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Supplemental Eastside Needs Assessment Report

Transmission System
King County

April 2015

Puget Sound Energy

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Executive Summary

This document summarizes the changes to the Eastside Needs Assessment Report dated October 2013, based upon the recent updates to the Puget Sound Energy (PSE) load forecast, system topology, facility ratings, changes affecting the Northern Intertie as the monitored flowgate for the Puget Sound Area Northern Intertie ("PSANI") issues, and changes to the Seattle City Light (SCL) system. This is a supplemental document that should be read in concert with the 2013 Eastside Needs Assessment Report ("2013 Needs Assessment").

The 2013 Needs Assessment concluded that there is a transmission capacity deficiency in the Eastside area which will develop by the winter of 2017-18. The assessment also concluded that the transmission capacity deficiency will continue to get worse as load grows. The 2013 Needs Assessment identified a number of concerns related to this transmission capacity deficiency, which included:

- Overload of PSE facilities in the Eastside area under certain contingencies
- Increasing use and expansion of Corrective Action Plans ("CAPs") to manage these overloads
- Inherent load forecast uncertainties which leave a small margin for error for the CAPs to be effective

The supplemental studies, utilizing the updated information discussed in this report, verified that there is still a transmission capacity deficiency in the Eastside area that will develop by the winter of 2017-18 and require the expanded use of CAPs to manage overloads for certain contingencies. In addition, the studies continued to show that this transmission capacity deficiency is expected to increase beyond that date. Cities in the deficiency area include: Redmond, Kirkland, Bellevue, Clyde Hill, Medina, Mercer Island, Issaquah, Newcastle, and Renton, along with towns of Yarrow Point, Hunts Point, and Beaux Arts.

The supplemental studies also verified that a transmission capacity deficiency still develops by the summer of 2018. However, the supplemental study showed that transmission capacity deficiency is actually worse than what was identified in the 2013 Needs Assessment. In the 2013 Needs Assessment, CAPs were required to mitigate the transmission capacity deficiency but load shedding was not required. In the supplemental study, both CAPs and load shedding are required to mitigate the transmission deficiency.

1. Introduction

This document summarizes the changes and results to the Eastside Needs Assessment dated October 2013, based upon the recent updates to the PSE load forecast, system topology, facility ratings, changes affecting the use of the Northern Intertie as the monitored flowgate for PSANI issues, and changes to the SCL system. This document also presents a comparison of the results using the updated information. The method, criteria, and key assumptions are the same as utilized in the 2013 Needs Assessment with the exception of those items discussed below.

2. Differences between the 2013 and 2015 Needs Assessments

2.1 Changes to the Power Flow Cases which have Minimal Impact

There are three changes that have minimal impact on the results of the supplemental study.

2.1.1 WECC Base Case Differences

Each year, Western Electric Coordinating Council (WECC), in coordination with its members, develops a set of "base cases" to model the bulk electric system. These base cases include the most up-to-date electrical system information for the entire WECC model including updated loads, generators, transmission lines, etc. All electric providers use these base cases as starting points to study their proposed system improvements and to understand the potential impacts to the regional electric grid, thereby ensuring no adverse impacts to the reliability and operating characteristics of its system or any surrounding system. The 2013 Needs Assessment was based on WECC base cases for the winter peak for years 2013-14, 2017-18, and 2021-22. Summer peak was analyzed for years 2014 and 2018 for the annual 2012 NERC TPL analysis.

For the 2015 Needs Assessment analysis, PSE utilized WECC winter peak base cases for the years 2019-20 and 2023-24. A 2017-18 case was developed from the 2019-20 base case. Summer peak base cases included the 2020 and 2024 WECC base cases. A 2018 summer case was developed from the 2020 base case.

2.1.2 Topology Changes in the Base Case

The studies within the 2015 Needs Assessment included all projects in the 2013 Needs Assessment, which are listed in Section 9 and Appendix B Tables B-1 and B-2 of the 2013 Needs Assessment. Changes in topology between the previous set of study cases and the current study cases are included in Appendix A of this report. Based on our analysis, no topology changes listed in Appendix A significantly impacted the study results. There was one change, the Talbot 230-115 kV transformer #1 replacement, which increased the winter normal and emergency limits from 383 MW and 464 MW to 398 MW and 484 MW respectively.

2.1.3 Northern Intertie vs. North of Echo Lake and South of Custer Flowgates

Prior to 2013, Bonneville Power Administration (BPA) used the West-Side Northern Intertie as the monitored flowgate for electricity transfers between the Puget Sound area and British Columbia. A one-line diagram of this flowgate is included in Appendix D. This flowgate was managed through the use of nomograms that would dictate the amount of capacity available on the Northern Intertie based on varying Puget Sound area generation levels, expected load levels, ambient temperature, and the next worst contingency. Nomograms were published on this Path for flows in both the north-south direction and the south-north direction. The amount of power that could be transferred between the Northwest and BC Hydro's system on the West-Side Northern Intertie was somewhat dependent on generation in the Puget Sound area. Transmission across the Northern Intertie would be curtailed if it was found that conditions would not support transfers, both in real time and in the operations planning timeframe. In February of 2013, BPA moved away from using the Northern Intertie as the basis for determining available transfer capability through the Puget Sound area and instead developed two new flowgates. These flowgates are the South of Custer (SOC) flowgate, used for determining acceptable north-south transfer levels through the Puget Sound area and the North of Echo Lake (NOEL) flowgate, used for determining acceptable south-north transfer levels. The lines that make up these new flowgates are included in Table 2-1. One-line diagrams of these updated flowgates are also included in Appendix D. These changes are used operationally to monitor flows that do not impact the study results but help determine and prevent adverse reliability impacts when power is flowing between the Northwest and BC Hydro's system.

Table 2-1: Definitions of PSANI Flowgates

North of Echo Lake (NOEL) Flowgate Definition:	South of Custer (SOC) Flowgate Definition:
Echo Lake – SnoKing Tap 500 kV	Monroe – Custer #1 & #2 500 kV
Echo Lake – Maple Valley 500 kV	Murray – Custer 230 kV
Covington – Maple Valley 230 kV	Bellingham – Custer 230 kV

2.2 Changes to the Power Flow Cases which had Substantial Impact

There are three changes that have a substantial impact on the results of the 2013 Needs Assessment. They are described below.

2.2.1 PSE has updated the Facility Ratings for all transmission lines in the system

For the 2013 Needs Assessment analysis, PSE used an Electric Power Research Institute (EPRI) tool called DYNAMP to establish transmission line facility ratings. By 2014, DYNAMP was no longer supported and PSE converted to a program called PLS–CADD. As a result of the conversion to this new tool, the transmission line facility ratings increased over the ratings used in the previous assessment. This increase in line ratings had an impact on post-contingency loadings, effectively reducing the percentage of overloads on facilities throughout the PSE system.

For example, the winter Emergency Facility Rating of the Talbot-Lakeside 115 kV line increased from 238.6 MVA to 249 MVA. In the 2017-18 Heavy Winter case, actual post-contingency MVA loading on the line for the worst Category B contingency in the 2013 Needs Assessment was 235.3 MVA or 98% of the 238.6 MVA line rating in the case. Actual post-contingency MVA loading on the line for the worst Category B contingency in the current study case was 218.3 MVA, or 87.6% of the 249 MVA line rating used in the case. If the line rating had not changed, loading in the current case would be 91.5% of the rating. Overloads seen on this line decreased by approximately 4% due to the change in line rating.

2.2.2 Seattle City Light Load Levels Decreased

In 2014, Seattle City Light made some corrections and adjustments to the load levels used in the WECC power flow base cases. These changes resulted in decreased Seattle City Light load levels.

2.2.3 Differences in load forecast levels utilized in the 2013 and 2015 Needs Assessments

The following briefly describes the PSE load forecasting process and the resulting differences between the 2012 and 2014 load forecast that were used in the 2013 and 2015 Needs Assessments.

PSE's service territory is very diverse, and hence, PSE experiences highly variable growth across its service territory. For the 2014 load forecast, PSE prepared a more detailed county-by-county forecast than had been done previously. The 2014 load forecast disaggregated the system wide forecast to county and sub-county regions to examine reasonableness from both system and sub-system perspectives. A small area forecast was also performed to focus on the Eastside study area.

PSE used data from PSE's electric demand and consumption history and federal and local government sources as inputs to develop an econometric load forecast using econometric-time series approach. PSE's electric demand and energy consumption history was also used to forecast future trending. Regional temperature taken at the National Oceanic and Atmospheric Administration (NOAA) station at SeaTac International Airport during the system peak was used to compare peak load reading. The load readings were normalized to 23˚ F, which was used as a 1-in-2 year normal ambient temperature at the time of system peak. Forecasts were also performed for a 1-in-20 year (or extreme temperature) forecast at 13˚ F.

To perform the system and county level forecasts, population data was also taken from the US Census as well as the US Bureau of Economic Analysis (BEA) and WA State Office of Financial Management (OFM). Employment data was taken from BEA, US Bureau of Labor Statistics (BLS), and Washington State Employment Security Department. Additionally, historic and forecasted US level data was from Moody's Analytics. At the sub-county level, population and employment data were obtained from Puget Sound Regional Council (PSRC) and WA State OFM.

PSE used the population and employment forecast evaluated by the PSRC for King, Pierce, and Kittitas counties. Population data was also taken from the US Census as well as the US BEA and WA State OFM. Employment forecast data were taken from the US BLS and PSRC.

To augment the data provided by the government agencies, PSE provided information about expected significant new loads, known as "block loads," over the next few years. This information was used for the first three years of the forecast period at full value, then at 50% value for the next three years. After six years, the forecast block loads were considered to be included in the data available on employment and population provided by the forecasting agencies so no additional load was added to the load forecast after year six.

Once an econometric forecast was developed for each county, or for the company as a whole, the peak demand and energy consumption were reduced by a forecast amount of conservation based on conservation target determined as optimal from the 2013 Integrated Resource Plan (IRP). This conservation target includes energy efficiency programs, Energy Independence and Security Act (EISA), distribution efficiency, and demand response. PSE has not implemented an active demand response program, so the demand response included in this forecast consisted of conservation programs and intrinsic conservation due to measures required by modern building codes.

It should be noted that a segment of PSE's transmission customers were not included in the corporate load forecast. These are interconnection or high voltage customers who connect to PSE for transmission service, but do not purchase energy from PSE. Approximately 250-300 MWs are required by the transmission customers on a nearly continuous basis.

There are some differences between the 2012 and 2014 load forecast worth noting:

a. The 2012 load forecast assumed faster recovery of the US economy from the recession than the 2014 load forecast.
b. The 2014 load forecast used updated US population growth forecast from the US Bureau of Census, which is lower compared to what was used in the 2012 load forecast.
c. Because of slower housing recovery, customer growth and customer counts in the 2014 load forecast are lower than the 2012 load forecast.
d. Peak load growth and peak load levels for the system and for King County are projected to be lower in the 2014 load forecast as compared to the 2012 load forecast.
e. Based on PSRC's population and employment growth forecasts, Eastside peak loads in the 2014 load forecast are projected to grow by 2.4% per year in the next 10 years, which is driven by growth in the commercial sector and high density residential sector. Also, updates to block loads over the study period influenced the load growth in the Eastside area.

The following tables show the comparison between the 2012 and 2014 system corporate load forecast and a breakdown by county of the 2014 corporate load forecast.

Table 2-2: Comparison of PSE's 2012 and 2014 Corporate Load Forecast

PSE Corporate Load Forecast				
	Forecasted 2012		Forecasted 2014	
Year	Max of Normal Peak w/ DSR	Max of Extreme Peak w/ DSR	Max of Normal Peak w/ DSR	Max of Extreme Peak w/ DSR
2012	4,837	5,316		
2013	4,785	5,267		
2014	4,836	5,333	4,803	5,255
2015	4,865	5,375	4,820	5,283
2016	4,909	5,432	4,844	5,317
2017	4,938	5,472	4,891	5,377
2018	4,938	5,483	4,891	5,385
2019	4,946	5,501	4,904	5,406
2020	4,923	5,490	4,856	5,365
2021	4,923	5,502	4,850	5,366
2022	4,972	5,562	4,863	5,388
2023	5,039	5,641	4,888	5,421
2024	5,117	5,732	4,961	5,504
2025	5,193	5,820	5,029	5,581
2026	5,266	5,905	5,085	5,645
2027	5,341	5,993	5,148	5,716
2028	5,426	6,090	5,224	5,802
2029	5,515	6,192	5,302	5,889
2030	5,605	6,296	5,376	5,972
2031	5,694	6,399	5,444	6,049
2032	5,785	6,504	5,512	6,126
2033	5,878	6,610	5,580	6,203
2034			5,649	6,282

Table 2-3: PSE's 2014 Corporate Peak Load Forecast by County

2014 PSE Corporate Peak Load Forecast by County									
Year	King	Thurston	Pierce	Whatcom	Skagit	Island	Kitsap	Kittitas	Total PSE
2014	2391	549	498	374	265	144	524	59	4803
2015	2410	550	500	373	263	143	523	59	4820
2016	2427	552	503	372	262	143	524	61	4844
2017	2458	557	508	375	262	143	526	62	4891
2018	2454	559	510	375	260	143	526	64	4891
2019	2465	561	511	375	259	143	526	65	4904
2020	2445	555	506	371	254	140	518	66	4856
2021	2443	555	505	370	252	140	516	68	4850
2022	2454	557	506	370	251	139	516	70	4863
2023	2472	559	508	371	250	139	517	71	4888
2024	2515	567	515	376	252	141	522	74	4961
2025	2555	574	521	380	253	142	527	76	5029
2026	2590	580	526	384	254	143	531	78	5085
2027	2628	586	531	388	255	144	536	80	5148
2028	2675	594	538	392	256	145	541	82	5224
2029	2723	601	545	397	258	146	547	84	5302
2030	2769	609	551	402	259	147	553	87	5376
2031	2814	615	555	406	260	148	557	88	5444
2032	2859	621	559	410	261	149	562	90	5512

The 2013 Needs Assessment used PSE's 2012 corporate load forecast as the basis for the analyses and adjusted the load based on PSE's knowledge of future block loads and non-PSE customers supplied by PSE. In PSE's 2012 corporate load forecast, the forecast was provided for PSE's system as a whole, and sub-area forecasts were proportionally derived from this overall forecast. For the 2015 Needs Assessment, PSE's 2014 corporate load forecast was used and was also adjusted for non-PSE load supplied by PSE. This 2014 corporate load forecast provided an overall PSE system forecast and it also included bottom-up sub-area load forecasts for the King County and Eastside areas.

Table 2-4 below lists the Eastside and King County load levels for the cases used in the 2013 Needs Assessment and Table 2-5 lists the load levels using the 2014 load forecast. Comparing the results of the load levels for winter 2017-18, the total load level for PSE's system is 46 MW less using the 2014 load forecast (5162 MW) than the 2012 forecast (5208 MW). Using the 2014 load forecast, the King County area, without the Eastside load, is 27 MW higher (1854 MW – 1881 MW) and the Eastside area is 11 MW less than 2012 forecast (699 MW–688 MW). The remaining reduction is distributed over the rest of PSE.

Table 2-4 Eastside and King County Load Levels Using 2012 Load Forecast in MW

Case	King County (excluding Eastside)	Eastside	Remainder of system	Total
17-18HW	1854	699	2654	5208
18HS	1258	550	1744	3552
21-22HW	1862	748	2548	5193

Table 2-5: Eastside and King County Load Levels Using 2014 Load Forecast in MW

Case	King County (excluding Eastside)	Eastside	Remainder of system	Total
17-18HW	1881	688	2592	5162
17-18EHW	2091	728	2828	5647
18HS	1379	538	1707	3625
19-20HW	1858	708	2609	5175
19-20EHW	2084	749	2843	5676
20HS	1373	561	1747	3681
23-24HW	1817	764	2577	5158
23-24EHW	2053	804	2833	5691
24HS	1399	618	1800	3817

2.3 Base Cases Used for Analysis

The WECC base cases are updated annually. The cases available for this update were Heavy Winter 2019-20 and 2023-24 and Heavy Summer 2020 and 2024. All other cases were derived from those WECC cases. Table 2-6 below includes a comparison of the cases utilized in the 2013 Needs Assessment and the 2015 Needs Assessment study cases using 2014 updated data.

Table 2-6: Comparison of the Cases Utilized in the Eastside Needs Assessment

Case	2012	2014
2013-14 Heavy Winter	✓	--
2017-18 HW SN 100% Cons	✓	✓
2017-18 HW SN 75% Cons	✓	--
2017-18 HW SN 50% Cons	✓	--
2019-20 HW SN 100% Cons	--	✓
2021-22 HW SN 100% Cons	✓	--
2021-22 HW SN 75% Cons	✓	--
2021-22 HW SN 50% Cons	✓	--
2021-22 HW SN Extreme 100% Cons	✓	--
2021-22 HW SN Extreme 75% Cons	✓	--
2023-24 HW SN 100% Cons	--	✓
2014 HS NS	✓	--
2018 HS NS	✓	✓
2018 HS SN	✓	--
2024 HS NS	--	✓
2024 HS SN	--	✓

2.4 Points of Clarification from the 2013 Needs Assessment

2.4.1 Use of Corrective Action Plans (CAPs)

PSE uses operating procedures, such as corrective action plans (CAPs), to prevent any loss of firm load, either intentionally or due to a credible outage condition while remaining compliant with mandatory NERC/WECC reliability requirements. CAPs are generally considered temporary in nature with the understanding that permanent solutions are forthcoming. NERC Standard TPL-001-4 allows CAPs to be used to meet the performance requirements for most N-1-1 and N-2 contingencies while specifying how long they will be needed as part of the CAPs.

2.4.2 Use of Load Shedding

While NERC and WECC allow dropping "non-consequential[1]" load for certain contingencies, intentionally dropping firm load for an N-1-1 or N-2 contingency to meet its federal planning requirements is not a practice that PSE endorses. All load modeled in the Needs Assessment studies was firm load and PSE does not consider any of its firm requirements to be non-consequential. This is consistent with the view of most utilities. It is also consistent with the views of virtually all community officials who do not consider intentionally blacking out segments of customers as a responsible way to operate a modern electricity delivery system.

PSE's concern about using load shedding for N-1-1 contingencies is best illustrated by the outage of two 230 kV-115 kV transformers in the Eastside area. Losing two 230 kV-115 kV transformers could result in the other remaining 230 kV-115 kV transformers being overloaded. In this scenario, simply re-dispatching PSE generation does not reduce these transformer overloads below the emergency rating. A transformer outage would require a minimum 24-hour outage to test and re-energize the transformer. Further, if the outaged transformer tests bad, then it must be replaced, and this can take up to another five to seven weeks. This scenario results in a significant amount of time to place PSE customers at risk either with CAPs or with exposure to load shedding.

To illustrate how other utilities in WECC address load shedding, the CAISO Planning Standards indicates in their Section 6, Planning for High Density Urban Load Area:

> *"Increased reliance on load shedding to meet these needs would run counter to historical and current practices, resulting in general deterioration of service levels. For local area long-term planning, the ISO does not allow non-consequential load dropping in high density urban load areas in lieu of expanding transmission or local resource capability to mitigate NERC TPL-001-4 standards P1-P7 contingencies and impacts on the 115 kV or higher voltage systems….In the near-term planning, where allowed by NERC standards, load dropping, including high density urban load, may be used to bridge the gap between real-time operations and the time when system reinforcements are built."*

3. Results of 2015 Needs Assessment

The detailed results of the 2015 Needs Assessment are shown in Appendix A for winter peak conditions and Appendix B for summer peak conditions. The results verified that there is a transmission capacity deficiency in the Eastside area that will develop by the winter of 2017-18. This transmission capacity deficiency in the Eastside area is expected to increase beyond that date.

Using the same methodology as the 2013 Needs Assessment, the supplemental analysis shows that a transmission capacity deficiency develops at a winter Eastside area load of 688 MW, requiring the use of CAPs, and worsens at an Eastside area load of 708 MW, requiring both the use of CAPs and exposing some PSE customers to load shedding. The transmission capacity deficiency also develops at a summer Eastside area load of 538 MW.

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[1] Non-Consequential Load is defined as Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment. Consequential Load is defined as all Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Similar to the 2013 results, there were a significant number of overloads that showed up in the results of power flow studies due to outages of high voltage lines owned by other utilities that interconnect to PSE. Most of these are outages in BPA's 230 kV or 500 kV network. BPA and the other interconnected utilities have operating procedures in place to prevent overloads of area facilities, including PSE lines and equipment. For example, the most frequent external contingency that causes PSE overloads is an outage of the [redacted]. BPA operates the interchange flows and generation levels so that this [redacted] line outage does not cause overloads. Therefore, overloads resulting from this [redacted] BPA line were not considered as necessary for PSE to resolve.

In addition, a number of overloads of area transmission lines can be partially mitigated by adjusting PSE generation levels in Western Washington. As such, this type of generation re-dispatch costs more than the optimal generation levels that PSE would elect, thereby driving up customer costs. Therefore, while these system adjustments are not a desirable operating condition, they are acknowledged as an available action to mitigate these types of overloads while remaining NERC compliant.

There are still a number of transmission transformer overloads which cannot be addressed by dispatching generation, similar to the 2013 Needs Assessment. These transformer overloads will require CAPs in the future to shift load; at some point the CAPs will be expanded to include load shedding in order to remain NERC compliant.

3.1 Winter Analysis

Utilizing the 2014 load forecast and the results of the winter analysis, Figure 3-1 shows two system capacity lines for the Eastside area – both of which are reflected on the graph as dashed red lines. These lines highlight the area of concern where the 2015 Needs Assessment indicates violations of the mandatory performance requirements developed for certain contingencies that put customer reliability at risk. The area of concern starts at an Eastside area load of 688 MW in the winter of 2017-18 and continues to 708 MW in the winter of 2019-20. The 2015 Needs Assessment established that a transmission capacity deficiency exists at an Eastside area load level of 688 MW that requires the use of CAPs to manage Category C overloads in winter of 2017-18. The 2015 Needs Assessment also established that the transmission capacity deficiency continues to worsen at an Eastside area load level of 708 MW, which requires the use of additional CAPs by winter of 2019-20. These additional CAPs placed approximately 63,200 customers at risk of losing power due to being served radially. By the winter of 2023-24 the CAPs will require load shedding affecting approximately 16,800 customers to prevent thermal violations under certain conditions.

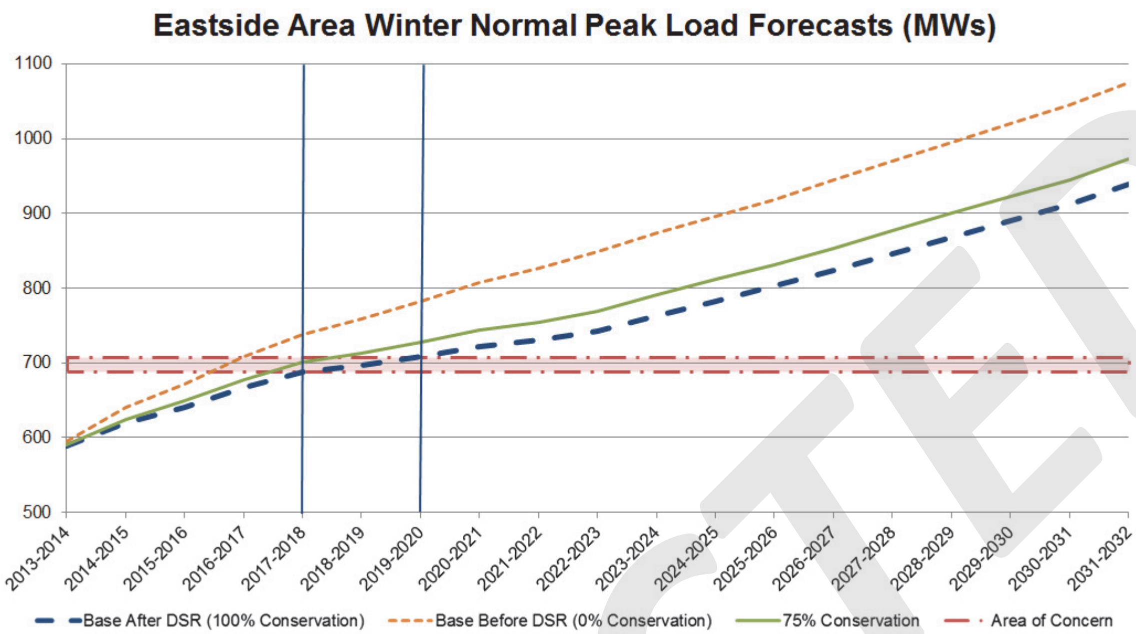

Figure 3-1: Capacity Need Results with 2015 Updated Information

The area of concern shown in Figure 3-1 is consistent with the 706 MVA level of concern identified for the Eastside area in the 2013 Needs Assessment. This value was reflected in the graph shown in Figure 4-3 of the 2013 Needs Assessment (where the units were mislabeled as "MW"). The actual MW value for the level of concern was 699 MW in the 2013 Needs Assessment. The 699 MW value reflected the load level of the Eastside area in the winter of 2017-18 in the previous study where the power flows indicated violations of the mandatory performance requirements that put customer reliability at risk. For ease of reference, this figure is repeated below as Figure 3-2.

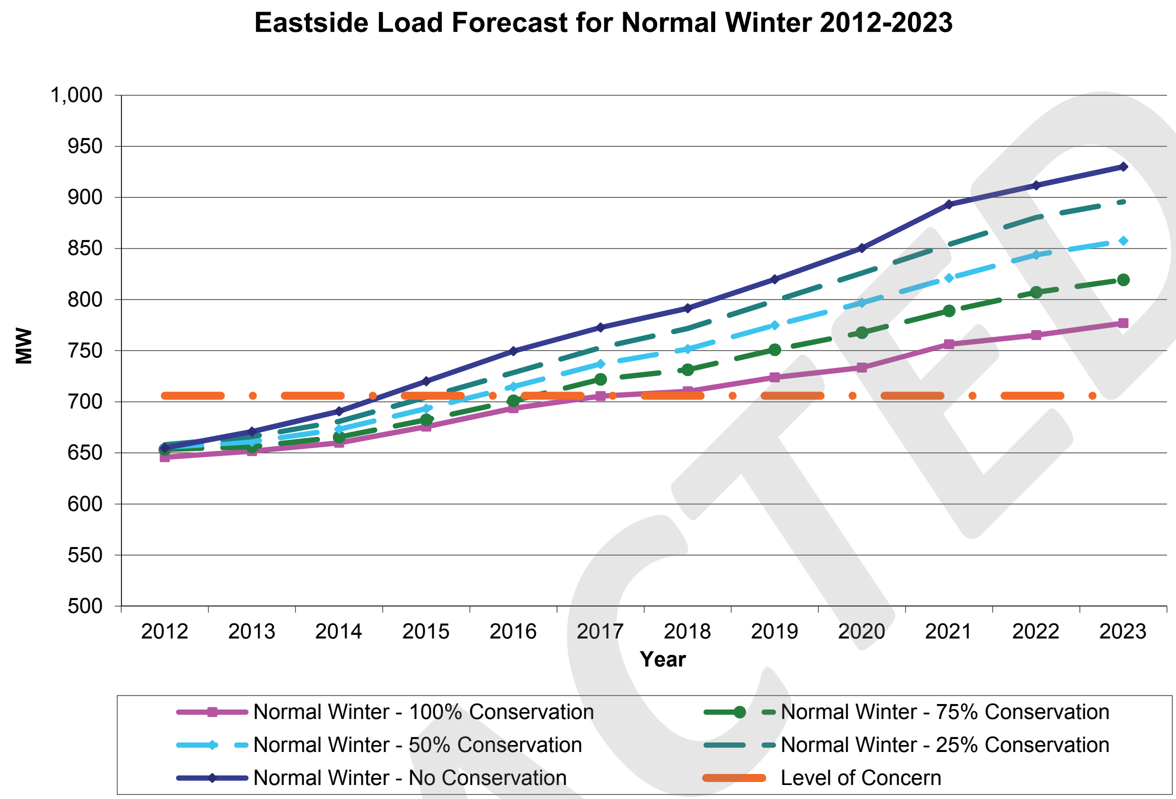

Figure 3-2: Level of Concern for Eastside Area Load in 2013 Needs Assessment

As the winter summary in Table 3-1 shows, CAPs are needed throughout the study period. As noted above, CAPs are required starting in the winter of 2017-18 to manage overloads on five elements from 12 Category C contingencies. By 2019-20, the overloads on these same five elements will be created from 18 Category C contingencies, which require additional CAPs to manage and which place approximately 63,200 customers at risk by placing them on radial feeds. By 2023-24 the overloads on these same five elements will be caused by 40 Category C contingencies, which require the use of even more CAPs and place approximately 68,800 customers at risk. In addition, by 2023-24 load shedding of approximately 133 MW will be needed to maintain a reliable and secure transmission system.

Table 3-1: Winter Power Flow Summary Comparison of 2013 and 2015 Needs Assessment

Winter Power Flow Summary						
	2012 Load Forecast			2014 Load Forecast		
	2013-14 Winter 5055 MW 100% Conserv-ation Eastside Load = 545 MW	2017-18 Winter 5208 MW 100% Conserv-ation Eastside Load = 699 MW	2021-22 Winter 5193 MW 100% Conserv-ation Eastside Load = 748 MW	2017-18 Winter 5162 MW 100% Conserv-ation Eastside Load = 688 MW	2019-20 Winter 5175 MW 100% Conserv-ation Eastside Load = 708 MW	2023-24 Winter 5158 MW 100% Conserv-ation Eastside Load = 764 MW
Elements Above Emergency Limit:						
Category B (N-1)	0	0	2	0	0	0
Category C (N-1-1 & N-2)	5	6	5	5	5	5
Corrective Action Plans Required	Yes	Yes	Yes	Yes	Yes	Yes
Customers at Risk from Corrective Action Plans	0	68,800	76,300	0	63,200	68,800
Customers at Risk from Load Shedding	0	0	4,400	0	0	16,800
Load Shed MW	0	0	22	0	0	133
Elements Above Normal Limit or 90% of Emergency Limit:						
Category B (N-1)	0	4	6	0	3	3
Category C (N-1-1 & N-2)	6	7	8	7	6	5
Contingencies that cause post-contingency loading above 100% of Emergency Limit:						
Category B (N-1)	0	0	1	0	0	0
Category C (N-1-1 & N-2)	13*	23*	37*	12	18	40

* Note: There were additional contingencies in the study using the 2012 Load Forecast that resulted in overloads between 100% and 104%. In the supplemental study, overloads on the PSE lines between 100% and 104% were eliminated to account for the change in line ratings from 2012 to 2014. Those overloads are not included in the 2012 Load Forecast counts provided in this table.

Detailed results of the winter analysis are shown in Appendix A.

3.2 Summer Analysis

The 2013 Needs Assessment showed a PSE area summer load level of need at approximately 3340 MW. This need was illustrated in Figure 1-2 of that document and is included as Figure 3-3 below for ease of reference.

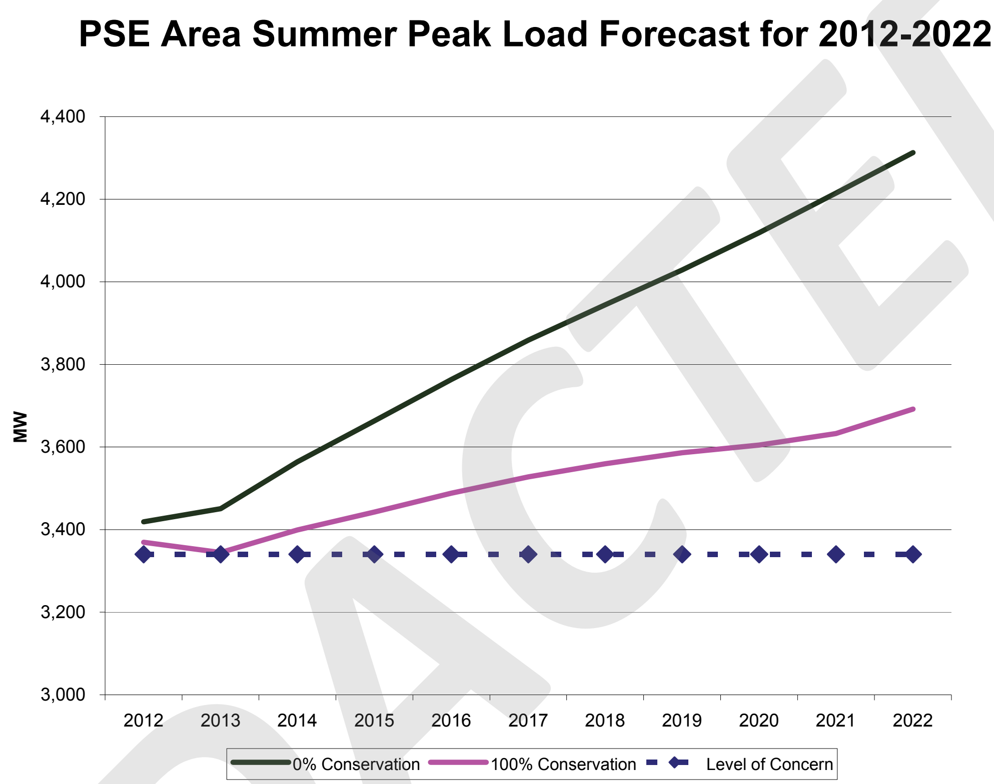

Figure 3-3: PSE Area Summer Peak Load Forecast for 2012-2022

The 2013 Needs Assessment, analyzed the summer of 2018, had a PSE area summer peak of approximately 3,552 MW. That 2013 assessment found there were two 230 kV elements above 100% and two 115 kV elements above 93% loadings for Category B (N-1) contingencies. Also, there were three elements above 100% loading and one above 99% loading for Category C (N-1-1) contingencies. In the 2013 Needs Assessment, the 3,552 MW system load corresponds to an Eastside Area load level of 550 MW. In the 2013 Needs Assessment, we identified that CAPs were needed to manage the Category C (N-1-1) contingencies and that up to 33,000 customers would be put at risk when those CAPs were utilized.

The 2015 Needs Assessment shows an Eastside summer load level of need at approximately 538MW. This need is shown in Figure 3-4 below.

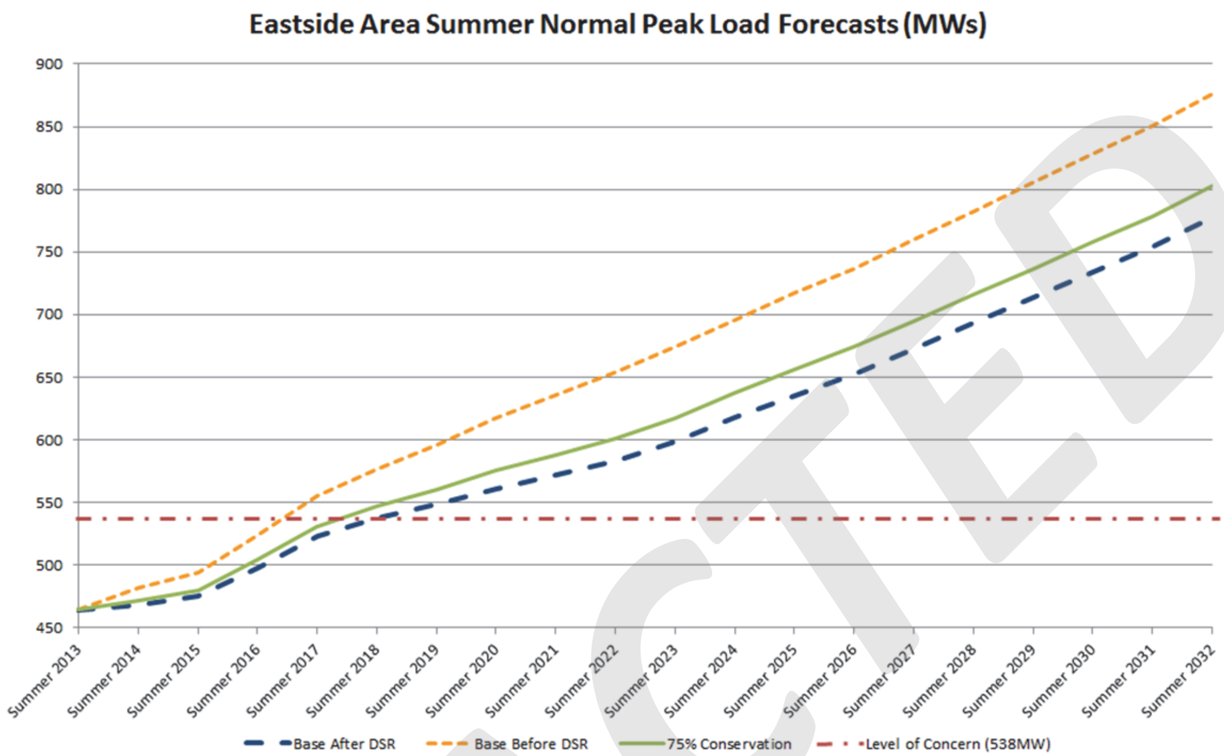

Figure 3-4: Eastside Summer Peak Load Forecast for 2012-2023

Table 3-2 summarizes the results of the 2015 Needs Assessment and it shows that the amount of customers at risk for losing power will increase to approximately 68,800 by the summer of 2018. The 2015 Needs Assessment also shows that load shedding of approximately 74 MW will be needed to maintain a reliable and secure transmission system starting in the summer 2018, increasing to approximately 78 MW in 2020 and approximately 123 MW by 2024. The number of contingencies that cause post-contingency loading above 100% Emergency Limit is six by the summer of 2018 and grows to nine by 2024.

Table 3-2: Summer Power Flow Summary Comparison of October 2013 and 2015 Updated Results

Summer Power Flow Summary				
	2012 Load Forecast	**2014 Load Forecast**		
	2018 Summer 3552 MW 100% Conservation Eastside Load = 550 MW	**2018 Summer 3625 MW 100% Conserv-ation Eastside Load = 538 MW**	**2020 Summer 3681 MW 100% Conserv-ation Eastside Load = 561 MW**	**2024 Summer 3817 MW 100% Conserv-ation Eastside Load = 618 MW**
Elements Above Emergency Limit:				
Category B (N-1)	2 [1]	1 [1]	2 [1]	2 [1]
Category C (N-1-1 & N-2)	3	5 [2]	5 [2]	5 [2]
Corrective Action Plans Required	Yes	Yes	Yes	Yes
Customers at Risk from Corrective Action Plans	62,800	68,800	68,800	68,800
Customers at Risk from Load Shedding	0	10,900	10,900	12,700
Load Shed MW	0	74	78	123
Elements Above Normal Limit or 90% of Emergency Limit:				
Category B (N-1)	4	1	2	2
Category C (N-1-1 & N-2)	4	6	6	6
Contingencies that cause post-contingency loading above 100% of Emergency Limit:				
Category B (N-1)	2	2	2	2
Category C (N-1-1 & N-2)	8	6	7	9

[1] These elements are BPA transmission lines leased by PSE

[2] These elements include 1 BPA transmission line leased by PSE

Detailed results of the summer analysis are shown in Appendix B.

4. Conclusions of the 2015 Needs Assessment using the 2014 PSE Load Forecast

The project date of need will remain the same at the winter of 2017-18 due to these key risk factors:

- The 2017-18 winter power flow cases still require the use of CAPs to mitigate transmission transformer overloads with load risk beginning between 2017-18 to 2019-20.
- The number of contingencies requiring the use of CAPs steadily increases as load grows.
- The forecast uses a 1-in-2 year weather forecast. Colder weather will result in higher load levels.
- 100% conservation may not be achieved, which would result in a higher load level. Even if 100% conservation is achieved, it may not be in the appropriate locations and magnitudes assumed for this assessment.
- There is only 20 MW difference on the Eastside between the winters of 2017-18 and 2019-20, and in the winter of 2019-20 with over 60,000 customers are at risk.
- By the summer of 2018, studies show that 68,800 customers will be at risk of outages and 10,900 customers at risk of load shedding using CAPs to mitigate transmission transformer overloads.
- Load shedding becomes an increasingly necessary action as load grows.

5. Statement of Need

The 2015 Needs Assessment reconfirmed that, by winter of 2017-18, there is a transmission capacity deficiency on the Eastside that impacts PSE customers and communities in and around Kirkland, Redmond, Bellevue, Issaquah, Newcastle, and Renton along with Clyde Hill, Medina, and Mercer Island. The transmission deficiency focuses on the two 230 kV supply injections into central King County at Sammamish substation in the north and Talbot Hill substation in the south. The transmission capacity becomes a need at an Eastside winter load level of approximately 688 MW, where overloads will result in operating conditions that require CAPs to manage. By winter of 2019-20, at an Eastside load level of approximately 706 MW, additional CAPs are required that will put approximately 63,200 Eastside customers at risk of outages. These results are summarized in Table 3-1 above.

The 2015 Needs Assessment also reconfirmed that by summer of 2018, there will be a transmission capacity deficiency on the Eastside which impacts PSE customers and communities in and around Kirkland, Redmond, Bellevue, Issaquah, and Newcastle along with Clyde Hill, Medina, and Mercer Island. By summer of 2018, CAPs will be required to manage overloads under certain Category C contingencies and the use of these CAPs will place approximately 68,800 customers at risk and will require 74 MW of load shedding, affecting approximately 10,900 customers. These results are summarized in Table 3-2 above.

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Appendix A. 2015 Needs Assessment Results for Winter Peak Season

Table A-1: Summary of Potential Thermal Violations for Winter Peak Load Season

2013-14 5055 MW 100% Con Eastside Load = 545 MW		2017-18 5208 MW 100 % Con Eastside Load = 699 MW		2021-22 5193 MW 100% Con Eastside Load = 748 MW		2017-18 5162 MW 100% Conservation Eastside Load = 688 MW		2019-20 5175 MW 100% Conservation Eastside Load = 708 MW		2023-24 5153 MW 100% Conservation Eastside Load = 764 MW		2023-24 Extreme 5690 MW 100% Conservation Eastside Load = 804 MW	
Category B: N-1 Contingency Results													
[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload
		[redacted]	Talbot Hill - Lakeside #1 115 kV line – 98.6%	[redacted]	Talbot Hill - Lakeside #1 115 kV line – 97.4%	[redacted]	Talbot Hill - Lakeside #1 115 kV line – 87.7%[3]	[redacted]	Talbot Hill - Lakeside #1 115 kV line – 91.1%	[redacted]	Talbot Hill - Lakeside #1 115 kV line – 96.1%	[redacted]	Talbot Hill - Lakeside #1 115 kV line – 101.0%
		[redacted]	Talbot Hill - Lakeside #2 115 kV line – 98.4%	[redacted]	Talbot Hill - Lakeside #2 115 kV line – 97.2%	[redacted]	Talbot Hill - Lakeside #2 115 kV line – 87.5%	[redacted]	Talbot Hill - Lakeside #2 115 kV line – 90.9%	[redacted]	Talbot Hill - Lakeside #2 115 kV line – 92.4%	[redacted]	Talbot Hill - Lakeside #2 115 kV line – 97.1%
		[redacted]	Talbot Hill 230-115 kV transformer #1 – 89.0%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 91.0% (see footnote 4)	[redacted]	Talbot Hill 230-115 kV transformer #1 – 85.1%[4]	[redacted]	Talbot Hill 230-115 kV transformer #1 – 85.6%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 87.1%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 95.9%
		[redacted]	Talbot Hill 230-115 kV transformer #2 – 90.3%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 91.5%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 89.3%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 90.2%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 92.8%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 101.9%

[2] All contingencies involving loss of the Monroe – Echo Lake – SnoKing 500 kV three-terminal line are unsolvable in the 21-22HW case without modeling the Intalco load tripping RAS. Study results reflect opening all Intalco loads, totaling about 300 MW, to get the case to a solvable state. Opening these loads slightly changes line flows in the case and may contribute to the decrease in post-contingency line loading.

[3] Decrease in post-contingency line loading can be attributed to lower area load, lower SCL load and increased line ratings between the 2012 study and the current study.

[4] The Talbot 230/115 kV transformer #1 is scheduled to be replaced in 2015 and the new expected ratings and impedance were included in the 2014 cases.

2013-14 5055 MW 100% Con Eastside Load = 545 MW		2017-18 5208 MW 100 % Con Eastside Load = 699 MW		2021-22 5193 MW 100% Con Eastside Load = 748 MW		2017-18 5162 MW 100% Conservation Eastside Load = 688 MW		2019-20 5175 MW 100% Conservation Eastside Load = 708 MW		2023-24 5153 MW 100% Conservation Eastside Load = 764 MW		2023-24 Extreme 5690 MW 100% Conservation Eastside Load = 804 MW	
				[redacted]	Sammamish-Lakeside #1 115 kV Line - 104.7%								
				[redacted]	Sammamish-Lakeside #2 115 kV Line - 104.5%								
Category C: N-1-1 Contingency Results													
[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload
[redacted]	Talbot Hill-Lakeside #1 115 kV Line - 115.2%	[redacted]	Talbot Hill--Lakeside #1 115 kV Line - 127.5%	[redacted]	Talbot Hill--Lakeside #1 115 kV Line – 125.9%	[redacted]	Talbot Hill--Lakeside #1 115 kV Line – 113.3%	[redacted]	Talbot Hill-Lakeside #1 115 kV Line – 117.4%	[redacted]	Talbot Hill - Lakeside #1 115 kV line – 123.9%	[redacted]	Talbot Hill - Lakeside #1 115 kV line – 130.5%
[redacted]	Talbot Hill-Lakeside #2 115 kV Line - 115.1%	[redacted]	Talbot Hill--Lakeside #2 115 kV Line - 127.7%	[redacted]	Talbot Hill-Lakeside #2 115 kV Line – 125.8%	[redacted]	Talbot Hill-Lakeside #2 115 kV Line – 113.1%	[redacted]	Talbot Hill-Lakeside #2 115 kV Line – 117.3%	[redacted]	Talbot Hill-Lakeside #2 115 kV Line – 120.8%	[redacted]	Talbot Hill-Lakeside #2 115 kV Line – 127.2%
[redacted]	Talbot Hill 230-115 kV transformer #1 - 100.9%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 105.8%	[redacted]	Talbot Hill 230-115 kV transformer #1 - 108.1%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 101.0%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 101.3%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 103.1%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 113.7%
[redacted]	Talbot Hill 230-115 kV transformer #2 - 100.5%	[redacted]	Talbot Hill 230-115 kV transformer #2 - 105.7%	[redacted]	Talbot Hill 230-115 kV transformer #2 - 107.0%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 104.6%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 105.4 %	[redacted]	Talbot Hill 230-115 kV transformer #2 – 108.1%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 118.5%

2013-14 5055 MW 100% Con Eastside Load = 545 MW		2017-18 5208 MW 100 % Con Eastside Load = 699 MW		2021-22 5193 MW 100% Con Eastside Load = 748 MW		2017-18 5162 MW 100% Conservation Eastside Load = 688 MW		2019-20 5175 MW 100% Conservation Eastside Load = 708 MW		2023-24 5153 MW 100% Conservation Eastside Load = 764 MW		2023-24 Extreme 5690 MW 100% Conservation Eastside Load = 804 MW	
[redacted]	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 101.1%	[redacted]	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 110.4%	[redacted]	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line – 110.5%	[redacted]	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line – 101.1%	[redacted]	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line – 103.0%	[redacted]	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line – 102.9%	[redacted]	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line – 110.2%
[redacted]	White River - Lea Hill - Berrydale 115 kV line - 91.7%	[redacted]	White River - Lea Hill - Berrydale 115 kV line – 98.0%	[redacted]	White River - Lea Hill - Berrydale 115 kV line - 99.7%	[redacted]	White River - Lea Hill - Berrydale 115 kV line – 90.6%	[redacted]	White River - Lea Hill - Berrydale 115 kV line – 92.0%	[redacted]	White River - Lea Hill - Berrydale 115 kV line – 88.4%[4]	[redacted]	White River - Lea Hill - Berrydale 115 kV line – 98.2%
Category C: N-2 and Common Mode Contingency Results													
[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload
		[redacted]	Talbot Hill-Lakeside #1 115 kV Line - 101.5%	[redacted]	Talbot Hill - Lakeside #1 115 kV line – 96.8%[5]	[redacted]	Talbot Hill-Lakeside #1 115 kV Line – 89.9%	[redacted]	Talbot Hill-Lakeside #1 115 kV Line – 92.3%	[redacted]	Talbot Hill-Lakeside #1 115 kV Line – 98.9%	[redacted]	Talbot Hill-Lakeside #1 115 kV Line – 102.3%
		[redacted]	Talbot Hill-Lakeside #2 115 kV Line - 102.1%	[redacted]	Talbot Hill - Lakeside #2 115 kV line – 107.1%[6]	[redacted]	Talbot Hill-Lakeside #2 115 kV Line – 94.5%	[redacted]	Talbot Hill-Lakeside #2 115 kV Line – 99.4%	[redacted]	Talbot Hill-Lakeside #2 115 kV Line – 103.4%	[redacted]	Talbot Hill-Lakeside #2 115 kV Line – 107.7%
		[redacted]	Talbot Hill 230-115 kV transformer #1 – 91.8%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 93.6%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 88.1%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 88.2%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 90.1%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 99.6%

[5] Using the 2012 load forecast in the 2021-22 Heavy Winter case, this contingency is unsolvable, even with the Intalco load tripping RAS modeled.

[6] N-2: ADJ Talbot – Lake Tradition #1 & Talbot – Lakeside #1 115 kV was second most limiting contingency and overloaded this element by 106.6%. It is possible that, as load drops, the limiting contingency will change.

2013-14 5055 MW 100% Con Eastside Load = 545 MW		2017-18 5208 MW 100 % Con Eastside Load = 699 MW		2021-22 5193 MW 100% Con Eastside Load = 748 MW		2017-18 5162 MW 100% Conservation Eastside Load = 688 MW		2019-20 5175 MW 100% Conservation Eastside Load = 708 MW		2023-24 5153 MW 100% Conservation Eastside Load = 764 MW		2023-24 Extreme 5690 MW 100% Conservation Eastside Load = 804 MW	
		[redacted]	Talbot Hill 230-115 kV transformer #2 – 92.8%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 93.2%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 93.14%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 92.6%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 95.7%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 104.8%
		[redacted]	Berrydale 230-115 kV transformer – 93.6%	[redacted]	Berrydale 230-115 kV transformer - 95.5%	[redacted]	Berrydale 230-115 kV transformer – 95.6%	[redacted]	Berrydale 230-115 kV transformer – 87.6%	[redacted]	Berrydale 230-115 kV transformer – 88.3%[7]	[redacted]	Berrydale 230-115 kV transformer – 96.7%

[7] BF: White River 115 kV bus section breaker resulted in loading the Berrydale 230/115 kV transformer to 87.3% for this case. As loading shifts off of the Berrydale transformer, the White River BSBF is less critical.

Appendix B. Supplemental Needs Assessment Results for Summer Peak Season

Table B-2: Summary of Potential Thermal Violations for Summer Peak Load Season

2014 3343 MW 100% Con		2018 3554 MW 100% Con Eastside Load = 550 MW		2018 3625 MW 100% Conservation Eastside Load = 538 MW		2020 3681 MW 100% Conservation Eastside Load = 561 MW		2024 3813 MW 100% Conservation Eastside Load = 618 MW	
Category B: N-1 Contingency Results									
[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload
[redacted]	Monroe-Novelty Hill 230 kV line - 132.6%	[redacted]	Monroe-Novelty Hill 230 kV line - 133.0%	[redacted]	Monroe-Novelty Hill 230 kV line – 143.9%	[redacted]	Monroe-Novelty Hill 230 kV line – 143.1%	[redacted]	Monroe-Novelty Hill 230 kV line – 139.8%
[redacted]	Maple Valley - Sammamish 230 kV line - 111.4%	[redacted]	Maple Valley - Sammamish 230 kV line - 132.3%	[redacted]	**N/A**	[redacted]	Maple Valley - Sammamish 230 kV line – 110.0%[9]	[redacted]	Maple Valley - Sammamish 230 kV line – 116.4%
		[redacted]	Talbot Hill - Lakeside #1 115 kV line - 93.9%	[redacted]	**N/A**	[redacted]	Talbot Hill - Lakeside #1 115 kV line – 81.5%	[redacted]	Talbot Hill - Lakeside #1 115 kV line – 87.8%
		[redacted]	Talbot Hill - Lakeside #2 115 kV line - 93.8%	[redacted]	**N/A**	[redacted]	Talbot Hill - Lakeside #2 115 kV line – 81.3%	[redacted]	Talbot Hill - Lakeside #2 115 kV line – 87.6%
Category C: N-1-1 Contingency Results									
[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload

[8] Loading reported on the Maple Valley – Sammamish 230 kV and Talbot Hill – Lakeside #1 & #2 115 kV lines occurred for a Heavy Summer condition with south-to-north transfers through the system. A 2018 Heavy Summer case with south-to-north flows was not available for this study. Due to consistency in the 2020 Heavy Summer and 2024 Heavy Summer with the results encountered in 2012 (see footnote 8 for discrepancies found in this case), the 2018 case was not developed and run.

[9] The 2012 TPL study modeled the Northern Intertie gen tripping scheme which trips Whitehorn and Fredonia generation and runs back Mica and Revelstoke generation in BC. Tripping this generation in a south-to-north condition without tripping the Northern Intertie exacerbates this overload. If the limiting contingency is run without the RAS in place, overloads on the Maple Valley – Klahanie line are only 106%.

[redacted]	Sammamish 230-115 kV transformer #1 - 95.5%	[redacted]	Sammamish 230-115 kV transformer #1 - 100.03%	[redacted]	Sammamish 230-115 kV transformer #1 – 104.2%	[redacted]	Sammamish 230-115 kV transformer #1 – 108.1%	[redacted]	Sammamish 230-115 kV transformer #1 – 109.4%
[redacted]	Sammamish 230-115 kV transformer #2 - 100.8%	[redacted]	Sammamish 230-115 kV transformer #2 - 106.4%	[redacted]	Sammamish 230-115 kV transformer #2 - 110.1%	[redacted]	Sammamish 230-115 kV transformer #2 – 114.3%	[redacted]	Sammamish 230-115 kV transformer #2 – 115.6%
				[redacted]	Novelty Hill 230/115kV Transformer #2 - 102%	[redacted]	Novelty Hill 230/115kV Transformer #2 - 103%	[redacted]	Novelty Hill 230/115kV Transformer #2 - 100%
		[redacted]	Beverly Park - Cottage Brook 115 kV line – 101.4%	[redacted]	Beverly Park - Cottage Brook 115 kV line – 110.5%	[redacted]	Beverly Park - Cottage Brook 115 kV line – 110.2%	[redacted]	Beverly Park - Cottage Brook 115 kV line – 106.4%
Category C: N-2 and Common Mode Contingency Results									
[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload
		[redacted]	Sammamish - Lakeside #2 115 kV line - 99.8%	[redacted]	Sammamish – Lakeside #2 115 kV – 90.8%	[redacted]	Sammamish - Lakeside #2 115 kV line 95.4%	[redacted]	Sammamish - Lakeside #2 115 kV line 99.2%
				[redacted]	Monroe-Novelty Hill 230 kV line – 143.6%	[redacted]	Monroe-Novelty Hill 230 kV line – 143.1%	[redacted]	Monroe-Novelty Hill 230 kV line – 139.9%

Appendix C. Upgrades Included in Base Cases

Table C-3: Projects Added to the Eastside Needs Assessment Winter Base Case

2017-18	2019-20	2023-24
Bothell – SnoKing reconductor	Bothell – SnoKing reconductor	Bothell – SnoKing reconductor
Cumberland substation reconfigured to 115 kV	Cumberland substation reconfigured to 115 kV	Cumberland Substation reconfigured to 115 kV
White River – Electron Heights reroute to Alderton	White River – Electron Heights reroute to Alderton	White River – Electron Heights reroute to Alderton
Talbot 230/115 kV transformer #1 replacement	Talbot 230/115 kV transformer #1 replacement	Talbot 230/115 kV transformer #1 replacement
Spurgeon substation, Similk substation & Maxwelton substation	Spurgeon substation, Similk substation & Maxwelton substation	Spurgeon substation, Similk substation & Maxwelton substation
Carpenter substation removed	Carpenter substation removed	Carpenter substation removed
Bus section breakers at BPA Olympia and BPA Tacoma	Bus section breakers at BPA Olympia and BPA Tacoma	Bus section breakers at BPA Olympia and BPA Tacoma
Switched shunt at Paul 500 kV, Broad St. 115 kV	Switched shunt at Paul 500 kV	Switched shunt at Paul 500 kV

Table C-4: Projects Added to the Summer NERC TPL Base Case for the Eastside Area

2018	2020	2024
Bothell – SnoKing reconductor	Bothell – SnoKing reconductor	Bothell – SnoKing reconductor
Cumberland substation reconfigured to 115 kV	Cumberland substation reconfigured to 115 kV	Cumberland substation reconfigured to 115 kV
Talbot 230/115 kV transformer #1 replacement	Talbot 230/115 kV transformer #1 replacement	Talbot 230/115 kV transformer #1 replacement
White River – Electron Heights reroute to Alderton	White River – Electron Heights reroute to Alderton	White River – Electron Heights reroute to Alderton
Spurgeon substation, Similk substation	Spurgeon substation, Similk substation	Spurgeon substation, Similk substation
Denny Way substation Phase 1	Denny Way substation Phase 1	Denny Way substation Phase 1 & Phase 2
Bus section breakers at BPA Olympia, BPA Tacoma and BPA Covington	Bus section breakers at BPA Olympia, BPA Tacoma and BPA Covington	Bus section breakers at BPA Olympia, BPA Tacoma and BPA Covington
Raver 500-230 kV Transformer	Raver 500-230 kV Transformer	Raver 500-230 kV Transformer
Switched shunt at Paul 500 kV	Switched shunt at Paul 500 kV	Switched shunt at Paul 500 kV
Switched shunt at Lake Tradition 115 kV removed	Switched shunt at Lake Tradition 115 kV removed	Switched shunt at Lake Tradition 115 kV removed

Appendix D. West-side Northern Intertie, North of Echo Lake and South of Custer Flowgate One-Line Diagrams

REDACTED

Figure D-1: One-Line Diagram – West-Side Northern Intertie

REDACTED

Figure D-2: One-Line Diagram - North of Echo Lake

REDACTED

Figure D-3: One-Line Diagram - South of Custer