established as soon as a Corrective Action Plan needs to be developed.*

Q45. We ask the consultant to forecast how many outages in the next five years (2016 – 2020) would be avoided by implementation of Energize Eastside.

A. *Please see the responses above.*

Q46. Is it true that PSE's "Eastside Customer Demand Forecast" graph is based on a hypothetical "grid-flow modelling scenario" in which a rare winter peak electricity demand event occurs on the Eastside at exactly the same time that there are two major and simultaneous equipment outages on nearby transmission lines?

A. *The demand forecast is independent of any equipment outages. The current system capacity line is determined by studies of system performance under multiple contingency scenarios with models that incorporated forecasted peak load. These studies are required to be run in this manner by the Requirements in the NERC TPL-001-4 Reliability Standard.*

Q47. Are PSE's conclusions reasonable?

A. *See the conclusions section of the Independent Technical Analysis and the Executive Summary of the OTA (Appendix B).*

8. Assessment of PSE's Identified Drivers for the Eastside Project (PSE's Results)

This section addresses PSE's findings based on their new 2014 normal winter forecast, with 100% conservation.

Table 8.1 shows the new forecasted loads for Eastside that were utilized in the powerflow cases; three normal winter and three normal summer cases were studied by PSE. The winter forecasts between 2017/18 and 2023/24 show Eastside growing, while King County otherwise declines. The ITA confirmed that the load values in Table 1 matched the new forecast and were modeled[42] in the cases.

Table 8.1: PSE's King County and Eastside Forecasted Loads in Studied Years

Forecast Development Year	King County (excluding Eastside)	Eastside
Normal Winter		
2017/18	1881	688
2019/20	1867	708
2023/24	1817	764
Normal Summer		
2018	1379	538
2020	1385	561
2024	1399	618

The ITA also confirmed the Northern Intertie (Path 3) transfers matched PSE's modeling plan (Table 8.2), and that PSE's winter generation dispatch scenario of "no PSE and SCL generation west of the Cascades" was modeled in the winter cases, as per Table 4.4 in the October 2013 Eastside Needs Assessment Report.

Table 8.2: Northern Intertie Flows

Northern Intertie	Flow Direction
Normal Winter	
3150 MW	South to North
Normal Summer	
1500 MW	North to South

Source: PSE. Verified by ITA.

Tables 8.3 and 8.4 list the overloaded elements that PSE identified based on the new 2014 forecast. The ITA confirmed these overloaded elements drive the need for an Eastside project by simulating the contingencies (outages) in the powerflow cases provided by PSE.

[42] The aggregate Eastside load matched the numbers in Table 8.1.

Table 8.3: PSE Projected Normal Winter, 100% Conservation – Overloaded Elements

South to North Flow	Type of Contingency and Season								
	2017/18 Winter (23°F) 100% Conservation			2019/20 Winter (23°F) 100% Conservation			2023/24 Winter (23°F) 100% Conservation		
Transmission Line or Transformer	N-1	N-1-1	N-2	N-1	N-1-1	N-2	N-1	N-1-1	N-2
Talbot Hill - Lakeside #1 115 kV line		OL			OL			OL	
Talbot Hill - Lakeside #2 115 kV line		OL			OL			OL	
Talbot Hill 230-115 kV transformer #1		OL			OL			OL	
Talbot Hill 230-115 kV transformer #2		OL			OL			OL	
Talbot Hill-Boeing Renton-Shuffleton 115 kV line		OL			OL			OL	

OL= Overload of Emergency Rating. Source: PSE Results. ITA verified overloaded elements driving project need.

Table 8.4: PSE Projected Normal Summer, 100% Conservation - Overloaded Elements

North to South Flow	Type of Contingency and Season								
	2018 Summer (86°F) 100% Conservation			2020 Summer (86° F) 100% Conservation			2024 Summer (86° F) 100% Conservation		
Transmission Line or Transformer	N-1	N-1-1	N-2	N-1	N-1-1	N-2	N-1	N-1-1	N-2
Sammamish 230/115 kV Xfmr[43] #1		OL			OL			OL	
Sammamish 230/115 kV Xfmr #2		OL			OL			OL	
Novelty Hill 230/115 kV Xfmr #2		OL			OL			OL	
BPA Monroe – Novelty Hill 230 kV	OL		OL	OL		OL	OL		OL
Beverly Park - Cottage Brook 115 kV line		OL			OL			OL	
Sammamish – BPA Maple Valley 230 kV line				OL			OL		

OL= Overload of Emergency Rating. Source: PSE Results. ITA verified overloaded elements driving project need.

Figure 8.1 utilizes the 2014 load forecast and was supplied by PSE. Two system capacity lines for the Eastside area reflect where the powerflow results indicated violations of the mandatory performance requirements that put customer's reliability at risk. The powerflow results show a range of need for the Eastside area between 688 MW in winter 2017/18 and 708 MW in winter 2019/20. These levels were chosen by PSE because at 688 MW system elements are overloaded, and by 708 MW they are not only overloaded but 63,200 customers are at risk of losing power, which is a more severe situation. Further detail is noted below.

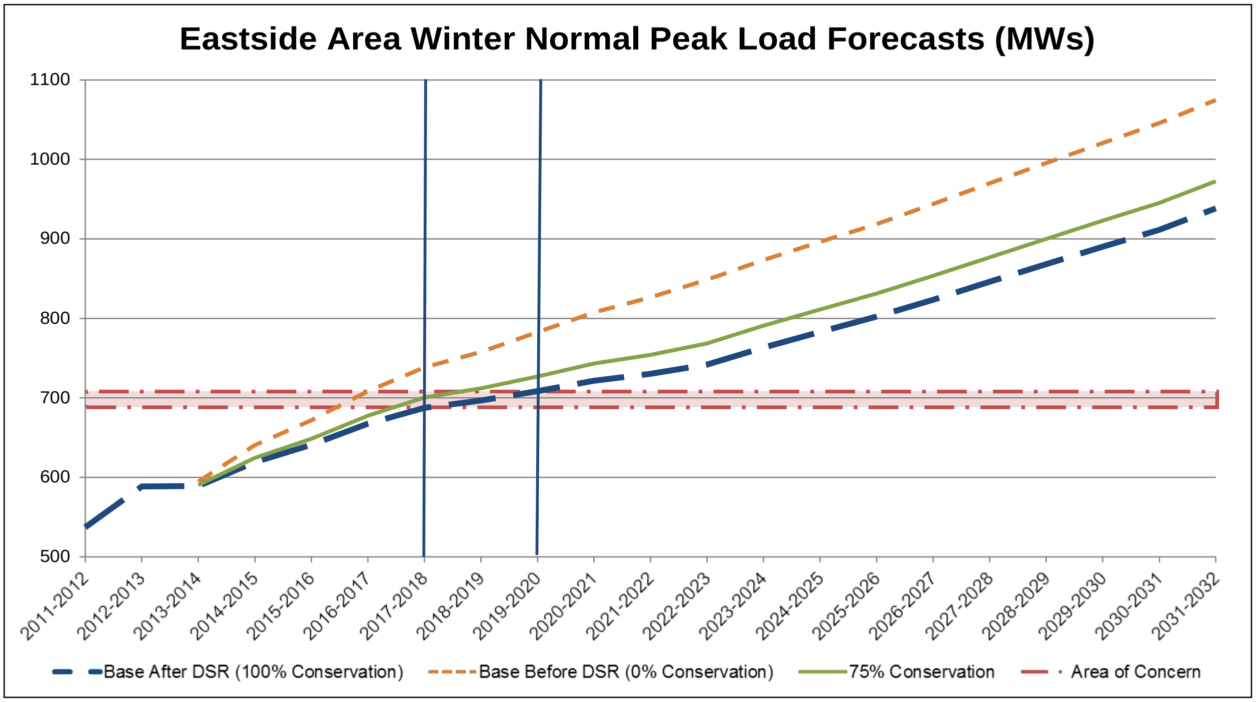
- In winter 2017/18 system elements would be overloaded requiring Corrective Action Plans (CAPs) for the Category C overloads. Zero customers are at risk of losing power by the CAPs[44].

[43] Xfmr = Transformer

[44] CAPs are implemented to protect system equipment from overload and resulting loss of equipment life or damage. CAPs can result in the forced reduction of load (intentionally causing customer outages) to bring

- By winter 2019/20, the CAPs radialize[45] existing loop service such that approximately 63,200 customers are at risk of losing power.
- By winter 2023/24, 16,800 customers are at risk from load shedding (intentional outage to customers to protect the system equipment), with another 52,000 customers at risk of losing power.

Figure 8.1: PSE's Graph of System Capacity, 2014 Forecast, 100% Conservation



In sum, PSE's need date for the Energize Eastside project remains as winter 2017/18. The following issues were identified by PSE and forecast levels and overloads were confirmed by the ITA:

- Transmission system elements will be over their capacity, and will require the use of CAPS to mitigate transmission overloads.
- Although the CAPS do not drop customer load in winter 2017/18, by winter 2019/20 approximately 63,200 customers are at risk of losing power. Intentionally dropping firm load for an N-1-1 or N-2 contingency to meet its federal planning requirements is not a practice that PSE endorses. This view is not unique amongst utilities. The CAISO Planning Standards states that "Increased reliance on load shedding … would run counter to historical and current practices, resulting in general deterioration of service levels."
- The forecast uses a 1 in 2 year weather forecast. Colder weather will result in higher load levels in winter 2017/18.
- 100% conservation may not be achieved which would result in a higher load level in winter 2017/18. Even if 100% conservation is achieved, it may not be in the appropriate locations and correct magnitudes.

the equipment loading below the emergency rating. This would only be used as a stopgap measure until system reinforcements (new equipment, etc.) are completed. CAPs as used here is a subset of CAPs defined in the NERC Reliability Standards. See Section 7 on Standards.

[45] Radialize: Convert from loop service to radial service (only one source).

- By the summer of 2018, studies show that customers will be at risk of outages and load shedding using CAPS to mitigate transmission overloads.

9. Regional Issues related to EE

Note: All ColumbiaGrid regional documentation of Energize Eastside refers to the project by its terminals: Sammamish-Lakeside-Talbot. The following text refers to Energize Eastside as the Project.

Background

ColumbiaGrid is a regional transmission planning organization with a footprint encompassing Oregon, Washington, parts of Idaho and Montana. A planning team was formed with all Puget Sound area transmission owners and operators as planning participants within a year after the creation of ColumbiaGrid in 2007 to address the beginning curtailments of firm service in the Puget Sound area. Since 1997 and prior to the formation of this team, BPA had been planning to address these needs with a major 500kV line project from Monroe to Echo Lake, but construction had not started. The study team was able to identify a collection of projects to achieve the planning objectives with a cumulative scope less than the 500kV project.

The ColumbiaGrid Puget Sound Area transmission planning activity created 150 document postings on the team website that provide a detailed history of the work that led up to the regional plan. Of the 150 postings, three postings provide the information sufficient to describe the Project's role in regional objectives. The three postings are final reports and are all publicly available. These documents are:

- Transmission Expansion Plan for the Puget Sound Area (October 20,2010)
- Updated Recommended Transmission Expansion Plan for the Puget Sound Area to Support Winter South-to-North Transfers (October 28, 2011)
- Updated Transmission Expansion Plan for the Puget Sound Area to Support Summer North-to-South Transfers (February 21, 2013)

Project Specific Information

The following Project specific regional information was obtained from the above documentation.

1. Either the Project or reconductoring BPA's and SCL's Maple Valley-SnoKing 230kV lines is needed, but not both.
2. The Project or rebuilding SCL's Bothell-SnoKing 230kV lines is needed, but not both. The Bothell-SnoKing lines still need to be reconductored with the Project, but rebuilding is avoided.
3. If the Project voltage level is 115kV, the Project does not achieve the regional objectives. With that scenario, the regional objectives will be achieved by reconductoring the Maple Valley-SnoKing 230kV lines and the Bothell-SnoKing 230kV lines will need to be rebuilt.
4. The Project at 230kV is identified as the preferred alternative because of its dual purpose for regional objectives and local load service. If the Maple Valley-SnoKing 230kV lines had been reconductored prior to development of the Project, there would have been unnecessary redundancy developed in the transmission infrastructure, assuming that the Project voltage level needed to be 230kV.

ColumbiaGrid determined that the Energize Eastside project at 230 kV is the preferred alternative of all the options studied because of its dual purpose for regional objectives and local load service.

Stakeholder Questions related to Regional vs. Local Need

Q49. What is the connection between the need for EE and Columbia Grid (CG) technical objectives?

- A *The CG technical objective is to identify effects of multiple systems that prevent fulfillment of firm transmission commitments. Mitigating transmission effects that do not involve multiple systems is not within the CG mandate. After the effects are identified, the multiple system owners are convened as a team facilitated by CG to identify mitigating alternatives and select the preferred alternative. The proposed 230kV scope of EE is identified by the CG facilitated team as a preferred alternative to reconductoring SCL's Maple Valley-SnoKing 230kV lines. EE at 230kV also changes the SCL scope of rebuilding the Bothell-SnoKing 230kV lines to reconductoring these lines.*

Q50. How are the technical needs of Columbia Grid prioritized and what criteria are used for evaluation and prioritization?

- A *CG performs system assessments to determine forecasted transmission constraints to serving firm transmission commitments. A constraint that affects more than one member is the criteria for creating a study team, facilitated by CG, composed of the affected members. The study team mandate is to determine the mitigating alternatives and select the preferred alternative. Each study team determines their own evaluation and prioritization criteria. In the Puget Sound Area Study Team (PSAST), the criteria is a qualitative combination of cost and a planning metric (i.e. Transmission Curtailment Risk Measure or TCRM).*

Q51. Who has regulatory oversight of Columbia Grid?

- A *There is no government regulatory oversight of CG. The oversight is by CG members, who have their own government regulatory oversight at state and federal levels. CG has no construction authority. The only CG authority is determining cost allocation, but this authority is only used if members do not agree on the cost allocation for a project they agree to implement.*

Q52. Is EE an "OPEN ACCESS" project?

- A *No. An "Open Access" project provides new requested transmission service. This project provides service for existing firm obligations. (The longer answer is as follows: This answer assumes that "Open Access" refers to a transmission service request under a transmission provider's Open Access Transmission Tariff (OATT). These transmission service requests are for new transmission service that involve study requirements, facility addition determinations, and FERC pricing policies. Since EE is for load growth that falls under existing transmission service, it isn't "open access" because it is not new transmission service. .*

Q53. How are the merits of each need evaluated independently and which need takes priority?

- A *The CG PSAST team evaluated the regional, multi-system needs for bulk power transfers independent of local load service needs. The local load service need is evaluated by the single systems. If a single system project (e.g. EE at 230kV) affects multi-system power transfer needs, then it is included in the multi-system evaluation. Firm commitments, regardless of bulk power transfers or local load service, are equal priority to be addressed and issues mitigated.*

Q54. Please describe how the need for EE and Power Wheeling are connected. What are PSE's power wheeling objectives for EE, and how much of the EE need is based on the ability to participate in additional power wheeling?

- A *Wheeling is the transportation of electric power over transmission lines by an entity that does not own or directly use the power it is transmitting.*
- A *(from PSE's Energize Eastside website, based on 2012 forecast) "PSE makes no profit on wheeling power. All revenue obtained from wheeling contracts is passed directly back to our customers in the form of lower rates. PSE does have contracts to wheel power across the region; those contracts bring in revenue of roughly $28 million a year. One hundred percent of this revenue is returned to our customers in the form of a rate reduction. As we stated in our presentation, 92-97% of the power flows on the Energize Eastside line will deliver electricity to local Eastside customers. The power flow studies show that the power used for regional purposes on the Energize Eastside project is 3 to 8% - not 38% (as was incorrectly stated at the meeting). This is the natural consequence of connecting a transmission line into an interconnected system."* June, 2014 http://energizeeastside.com/Media/Default/CAG/Meeting3/2014_0609_CAGLetter_SCL.pdf

Q55. Is any of the capacity of the planned EE 230 kV line, or the existing 115 kV lines between Sammamish and Talbot Hill, allocated for transmission contracts to BC Hydro or CA? If so, what %? What are PSE's power wheeling objectives for Energize Eastside? Does existing or planned/potential wheeling affect the Project capacity?

- A. *No/None. PSE makes no profit from wheeling contracts. See Q56.*
- A. *Per PSE, Project capacity is not affected by existing or planned/potential wheeling.*

10. Conclusion

The independent technical analysis (ITA) determined that PSE used reasonable methods to develop the 2014 forecast by following industry practice (See section 6.6.). The ITA reviewed PSE's powerflow cases and verified PSE's modeling of the updated load forecast, the Northern Intertie transfers, and the identified winter generation dispatch.

The ITA verified the following key result:
Although the new 2014 forecast resulted in an 11 MW decrease in the Eastside area's 2017/18 winter forecast, the reduced loading still resulted in overloaded transmission elements that drive the project need to address Eastside system reliability issues.

Although the CAP required in the 2017/18 winter to avoid facility overload doesn't drop load, by winter 2019/20 approximately 63,200 customers are at risk of losing power. In addition, by summer 2018, studies show that customers will be at risk of outages and load shedding due to CAPs used to mitigate transmission overloads. One might argue to delay the Energize Eastside project six months until summer 2018 when PSE studies show that customers will be at risk of outages and load shedding. However, balancing a six month delay in a complex and multi-year EIS process, which can have its own delays, against the risk of an adverse winter or less realized conservation (which could increase 2017/18 winter loading to a point where customers are at risk of load shedding) suggests it is reasonable to maintain the schedule for the existing project in-service date.

Appendix A – Glossary

AC	Alternating Current
aMW	aMW - The average number of megawatt-hours (MWh) over a specified time period; for example, 295,650 MWh generated over the course of one year equals 810 aMW (295,650/8,760 hours). (Source: PSE's 2013 IRP Definitions)
Balancing Authority (BA)	Balancing Authority (BA) -- an entity that manages generation, transmission, and load; it maintains load-interchange-generation balance within a geographic or electrically interconnected Balancing Authority area, and it supports frequency in real time. The responsibility of the PSE Balancing Authority is to maintain frequency on its system and support frequency on the greater interconnection. To accomplish this, the PSE BA must balance load with generation on the system at all times. When load is greater than generation, a negative frequency error occurs. When generation is greater than load, a positive frequency error occurs. Small positive or negative frequency deviations are acceptable and occur commonly during the course of normal operations, but moderate to high deviations require corrective action by the BA. Large frequency deviations can severely damage electrical generating equipment and ultimately result in large-scale cascading power outages. Therefore, the primary responsibility of the BA is to do everything it can to maintain frequency so that load will be served reliably. (Source: PSE 2013 IRP)
BES	BES - Bulk Electric System - Unless modified by the inclusion and exclusion lists in the full definition that is available in the NERC Glossary of Terms (http://www.nerc.com/files/glossary_of_terms.pdf), all Transmission Elements operated at 100 kV or higher and resources connected at 100 kV or higher. The BES does not include facilities used in the local distribution of electric energy. (Source: NERC Glossary of Terms)
BPS	BPS - Bulk Power System - A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. (Source: NERC Glossary of Terms)
CAP	CAP - Corrective Action Plan - A list of actions and an associated timetable for implementation to remedy a specific problem. (Source: NERC Glossary of Terms)
COI	COI - California–Oregon Intertie - The three 500 kV AC electric transmission lines between southern Oregon and northern California.
CPI	Consumer Price Index (CPI) – A measure that examines the weighted average of prices of a basket of consumer goods and services, such as transportation, food and medical care. The CPI is calculated by taking price changes for each item in the predetermined basket of goods and averaging them; the goods are weighted according to their importance. (Source: Investopedia)
Critical Energy Infrastructure Information (CEII)	Critical Energy Infrastructure Information (CEII) Regulations –- Established by the Federal Energy Regulatory Commission (FERC). "CEII is specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure (physical or virtual) that: Relates details about the production, generation, transmission, or distribution of energy; Could be useful to a person planning an attack on critical infrastructure; Is

	exempt from mandatory disclosure under the Freedom of Information Act; and Gives strategic information beyond the location of the critical infrastructure." (Source: FERC)
DC	Direct Current
Demand (Utility)	Demand (Utility) – The level at which electricity or natural gas is delivered to users at a given point in time. Electric demand is expressed in kilowatts. (Source: CEC Glossary)
Demand-Side Resources (DSR)	Demand-Side Resources (DSR) - Resources that reduce the demand. (As opposed to Supply-Side Resources)
Demographic	Demographics - Studies of a population based on factors such as age, race, sex, economic status, level of education, income level and employment, among others. Demographics are used by governments, corporations and non-government organizations to learn more about a population's characteristics for many purposes, including policy development and economic market research. (Source: Investopedia.com)
Direct Control Load Management (DCLM)	Direct Control Load Management (DCLM) - Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand. (Source: NERC Glossary)
Distribution System	Distribution System - An electric power distribution system is the final stage in the delivery of electric power; it carries electricity from the transmission system to individual consumers. (Source: Wikipedia)
Econometric Data	Econometric Data – Data sets to which econometric analyses are applied.
Econometrics	Econometrics – The application of mathematics and statistical methods to economics. Econometrics tests hypotheses and forecasts future trends by applying statistical and mathematical theories to economics. It's concerned with setting up mathematical models and testing the validity of economic relationships to measure the strengths of various influences.
EPAct 2005	EPAct 2005 – The federal Energy Policy Act of 2005
ERO	ERO - Electric Reliability Organization
Firm Transmission Service	Firm Transmission Service – 1) Transmission service available at all times during a period covered by an agreement. 2) The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption. (Source: NERC)
GO	GO - Generator Owner
Interruptible Load or Interruptible Demand	Interruptible Load or Interruptible Demand - Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment. (Source: NERC Glossary)
IRP	Integrated Resource Plan - A comprehensive and long-range road map for meeting the utility's objective of providing reliable and least-cost electric service to its customers while addressing applicable environmental, conservation and renewable energy requirements. A process used by utility companies to determine the mix of Supply-Side Resources and Demand-Side Resources that will meet electricity demand at the lowest cost. The IRP is often developed with input from various stakeholder groups. Also Integrated Resource Planning.

Levelized Cost	Levelized Cost - An economic assessment of the cost to build and operate a power-generating asset over its lifetime divided by the total power output of the asset over that lifetime. It is also used to compare different methods of electricity generation in cost terms on a comparable basis.
MW	MW - Megawatt - A unit of power equal to one million watts or one thousand kilowatts.
N-1	N-1 - Loss of a single element such as a generator, a transmission line, or a transformer (P2)
N-2	N-2 - Simultaneous loss of two elements due to a single event. For example, loss of two transmission lines on a common tower due to failure of the tower (P6)
N-1-1	N-1-1 - Loss of a single element such as a generator, a transmission line, or a transformer followed by a system readjustment such as generation redispatch, then loss of a second element such as a generator, a transmission line, or a transformer (P7)
Native load	Native load – 1. The cumulative load (power requirement) of a utility's retail customer base. 2. The end-use customers that the Load-Serving Entity is obligated to serve. (NERC Glossary) http://www.energy.ca.gov/glossary/glossary-d.html
NAICS	NAICS - The North American Industry Classification System (NAICS) is the standard used by Federal statistical agencies in classifying business establishments for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. business economy (Source: Census.gov)
NERC	NERC - North American Electric Reliability Corporation
Northern Intertie	Northern Intertie - transmission interconnection between Washington and British Columbia (Also called Path 3.)
Off-system sales	Off-system sales – Sales by a utility to a customer outside of its current traditional market.
PC	PC - Planning Coordinator
PDCI	PDCI - Pacific Direct Current Intertie
PJM	PJM – PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.
Personal Consumption Expenditure Deflator (PCE Deflator)	Personal Consumption Expenditure Deflator (PCE Deflator) - Measures the average change over time in the price paid for all consumer purchases, thus measures changes in the cost of living. (Source: Investopedia)
Powerflow	Powerflow - a numerical analysis of the flow of electric power in an interconnected system. It can refer to the analysis program, or to a simulation
RE	RE - Regional Entity.
Regression Analysis	Regression analysis is a statistical process for estimating the relationships among variables. It seeks to determine the strength of the relationship between one dependent variable (usually denoted by Y) and a series of other changing variables (known as independent variables). It is also known also as curve fitting or line fitting because a regression analysis equation can be used in fitting a curve or line to data points. It includes many techniques for modeling and analyzing variables.

Renewable energy credits (RECs)	Renewable energy credits (RECs) - A REC represents the property rights to the non-power qualities of renewable electricity generation, such as environmental and social qualities. A REC, and its associated attributes and benefits, can be sold separately from the underlying physical electricity associated with a renewable-based generation source. At the point of generation, both product components can be sold together or separately, as a bundled or unbundled product. (Source: US EPA)
Renewable Portfolio Standard (RPS)	Renewable Portfolio Standard (RPS) – A regulatory mandate to increase production of energy from renewable sources such as wind, solar, biomass and other alternatives to fossil and nuclear electric generation. It's also known as a renewable electricity standard. (Source: National Renewable Energy Laboratory - NREL)
Substation	Substation – Substations transform voltage from high to low or from low to high. They also perform other functions, such as limiting outages, protecting equipment, et cetera.
Supply-Side Resources	Supply-Side Resources – Conventional generation plants, renewable generation, etc. (as opposed to Demand-Side Resources).
TO	TO - Transmission Owner
TP	TP - Transmission Planner
Weather Normalizing	Weather normalization is a process that adjusts actual energy or peak outcomes to what would have happened under normal weather conditions. Normal weather conditions are expected on a 50 percent probability basis, also known as a 50/50 forecast (i.e., there is a 50 percent probability that the actual peak realized will be either under or over the projected peak).
WECC	WECC - Western Electricity Coordinating Council. WECC has been approved by the Federal Energy Regulatory Commission (FERC) as the Regional Entity for the Western Interconnection. The North American Electric Reliability Corporation (NERC) delegated some of its authority to create, monitor, and enforce reliability standards to WECC through a Delegation Agreement.
Western Interconnection	Western Interconnection - North America is comprised of two major and three minor alternating current (AC) power grids, also called "interconnections." The Western Interconnection stretches from the Pacific Ocean eastward over the Rockies to the Great Plains, and from Baja California, Mexico in the South into Western Canada. (Source: Energy.gov)
Wheeling	Wheeling -- The transmission of electricity by an entity that does not own or directly use the power it is transmitting. Wholesale wheeling is used to indicate bulk transactions in the wholesale market, whereas retail wheeling allows power producers direct access to retail customers. This term is often used colloquially as meaning transmission.
WSCC	WSCC - Western Systems Coordinating Council. The predecessor to WECC.

Appendix B – Optional Technical Analysis

Executive Summary

Utility System Efficiencies, Inc. (USE) was engaged by the City of Bellevue in February 2014 to conduct an Optional Technical Analysis (OTA) of the purpose, need, and timing of the Energize Eastside project. Energize Eastside (EE) is Puget Sound Energy's (PSE's) proposed project to build a new electric substation and new higher–capacity (230 kilovolt) electric transmission lines in the East King County area, which encompasses Bellevue, Clyde Hill, Medina, Mercer Island, Newcastle, the towns of Yarrow Point, Hunts Point, and Beaux Arts, and portions of Kirkland, Redmond, and Renton (the Eastside). The transmission lines would extend from an existing substation in Redmond to one in Renton (See Figure 3.1).

The scope of the OTA was to perform an analysis on PSE's study cases to determine the impact of potential forecast variability on the timing of improvements, and was later expanded to evaluate whether regional requirements rather than local requirements might be driving the project need. The OTA examined several hypothetical scenarios by conducting analysis on PSE's study cases. It looked at the effect of a) reducing load growth in the *Eastside* area to 1.5%, b) reducing load growth in *PSE's portion of King County* to 0.25% while keeping the Eastside growth the same, c) increasing power output of existing Puget Sound area generation, and d) reducing the Northern Intertie[46] flow to zero (no transfers to Canada). Although d) is not actually possible due to extant treaties, it was modeled to examine if regional requirements might be driving the need. In the winter cases, the OTA also combined scenarios c) and d). Finally, the OTA looked at the impact of an Extreme Winter forecast.

IF THE LOAD GROWTH RATE WAS REDUCED, WOULD THE PROJECT STILL BE NEEDED? YES

The OTA results showed that reducing the Eastside average load growth from an average of 2.4%/year to an average of 1.5%/year from winter 2013/14 to winter 2017/18 did not eliminate any overloaded elements; there is still project need. Similarly, reducing PSE's *King County growth rate* (less Eastside) from an average of 0.5 %/year to an average of 0.25%/year from winter 2013/14 to winter 2017/18 did not eliminate any overloaded elements; there is still project need.

IF GENERATION WAS INCREASED IN THE PUGET SOUND AREA, WOULD THE PROJECT STILL BE NEEDED? YES

Results showed that increasing the power output of existing Puget Sound area generation to the levels specified in ColumbiaGrid's July 2010 "Puget Sound Area Generation Modeling Guideline" eliminated one of five overloads in the 2017/18 normal winter, but did not eliminate project need. (This study increased the amount of PSE and SCL generation west of the Cascades from zero to the level identified in the above document. Since the document is confidential (CEII) the generation output is not provided in this report.)

[46] Northern Intertie - transmission interconnection between Washington and British Columbia (Also called Path 3.)

IS THERE A NEED FOR THE PROJECT TO ADDRESS REGIONAL FLOWS, WITH IMPORTS/EXPORTS TO CANADA (COLUMBIAGRID[47])? Modeling zero flow to Canada, the project is still necessary to address local need.

The Optional Technical Analysis examined this issue by analyzing a reduction in the Northern Intertie flow to zero (no transfers to Canada). Although this scenario is not actually possible due to extant treaties, it was modeled to provide data on the drivers for the EE project, to examine if regional requirements might be driving the need. The results showed that in winter 2017/18, even with the Northern Intertie adjusted to zero flow, the Talbot Hill 230/115 kV transformer #2 is still overloaded by several contingencies. This indicates there is a project need at the local level.

The OTA results showed that all studied scenarios resulted in at least one equipment overload in normal winter 2017/18 with 100% conservation, indicating project need.

Analysis and Findings

The OTA studied five normal winter scenarios and three extreme winter scenarios for winter 2017/18 and winter 2019/20. The OTA also studied five normal summer scenarios for 2018 and 2020. The scenarios were modeled in the powerflow cases. Details on the modeling are not provided due to Critical Energy Infrastructure Information (CEII) restrictions.

Table B.1 lists the overloaded elements for winter 2017/18 for each studied scenario. The scenarios are listed in the second blue row in Table B.1 (the vertically oriented text). The normal winter scenarios are numbered 1-6 (with #1 representing the original PSE case). The extreme weather scenarios are numbered E1-E3.

Normal winter results showed:

- Reducing the Eastside average load growth to 1.5% did not eliminate any overloaded elements; there is still project need.
- Reducing PSE's King County growth rate (less Eastside) to 0.25% did not eliminate any overloaded elements; there is still project need.
- Increasing the power output of existing Puget Sound area generation to the levels specified in ColumbiaGrid's July 2010 "Puget Sound Area Generation Modeling Guideline"[48] eliminated one of five overloads, but did not eliminate project need.
- Reducing the Northern Intertie flow to zero (no transfers to Canada) eliminated all but one overload; there is still local project need.
- Reducing the Northern Intertie flow to zero (no transfers to Canada) AND Increasing the Puget Sound area generation to ColumbiaGrid's July 2010 "Puget Sound Area Generation Modeling Guideline" eliminated all but one overload; there is still project need.

Extreme winter results increased the overload levels and/or caused overloads on additional elements. Although the normal winter results showed only one overload when the Northern Intertie flow was reduced to zero, the extreme winter case showed four overloads.

[47] ColumbiaGrid (single word) is a regional transmission planning organization with a footprint encompassing Oregon, Washington, parts of Idaho and Montana.
[48] Confidential (CEII) document that provides modeling values (MW levels of generation) for applicable generators.

Table B.1: Winter 2017/18, 100% Conservation - Overloaded Elements

Northern Intertie: South to North	2017/18 Normal Winter 100% Conservation						2017/18 Extreme Winter, 100% Cons.		
Overloaded Element (Transmission Line or Transformer)	1) Original PSE Case	2) Reduce Eastside load growth to 1.5%	3) Reduce PSE's King County growth to 0.25%[49]	4) Increase Puget Sound area generation	5) Set Load transfers to Canada = 0 (North. Intertie = 0)	6) Combination of Scenario 4 and & 5	E1) Original PSE Case adjusted for extreme weather	E2) Set Load transfers to Canada = 0 (North. Intertie = 0)	E3) Scenario E2 + Increase Puget Sound area generation
Talbot Hill - Lakeside #1 115 kV line	OL	OL	OL	OL			OL		
Talbot Hill - Lakeside #2 115 kV line	OL	OL	OL	OL			OL		
Talbot Hill 230-115 kV transformer #1	OL	OL	OL	OL			OL	OL	OL
Talbot Hill 230-115 kV transformer #2	OL	OL	OL	OL	OL	OL	OL	OL	OL
Talbot Hill-Boeing Renton-Shuffleton 115 kV line	OL	OL	OL				OL		
Sammamish 230/115 kV transformer #1								OL	OL
Sammamish 230/115 kV transformer #2								OL	OL

OL = Overload of Emergency Rating. Source: OTA Results

Table B.2 lists the overloaded elements for winter 2019/20 for each studied scenario. The scenarios are listed in the second blue row (the vertically oriented text).

The 2019/20 winter results showed the same overloaded elements as 2017/18. The overloads in the base cases and in the load reduction cases were more severe in 2019/20. The overload levels in the generation dispatch and Northern Intertie=0 scenarios were mixed; some overloads were more severe in 2019/20, but some were slightly less. Nevertheless, project need was shown in all cases. Extreme winter results increased the overload levels over normal winter and/or caused overloads on additional elements.

Table B.2: Winter 2019/20, 100% Conservation - Overloaded Elements

Northern Intertie: South to North	2019/20 Normal Winter 100% Conservation						2019/20 Extreme Winter, 100% Cons.		
Overloaded Element (Transmission Line or Transformer)	1) Original PSE Case	2) Reduce Eastside load growth to 1.5%	3) Reduce PSE's King County growth to 0.25%[50]	4) Increase Puget Sound area generation	5) Set Load transfers to Canada = 0 (North. Intertie = 0)	6) Combination of Scenario 4 and & 5	E1) Original PSE Case adjusted for extreme weather	E2) Set Load transfers to Canada = 0 (North. Intertie = 0)	E3) Scenario E2 + Increase Puget Sound area generation
Talbot Hill - Lakeside #1 115 kV line	OL	OL	OL	OL			OL		
Talbot Hill - Lakeside #2 115 kV line	OL	OL	OL	OL			OL		
Talbot Hill 230-115 kV transformer #1	OL	OL	OL				OL	OL	OL
Talbot Hill 230-115 kV transformer #2	OL	OL	OL	OL	OL	OL	OL	OL	OL
Talbot Hill-Boeing Renton-Shuffleton 115 kV line	OL	OL	OL				OL		
Sammamish 230/115 kV transformer #1									OL
Sammamish 230/115 kV transformer #2								OL	OL

OL = Overload of Emergency Rating. Source: OTA Results

[49] Excluding Eastside load
[50] Excluding Eastside load

Table B.3 lists the overloaded elements for summer 2018 for each studied scenario. The scenarios are listed in the second green row. The normal summer scenarios are numbered 1-5 (with #1 representing the original PSE case). There is no extreme weather summer forecast.

The 2018 normal summer results showed:

- Reducing the Eastside average load growth did not eliminate any overloaded elements; there is still project need.
- Reducing PSE's King County growth rate (less Eastside) did not eliminate any overloaded elements; there is still project need.
- Increasing the Puget Sound area generation to ColumbiaGrid's July 2010 "Puget Sound Area Generation Modeling Guideline" eliminated one of six overloads, but did not eliminate project need.
- Reducing the Northern Intertie flow to zero (no transfers to Canada) eliminated all the summer overloads; however, there is still a winter overload which means there is still local project need.

Table B.3: Summer 2018, 100% Conservation - Overloaded Elements

Northern Intertie: North to South	2018 Summer (86°F) 100% Conservation				
Overloaded Element (Transmission Line or Transformer)	1) Original PSE Case	2) Reduce Eastside load growth	3) Reduce PSE's King County growth	4) Increase Puget Sound area generation	5) Set Load transfers to Canada = 0 (Northern Intertie = 0)
Sammamish 230/115 kV Xfmr #1	OL	OL	OL	OL	
Sammamish 230/115 kV Xfmr #2	OL	OL	OL	OL	
Novelty Hill 230/115 kV Xfmr #2	OL	OL	OL		
BPA Monroe – Novelty Hill 230 kV	OL	OL	OL	OL	
Beverly Park - Cottage Brook 115 kV line	OL	OL	OL	OL	
Sammamish – BPA Maple Valley 230 kV line	OL	OL	OL	OL	

OL = Overload of Emergency Rating. Source: OTA Results

The 2020 summer results (Table B.4) showed the same overloaded elements as 2018. The overloads were more severe in 2020, with the exception of the Beverly Park – Cottage Brook 115 kV line which was either unchanged or reduced by less than 0.1%.

Table B.4: Summer 2020, 100% Conservation - Overloaded Elements

Northern Intertie: North to South Overloaded Element (Transmission Line or Transformer)	2020 Summer (86°F) 100% Conservation				
	1) Original PSE Case	2) Reduce Eastside load growth	3) Reduce PSE's King County growth	4) Increase Puget Sound area generation	5) Set Load transfers to Canada = 0 (Northern Intertie = 0)
Sammamish 230/115 kV Xfmr #1	OL	OL	OL	OL	
Sammamish 230/115 kV Xfmr #2	OL	OL	OL	OL	
Novelty Hill 230/115 kV Xfmr #2	OL	OL	OL		
BPA Monroe – Novelty Hill 230 kV	OL	OL	OL	OL	
Beverly Park - Cottage Brook 115 kV line	OL	OL	OL	OL	
Sammamish – BPA Maple Valley 230 kV line	OL	OL	OL	OL	

OL = Overload of Emergency Rating. Source: OTA Results

<u>Stakeholder Questions related to the OTA</u>

Q56. The study must as clearly, but non-technically as possible, define will happens regarding power flow to and from Canada.

- A *See the OTA in Appendix B. Sensitivities were performed where power flow to and from Canada were reduced to zero. These cases still showed overloads so there is clearly a local need. Some overloads were eliminated when flows were reduced to zero, which indicates that flows to and from Canada also have an impact on the need.*

Q57. Clarify Eastside vs. regional needs. What load is causing the problem? Local or regional?

- A *Local. The Optional Technical Analysis results showed that in winter 2017/18, even with the Northern Intertie adjusted to zero flow, the Talbot Hill 230/115 kV transformer #2 is still overloaded by several contingencies. This indicates there is a project need at the local level. See the full Appendix B for further detail.*

Q58. I am concerned that the need is not just for Bellevue and the Eastside but more for Bonneville Power, Snohomish Power, Seattle City Light -- the Columbia Grid. I would ask the consultants to provide a simple quantitative and pie chart breakout of the need that each stakeholder has in "Energize Eastside".

- A *See Q56.*

Q59. Provide a quantitative analysis and pie charts (both historical and futuristic) showing a breakout of the need (demand and reliability) for each of the members of the Columbia Grid.

- A *The Optional Technical Analysis results showed that in winter 2017/18, even with the Northern Intertie adjusted to zero flow, the Talbot Hill 230/115 kV transformer #2 is still overloaded by several contingencies. These results indicate there is a project need at the local level.*

Q60. Given the scenario and contingency driving the EE project, how much regional load will flow through the line?

- A *See Q61 below.*

Q61. What percentage of North-South flow-through load (to Canada/California) will be carried on EE during an N-1-1 event (failure of BPA bulk main PLUS a second transmission line failure?

A *The OTA studied a scenario with flows to Canada at 1500 MW and a scenario with flows to Canada set to 0 MW. Under the worst contingency condition (N-1-1), the reduction in flow on the Talbot Hill - Lakeside lines was 22.5%. Under the worst contingency condition (again N-1-1), the reduction in flow on the Talbot Hill 230/115 kV transformer was 2.6%. These results are before EE and reflect the effects on the current transmission system serving the EE area. As you can see from these results, the impact of flows to Canada on the Talbot Hill 230/115 kV transformer (the main driver of the need for EE) is almost insignificant.*

Q62. Was the system studied with generation on the west side?

A *Yes, the OTA studied a scenario with generation on the west side.*

Q63. Is EE a "BLENDED PROJECT" to satisfy the needs of Columbia Grid, BPA grid reinforcement (Monroe-Echo Lake bottleneck), Columbia River treaty "Canadian Entitlement" curtailments, Seattle City Light load needs, as well as PSE load growth?

A *The term "Blended Project" is not clear. However, the OTA results do show that there is a need for a project to satisfy local needs. A review of ColumbiaGrid documentation indicates that EE will also help satisfy a regional need which is why EE was included in the recommended transmission solution from ColumbiaGrid Puget Sound Area transmission planning activity.*

Appendix C – End-Use Data and IRP

End-use data is evaluated in Integrated Resource Planning, where a utility examines both Supply-Side and Demand-Side options with the objective of providing reliable and least-cost electric service to its customers while addressing applicable environmental, conservation and renewable energy requirements. Because energy efficiency is generally a low-cost resource, the IRP tends to incorporate energy efficiency as a utility system resource and reduce the need for additional Supply-Side resources.

PSE commissioned The Cadmus Group, Inc. (Cadmus) to conduct an independent study of Demand-Side Resources (DSR) in the PSE service territory as part of its biennial integrated resource planning (IRP) process. The study considered energy efficiency, fuel conversion, Demand Response, and distributed generation. PSE also considered distribution efficiency.

Energy efficiency looked at naturally occurring conservation, which occurs due to normal market forces such as technological change, energy prices, improved energy codes and standards, and efforts to change or transform the market. This includes gradual efficiency increases due to replacing or retiring old equipment in existing buildings and replacing it with units that meet minimum standards at that time. It also includes new construction which reflects current state specific building codes, and improvements to equipment efficiency standards that are pending and will take effect during the planning horizon.

Fuel Conversion considered opportunities to substitute natural gas for electricity through replacements of space heating systems, water heating equipment, and appliances.

Demand Response options seek to reduce peak demand during system emergencies or conditions of extreme market prices. It may also be used to improve system reliability and could potentially help to balance variable-load resources such as wind energy.

Washington State's Renewable Portfolio Standard (RPS) law requires conservation potential be developed using Northwest Power & Conservation Council (NWPCC) methodology, and conservation targets are based on IRP with penalties for not achieving them. It requires PSE to meet specific percentages of its load with renewable resources or renewable energy credits (RECs) by specific dates.

The Energy Independence and Security Act (EISA, 2007) provides for minimum federal standards for lighting and other appliances beginning in 2012. It also sets standards for increasing the production of clean renewable fuels, increasing the efficiency of buildings and vehicles, and more.

Cadmus compiled technical, economic, and market data from the following sources:

- PSE Internal Data: Historical and projected sales and customers, historic and projected DSR accomplishments, and hourly load profiles
- 2010 Residential Characteristic Survey (PSE Service Territory)
- 2008 Fuel Conversion Survey (PSE Service Territory)

- 2007 Puget Sound-Area Regional Compact Fluorescent Light (CFL) Saturation Study
- NEEA's 2009 Commercial Building Stock Assessment (CBSA)
- Building Simulations for the residential sector, employing separate models for customer segments and construction vintage
- Pacific Northwest Sources. Technical information included on hourly end-use load shapes (to supplement building simulations), commercial building and energy characteristics. Information on measure savings, costs, and lives
    - The Northwest Power and Conservation Council (Council)
    - The Regional Technical Forum (RTF)
    - The Northwest Energy Efficiency Alliance (NEEA)
- Sources to characterize measures, assess baseline conditions, and benchmark results against other utilities' experiences
    - The California Energy Commission's Database of Energy Efficiency Resources (DEER)
    - ENERGY STAR
    - The Energy Information Administration
    - Annual and evaluation reports on energy-efficiency and Demand Response programs from various utilities

Only new opportunities for conservation are captured in the DSR value and thousands of measures were evaluated. Conservation programs included Energy Efficiency, Fuel Conversion, Distributed Generation, Demand Response and Distribution Efficiency (voltage reduction and phase balancing[51]). Lighting savings in the 2013 IRP assume the availability of a technology meeting the minimum requirements of EISA, and that savings from Compact Fluorescent Lamp (CFL) installations will remain available[52]. (Cadmus estimated that 33% of sockets have CFLs before the 2013 IRP measures are selected.) EISA accounts for 31% of residential DSR and 26% of commercial DSR. DSR targets are reviewed by the Conservation Resource Advisory Group and the Integrated Resource Plan Advisory Group.

The 2013 IRP identified market achievable, technically feasible Demand-Side measures. These measures (over four thousand) were combined into bundles[53] based on levelized cost[54] for inclusion in the generation optimization analysis. The effect of the bundles is to reduce load, so the costs to achieve the savings must be added to the cost of the electric portfolios.

The optimization analysis identifies the economic potential (cost-effective level) of DSR bundles that would work well in planning for generation requirements. (For example, solar energy has a different impact on the summer peak than on a winter peak.) The optimization model developed and tested different portfolios, combining Supply-Side Resources with Demand-Side bundles, to find the lowest cost combination of resources that a) met capacity need b) met renewable resources/RECs need, and c) included as much conservation as was cost effective. (Once the capacity and renewable resources/RECs needs are met, the decision to include additional

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[51] Phase balancing: Balancing the single-phase load among the three phases so that unbalanced load isn't driving the peak load value.
[52] LED lighting: The LED programs were not specifically identified in the 2013 IRP. The LED technology and availability is different today than it was when the 2013 IRP study began. PSE is planning on including LED lighting in the 2015 IRP.
[53] An example bundle is the set of measures that cost between $28/MWh and $55/MWh.
[54] Levelized Cost - An economic assessment of the cost to build and operate a power-generating asset over its lifetime divided by the total power output of the asset over that lifetime. It is also used to compare different methods of electricity generation in cost terms on a comparable basis.

conservation bundles is simply whether that next bundle of measures increases the cost or decreases it.)

The optimization analysis results in the final set of cost effective measures, which are identified as the “100% conservation” set.

Appendix D – Ask the Consultant

A key purpose of the ITA and the OTA was to provide an increased level of understanding of the purpose, need and timing of the EE project to the City Council and to community stakeholders. Over the course of the project, dozens of questions were received from various stakeholders. The City engaged such comments through an online outreach feature called 'Ask the Consultant.' In addition to this outreach the City initiated separate interviews with key stakeholders and USE staff. City staff filtered all Ask the Consultant stakeholder comment through the various Tasks in the Scope of Services and submitted the need-related comments to USE for report inclusion. Other comments were directed as appropriate to other comment venues including for example to the scoping process for the Environmental Impact Statement (EIS) the Integrated Resource Plan (IRP) process. That filtering is documented in the chart below.

A Q&A discussion is documented at the end of each section of the ITA.

See Attached Table 1.

Date	Name	Question or Comment	Directed to:
1/27	Plummer	Industry standards, IRP, average yearly loads	Extensive reference to lack of industry wide standards; paragraph 4 and 5 to ITA
1/22	Marsh	Questions for ITA consultant: Overview, Real need, distribution of peak use, Eastside vs regional needs, reliability	Skype session
1/28	Marsh	Questions for ITA consultant: extreme winter study case, other adjustments modeled, System Cap.	Role of Case Study Assumption, clarify reference to Needs Assessment Section 6, connection between CSA and CDF to ITA
1/30	Sweet	Data center consolidation comment	ITA
2/6	Plummer	Quantitative reliability metrics	ITA
2/9	Lander	Choice of USE and communications	Communications response
1/15	Osterberg/ Laughlin	E3 and Cadmus Study, declining revenue, blended project	EIS
2/3	Borgmann	12 questions: forecast, growth rates, Columbia Grid role, used and useful comparison, alternatives	1, 2, 7, 8, 12 to ITA 3 ? to ITA, comments to EIS 5 ? to ITA, comments to EIS 6 ? to ITA, comments to EIS 7- 2nd set? to EIS 4, 9, 10, 11 to EIS
2/9	Kim	2 comments on tech study and CDF chart; 2 questions on growth forecast disparity, show project stakeholder pie chart	1 and 2 to EIS 3 and 4 to ITA

2/10	McCray	4 questions: Load projection, options, trend down, Chang proposal	1 and 3 to ITA 2 and 4 (Chang) to EIS
2/10	Marsh	Circumstances of all-time peak usage occurrence	EIS
2/10	Marsh	PSE and SCL electricity trends	EIS
2/11	Alford	comment on tech study and CDF chart; questions on growth forecast disparity, show project stakeholder pie chart	See Kim comment
2/11	Mozer	Magnitude and timing of EE, alternatives, Canada powerflow	ITA (1) and EIS (2)
2/12	Andersen	4 questions: SCL capacity, Peak load information, use of temperature in modelling, distributed generation, use of peaking turbine generation	New Q1 to EIS Add 1 Q4 not in ITA scope Add 2 Q7 not in ITA scope Add 3 Q15 DSR and DG in ITA modelling, cost info not in scope Add 4 Q19 to EIS
2/12	Merrill	7 questions: Reasonableness of PSE conclusions, rational look, Eastside Customer demand, use of actual data, replacement, outages	1, 3, 5, 6 to ITA 2, 4, 7 to EIS
2/12	Hansen	Bridle Trails Subarea infrastructure reliability	EIS or ERS implementation
2/12	Halvorson	Customer Demand Forecast and Columbia Grid need pie chart	ITA
2/12	Marsh	7 questions: Top assumptions and parameters of the load forecast, economic projections, Spring District, increased efficiency, local government actions, regional transmission flow, regional grid	ITA

Appendix E – Transmission Planning Standards TPL-001-4

See attached Table 1.

Appendix F – Utility System Efficiency, Inc. (USE) Qualifications

Utility System Efficiencies, Inc.

R. Peter Mackin, P.E.
Vice President of Analytical Services

ACADEMIC BACKGROUND
M.S., Electrical Engineering, Montana State University, 1982
B.S., Civil Engineering, Montana State University, 1981

PROFESSIONAL EXPERIENCE
Peter Mackin has over 33 years of power system planning and computer application development experience and has been involved in WSCC/WECC planning and operating activities since 1985. In April of 2006, Mr. Mackin joined Utility System Efficiencies, Inc. (USE) as Vice President of Analytical Services. At USE, among other duties, Mr. Mackin has directed and performed system studies to meet the requirements of the WECC Project Rating Review Process, assisted developer clients with interconnection applications, and supervised a wind integration study for FERC.

While employed at Navigant Consulting, Inc., Mr. Mackin performed several transmission and resource integration studies for the Alberta Electric System Operator (AESO) as well as generation interconnection studies and transmission feasibility analyses for other clients. Mr. Mackin was a member of the NERC Version 0 and Phase III/IV Standards drafting teams. In addition, Mr. Mackin provided expert witness testimony at FERC in Docket No. ER01-1639-006.

While employed by the California Independent System Operator (CAISO), Mr. Mackin performed or reviewed system planning studies for Reliability Must Run generation requirements, new generator interconnection studies, as well as Participating Transmission Owner annual Transmission Assessments. In addition, Mr. Mackin helped develop the CAISO's New Facility Interconnection Policy and Long-Term Grid Planning Policy. Mr. Mackin provided expert witness testimony regarding six new generation projects before the California Energy Commission.

While employed by Pacific Gas and Electric Company (PG&E), Mr. Mackin was the lead transmission planning engineer performing transient stability simulations for the 500 kV California – Oregon Transmission Project. In addition, Mr. Mackin performed, supervised or reviewed studies to determine simultaneous import capabilities into California from the Pacific Northwest and the Desert Southwest. For two years, he served as chairman of the work group that undertook these studies. This work group was comprised of utilities from California, the Northwest, and the Desert Southwest.

Jennifer Geer, P.E.
Principal Power Systems Engineer

ACADEMIC BACKGROUND

B.S., Electrical Engineering, University of New Mexico, 1985

PROFESSIONAL EXPERIENCE

Ms. Geer has over 25 years of electric utility industry experience and has extensive background in the transmission and distribution areas, including transmission planning and generation interconnection studies, distribution planning and forecast development and approval, outage analysis, reliability analysis, project development, and project management. Ms. Geer has also provided training in many of these areas. Ms. Geer joined Utility System Efficiencies, Inc. (USE) in 2009. At USE, Ms. Geer's focus has been on generation interconnection studies, transmission planning and project development.

Prior to joining USE, Ms. Geer was a member of San Diego Gas and Electric's Transmission Planning Department. Though part of their generation interconnection team, she was also involved in studies to determine the need and benefit of new transmission projects on the existing system, examining different route and voltage options.

While running Geer and Geer Engineering, Ms. Geer developed a procedure to determine if a new substation was needed; part of this procedure involved developing long term forecasts for the relevant areas. She also led teams to optimize substation site selection based on both engineering and non-engineering issues, and provided project management for a long term transmission study that was used to determine client company strategy. In addition, Ms. Geer developed or reviewed many distribution projects, trained engineers and leads on distribution planning, developed a training manual, conducted process mapping of distribution functions, and analyzed visibility and accuracy of distribution accounting.

While employed by San Diego Gas & Electric (SDG&E), Ms. Geer forecasted distribution loads, identified issues and alternatives, and developed circuit and substation projects. Ms. Geer also conducted distribution reliability studies to improve performance indices and developed training documents on multiple topics. She reviewed the entire set of distribution circuit forecasts and proposed distribution capital projects for San Diego Gas & Electric in later years, and provided feedback and/or modification as needed. Ms. Geer also developed checklists and forms to assist in forecasting, project development and new business engineering review, and trained engineering personnel on distribution planning procedures.