Alternatives to Energize Eastside

Response to Draft EIS

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CENSE

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Figures

1 Introduction

EQL was asked to comment on Alternative 2 "Integrated Resource Approach" discussed in Chapter 2 of the Energize Eastside Draft EIS January 28, 2016.

EQL has reviewed and commented Energize Eastside studies and has participated in several PSE IRP advisory group meetings, EQL has commented on the following topics through Energize Eastside and IRP Advisory process:

1. Distributed energy resources (DER), (e.g., energy efficiency, demand response, dispatchable standby generation, solar, storage, EV charging, CHP, distributed generation, etc.),
2. Demand Side Resource and transmission alternatives to Energize Eastside.
3. Integration of transmission and distribution planning/costs into the utility least cost planning process,
4. Resource adequacy modeling and methods (e.g., EUE expected unserved energy, focus on resource types), and
5. Reliability in IRP, Transmission Planning, and SAIFI/SAIDI statistics, as well as scenario and sensitivity analysis.

EQL is an energy industry consultancy started in 2010 to assist utilities, utility customers, and vendors develop smart grid technologies and business cases that lower cost of utility service, improve reliability, and integrate renewable energy. Our staff has supported IRPs throughout the Western Electricity Coordinating Council and MISO since 1993. Since 2010, our work has been related to smart grid technology evaluation/planning, and integration of renewable energy and distributed energy resources (DER).

EQL's comments are those of EQL, and are meant to promote improved least cost utility planning.

2 Critical Points on EIS Alternative 2

Alternative 2 if done properly could meet criteria for Eastside expected growth in peak load. Unfortunately, the work and discussion of Alternative 2 in the EIS is confusing, insufficient to determine feasibility, uses bad data and forecasts, and demonstrates very little attention by City of Bellevue and PSE.

Many utilities around the world are considering Distributed Energy Resources (DER) to defer or avoid transmission infrastructure, including ConEd (NY), SCE (CA) BC Hydro (BC), BPA (OR/WA), etc.[1], DERs include targeted energy efficiency, demand response, dispatchable standby generation, solar, storage, EV charging, CHP, distributed generation, etc.

2.1 A proper Alternative 2 analysis would prevent increases in Eastside winter peaks and meet all 15 electrical criteria, and 4 non-electrical criteria.

A proper analysis would include accurate peak load forecast, cost effectiveness analysis, and ideally an all source RFI. A rule of thumb Eastside forecast is provided in Figure 1 below.

To put it simply, Alternative 2 DER would avoid ratepayer funding for transmission, distribution, generation, and environmental costs. To meet the peak load growth Puget Sound Energy will request to spend over $300MM on Energize Eastside and another $300MM for a peaking power plant (PSE 2015 IRP). If we assume that expected peak load to be met is 200 MW, the capital expenditure would be $3,000/kW. Most DER, TODAY, can be installed and operated for less. When you consider expected cost reductions and performance improvements Alternative 2 is the lowest cost choice.[2]

[1] https://www.raponline.org/document/download/id/4765

[2] storage cost reductions expected to be 50% over next 5 years, Internet of things, sensors and controls for demand response will become more cost effective and prevalent, EV charging control to avoid peak.

Figure 1: DER potential at PSE above the DSR 100% forecast

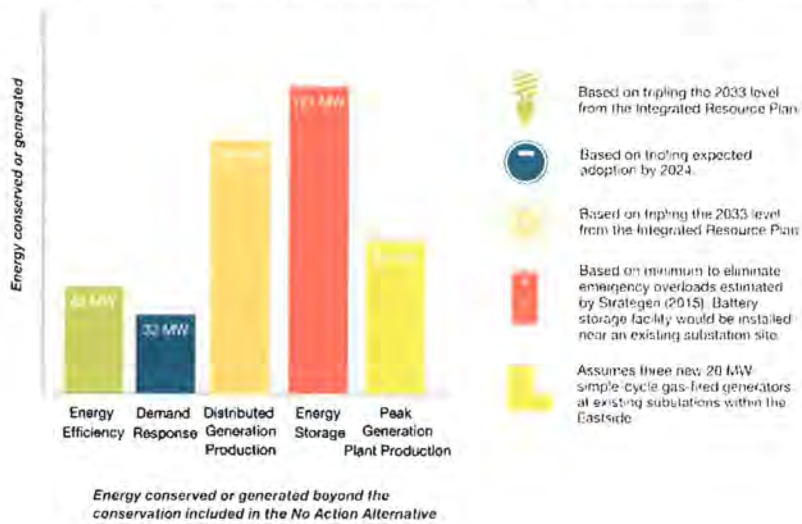
DER Measure	% of winter peak
System Winter Peak load	
Solar	0.0%
Targeted Energy Efficiency	4.0%
Distribution Efficiency (CVR)	2.5%
Combned Heat & Power (CHP)	4.0%
Storage	2.0%
Dispatchable Standby Generation (10 minute)	2.5%
DR Day Ahead	4.0%
DR (10 minute)	1.5%
Total	20.5%

If PSE proceeds with transmission and generation, then DER will become less cost effective. In fact, Idaho Power after finishing construction of their Langley Gulch gas plant tried to shut off all their demand response programs. You don't need DER capacity if your trying to pay off a new gas plant.

2.2 Alternative 2 assessment is insufficient to determine feasibility and lacks credible analysis or estimate.

The EIS provides only a theoretical example of technology that could address winter peak load reductions which has no value in determining feasibility. See example graph in Fig. 2-14 in EIS.

(EIS Fig. 2-14) Theoretical example of Energy conserved or distributed generation



In order to properly assess an Integrated Approach the EIS should either hire independent consulting firm to estimate cost effective DER on Eastside, or issue an all source RFP for all DER in affected eastside area. This process would include all avoided costs and provide actual estimates for DER capacity amounts and cost, as well as real vendors estimates. This process is being used in New York's Brooklyn-Queens Demand Management program which started in 2014. New York utility ConEd is expected to invest $200MM to implement DER to avoid transmission build.

2.3 PSE Eastside winter peak load forecast has been a moving target throughout planning process, and has steadily increased over study period.

PSE has been changing the required winter peak load reduction on the Eastside throughout the Energize Eastside planning process. (see figure below). PSE has a history of changing methods and planning standards when justifying capital expenditures, e.g., peaking power plants. In the 2015 Integrated Resource Plan, PSE changed their planning standard, which led to an increase in 2021 peak load of 351 MW. Figure 1 below summarizes the source and the estimate of peak load reduction required to meet Eastside load requirement.

Figure 2: Range of Estimates for Eastside Peak Load increase through 2024

[illegible]	[illegible]	[illegible]	[illegible]
E3 Non-Wires Study	70 MW	Oct 2014	
Quanta - Eastside Needs Assessment	123	Apr 2015	Page 19
Stantec Review Memo (referenced in EIS)	133	July 2015	Page 1-7 Draft EIS
PSE 2015 IRP	166	Jan 2016	IRP Ch.5 page 31
Draft EIS (2016)	205	Jun 2015	EIS Page 2-34

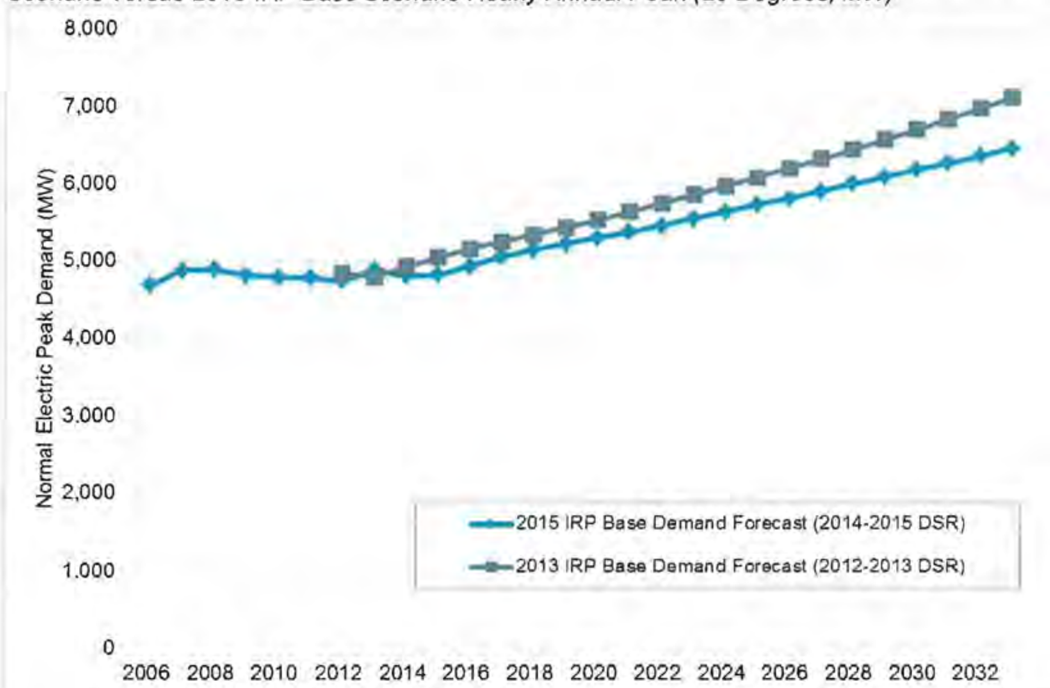
* Assumes peak load after planned baseline energy conservation

The Draft EIS discusses 205MW non-transmission resources needed by 2024, which is a likely mistake. This value stems from an email from Jens Nedrud, Energize Eastside project manager, where he explains that the amount of conservation required to be equivalent to transmission capacity is 205 MW. Mr. Nedrud only mentions conservation, not other DER. Mr. Nedrud is the project manager for Energize Eastside, so estimates from him should be questioned.

2.4 PSE Eastside winter peak load forecast is wrong and has been consistently too high for the past 6 years.

Figure 2 below shows how peak load is historically flat, then suddenly takes off in the future. You'll find this to be true with PSE's previous peak load forecasts. I understand that forecasts are, by their nature are wrong, but PSE has a habit of overestimating peak load.

Figure 3: PSE 2015 IRP *Figure 5-21: Electric Peak Demand Forecast before DSR 2015 IRP Base Scenario versus 2013 IRP Base Scenario Hourly Annual Peak (23 Degrees, MW)*



Winter peaks have gone down in the Pacific Northwest in the last 5 years, and growth in the winter peak will continue to be less than the increase in growth in energy use. PSE's winter peak decreased by 11 MW from 2013 to 2014. This holds true because:

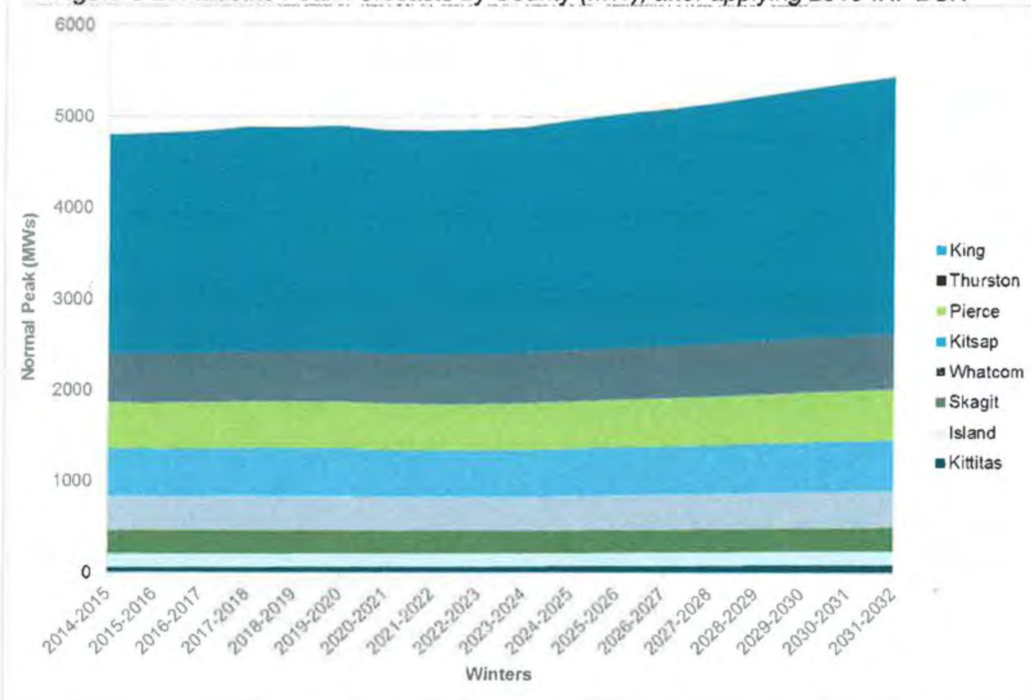
1. Electric heating load is saturated. I.e., new growth does not include electric heating that contribute to winter peak,
2. Fuel Conversion from electric to gas and propane are reducing winter peaks,
3. Milder winter temperatures reduce chance of extreme cold weather, and
4. Higher growth in multifamily and commercial,

PSE's 2011 IRP had peak forecasts rising from 2011 forward.[3] This is not happening.

Notice in Figure 5-27 from PSE's 2015 IRP, the peak demand does not begin to increase until 2024.

[3] http://www.utc.wa.gov/_layouts/CasesPublicWebsite/GetDocument.ashx?docID=42&year=2010&docketNumber=100961

Figure 5-27: Electric Peak Forecasts by County (MW), after applying 2013 IRP DSR



3 Other Points on EIS Alternative 2

3.1 PSE local needs assessment is not a local cause

PSE has suggested the transmission need is based on local winter peak demand on the eastside. This is only a small part of the story. The issue arises by modeling a series of unlikely regional wholesale power scenarios (e.g., plants offline, Canadian imports, transmission line outages, and high winter peak demand) that creates: 1) high winter power flows South to North through the PSE's eastside transmission corridor, and 2) increased loads on eastside substations. These modeled events would lead to equipment exceeding their thermal limits and the need to shed load at substations or limit power flow on the PSE 115kV system through eastside.

Based on the 2012 Memorandum of Agreement between PSE, Seattle City Light (SCL), and BPA, PSE has agreed to provide expanded transmission service through Puget Sound Area. SCL agreed to projects that would limit flow through their system by placing series inductors at two of their substations. This demonstrates that the issue and needs are indeed a regional one, not just local

This local problem, if it were ever to occur, would happen for a few hours of the year during extreme cold days and hours of peak load on eastside. The EIS extreme scenarios suggest up to 13 days this could occur, but does not forecast number of hours. Given PSE's winter peak is in morning (8am) or evening (6pm) The load reduction would need to be for a few hours during these times. EQL's experience suggests that the winter peaks come in 2-3 day consecutive days (cold snaps) and last maybe one to two hours per day.

According to EIS scenarios, in 2026 eastside load will need to shed 133MW to accommodate flows to Canada over PSE 115kV system.

Another troubling area is how PSE attributed winter peak demand reductions to forecasted energy efficiency measures. It is impossible to determine how PSE and its contractors did this conversion. However, EQL Energy is familiar with the issue that load shapes used in the Pacific Northwest to attribute capacity reductions from energy efficiency are inaccurate and out of date. Some end use load shapes (ELCAP) date back to the 1980s. The topic of inaccurate load shapes and hence capacity contribution of energy efficiency has been consistently discussed and agreed upon by the Northwest Power and Planning Council, as well as the Regional Technical Forum on energy efficiency.

3.1.1 The Problem – several days and a few hours in the winter

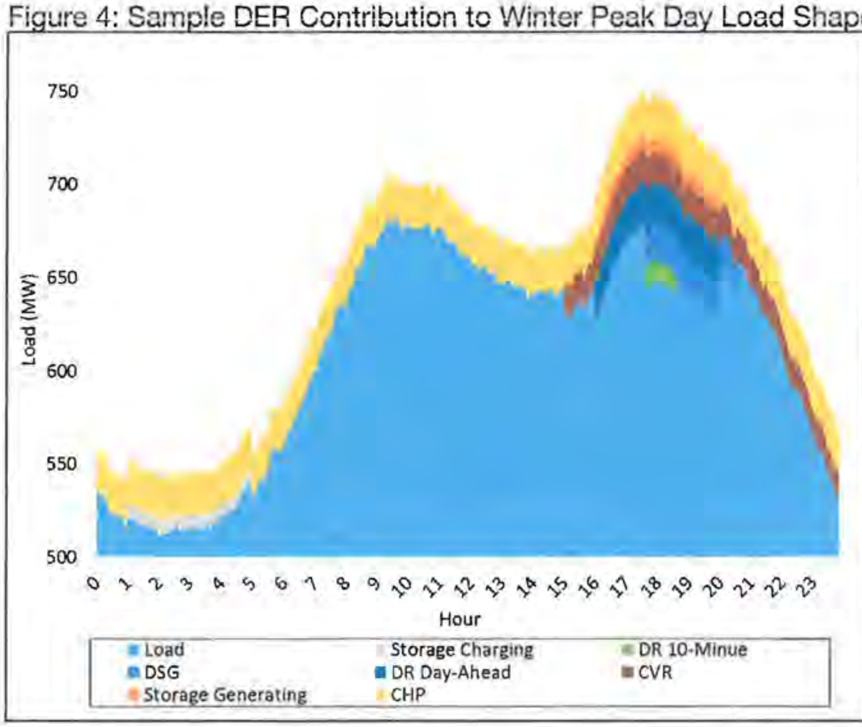
The problem PSE has identified in their Energize Eastside proposal comes about through a series of unlikely events that lead to high winter power flows South to North through the Eastside and creates overloads on certain substations. This problem, if it were ever to occur, would only happen for a few hours of the year. PSE has not estimated the number of hours because the scenarios and stress cases they use don't lend themselves to firm estimates. If PSE could estimate the number of hours they would need winter peak demands to be reduced, it likely would come in 2-3 day consecutive days (cold snaps) and last maybe one to two hours per day.

If Energize Eastside or one of the alternatives were not to be pursued, power outages would not be imminent during these peak demand hours unless at least three failures occur in the grid, a scenario that exceeds NERC reliability requirements. The total number of customers affected by these unlikely outages would be 3 to 5 percent of the 1.1 million customers that will pay for the project with higher electricity bills for the next 40 years.

3.1.2 The DER Solution

Distributed Energy Resources are well suited for targeting winter peak demands in the Eastside Area. Many North American electric system operators invest in DER to avoid transmission and peaking generation. These DER include demand response, storage, EV charging control, DSG, and Distribution Efficiency. If the problem is less than 60 hours per year, it is often much less expensive to manage demand than build Transmission and Generation. Efficiency and CHP tend to provide reductions throughout the day, but can be targeted for time of day contributions. Figure 4 shows a sample peak day load shape for the Puget Sound area with a stack of resources deployed both throughout the day and during a dispatch at 5:30PM during the peak to depict what could happen in the event of an outage.

Figure 4: Sample DER Contribution to Winter Peak Day Load Shape[4]



4 Data source for load shape: Puget Area Net Load for 12.20.2008
http://transmission.bpa.gov/Business/Operations/Misc/default.aspx

* This is not an Eastside area load shape, but is representative of typical winter peak load patterns for NW utilities.

3.2 PSE lags rest of country in DER

Utilities like Puget Sound Energy are way behind other areas of the country in investing in DER, especially demand response. For example, the rest of North America relies on over 60,000MW of demand response, and has eliminated billions of dollars of investments in peaking generation and transmission. The Northwest Power and Conservation Council in their recently released 7th Power Plan, identified 4,300 megawatts of regional demand response potential. PSE currently has no demand response resources it can rely upon.

One example of a DER approach to avoiding transmission project is New York's Brooklyn-Queens demand management project.[5] Growth began to occur in this area from gentrification and employment growth. The utility ConEd estimated the cost to meet this growth would require a $1Billion investment in expanded transmission and substation capacity. In 2014 the Public Service Commission approved the Brooklyn/ Queens Demand Management program to invest up to $200MM to avoid the larger infrastructure costs.

The Northwest is not new to Non-Wire Alternatives. In the 1990s BPA was considering transmission across the Cascades to support Puget Sound Area growth and reliability. The transmission cost assessment led to a plan that included aggressive demand side resources in Puget Sound Area, and use of series capacitors for voltage support. These lower cost alternatives deferred the project to the point of never being built.

3.3 EIS Impacts of Alt 2

The negative impacts of Alternative 2 were primarily associated with peaking generation and storage located on the Eastside, and relate to land and greenhouse gas (GHG) emissions.

EQL Energy, however, is not suggesting any new reciprocating engines, or peaking power units as part of EIS Alt. 2. We would expect primarily Combined Heat and Power (CHP) to be constructed in this alternative. CHP often uses biomass/biogas as well as natural gas, and would contribute to GHG, or could have noise impact. CHP has the benefit of also being "energy efficient" because the low value heat is used in industrial or commercial processes. Puget Sound Area has examples of CHP, e.g.,

a. Renton, WA South Treatment Plant that can produce up to 8MW of power. [6]

b. Seattle, WA Enwave Seattle uses biomass and natural gas to produce 50 MW of electricity, and 35 MW of heat equivalent.

[5] http://www.neep.org/file/2414/download?token=bNV2vVea, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B83594C1C-51E2-4A1A-9DBB-5F15BCA613A2%7D

[6] http://www.kingcounty.gov/services/environment/wastewater/resource-recovery/Energy/Renewable/cogen.aspx

c. Univ. of Washington has 5MW natural gas CHP

CHP would require capacity on natural gas infrastructure.

A Dispatchable Standby Generation (DSG) program would have to go through air permitting compliance, but it is a permittable use. PSCleanAir has suggested that a DSG program like PGE would follow EPA NESHAP RICE rules.

EQL Energy would not recommend storage implementation as described in Alt. 2 of EIS. Six acres of storage does not make much sense. Energy storage highest value is utility owned and managed, yet behind the meter at a customer site. This means customers get backup and reliability, and utility can use for system issues, e.g., winter peak demands. This also avoids the 6 acres of storage containers suggested in the EIS draft (which is ridiculous). Fire and environmental authorities are becoming comfortable with both Li-ion and flow battery technology. PSE is working on a Li-ion storage system at Glacier. State of Washington is also granting $40MM to projects in grid modernization and storage.

Alt 2 would cost less than Alt 1 and provide secondary benefits to customers through improved reliability and resiliency.

Alt 2 would have less risk during weather and natural disasters. DERs would provide backup power during intermediate or sustained outage.

3.4 Alt 2 works with PSE Economic Study of Flexible AC Transmission (FACTS).

Flexible AC Transmission systems on high voltage lines would protect PSE transmission facilities from reaching thermal limits while providing required service to loads. Combining this alternative with appropriately procured and analyzed DER provides a good alternative in Draft EIS.

See PSE Economic Study request at link below.

http://www.oasis.oati.com/PSEI/PSEIdocs/Oct_31_PSET_Economic_Study_Request_from_EQL.PDF

4 Alternative 2 Issue Details

In estimating Non-Wires Alternatives (NWA) like Alternative 2, PSE and its contractors have miscalculated both the technical and cost effective potential for DER in the Eastside area. They have used outdated information and methods, overestimated winter peak demand, improperly calculated "cost effectiveness", and have not considered forecasts of technology cost and performance improvements.

4.1 2014 Non-Wires Alternative Screening Study underestimates DER Potential for Eastside

PSE relies on 2013 Cadmus report and a 2014 E3 report to estimate DER potential on the eastside. These analysis both have used bad or out-of-date data, improper analysis, and have underestimated the DER potential for the Eastside.

E3's 2014 Screening study[7] has bad data and provides no data or description of DER measures that were considered cost effective beyond the PSE baseline:

i. Estimated cost of Energize Eastside at the time of the Screening Study was $220 MM. The cost has been stated to be between $150 and $300MM.

ii. Avoided cost analysis should use avoided cost of Transmission, Generation, and Distribution over 10 year period. A non-wires study should be performed that combines EE project deferral ($155/kW-yr) with avoided cost of peaking Generation Capacity ($184/kW-yr) and generic T&D deferral ($23/kW-yr[8]). The sum of these ($362/kW-yr) will buy PSE more DER than that forecasted by E3 and PSE. Other avoided costs that could play a role include environmental costs, customer cost savings, etc.

    PSE's proposal to rebuild Sammamish-Lakeside-Talbot 115 kV line to 230 kV (Energize Eastside) is a project PSE says is needed to support a 65 to 133MW load growth in PSE's eastside. This transmission project is estimated to cost $300MM or $1,500/kW, about the same capital cost of a 200MW reciprocating engine. By integrating cost of transmission with system generation the cost to serve this 200MW load growth is $600MM or $3,000/kW capital cost.

iii. DER alternatives and cost estimates are not well defined, so it is difficult to evaluate the accuracy of Alternative 2.

iv. Include backup generators to be used as contingency reserve (e.g., Portland General Electric).

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[7] http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/attachment_5_-_screening_study.pdf

[8] E3 2014, page 23 PSE's IRP team also provided avoided generation capacity cost of $184/kW-year and an avoided generic T&D cost of $23/kW-year, which are both represented in 2014 dollars. For this analysis, we assumed that PSE's generic T&D avoided cost and the specific transmission line deferral value related to PSE upgrades are additive. This additive assumption presumes that load reductions in King County can defer the need for more general planned distribution system upgrades, in addition to deferring the construction of the specific Eastside upgrades.

v. Storage is quickly becoming more cost effective and accepted as an alternative to T&D investments.

Recommendation. PSE should redo DSR, DR, and DER forecasts on Eastside using all levelized costs, including transmission (e.g., Energize Eastside), distribution, and supply-side resource alternatives. This will undoubtedly increase the amount of DSR and DER PSE has forecasted in the Draft IRP.

2016 PSE all source RFP. In 2016 PSE is expected to issue an all source RFP for distributed resources. WUTC should ensure that the avoided cost for resources in the Eastside accurately reflect all avoided costs, e.g., transmission, generation, distribution, customer benefits, environmental costs, etc. Through needs assessment of Energize Eastside, PSE's Eastside zone needs winter capacity resources to address transmission congestion and reliability by 2018. The IRP analysis supports addition of further distributed energy resources by 2021.

4.1.1 Defining distribution located resources

PSE should move away from current categories of distribution-side resources towards resource descriptions that meet utility requirements (energy, capacity, reserves, etc). As mentioned above these requirements need better descriptions than just MW and aMW. These requirements need amount, duration, time of day/season, etc.. The distribution located resources PSE has used 3 categories of distribution located resources seen in Cadmus report 2014:[9]

1. DSR, Demand Side Resources, energy efficiency. (which uses bad estimates for peak demand reductions (MW)
2. DR, demand-response
    a. Residential DLC- Water Heat
    b. Residential DLC – Space and Water heat
    c. Residential Critical Peak Pricing (CPP)
    d. C&I CPP
    e. C&I Load Curtailment
3. DG, distributed generation, solar

Figure 5 is suggests a better way to describe all distribution level resources. This categorization allows planners to place different values on a resource based on its quality and location. For instance, getting dispatchable capacity for winter peaks is more valuable ($/kW-year) than non-dispatchable capacity.

[9] https://pse.com/aboutpse/EnergySupply/Documents/IRPAG_Cadmus_presentation_2014-12-08.pdf

Figure 5: EQL Categories of Distributed Energy Resources

4.2 Energy Efficiency contribution to peak demand reductions underestimated

PSE and its consultants use end use load shapes that are out of date to calculated peak demand reduction from energy efficiency programs. Many of these load shapes are based on end uses and technologies from the 1980s. This leads to lower peak reduction (MW) per unit of energy efficiency (MWh). The Northwest Power and Conservation Council has been building a business case to update these load shapes, and is expected to pursue this work in 2016.[10]

4.3 Puget Sound DER and DSR avoided Cross-Cascades Transmission in 1990s

In the 1990s BPA was considering transmission across the Cascades to support Puget Sound Area growth and reliability. The transmission cost assessment led to a plan that included aggressive demand side resources in and use of series capacitors for voltage support. These lower cost alternatives deferred the project to the point of never being built.

DER, when cost of Transmission is considered, will increase dramatically. Estimates in Figure 2 below are estimates based on EQL estimates from WECC and NPCC forecasts.

[10] http://rtf.nwcouncil.org/subcommittees/enduseload/

4.4 Western electricity markets

On March 5, 2015, PSE announced it would participate in the California ISO energy imbalance market that will provide imbalance energy via locational marginal pricing. This decision by PSE management to participate in EIM, demonstrates that PSE believes in a planning and operational paradigm that explicitly recognizes locational value of generating and demand-side resources.

PSE participation in Western energy imbalance market will allow better management of existing transmission assets to existing generation and load balance. In Energize Eastside assessment, PSE has not considered the operational improvements that will exist for generation, demand management, and DER.

PSE joining the EIM does not have much effect on capacity procurement, except a possible reduction in flexibility requirement for resources.

5 Assessment of Eastside DER Potential

EQL Energy expects PSE could add over 160MW of capacity to Eastside DSR forecast by 2021. below. Using an Avoided Cost analysis that includes avoiding cost of Transmission, Distribution, and supply-side generation should include:

Capital Cost ($/kW)	$1,500/kW	Transmission
Capital Cost ($/kW)	$1,500/kW	Thermal Resource (e.g., Peaker)
Capital Cost ($/kW-yr)	$31.00	Distribution
O&M Fixed $/kW-yr	$10.55	
O&M Variable $/MWh	$2.96	

5.1 DSR and DER Contribution

The terminology around resources on the distribution side can be confusing. PSE uses DSR or demand side resources, which includes energy efficiency, demand response, and distributed generation. The EE Documents we reviewed focus on energy efficiency and do not fully address DSR and its impact on peak capacity (MW). Analysis that is reported in Annual Average Megawatts (aMW) provides limited useful information for analyzing for transmission and distribution infrastructure needs.

In our report, we distinguish between DSR and DER forecasts and work to not double count resources.

DSR – Demand Side Resources: efficiency, demand response, and distributed generation (detail and types are unknown in PSE EE analysis). Cadmus 2013 IRP DSR

assessment does not include kW or peak contribution, nor do they provide DR assessments.
DER – Distributed Energy Resources: EQL uses this term to refer to all resources on the distribution system, including distribution efficiency (CVR and power factor correction), demand response, combined heat and power, dispatchable standby generation, and storage.[11]

DER and load management in critical areas is an opportunity to invest in measures that address infrastructure costs and regional load growth while engaging and benefitting customers, just like energy efficiency. Through the evaluation of Energize Eastside it is unclear the extent to which PSE has considered the use of distributed energy resources (DER) in their modeling, either as a resource or as a means to reduce load.

The DER resources described below should be considered in addition to the PSE's DSR contribution to the 100% conservation load forecast.

Many of these DERs are dispatchable, including demand response, dispatchable standby generation (DSG), and energy storage and can therefore target peak load and reduce the need for infrastructure expansion in transmission and distribution.

5.1.1 Distributed Resource Planning

The DER contribution to peak load should be appropriately allocated among existing and future Eastside substations such that DER quantity reasonably matches the load assumed to be present at these substations.

Figure 8 below shows substation locations in the Eastside area that have historically recorded higher load and may be more likely to serve larger customers sites with high DER potential such as commercial/industrial, multifamily residential, institutional, government, campus and hospital loads.

Distributed Resource Planning is a process which more accurately calculates capacity and value for DER in specific areas of a utility distribution system.

On February 6, 2015 the CPUC released a ruling providing guidance to IOUs with respect to the DRPs that are to be filed by July 1, 2015. The document[12] provides additional guidance to utilities beyond AB 327. The guidance specifics 11 components that are to be included, at a minimum, in the locational DER benefits analysis.

Figure 6: Distributed Resource Planning Value Analysis

	Locational Value Component
1	Avoided Sub-transmission, Substation and Feeder Capital and Operating Expenditures: DER ability to avoid Utility costs incurred to increase capacity to ensure the system can accommodate forecasted load growth

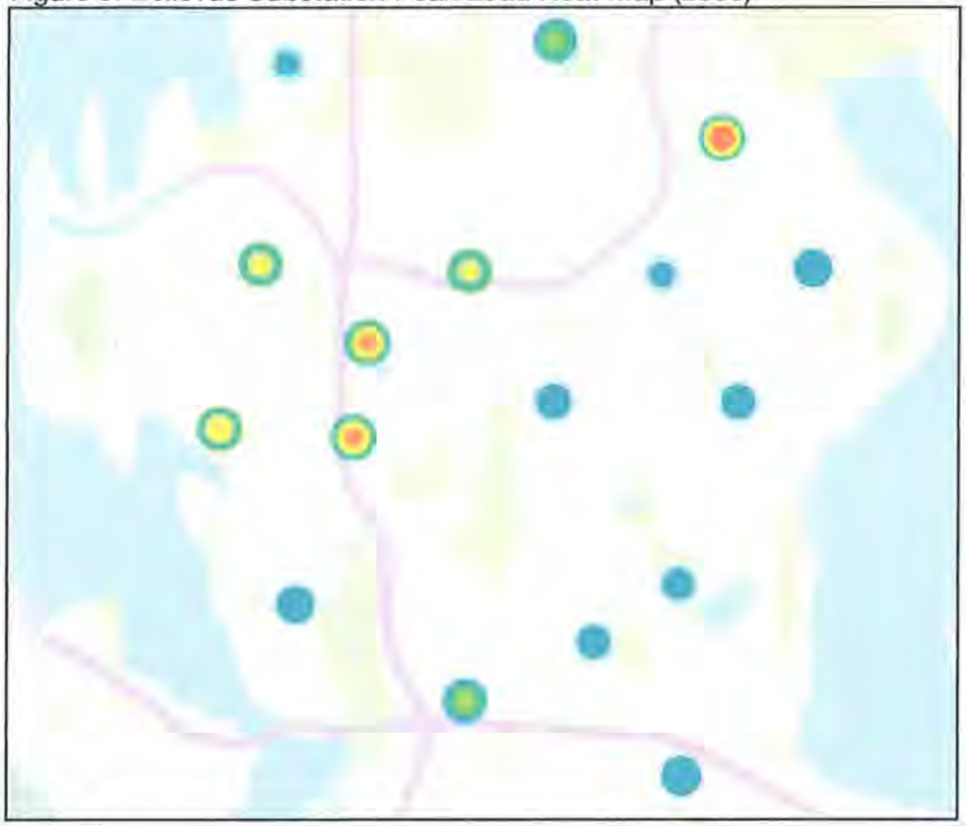
[11] In California Distribution Resources Planning they include energy efficiency into their DER analysis.

12 Docket R14-08-013 DRP Guidance: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M146/K374/146374514.PDF

2	Avoided Distribution Voltage and Power Quality Capital and Operating Expenditures: DERs ability to avoid Utility costs incurred to ensure power is delivered within required operating specifications, including transient and steady-state voltage, reactive power and harmonics
3	Avoided Distribution Reliability and Resiliency Capital and Operating Expenditures: DERs ability to avoid Utility reliability related costs incurred to prevent, mitigate and respond to routine outages (Utilities shall identify specific reliability metrics DERs could improve), and resiliency related costs incurred to prevent, mitigate, or respond to major or catastrophic events (Utilities shall identify specific resiliency metrics DERs could improve)
4	Avoided Transmission Capital and Operating Expenditures: DERs ability to avoid need for system and local area transmission capacity
5	Avoided Flexible Resource Adequacy (RA) Procurement: DERs ability to reduce Utility flexible RA requirements
6	Avoided Renewables Integration Costs: DERs ability to reduce Utility costs associated with renewable integration (for this line item, the Utilities shall attempt to coordinate their efforts with the development of the updated RPS Calculator and the Renewables Integration Charge)
7	Any societal avoided costs which can be clearly linked to the deployment of DERs
8	Any avoided public safety costs which can be clearly linked to the deployment of DERs
9	Definition for each of the value components included in the locational benefits analysis
10	Definition of methodology used to assess benefits and costs of each value component explicitly outlined above, irrespective of its treatment in the E3 Cost-Effectiveness Calculator
11	Description of how a locational benefits methodology can be a into long-term planning initiatives like the Independent System Operator's (ISO) Transmission Planning Process (TPP), the Commission's Long Term Procurement Plan (LTPP), and the California Energy Commission's (CEC) Independent Energy Policy Report (IEPR), including any changes that could be made to these planning process to facilitate more integrated analysis

Figure 7: DRP locational value components (CPUC DRP Guidance)
Notes:
The Resource Adequacy (RA) program, administered by the CPUC and CAISO is a 1-year forward bilateral capacity market. Utilities must procure sufficient resources to meet their expected peak load. Since it began in 2006, utilities were required to procure system-wide peak capacity resources, and local resources as needed in constrained areas. In 2013, a flexible resource requirement was added.

Figure 8: Bellevue Substation Peak Load Heat Map (2006)



Sources:

Data: City of Bellevue substation peak load for 2002 and 2005[13]
See Appendix A for data table
Map: EQL (using Microsoft Excel/Bing Maps)
Note: PSE's transmission topology in this area has changed and is expected to continue to change to serve changing load patterns, therefore this rendering is for sample purposes only.

PSE's existing 115 kV network in the Eastside with suggestions of areas that may experience higher load growth, may require additional infrastructure such as new substations, and therefore would represent advantageous locations for PSE and/or other appropriate parties to incentivize and site distributed energy resources.

Customer Driven DER

DER adoption behavior and demand for services is customer driven based on broad socio-economic factors and technology advancements –not strictly regional or based only on energy cost.

Customer desire for self-reliance is increasing

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13 City of Bellevue Comprehensive Plan Utilities Element Update, November 2006
http://www.ci.bellevue.wa.us/pdf/PCD/PSE_System_Plan_Update_November_2006.pdf
(accessed 06.08.2015)

- **Ernst & Young**: **33%**of the multi-national firms are expected to meet a greater share of their energy needs through **self-generation over the next five years**
- **Navigant**: nearly **75%** of surveyed **residential customers** have "**concerns about the impact electricity costs** have on their monthly budgets, and **63%** are interested in **managing energy used in their homes**"
- **Best Buy**: **36% of residential** customers desire to "financially and physically protect the home" (Home Safeguarding persona)

5.1.2 Distributed Solar

PSE currently has 2,800 customers and 17.4MW of capacity producing 17,037MWh of energy a year. As mentioned above, the Cadmus March 2015 memorandum has many errors regarding PV Solar forecasting and should not be reference by PSE. EQL suggests the following as an estimate of growth in energy from distributed solar.

Figure 9: Range of Distributed Solar by 2030

MW	Capacity	Energy	
	MW	MWh	aMW
Minimum	5	5,000	0.57
BaseCase	50	50,000	5.71
Maximum	400	400,000	45.66

5.1.3 Distribution Efficiency (aka CVR)

In 2007 Puget Sound and 12 other Pacific Northwest Utilities participated in a Northwest Energy Efficiency Alliance (NEEA) pilot to evaluate the energy and capacity savings from operating Conservation Voltage Reduction. [14] The study tested and found a 2 to 4 percent capacity reduction through distribution efficiency projects. An updated 2014 NEEA study found that over half the CVR projects operating in the United States are used for peak demand reductions versus energy efficiency. [15]

Wide scale adoption is beginning. One hurdle to adoption was mentioned in NEEA paper as, "hurdle to CVR implementation includes the lost customer revenue due to CVR rollout. End users reduce energy consumption with CVR and thus lower utility revenue. Utilities are often reluctant to recuperate lost revenue through rate increases, especially during times of slow or no load growth in the utility service area. Utilities can recuperate lost revenue from CVR more easily during periods of more rapid load growth. BPA currently offers incentives for CVR initiatives, which can help with utility cost recovery."

[14] https://www.leidos.com/NEEA-DEI_Report.pdf

[15] http://neea.org/docs/default-source/reports/long-term-monitoring-and-tracking-distribution-efficiency.pdf?sfvrsn=5 (page 45)

In Washington, Energy efficiency standard I-937 is currently a main driver for CVR implementation for IOUs in Washington State. I-937 mandates IOUs to undertake cost effective energy efficiency measures, such as CVR.

PSE has implemented Conservation Voltage Reduction (CVR) on three to six PSE substations before energy is sent to customers, thereby reducing customers' electric power consumption at the point of consumption on the customers' side of the meter.

CVR will be useful to PSE during winter peak load events due to the influence of resistive loads during those times. Reducing voltage is more effective for winter resistance heating load than for other types of load such as motors that experience greater use in summer for cooling loads.

CVR Target: 2.5% of peak load

5.1.4 Demand Response

By 2021 NPCC estimates the Pacific Northwest states will obtain between 600 and 1,080 MW (or 3%) of winter peak through demand response. At present, only a fraction of that quantity is operational. The Council is currently preparing their 7th power plan and has been working with regional utilities and industry stakeholders. [16]

In a 2015 report for NPCC, Navigant estimates that by 2030 Northwest utilities will have achieved nearly **9% of winter peak** load from demand response.

> *The estimated cumulative DR market potential for capacity programs represents nearly 9% of winter peak load by 2030. This estimate is in line with estimates of other DR potential studies conducted both in the Northwest and other parts of the country.*[17]

Cadmus 2013 DSR report for PSE IRP (page 7) suggests that by 2033 PSE could expect **4.7% of winter peak** to be reduced by Demand Response. Cadmus (2013) is approximately half of Navigant (2015) winter peak reduction forecast.

Two types of DR are likely to be beneficial for eastside areas:

1. Day-Ahead notification peak load reduction DR
2. Emergency 10-minute response DR

Because PSE identifies a peak load resource requirement for the Eastside, we have identified a need to study a demand response program to operate during these times, when PSE's most expensive resources will likely be supplying power. DR programs are often cost effective when displacing this expensive generation, such as PSE's peaking units in Whatcom County. When combined with the additional value of

[16] https://www.nwcouncil.org/news/meetings/2015/06/

[17] http://www.nwcouncil.org/media/7148943/npcc_assessing-dr-potential-for-seventh-power-plan_updated-report_1-19-15.pdf

providing an infrastructure alternative, the cost effectiveness of such a DR program is improved. Many utilities have implemented day-ahead notification DR programs that call upon enrolled customer or 3rd party resources to reduce their demand for a specified duration, typically 2-4 hours.

In addition, emergency DR programs have successfully been implemented that are capable of fast response for contingency reserve purposes. An example is a 10-minute response program run by Southern California Edison.[18] These programs are typically of higher value due to the short notice time and reliability service provided. SCE's program pays customers $240/kW-year for capacity that successfully participates.

For purposes of the EIS analysis, we have requested conservative DR quantities, shown in Figure 10, for the eastside area that are reflective of percentages of peak load that have been achieved in other areas and below those estimated by Navigant (2015).

Figure 10: Eastside Area DR by 2021

	Eastside DR Estimate
Day-Ahead DR quantity	4%
10-minute DR quantity	1.5%

Because PSE has indicated it may include DR at a level of approximately 2.7% of load by 2020, the 4% DR estimate above for day-ahead programs is incorporated into the 100% conservation forecast used by PSE.[19]

WECC rule Bal-002-WECC-1 was referenced by PSE[20] as one of the reasons the reserve amounts are increasing. This same rule allows a balancing authority to use a number of different resources to meet this requirement including demand response:

> "* A resource, other than generation or load, that can provide energy or reduce energy consumption
> * Load, including demand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement."

5.1.5 Dispatchable Standby Generation (DSG)

Portland General Electric's DSG program can be used as an example for one designed to provide enhanced reliability in the Eastside area. The DSG program connects customer backup generators to the distribution grid using parallel switchgear at sites such as hospitals, commercial/industrial, and government buildings. PGE remotely dispatches the generators, which are capable of providing uninterrupted service to

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[18] https://www.sce.com/NR/rdonlyres/7A1BC024-698D-44A0-98D1-ABD8DEE9E451/0/NR572V20810_BIP.pdf

[19] May 19 PSE IRP Advisory Group meeting materials

[20] PSE IRP Chapter 6 page 16

customers in the event of a grid outage. As part of the program, PGE invests in and owns some of the interconnection equipment, pays for fuel, and performs ongoing testing – required for units at many sites such as hospitals.

DSG potential is determined by using a simple proportion of peak load to DSG capacity installed at PGE and applying it to PSE, as shown in Figure 11 below.

Figure 11: Potential DSG by 2021

DSG Potential	MW
2018 PGE System Peak	4000
Current PGE DSG Capacity	94
DSG MW per System MW	2.5%
2018 PSE System Peak	6000
2018 Eastside Peak Load Forecast	750
PSE System DSG Potential	141
PSE Eastside Area DSG Potential	**18.8**

Note that the size of PGE's DSG program is growing and has plans to increase the program capacity to 125 MW in the next 5 years. Using the proportion method described above, Eastside DSG potential would increase to 22.7 MW.

While the simple DSG potential figures provided here are adequate to inform planning at this stage, additional detailed analysis of DSG capacity will be valuable to PSE and Eastside reliability regardless which transmission projects are built. PSCleanAir has suggested that a DSG program like PGE would follow EPA NESHAP RICE rules. Developer of DSG program would have to go through air permitting compliance, but it is a permittable use.

PSE evaluated using DSG as part of a stipulation in Washington Utilities and Transportation Commission (WUTC) Order 06 in docket UE-130617, in which both parties agreed that PSE should perform an evaluation. Specifically, the Settlement agreement states: PSE agrees to evaluate the PGE Dispatchable Standby Generation (DSG) program, described in the testimony of staff witness Juliana Williams, and either provide a report to the Commission of PSE's conclusions and recommendations by December 1, 2014, regarding the financial and technical feasibility of PSE implementing a similar DSG program in its territory, or file a tariff implementing DSG service by December 1, 2014.

EQL evaluated the PSE report and finds it evasive, inconclusive, and provides the following feedback.

Specific Comments on PSE DSG Findings and select sections. (Dec. 1, 2014)

[illegible]	[illegible]
The primary benefit of the PGE DSG program has been the ability to use the standby generators as a cost-effective resource to meet non-spin operating reserve obligations.	True

PSE does not have a near-term need for non-spin operating reserves and has maintained more than adequate operating reserves during peak events	PSE can use DSG to meet winter peak demands.
While originally established as peaking resource, PGE's use of its distributed standby generator fleet as a peaking resource has been *de minimis* during the life of the program	True. Program is not used as peaking resource.
New Environmental Protection Agency (EPA) emissions requirements that limit operation and testing on diesel-fired emergency standby generators create uncertainty and potential operational constraints during times of peak need	True that EPA rules are in flux for legal reasons. Current laws to watch are state and local air permits. PSCleanAir has suggested that a DSG program like PGE would follow EPA NESHAP RICE rules
Under normal conditions, PGE's standby generator fleet is not economic compared to other alternatives during dispatch decisions	DSG resources are not part of normal dispatched resources
PSE lacks sufficient market research of its customers that would justify investment in a DSG program including potential participation rates and standby generator inventory	Getting this information would be very easy
It is unlikely PSE would be able to implement a DSG program to meet any near-term capacity needs given time, resources, and current systems capability	PSE has time to develop DSG
Section 4.6 Compliance	
Section 5.2 Constraints and Opportunities	
Market Barrier. The 2011 CBRE market search led to no customers expressing interest in further engagement with PSE to interconnect a standby generation system to the grid.	PGE Customers are not that different than PSE Customers. It takes a clear customer value proposition and a few key customers to get it started.
Monitoring and dispatch. PSE does not own software that allows for monitoring and dispatch. PSE need operational and technical knowledge to operate new software.	EQL can assist.
Interconnection. PSE needs specifications for interconnecting standby generators. PSE does not have interconnection agreement	EQL Team can assist
PSE has several low-cost resources to meet non-spin reserve obligations.	**Contradicted in IRP**
Operating reserves exceed need by 200-400MW in most peak hours.	**Contradiction with IRP forecasts**

The NERC contingency reserves standard (BAL-002-WECC-2[21]) applies to the NW Power Pool Reserve Sharing Group (RSG), and requires the RSG to carry the larger of: 3% of load + 3% of generation OR the **Most Severe Single Contingency (what is this for PSE?).** Contingency reserves can be comprised of any combination of seven types defined in the standard. DSG is categorized as the Operating Reserve – Supplemental subcategory of Contingency Reserve. This reserve type was formerly

[21] http://www.nerc.com/files/BAL-002-WECC-2.pdf

defined as Non-Spin reserve, but was changed to supplemental in the current standard to be inclusive of demand side management pursuant to FERC Order 740.[22]

E3 incorrectly ruled out DSG in their 2014 non-wires study for Energize Eastside. They wrote,

> "The US Environmental Protection Agency (EPA) prohibits PSE from relying on customer-sited backup generation for peak shaving of utility loads for resource planning purposes, which PSE planners believe would prevent them from planning grid conditions that rely on backup generation to defer transmission upgrades. This regulation exists primarily to protect local air quality. Therefore, customer-sited backup generation was excluded from the DG non-wires potential estimates."

5.1.6 Combined Heat and Power (CHP)

CHP is the simultaneous use of a fuel, primarily natural gas, to generate electricity and provide heat. When properly designed, CHP is capable of operating at higher efficiency than typical central station power plants.

PSE's Non-Wires Screening Study[23] CHP analysis, performed by E3 and informed by earlier work by Cadmus, found approximately 1 MW of peak CHP resource by 2023 across all of PSE's King County service area. Because this quantity can reasonably be achieved in a single building, the previous estimate is likely not reflective of actual potential. In order to determine this potential, a new study is warranted, especially in light of the amount of growth expected to occur in Bellevue and PSE's need for peak capacity resources.

With the cost of capacity to utilities often exceeding $100/kW-year, infrastructure deferral benefits and electricity sales revenue are components that contribute to cost effectiveness determination and would inform the ultimate potential of this resource. PSE needs over 1000 MW of new capacity by 2025, according to recent IRP development information.[24]

150 MW of load growth could occur in the Bellevue downtown and Bel-Red areas in the next 20 years.[25] The new development represents a large opportunity because many DER technologies such as CHP make the most sense when incorporated during the design phase and provide further benefits when central utility plants serve multiple buildings. But such a strategy requires deliberate planning and clear leadership to become successful.

Because Downtown and Bel-Red will consume significant quantities of natural gas regardless of PSE's electricity infrastructure decisions, the extent to which this gas can be put to use generating electricity should be studied. Additionally, the civil construction work to occur in these areas in future years points toward investigation of co-locating energy infrastructure and potentially common use infrastructure such as district energy where central utility plants supply heating, cooling and electricity to a potentially large development, such as the Spring District.

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[22] http://www.ferc.gov/whats-new/comm-meet/2010/102110/E-6.pdf

[23] http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/attachment_5_-_screening_study.pdf

[24] May 19 PSE IRP Advisory Group meeting materials

[25] Exponent Reliability Study

Recommendation: Explore 3rd party or PSE owned central utility plants with CHP in parts of the Eastside that will experience the most new construction.

Figure 12: Base CHP Quantity 2021

	Eastside CHP Estimate
CHP	4% of peak load

Note:
Transmission topology alternative D adds Eastside generation. Because a larger central plant CHP project should be considered for this option, selection of this alternative could result in a substantially higher CHP penetration.

5.1.7 Energy Storage

Energy Storage is receiving a great deal of attention right now due to the cost declines seen in recent years and an increasing number of predictions for continuing storage cost reduction.[26] PSE, Avista, and Snohomish PUD have received $15MM to study use of energy storage.

Figure 13: Energy Storage Quantity 2021

	Eastside Storage Estimate
Storage	2% of peak load

5.1.8 PSE DER Potential & Interconnection

Many existing and future commercial, multifamily residential, institutional and corporate campus sites are centered near downtown Bellevue, Bel-Red and South Redmond– areas that are driving the need for new transmission and distribution infrastructure. Cost effectiveness of DER investments in these areas stands to be influenced to the extent they can substantively contribute to load service and reliability needs. In other words, a next-generation energy system, which is being pursued by leading utilities, will make full use of DERs by integrating their capabilities into utility planning and operations, a step that may well deliver cost reductions to PSE ratepayers – and one that will require developing appropriate compensation mechanisms to DER owners. In addition, PSE or 3rd parties could own DERs that may be designed to provide benefits directly to specific customers (i.e. storage installed behind-the-meter), while simultaneously providing infrastructure deferral benefits enjoyed by all ratepayers.

DER interconnection and operations practices will become more important as these resources grow in quantity and take on additional performance obligations related to reliability and system resiliency. Should PSE and Eastside communities decide to move to make full use of DER options as part of a strategy to support and enhance regional growth, appropriate technical interconnection and operations procedures and

[26] Sample media story addressing storage:
http://cleantechnica.com/2015/03/04/energy-storage-could-reach-cost-holy-grail-within-5-years/

standards will be needed. DER best practices are emerging from California, New York, and Hawaii, states that have taken the lead. The standards by which PSE designs and operates the 12.5 kV distribution system will be important for DERs so as to ensure maximum utilization of the system, including supporting 2-way power flows.

Most distribution systems move electricity in one direction – from power plants to substations to customers. But when customers interconnect generation resources, their power will flow the other direction, serving other customers and in some cases flowing power back to the substation itself and serving load further upstream, possibly at higher voltages. While there is no fundamental reason why these new flows of electricity cannot occur, investments in additional monitoring equipment and advanced control technologies will be needed.

These types of investments, involving software, communications, controls, and switching equipment, are also likely to provide reliability benefits by enhancing the ability of utilities to automatically switch customers to alternate feeds in the event of an outage on a given distribution circuit.