SECTION 6: INTRODUCTION
21st Century Alternatives

City of Bellevue land use codes require PSE to "describe the technologies best suited to mitigate impacts on the surrounding properties."

Electrical demand forecasts do not indicate a need for additional electrical infrastructure on the Eastside, Even if demand did increase, it would do so incrementally. Smaller, site-specific technologies would be far more cost effective than Energize Eastside. The Washington Utilities and Transportation Commission (WUTC) requires PSE to prove that their infrastructure investments are the most prudent for ratepayers. Energize is a large front-end investment, an all-or-nothing approach that is not a prudent solution to the electrical needs of the Eastside.

The reports in this section demonstrate that PSE predicated its evaluations of alternative technologies on studies that were outdated even at the time of analysis and ignored industry-wide recognition of the quickly advancing cost-effectivenss and technical feasibility of many of the alternatives that PSE dismissed. In addition, PSE evaluated each technology as a stand-alone solution rather than as an element of an integrated resource approach.

One additional report looks at the under-explored option of using Seattle City Light Transmission lines that on the Eastside closely parallel PSE's 115kV line.

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Non-Wire Alternatives to Energize Eastside

submitted by

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EQL Report for Bellevue Land Use Hearing on PSE's Energize Eastside

For Bellevue Land Use Hearing on Puget Sound Energy's application for a Conditional Use Permit ("CUP") to construct and operate the Richards Creek substation and 3.3 miles of 230 kV transmission line located in the City of Bellevue ("City"), Washington. The Talbot Hill/Lakeside Transmission Line Project

Abstract

Through increased investments in demand side resources, storage and modern power flow control and transmission technology PSE could avoid future Eastside transmission deficiencies, address NERC reliability criteria, and meet customer objectives for power reliability, clean energy, and low cost. These technologies would also avoid the higher expense and environmental damage that PSE's proposed higher-voltage transmission lines would cause.

Bellevue and the surrounding areas are seen as leaders in technology development, while Puget Sound area sees itself as a leader in clean energy. In contrast, Energize Eastside is an example of a project that might have made sense three decades ago, and an opaque planning process considered antiquated in today's energy systems planning processes. From City of Bellevue's 2015 Comprehensive Plan "Bellevue encourages new technology that improves utility services and reliability while balancing health and safety, economic, aesthetics, and environmental factors."

PSE asserts in their application that upgrading 8.8 miles 115kV line from Talbott Hill substation to a new 230kV substation ("THLTL" or "Project") is needed to meet their NERC reliability requirements and Eastside power demand starting in 2018.

EQL asserts that PSE has not met the decision criteria in Bellevue's Land Use Code decision criteria for LUC 20.20.255.E. 1, 3, 4 and 5.

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1. The Project is not consistent with PSE's System Plan LUC 20.20.255.E.1

In 2018, the Washington Utilities and Transportation Commission (WUTC) Acknowledgment IRP commented on PSE's Energize Eastside project by saying PSE had "complied with state law by providing a history of its Needs Assessment Reports. However, the Plan did not answer many questions that are needed for determining if the Company's (PSE) conclusions are justified. The WUTC letter goes on to say: "PSE would not discuss these [Energize Eastside] studies in the advisory group, and therefore left unresolved some basic questions about the studies' assumptions, methodologies, and conclusions. For example, the Plan does not include a narrative regarding:

1. The effect of the power flows due to entitlement returns on the need for the Energize Eastside Project.
2. The reason for, and effect on the need for the Energize Eastside Project, of modeling zero output from five of PSE's Westside thermal generation facilities.
3. PSE's choice not to provide modeling data to stakeholders with Critical Energy Infrastructure Information clearance from FERC.
4. Resolution of the effect of lower load assumptions on the need for Energize Eastside Project.

"*The IRP process is specifically structured to allow public discussion and inquiry, including a thorough examination of the analysis supporting a conclusion of need. This is an area in which we [WUTC] would like to see more engagement from the Company." WUTC 201*

WUTC began a rulemaking proceeding (UE-161024) in 2016, where transmission and distribution planning and investments must undergo similar scrutiny as new generation investments, which includes determination of need and RFPs.

2. PSE has not demonstrated Operational Need LUC 20.20.255.E.3

The City of Bellevue ("City) does not know the peak loads of Eastside substations that serve the City. PSE has this data, provided it to the City in 2006, and has chosen not to provide throughout the permitting process. In 2006, PSE provided City of Bellevue with 2005 Peak Load data and an exaggerated PSE forecast. PSE has not responded to requests by city staff, and stakeholders for historical and current data documenting Eastside substation peak loads.

Table 1 - Substation Peak Loads

Substation Name	2005 Peak Load	2020 Projected Peak Load
	MW	MW
Ardmore	-	20
Bridle Trails	25.7	32.4
Center	24.7	49.3
Clyde Hill	23.4	38.3
College	20.2	21.8
Eastgate	32	27.1
Evergreen	54.1	57.6
Factoria	28.9	33.8
Houghton	22.8	19.9
Kenilworth	24.6	25.3
Lake Hills	22.4	22.6
Lochleven	19.2	41.1
Midlakes	20.7	22.9
North Bellevue	43.9	48.2
Northrup	26.5	37.5
Phantom Lake	19.3	21
South Bellevue	22.8	24.3
Somerset	18.3	19.6
Totals	**449.5**	**562.7**

Bellevue substation load provided by PSE in City of Bellevue Comprehensive Plan Utilities Element Update, November 2006[2]

[2] 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)

The 2020 forecast PSE provided in 2006 is greatly exaggerated given that **PSE's actual annual growth rate for peak load was 0.8% from 2006 to 2014.** (See next section study on PSE load forecasting errors). Using actual peak load growth suggests 2020 load would be 506MW, not 563MW.

PSE has a documented 15-year history of exaggerating load forecasts to justify capital projects and has exaggerated load forecasts to justify THLTL.

Since 2003, PSE has provided inflated load forecasts as part of their state-mandated IRP process. This was documented in a report by Department of Energy[3], as well as various stakeholders in IRP hearings at WUTC. Between 2006 and 2014 average load forecast PSE used was 1.75% Average Annual Growth Rate (AAGR), while the actual AAGR during that time frame decreased by 0.19% per year.

Table 2 - Projected vs Actual PSE Average Annual Growth Rate (AAGR)

Period	PSE-Projected AAGR	Actual AAGR
2006-2014	1.75%	-0.19%
2012-2014	1.90%	-1.19%

PSE Load Average Annual Growth Rates, Forecasted and Actual

Comparison of PSE Load Forecasts vs Actual Load Growth 2005 to 2011

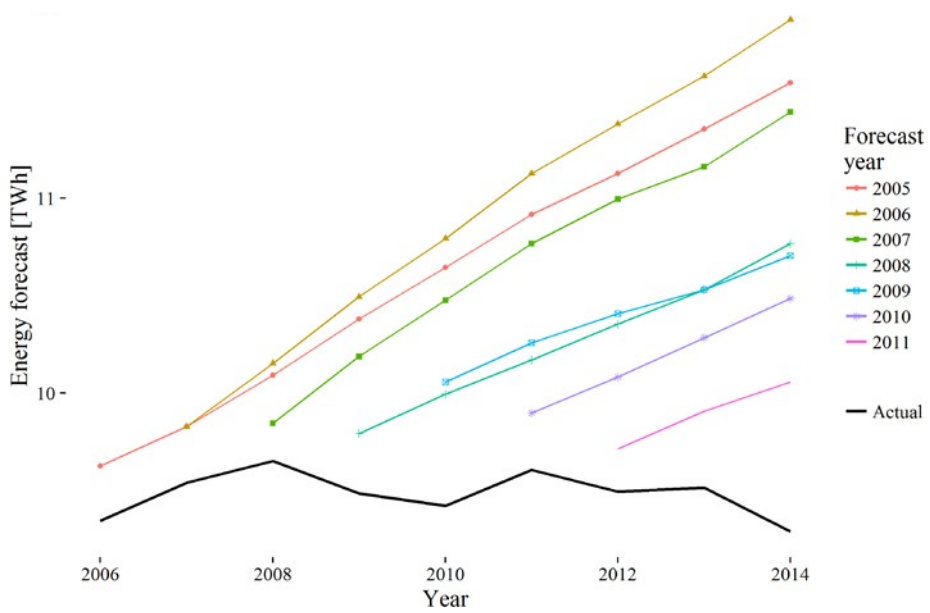

Figure 3: PSE's peak load growth during this time frame grew at an Average Annual Growth Rate (AAGR)of 0.8%

[3] http://eta-publications.lbl.gov/sites/default/files/lbnl-1006395.pdf

The PSE 2014 screening report exaggerates the PSE actual peak load and the growth estimate. The growth estimate is:

- 17.6 times larger than Seattle City Light's (SCL) 2017 peak load forecast,
- 9 times larger than PSE's own 2017 IRP forecast.

Throughout the Energize Eastside permitting process, PSE's inflated forecasts for peak loads have led to inappropriate modeling, analysis, and conclusions.

PSE's choice to proceed with only the southern segment suggests that suggests that peak loads on the Lakeside substation have been increasing to a point of concern. The City of Bellevue does not have independently verified historic load data at Lakeside Substation or any of the substations in the City.

Without real and verified load data it is clear that PSE has not demonstrated operational need.

3. PSE failed to demonstrate how a non-wire alternative improves customer and system reliability better than the proposed alternative LUC 20.20.255.E.4

1. North American Distributed Energy Resources (DERs) contribute over 50,000 MW to power system reliability and participate in power system operations.

2. US Supreme court ruling in 2015 allows demand response to participate in wholesale power market operations in order to reduce price and improve reliability.[4]

3. The Federal Energy Regulatory Commission (FERC) in Feb. 2108 issued an order that transmission operators must allow electricity storage to participate in energy, capacity, and ancillary service markets which provide system reliability.[5]

4. NERC interpretation of regional Reliability Standard BAL-002-WECC-2 states that non-traditional resources, including electric storage resources are capable of meeting the operating reserves-spinning requirement of the regional standard.[6]

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[4] https://www.ferc.gov/media/statements-speeches/bay/2016/01-25-16-SupremeCourt.pdf?csrt=14053913403996174958

[5] https://www.ferc.gov/whats-new/comm-meet/2018/021518/E-1.pdf

[6] Ibid., p 82.

5. PSE reliability issues are related to operational errors and equipment outages. PSE received two NERC compliance penalties in 2013 that found that transmission operators failed to respond timely and correctly to a line outage, which caused an exceedance of System Operating Limit on a 115kV line in Whatcom county.[7]
    a. TOP-004-2 R1 Transmission Operations
    b. TOP-008-1 R1 Response to Transmission Limit Violations.
6. PGE operates a dispatchable standby generation program that has over 100MW of backup generators that can be called to provide grid and system reliability support. PSE service territory has over 500MW of backup generators which could be used for grid reliability. PGE controls 2,400 hot water heaters to address peak loads. PGE has proposed a 20 MW battery to be used at a 115kV substation.

4. PSE has failed to perform Alternative Analysis that considered all technologies to meet the system needs LUC 20.20.255.E.5 and LUC 20.20.255.D.3

In 2015, EQL submitted an Economic Study Request to Puget Sound Energy's Transmission group, (Grow Eastside Smart Transmission Project Local Economic Study Request) [8] The study request was essentially a request to study an alternative to THLTL. The study request would address performance criteria listed in the 2015 Supplemental Eastside Solutions Study Report, and would be an alternative to PSE's THL TL.[9] PSE refused to perform the study saying that:

"The EQL Requests Would Be Unnecessary in light of the Energize Eastside Project"

The study included the following technologies and alternatives. These technologies were never considered, nor were they properly addressed in PSE's application.

1. installation of new 230/115 kV transformers at Lake Tradition (looping in to BPA 230kV line) and/or at Talbot Hill as needed. One of these may not be needed for several years,

2. Installation of Flexible AC transmission system (FACTS) control devices on all 115kV transmission lines serving Eastside load that are affected by all Corrective Action Plans (CAPs) that PSE implements during periods of high flows.

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[7] https://www.nerc.com/pa/comp/CE/Enforcement%20Actions%20DL/FinalFiled_NOP_NOC-2174.pdf

[8] http://www.oatioasis.com/PSEI/PSEIdocs/Oct_31_PSET_Economic_Study_Request_from_EQL.PDF

9http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/supplemental_solutions_study_redacted_final_may2015.pdf

3. Increased investment in Distributed Energy Resources (DERs), e.g., energy efficiency, distributed generation, demand response, and storage in affected Eastside areas.

Utilities across the country issue RFPs or procure resources to avoid or defer building transmission line projects like THLTL. PSE could provide a non-wire alternative (NWA) to THLTL that would not require an upgrade of the transmission line from 115kV to 230kV.

In the US there are over 133 examples of utilities and projects implementing NWA programs to avoid or defer transmission and distribution investments. Example RFPs include:

- Open RFIs and RFPs at REV Connect[10]
- Joint Utilities of New York – Utility-specific Non-Wires Alternatives Opportunities[11]

Since the 1990s utilities across the United States have avoided the need for over 1,000MW of transmission investments through RFPs and procurement of cost-effective distributed energy resources and non-wire alternatives. In the last 5 years, over 1,900MW of NWAs have been evaluated and/or implemented.[12]

1. APS recently announced 850 MW of energy storage on their system. One of the projects is replacing a proposed 20-mile transmission line.[13] These projects were procured through RFPs.
2. In the US, 10 million customers participate in demand response programs that yield an average peak reduction of 6%. PSE has zero customers in demand response programs with 0% peak reduction. 6% of PSE's peak load would be 300MW.
3. In February 2018 the Federal Energy Regulatory Commission issued an order that utility transmission operators must allow electricity storage to participate in energy, capacity, and ancillary service markets.[14]

Cost-effective investments in energy efficiency, demand response, storage, and other distributed energy resources, would alleviate any need to build the proposed transmission line, and would improve power service reliability to customers.

1. PSE issued an RFP in 2018 for general system resources including DERs. These resources unfortunately will not be evaluated to address peak load growth in the Eastside and address the operational need PSE says they have on the Eastside.
2. RFP responses included over 200MW of battery storage and 40MW of demand response.[15] I know several vendors that did not provide responses for Demand Response because PSE has been doing DR RFPs since 2010 and has never invested in these capacity reducing programs.

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[10] https://nyrevconnect.com/open-rfis-rfps/

[11] https://jointutilitiesofny.org/home/

[12] https://sepapower.org/resource/non-wires-alternatives-case-studies-from-leading-u-s-projects/

[13] https://www.greentechmedia.com/articles/read/aps-battery-storage-solar-2025#gs.8PMnrfxI
https://www.utilitydive.com/news/aps-to-deploy-8-mwh-of-battery-storage-to-defer-transmission-investment/448965/

[14] https://www.ferc.gov/whats-new/comm-meet/2018/021518/E-1.pdf

[15] https://www.pse.com/pages/energy-supply/acquiring-energy

3. PGE has proposed a 20MW battery to be used at a 115kV substation on its system called Coffee Creek.

Since proposing Energize Eastside in 2015, PSE has reduced its investment in energy efficiency and has not pursued any DER investments that provides capacity reductions on their eastside system. These actions also do not support City of Bellevue Utilities[16] policy UT-91 to encourage public to conserve energy.

1. Since 2017 PSE has annually reduced its Energy Efficiency budget from $103MM in 2017 to $83MM for 2019.[17]
2. PSE, as a board member of the Northwest Energy Efficiency Alliance, has been a vocal opponent of increasing investment in energy efficiency and demand response market transformation.
3. PSE participated in the Glacier 2MW battery storage demonstration project to provide improved service to community of Glacier. Unfortunately, they did not outsource the project, and PSE's energy management system has not performed well. In fact, it failed to discharge during a line outage over Thanksgiving 2017. The reasons for failure are related to PSE's lack of expertise in battery management systems.

[16] https://bellevuewa.gov/UserFiles/Servers/Server_4779004/File/pdf/PCD/07_Utilities_FINAL_20150807.pdf

[17] https://www.utc.wa.gov/regulatedIndustries/utilities/energy/Pages/CompanyProgramPlansandTargets.aspx

Appendix A Non-Wired Alternatives

Abstract

PSE is opting for a self-build transmission line to increase its rate base and return on investment to the detriment of Eastside communities, ratepayers and the environment. According to the Regulatory Assistance Project, an organization that assists utility commissions and regulatory policymakers, the number one reason utilities prefer transmission lines over Non-Wire Alternatives (NWA) is Return on Equity.[1] Capital projects that offer a generous return on investment provide higher revenue opportunities than NWA programs, which are often expensed. Utilities nationwide are getting out of the generation business and are looking for Transmission & Distribution (T&D) projects to deploy capital.

Instead of investing $300MM on poles and wires, PSE could instead accelerate investments in projects that address existing reliability issues as discussed in **Exponent's 2012 City of Bellevue Electric Reliability Study**.[2] These include:

- distribution automation and undergrounding circuits,
- transmission flow control devices,
- smart thermostats,
- LED lighting with controls,
- communicating hot water heaters,
- Building Management Systems/Controls,
- home/business back up energy storage,
- smart EV chargers, and
- many other energy conservation and distributed resources.

These mature technologies, programs, and other non-wire alternatives are being used across the US to avoid transmission line investments. In addition to avoiding additional rate increases to cover the $300MM in project costs plus another $700MM in interest over the life of the project, these alternatives would improve reliability, reduce atmospheric CO2 levels, and integrate more renewable power. The Northwest Power Planning and Conservation Council in their most recent 7th Power Plan suggested that demand response if implemented in the Northwest would be sufficient to meet capacity needs for through 2025

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[1] "Non-Wires Alternatives to Grid Congestion," Frederick Weston, Regulatory Assistance Project, July 21, 2015.

[2] *http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/final_electrical_reliability_study_phase_ii_report_2012.pdf*

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1. Concealing peak loads, exaggerating load forecasts

Every utility in the nation tracks system, substation and feeder load data. With smart meters many utilities can track demand from each customer in time intervals as precise as 5 minutes. EQL has worked with utilities on load management projects. To develop economically sound projects, historical load data and a sound load forecast are of paramount importance.

PSE has ignored numerous requests from CENSE to share historical peak load data for Eastside communities and substations that could help substantiate and evaluate the company's claims that the Eastside transmission infrastructure will soon be stressed. In fact, PSE Transmission stopped publishing system peak load in 2010, so PSE's measured system loads are not available to the public.[3] Peak load data is the primary driver for decisions regarding new generation, transmission, and distribution. Instead, PSE points to population growth or the age of existing infrastructure as justifications for THLTL. Historic peak loads are the starting point of a load forecast. While its clear Eastside communities are growing, it is also clear that peak loads are not. According to public data from Seattle City Light and PSE system loads, document that peak loads have been declining or have remained flat since 2008.

PSE's 2014 Energize Eastside Screening Study[4]

As part of the planning process for Energize Eastside, PSE commissioned Energy and Environmental Economics, Inc. ("E3") to conduct a "Screening Study" to consider the role of NWAs in the proposed upgrades for the Eastside portion of PSE's transmission system. This minimal effort by PSE to consider non-wire alternatives, did not involve an RFP or any procurement process to evaluate real solutions. The E3 Screening study was paid for by PSE, and the assumptions, requirements, and data were provided to E3 by PSE. Most of the data and assumptions provided were not accurate and lead to poor conclusions and summaries. E3 did not independently verify the data and assumptions provided by PSE.

The first and largest error in the E3 2014 screening report relates to the Eastside load forecast. The PSE peak load growth estimate in the study is:

- 17.6 times larger than Seattle City Light's (SCL) 2017 peak load forecast,
- 9 times larger than PSE's own 2017 IRP forecast.

In addition, Seattle's population is growing faster than PSE's service area on the Eastside. The 2014 E3 Screening Study assumed a 320MW increase in PSE's peak load in King County through 2027. The study divided the growth into two increments: a 70MW increase by 2021 and another 250MW increase by 2027. This assumes peak load increases of approximately 40 MW/year. Current Eastside peak, according to PSE, is 750MW, so the annual average rate of assumed peak load growth for PSE is 5.3, while SCL assumes an annual 0.3% growth rate in system peak load.

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[3] http://www.oatioasis.com/psei/

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

The annual average rate of assumed peak load growth for PSE in King County is 5.3%, while SCL assumes an annual 0.3% growth rate in system peak load.

Other data points reveal PSE's exaggerations of anticipated peak load:

- Population growth is NOT correlated with winter peak.
    - In the last nine years, PSE system peak demand for its service territory has declined or remained the same, while population growth has been one of the highest in the US.
    - In the Eastside area, population has increased by 20,000 in the last six years while winter peaks have declined.
    - Although Seattle is served by a different electric utility, it's interesting to note that Seattle's population has grown by 70,000 during the last decade, but SCL's winter peaks have been flat or declined.
- PSE's 2011 Integrated Resource Plan (IRP) forecasted a winter system peak of 6,300MW in **2012**. The recent 2017 IRP forecasted the same winter peak of 6,300 occurring in **2031**.
- PSE's 2017 IRP entire service area system peak load has an AARG (Average Annual Rate of Growth) of 10 MW/yr. That means Eastside growth of perhaps 2 MW/yr. E3's Non-wires screening study assumes 40MW/yr. just for the Eastside, *20 times higher than current estimate.*
- PSE's 2017 IRP forecasts system peak load with minimum energy efficiency investment at an annual average rate of growth of **0.6%.** However, considering the data above, it is likely that Eastside peak loads will ***continue to decline or remain flat***.
- 2016 SCL IRP forecasts a 1,760MW winter peak, and assumes an increase load of 7MW/year which is 0.3% /yr.
- Electric power winter peak load is declining due to DER investments and direct use of natural gas. PSE's 2017 IP assumes power use per customer declines every year through 2035.

The second mistaken assumption in the 2014 E3 Screening Study is the project could be deferred for only seven years (through 2021). However, the Project could be deferred indefinitely as demonstrated by:

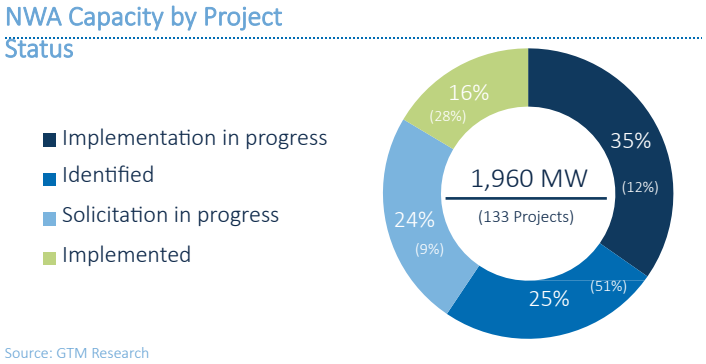
- Estimates of energy conservation, demand response, and DER in NPPCC 7th plan;
- PSE's 2017 IRP winter peak demand reduction estimate from Navigant.

With a 20-year deferral, the deferral value would increase the cost effectiveness of a NWA by over $300/kW/yr. This higher value would allow the inclusion of most technical options offered by DERs.

2. Non-Wire Alternatives to Energize Eastside

Energy Efficiency, Demand Response, and Distributed Energy

Utilities have used distributed energy resources to avoid specific transmission projects since the early 1990s. In fact, BPA avoided building a proposed North Cascade Crossing transmission line in the mid-1990s using non-wire investments, which included increased spending on energy conservation in the Puget Sound area.[10] Since 1995 the technology, programs, and resources to provide non-wire alternatives have grown exponentially. Over 1,000 MW of US transmission capacity has been avoided with Non-Wire Alternatives (NWA). According to a 2017 report for the Vermont Public Service Commission, in the last five years 1,900 MW of transmission and distribution capacity upgrades are being implemented or evaluated with NWA.[11] Most of these NWA investments are in Energy Conservation, Demand Response, and other Distributed Energy Resources.



Source: 2017 GTM Report for Vermont Public Service Commission

Figure 1: US Non-Wire Alternative Projects,

a. What are Non-Wire Alternatives (NWA)?

NWA include:

1. Energy conservation
2. Demand response (DR)
3. Distributed generation
4. Energy storage
5. Dynamic voltage regulation
6. Grid infrastructure investments (e.g., series inductors, transformers, static VAR compensation, capacitance
7. Market solutions, (e.g.) locational marginal price (as seen in open electric power markets)
8. Generation redispatch

[10] https://www.enerfy.gov/sites/prod/files/2015/04/f22/EIS-0160-FEIS.pdf

[11] https://www.vermontspc.com/library/document/download/5936/GTMR_-_Non-Wires_Alternatives_Projects.pdf

This report focuses on energy conservation, demand response, and other distributed energy resources.

1. Energy conservation

Utilities can increase energy conservation by implementing programs that incentivize customers to *purchase* efficient electric-using equipment (i.e.,LED bulbs, refrigerators, washers and dryers) or to *modify* their energy-using behaviors (i.e. running appliances during non-peak hours.) Energy Conservation programs and investment have been implemented since the 1970s. The Pacific Northwest is a national leader in acquiring energy efficiency and it is a MANDATED top priority all other regional utilities, including PSE, to procure *all cost-effective energy conservation.*[12]

2. Demand Response (DR) or load management

Demand Response (DR) is a reduction or shift in electric use based on a system operator or price signal. It has been used since the mid 1980s. Demand response is used primarily for reducing peak loads, deferring transmission and distribution investments, and providing regulation services and other ancillary services. The first demand response program in the Northwest was started in 1985 by the City of Milton-Freewater's municipal utility in Oregon. Milton-Freewater used radio receivers to control hot water heaters to reduce winter peak loads and avoid infrastructure and power costs. Nationwide demand response provides over 50,000MW of peaking capacity and the North American Electric Reliability Council (NERC) includes demand response programs in their reliability assessments.[13] On average, utilities reduce their seasonal peak capacity by 6% through operation DR programs. The technology for demand response has become more sophisticated, more cost effective and more flexible ,(able to work on most electric load types). Besides small DR programs like that at Milton Freewater, the only commercially operating demand response programs in the Northwest are summer irrigation programs in Idaho via Idaho Power and PacifiCorp.

3. Distributed Energy Resources (DER)

Distributed Energy Resources (DER) include Energy Efficiency (EE) and Demand Response, but also includes generation, storage, voltage regulation, and other demand-side resources at customers sites or downstream of the substation, e.g., distributed renewables (e.g., solar), energy storage, controlled EV charging, etc.

b. How do utilities plan transmission and procure NWA?

Many utilities that identify a transmission need to support load are mandated to conduct an open NWA-RFP process. RFPs for NWAs are drafted by utilities, evaluated and modified by independent evaluators and stakeholders, and administered by an independent evaluator. Many of these same utilities also employ distributed resource planning and integrating transmission and distribution with the Integrated resource plan. Such planning processes consider the capacity of the utility's distribution systems to accommodate generation/storage, as well as evaluate the cost-effectiveness of demand- side management, e.g., energy

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[12] https://www.nwcouncil.org/media/7491066/eeonepager.pdf

[13] https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf

conservation and demand response.

New York: In New York, the commission articulated its vision for NWAs, stating, " it does not want the utilities to contemplate necessary infrastructure upgrades and then issue RFPs to resolve the underlying system needs, but rather to "consider the procurement process earlier and more broadly incorporate system design into NWA solutions."

Vermont: Vermont's transmission planning committee (VSPC), bulk transmission owner (VELCO), and its distribution utilities participate in a least-cost integrated resource planning process that guides the expansion of the state's transmission system. The process, instituted in 2006, institutionalizes the identification, procurement and cost allocation of NWAs at the transmission and sub-transmission levels. It has evolved into a 10-step process that includes RFPs.[16]

Washington State: In 2016, the Washington Utilities and Transportation Commission (WUTC) created an open docket (UE-161024) to modify the Integrated Resource Planning methodology to include transmission and distribution planning. Currently, PSE separates its resource and transmission planning and does not consider *specific locational values* of DER programs. In comparison, across the US a separate-planning methodology has been replaced by unified planning, especially in places with open markets and progressive regulatory environments, e.g., CA, TX, NY, and New England. PSE and other Independently owned utilities (IOUs) in Washington will likely join the rest of the country in a unified evaluation as the WUTC rulemaking process provides clear rules and processes for improved planning and procurement processes. EQL Energy has provided comments and testimony on UE-161024.

c. Recent examples of Utility NWA programs

In the U.S there are at least 133 examples of utilities and projects implementing NWA programs to avoid or defer transmission and distribution investments.

New York has a mandated and defined process for procuring NWAs. Listed are examples from ConEd, Rochester Gas & Electric, and NYSEG are below.

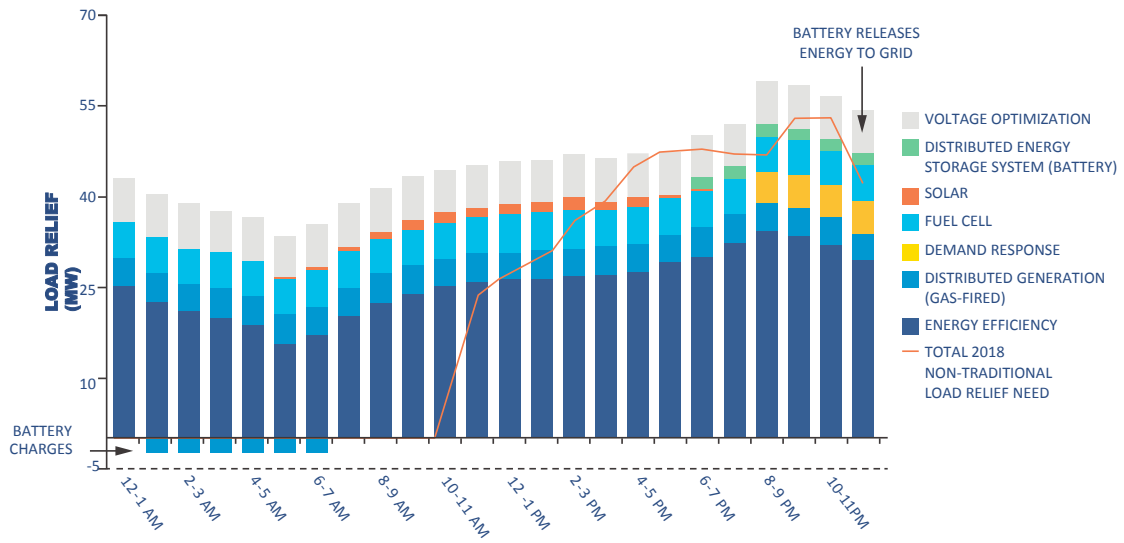
1. https://www.coned.com/en/business-partners/business-opportunities/non-wires-solutions
2. http://rge.com/SuppliersAndPartners/NonWiresAlternatives/ProjectOpportunities.html
3. http://www.nyseg.com/SuppliersAndPartners/NonWiresAlternatives/ProjectOpportunities.html

The largest project is the Brooklyn-Queens Demand Management (BQDM) Program in New York where ConEd is avoiding a $1Billion transmission project. The program has used efficiency and demand management since 2014 and is expected to save customers about $24.5 million over its lifetime and save ratepayers $800MM in capital costs. By the summer of 2018, the BQDM program will have contracted over

[16] https://www.vermontspc.com/library/document/download/5936/GTMR_-_Non-Wires_Alternatives_Projects.pdf

52 MW of DER to meet demand. The program budget is $200MM and undergoes an evaluation and extension process every two years. If the DER program did not meet its goals, the NY Public Service Commission could choose to end the program and proceed with the proposed ConEd transmission project. Since 2014 the program has achieved its goals and was extended in 2018.

The program includes 6,000 small businesses, 1,400 multi-family buildings and 8,800 homes that cut overall load on the distribution system and thus saw lower bills. Small business efficiency measures resulted in 110 GWH of annual energy reduction. The residential sector saved 27 GWH/year. Figure 2 below summarizes the DER resources that provided over 55MW of peak load reductions after 3 years.



Source: Consolidated Edison, 2016.

Figure 2: 2017 ConEd BQDM NWA Resource Portfolio (MW)

The BQDM is creating partnerships for DER services between private energy developers and utilities for DER. Over 12 third-party providers are providing smaller, cleaner energy systems using a variety of technologies such as solar, combined heat and power, microgrids, gas micro-turbines and storage.

How do DERs address transmission issues?

DER resources reduce the energy and capacity load on the distribution system and, in many cases, improve customer reliability and resiliency. These resources can be implemented to target specific locations, seasons, and times of day, and hence can be very helpful at reducing peak capacity requirements at specific locations.

1. *System Perspective.* Most utility planners, when evaluating DERs, include a generic avoided Transmission and Distribution (T&D) cost adder as a proxy for avoiding the need to transmit power from a distant source. This savings impacts cost effectiveness analysis which identifies a positive benefit/cost ratio for DER investments.

2. *Local Perspective.* In the 1990s, utilities began to target specific areas to incorporate DERS as non-wire investments to avoid building specific transmission or distribution projects. The list of these projects nationwide is quite long and has been summarized by groups such as the Regulatory Assistance Project in 2004 and 2015.[17] As of mid-2016, there were 133 NWA projects that had either been implemented or were in the pipeline. Those projects add up to a total of 1,960 MW of capacity with 1,150 MW in post-identification stages and 490 MW of earlier-stage projects listed as "identified NWA opportunities."[18] The amount of MW of NWA implemented since 1990 is over 1,000MW.

The main challenge for Non-Wire Alternatives (NWAs) -- and the reason they've been driven by mandates, not economics -- is that they don't provide utilities and their shareholders a return on investment. Utilities can recover the costs of DER programs and lower bills for ratepayers. However, shareholders aren't satisfied with cost recovery alone, they want a return on capital that comes with large generation and transmission projects. PSE shareholders receive a 9.8% return on investment for capital projects.

Many states, e.g., New York, California, Maine, Vermont, Massachusetts, Hawaii, Connecticut, Maryland and New Jersey have recognized these barriers and have developed mechanisms and incentives for utilities to plan and pursue NWA.[19]

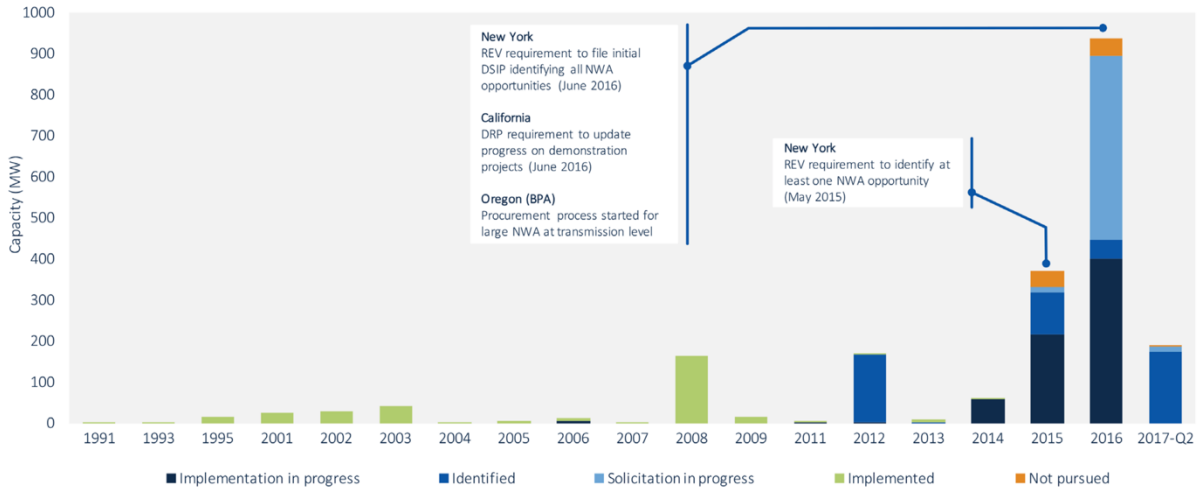


Figure 3: History of NWA Project in United States (source GTM 2017)

[17] http://www.raponline.org/wp-content/uploads/2016/05/rap-weston-non-wires-alternatives-nga-webinar-2015-7-21.pdf
http://www.raponline.org/wp-content/uploads/2016/05/rap-sedano-nonwirealternatives-2004-12-16.pdf
[18] https://www.greentechmedia.com/articles/read/gtm-research-non-wires-alternatives-market#gs.zDFpMNc
[19] https://pubs.naruc.org/pub.cfm?id=536EF440-2354-D714-51CE-C1F37F9B3530

d. How do EE/DR/DER address the requirements for the Talbot Hill to Lakeside Transmission Line?

Energy Efficiency, Demand-Response and Distributed Energy Resources can be designed to focus investment and programs in regions susceptible to winter peak-loads. Figure 1 represents how PSE could focus DER technology and programs on Eastside load, in addition to targeted energy efficiency programs. (Data represents load on a winter peak day for a 55MW campus in British Columbia).

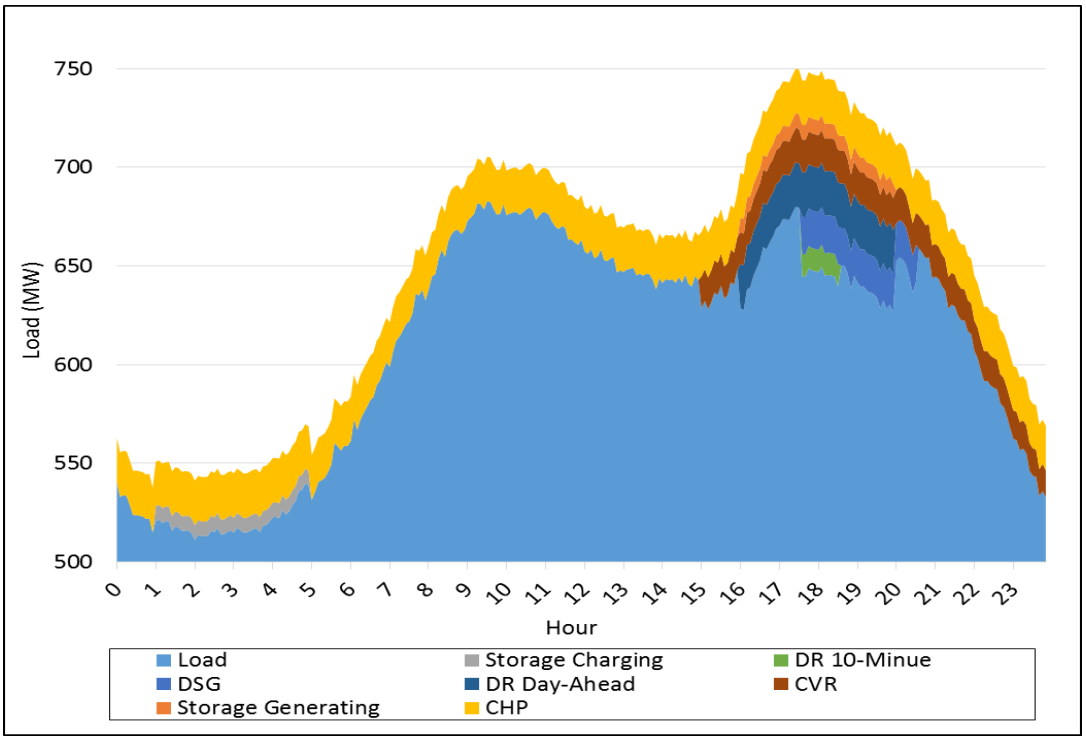


Figure 4: Example of DERs effect on Eastside Peak Loads (excluding EE)

Because PSE has not responded to requests for historical peak loads on Eastside substations, it is difficult to determine the actual need and objectives for a NWA program.

What type of resources and programs would avoid the need to build the Project?

Many utilities are using specific, mature programs to address peak loads. These include:

1. Commercial & Industrial energy efficiency and demand response
    a. HVAC and Roof Top Unit retrofit, new units, and demand response
    b. Lighting
    c. Strategic Energy Management both commercial and industrial (includes both EE and DR)
2. Smart Thermostats – especially for electric furnaces, baseboard and Line Voltage Thermostats (LVT)
3. Smart EV Charging program.

4. Electric Hot Water Heat Pumps and communications (CTA-2045).
   For example, if the 3.5MM electric water heaters in the Northwest were equipped with communication and controls to avoid peak time usage, they would provide (or eliminate) 500MW of peak capacity, at a cost of approx. $150MM. *This is 5 times more cost effective than Energize Eastside.*
5. Heat pump programs directed at inefficient space heating, e.g., ductless heat pumps.
6. Customer energy storage
7. Combined Heat and Power (generate electricity along with a heat process)
8. Voltage Optimization
9. Dispatchable Standby Generation (DSG)

Cost of NWAs

A variety of cost-effective resources could be deployed for NWA. In 2014, E3 Screening Study used $155/kW-yr. as the cost effective measure for NWA investments. Given the increase in Energize Eastside project costs since 2014, and that E3 assumed only 4 years of deferral, this value has potentially doubled to over $300/kW-yr. Northwest Power Plan Conservation Council (NPPCC) states in their 7th plan that over 1,400 MW of demand is available at a price below $25/kW-yr.

Table 1: Categories of EE, DR, and DER to address Transmission requirement

Resource Characteristic	Dispatchable and Higher system value	Seasonal Peaks and High priced times	Load Management and distributed renewables
Response Times	Day-ahead - 10 minutes	Day-ahead	None
Duration	1-3 hours	3 hours	Dependent
Availability	3 consecutive days	3 consecutive days	Measured Capacity
Hours per year	40	60-100	dependent
Supply Curves	$20/kW-yr. to $300/kW-yr	12$/kW-yr. to $210/kW-yr.	$25/kW-yr. and $150/MWh
Firmness	Fixed amount	MW and hour forecast based on agreed variable, e.g., temperature	Baseline M&V
Examples	Storage, Dispatchable Standby Generation, DR 10 min, CHP w/storage	Day ahead DR, EV charging	EE, CHP, pricing (e.g., critical peak pricing), solar

If PSE accelerated its investment and emphasis on DR to address Eastside peak loads, loads could drop sufficiently to eliminate the need for Energize Eastside .

What is the potential load reduction from EE/DR/DER on PSE's Eastside?
Based on data from reports by PSE consultants and estimations of load size and type, PSE could procure enough DERs to ensure that Eastside peak loads would not increase until 2035.

What is needed?

Assuming a 0.6% growth rate[20] on a 700MW peak, load increase would be 3MW in 2020 rising to a cumulative of 56MW by 2037.

[20] PSE's 2017 IRP system peak load growth rate is 0.6%. Likely exaggerated higher as system peak has declined since 2009.

What could be done?

As part of PSE's 2017 IRP, Navigant suggested that, starting in 2018, PSE has the potential to reduce winter *system* peak demand by188MW - excluding distributed generation and energy storage. Figure 5 shows that by 2037, potential demand reduction would exceed 1,800MW.

This is not surprising, since PSE has not integrated load management, demand response, or distributed generation into its non-wired alternatives. If PSE added backup power and customer storage to this analysis, peak demand reductions would improve by 50%. Most utilities achieve a 6% peak capacity reduction from demand response programs alone. PSE's stated winter peak is 5,000MW, Therefore, PSE's potential for *system* peak demand reduction is 282MW in 2018 and 2,500MW by 2037.

If we assume Eastside load growth is 20% of PSE's system load growth, that would mean potential Eastside peak load reduction through EE/DR/DER would start at 57MW in 2018 and increase to 500MW by 2035.

Because load grows at 0.6%/yr., in 2020 Eastside may need 3MWof peak reduction and could achieve 57MW. To meet a 0.6%/yr. load growth, PSE DER vendors would need to add 3-4 MW of load reduction measures every year through 2037. This is relatively easy using mature technologies and utility programs.

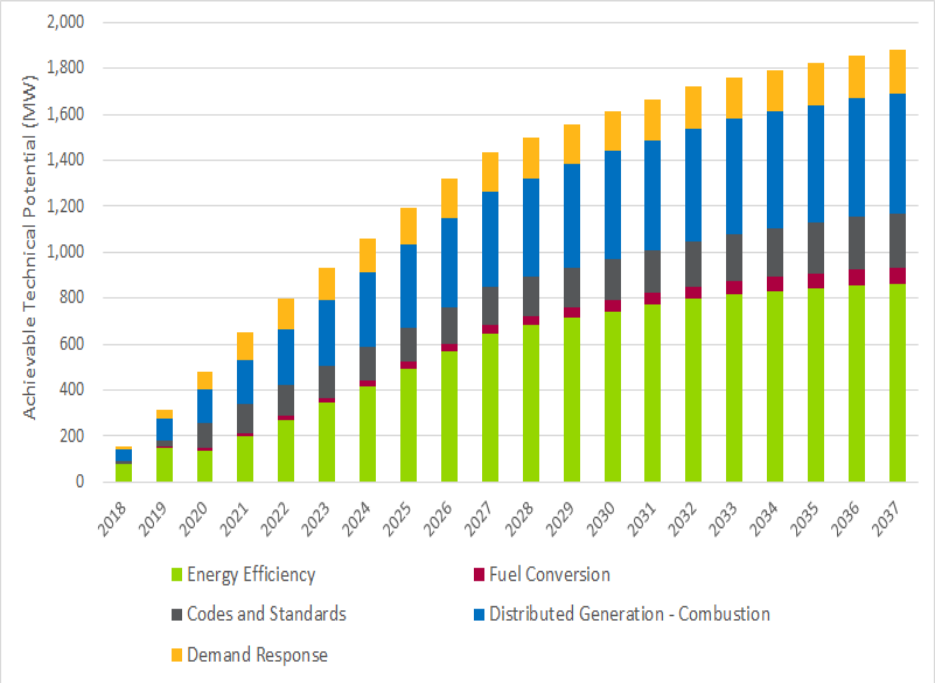


Figure 5: 2017 Navigant Assessment of PSE Winter Peak Demand Reduction Potential excluding storage and distributed generation)[21]

[21] https://pse.com/aboutpse/EnergySupply/Documents/DSR-Conservation-Potential-Assessment.pdf

Just as energy conservation measures decrease the need for new generating facilities, load reducing strategies decrease the need for more and/or larger transmission lines.

3. Energy Conservation

PSE has not issued an RFP for energy conservation or any distributed energy resources to *specifically* reduce Eastside peak loads as strategies to avoid construction of Energize Eastside. In the Northwest, the NPPCC 7th Plan has set regional goals achievable from accelerated energy conservation. Efficiency is by far the least expensive resource available to the region, avoiding the risks of volatile fuel prices and large-scale resource and infrastructure development, while mitigating the risk of potential carbon pricing policies.[22]

In 2015, Northeast Energy Efficiency Partnership cited many examples of energy efficiency being used to avoid transmission and distribution (T&D) infrastructure projects. Energy conservation has been used to avoid T&D investments in both passive and active. [23]

- *Passive deferral* - System-wide efficiency programs, implemented for broad-based economics nevertheless produce enough load reduction to defer specific T&D investments.
- *Active deferral* - when geographically-targeted efforts to promote efficiency – intentionally designed to defer specific T&D projects – meet their objectives.

The concept of ratepayer-funded energy conservation was introduced in 1976 by Dr. Amory Lovins in his book, *Soft Energy Paths*. Dr. Lovins would later coin the term "negawatt" to represent utility investments in energy conservation and renewables as a means to avoid construction of supply side infrastructure, e.g., power plants and *transmission infrastructure*. Energy conservation planners use utility-provided avoided-costs to determine energy conservation actions that would result in lower costs per kilowatt hour than supply side alternatives.

The Washington Public Power Supply System, or WPPSS, disaster was caused by building generation **based on unrealistically high load forecasts**. During the 1970s and 80s, many Northwest utilities had exaggerated load-forecast growth rates, and electric intensity (kWh/person) decreased annually due to energy conservation and changes in consumer behavior. SCL's "Energy 1990" study concluded that loads could be met with conservation and opted out of the nuclear plants. At the same time, Northwest utilities were busy planning the construction of five nuclear plants. Eventually the utilities mothballed all but one of the nuclear plants due to a combination of continued low load growth and increasing costs for nuclear

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[22] Northwest Power Planning and Conservation Council, 7th Plan Executive Summary.
[23] http://www.neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf

plants. The only plant actually constructed is now known as the Columbia Generating Station and is operated by Energy Northwest.

In 1983, Energy Northwest, formerly known as Washington Public Power Supply System, or WPPSS, defaulted on $2.25B in bonds. BPA had provided financial security for the construction of three of the five plants and continues to carry $6 Billion in debt on its books. The Northwest continues to pay for what is still considered the largest municipal bond default in our US history.

Seattle City Light avoided a portion of the WPPSS crisis by opting out of the Plants 4 and 5 in 1975. Seattle decided to increase investment in energy conservation measures including the "Kill-a-Watt" program that began in 1974. During this time the environmental movement was beginning to question the wisdom of nuclear power. The Washington Environmental Council filed suit to require City Light to produce an environmental impact statement on the nuclear plants which would have delayed the process five years. The environmental group dropped its suit when City Light Superintendent Vickery opened up the decision-making process. He established a 27-member Citizens' Overview Committee, made up of citizens and including environmentalists, to look at the needs for power and the best ways to provide it. City Light produced a study, Energy 1990, which examined ways to meet future power needs.

City Light staff supported first a 10 percent piece of the two new nuclear plants, then a 5 percent piece. The citizens' committee opposed participation in nuclear power and instead proposed that conservation be used to meet growth. The Seattle City Council supported the committee's approach and voted 6 to 3 not to participate in WPPSS 4 and 5. Good decision Seattle.

The WPSS default is relevant to the current debate on Energize Eastside and utility proposals to build peaking power plants. PSE continues to rely on 100-year old supply side solutions in an environment where customer preference and technologies will eventually provide 40% of energy resources on the distribution system, i.e., distributed energy resources.

In 1980, Congress passed the Northwest Power Act which put into law the priority of achieving all cost effective energy conservation, distributed renewables, and efficient production of electricity (e.g., CHP). The state of Washington put this into law in 2006, called I-937, for all utilities to pursue all available cost-effective energy conservation.[24] The only interesting hitch to the law is that the utility gets to decide what is cost-effective. So, every two years there is a debate between stakeholders and utilities as to what is cost-effective.

PSE has not issued an RFP or evaluated the cost effectiveness of increased amount of energy conservation to address the winter peak they say is growing on the Eastside.

[24] https://www.sos.wa.gov/elections/initiatives/text/i937.pdf

4. Demand Response

There are over 10 million customers participating in some form of Demand Response program in the US. In North America DR peak capacity reductions are over 50,000 MW and provide utility systems with 5-10% in seasonal peak reduction. PSE has 0% peak capacity reduction from DR.

The Northwest Power Planning and Conservation Council ("NPPCC") in their most recent power plan (7th) identified more than 4,300 megawatts of regional demand response potential. "A significant amount of this potential, nearly 1,500 megawatts, is available at relatively low cost; less than $25 per kilowatt of peak capacity per year. When compared to the alternative of constructing a simple cycle gas-fired turbine, demand response can be deployed sooner, in quantities better matched to the peak capacity need, deferring the need for transmission upgrades or expansions." [25]

In 2016, the Supreme Court struck down a lower court opinion and ruled that the Federal Energy Regulatory Commission (FERC) has the authority to regulate demand response and operators should pay the wholesale market price to DR providers just like a generator.[26] This means that customers and vendors that provide a curtailment would receive the locational marginal price for power.

"The Federal Power Act (FPA) provides FERC with the authority to regulate wholesale market operators' compensation of demand response bids because the practices at issue directly affect wholesale rates, FERC has not regulated retail sales, and the contrary view would conflict with the FPA's core purposes. Moreover, FERC's decision to compensate demand response providers at the locational marginal price, which is the same price paid to generators, instead of at the locational marginal price less the retail rate for electricity, is not arbitrary and capricious when FERC provided a detailed explanation for that decision and responded at length to contrary views."

Why has PSE hesitated to implement DR?

It is not mandatory, it doesn't provide a return on investment, and it would reduce their peak load. PSE is not mandated by NPCC planning requirements and it is not included in I-937 law. Energy Efficiency investments are mandated in Washington by I-937, but this mandate does not include load management or programs to address system or infrastructure capacity. PSE does not want to reduce peak load, because load growth is what allows them to justify investments in T&D and peaking gas power plants.

In its 2015 IRP, PSE's identified a need for 122MW of DR by 2020 to meet winter capacity. PSE issued an RFP, received bids, and then, without additional scrutiny, changed its cost-effectiveness analysis and informed the WUTC, that the company decided not to include DR in the IRP.

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[25] https://www.nwcouncil.org/media/7149940/7thplanfinal_allchapters.pdf Page 1-10.

[26] https://www.supremecourt.gov/opinions/15pdf/14-840-%20new_o75q.pdf

Evidence of PSE avoiding DR can be seen in how PSE dealt with demand response in their 2015 IRP. PSE determined a need for 122MW of DR for winter capacity by 2020. They issued an RFP, received bids, and then changed their cost effectiveness analysis with no scrutiny and told WUTC they were not going to do DR. PSE wrote and RFP requiring hour ahead response, which requires more costly communication and control and is more difficult to attain participation. An hour-ahead response is not a requirement to manage or reduce winter peaks. This issue, among others, was pointed out to the WUTC in their review of the 2016 RFP. WUTC commissioners acknowledged the arguments but chose to allow PSE to proceed.[27] Moreover, PSE changed their avoided cost values and determined they would not pursue DR at this time.

PSE has again identified DR in its most recent 2017 IRP. The 2018 RFP was issued March 29, 2018 and is received comments at WUTC through May 25, 2018. PSE does not actively focus on winter peak capacity extra value or cost-effectiveness for Eastside NWA.[28]

5. Community Choice

Eastside communities have the potential to control their power supply and reliability. In 2017 Microsoft successfully exited regulated service from PSE and is now enacting its own strategy for energy supply and demand management. Microsoft wanted to pursue more renewable energy and more demand-side resources at lower cost. Currently Community Choice Aggregation (CCAs) is possible in the states of Massachusetts, Ohio, California, Illinois, New Jersey, New York, and Rhode Island, and as of 2014, served nearly 5% of Americans in over 1300 municipalities...[29] CCAs allow communities to manage their power supply procurement and allow spending and customer programs that promote DERs or other community priorities.

Though Washington does not have a CCA law, Eastside communities should understand that successful examples of community-controlled electricity exist.

6. Reliability

A recent survey of US utilities found that three-quarters of survey respondents name AMI as the top distribution automation solution planned at their utility, followed by fault location, isolation and service restoration (FLISR) technology (67 %) and advanced distribution management systems (ADMS) (62 %). These solutions — AMI, ADMS, FLISR and asset management tools in addition to providing improved reliability — will play a critical role in collecting and delivering the data that will help utilities accommodate the most important application – DER

[27] https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=27&year=2016&docketNumber=160808
[28] https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=34&year=2016&docketNumber=160808
[29] https://en.wikipedia.org/wiki/Community_Choice_Aggregation

7. Conclusion

Puget Sound Energy has not provided the historical or a valid load forecasts to verify an increasing peak load on the Eastside. Instead the company has resorted to irrelevant facts, e.g. population is growing and the transmission line is old. Most evidence demonstrates that PSE has exaggerated eastside load forecast by a factor of 17.

If, in fact, there is a peak load issue, it could be addressed in better ways than higher voltage transmission lines. Keith DeClerck, City of Bellevue's independent analyst, summarizes PSE's proposed Energize Eastside project[30] using the analogy of a hose serving water to the Eastside communities. DeClerck suggested the solutions include:

1. Shifting the demand for water away from peak times (load shift),
2. Drilling wells to provide water during peak times (distributed generation),
3. Reducing the use of water (energy conservation),
4. Storing water to be used at peak times (energy storage), or
5. Increasing the pressure in the hose to the sprinkler heads (higher voltage transmission and new pressure regulators).

PSE's non-wire screening study was based on incorrect assumptions and data and provided invalid conclusions. PSE has not issued an RFP or made any attempts to price real NWA solutions. These active Non-Wire procurements and programs are a normal business process and have been happening in the United States since the 1990s. PSE does only what is minimally required to meet the energy efficiency mandates of I-937 and the company has postponed demand response and other peak-load management tools since 2001.

Recommendations to Eastside Communities

Deny permits for Talbot Hill/Lakes and:

1. Demand PSE provides verifiable, historical, peak-seasonal-load data on all Eastside substations and feeders that are creating the transmission need;
2. Hire independent consultant to construct a valid load forecast and transmission model based on ta verifiable load forecast;
3. Mandate PSE appoint a third party to evaluate load forecast and coordinate planning and procurement of Non-Wire Alternatives; and
4. Demand PSE develop an open RFP for Eastside Non-Wire Alternatives and use a community-sponsored independent evaluator to receive public stakeholder input, approve the RFP and evaluate the outcomes.

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[30] http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/stantec_review_memo_eastside_needs_assessment_report.pdf

APPENDIX B: Ken Nichols Resume

Ken Nichols, Principal, EQL Energy LLC
ken@eqlenergy.com
503 438 8223

Mr. Nichols' practice areas at EQL are smart grid business planning and operations, demand response and energy efficiency program design and evaluation, renewable development, utility resource and transmission planning, and wholesale market operations, and supporting policy. His clients include utilities, vendors and utility service providers, as well as large energy consumers.

- Bonneville Power Administration. DSM emerging technology research, program design/tools, custom projects – residential and non-residential lighting and controls. (2016-17).
- Utility and research grant proposal development related to solar, storage, and IDSM pilots. (ongoing)
- Western Interstate Energy Board. "Distributed Energy Resources and changes in Distribution planning and operations." (https://westernenergyboard.org/) (2015)
- BC Hydro – Capacity DSM planning and RFP development.
- University of British Columbia, Electric Load Management study (T&D infrastructure deferral), (2014- 2016)
- IDSM (demand response and EE) program planning, utility resource and transmission planning, and DSM evaluation and planning (ongoing)
- Innovari Inc., Hillsboro, OR. Product Marketing, BMS controls, utility dispatchable backup generation, inverter utility integration. (2014-2015)
- Industrial Energy Efficiency firm, Strategic and business planning, networked projects (2013)
- VP, Energy Management at PureSense Environmental Inc., Fresno, CA. (2011-2013). Managed vendor based agricultural demand response program that achieved 26MW of AutoDR and over $60MM in products and service sales.
- Refrigeration controls company, AutoDR development, DR pilot, and marketing
- Energy Storage startup – Utility demonstration, Arpa-E grant, commercialization, market assessments (2012)
- Assistant Professor, Portland State University "Smart Grid for Sustainable Communities." (2010-12)

Ecofys US, LLC
Director, US Risk Management Portland, OR
Director, Power Systems and Markets 2010-2011

Managed AutoDR pilot at BPA and 9 PNW utilities. Evaluating capabilities of technologies, e.g., commercial thermostats, industrial refrigeration, and water heater controls, to provide both increase and decrease of loads with 10-minute notice. Work involved technology assessment, contract negotiation, customer and utility engagement, business case development, and financial analysis.

PG&E / TransCanada Portland, OR
Director, US Risk Management 2002 - 2010

Responsible for risk management of $1.6 Billion in annual US operating revenues in power and gas transmission. Managing policies, FERC tariff and rate cases related to financial risk management, integrated CFO operations at 4 separate US offices, designed and implemented new IT systems, part of rate case team, and managed the recovery of over $400 Million in defaulted obligations. Other group duties include evaluate risk on new projects, credit/financial risk analysis, project valuation/negotiation, financial reporting, FERC tariff and policy setting, and relationships with lenders and rating agencies.

Hafslund Energy Trading Seattle, WA
General Manager 1997 - 2001

Startup and management of Hafslund Energy Trading (HET) a power/gas trading and marketing firm in the WECC from 1997-2002. HET had 15 employees at its peak and was profitable a year after startup. Markets traded included OTC power throughout WECC, CA ISO and PX, and natural gas futures. Responsibilities included: Risk Management, HR, Representative on CAISO groups, power modeling and IT development.

Barakat & Chamberlin Boulder, CO
Consultant 1992-1997

Barakat & Chamberlin was a leading DSM and Utility consulting firm sold to PG&E in 1998. Mr. Nichols worked on projects in areas such as: integrated resource planning, energy efficiency, rate case studies, demand side management program design and evaluation, renewable energy assessment, and load/price forecasting. Clients include PSCO (nka Xcel Energy), Midwest Power, PG&E, PacifiCorp, Nevada Power, Tacoma PUD, TVA, and Denver Water Dept.

National Renewable Energy Lab Golden, CO
Economist 1992

Market penetration and resource studies for Solar PV, and Biomass. (11 months)

Education

Portland State University Portland, OR
Assistant Professor 2011-2013

Stanford University Stanford, CA
M.S., Management Science and Engineering June 1992
Energy Modeling Forum, contributor

Willamette University Salem, OR
B.A., Physics & Computer Science June 1986

Universite Aix-Marseilles Aix-en-Provence FRANCE
1985

Groups

- AESP (Association of Energy Service Professionals http://www.aesp.org/)
- WIEB – Technical Advisory, Interconnection and Reliability working group
- SmartGrid Northwest (www.smartgridnw.org)
- DisCo (Distribution System Collaborative, Washington State)
- PLMA (Peak Load Management Alliance)
- Northwest Energy Coalition (Northwest Policy Stakeholder)
- Northwest Intermountain Independent Power Producer Coalition (NIPPC)
- Renewable Northwest (www.renewablenw.org)
- OpenADR standards committee (www.openadr.org)
- LNBL/DRRC – Demand Response Research Center
- ACEEE (American Council for an Energy Efficient Economy)
- NWGA (Northwest Gas Association (www.nwga.org) at PG&E
- WPTF (Western Power Trading Forum, www.wptf.org) while at HET
- WSPP (Western Systems Power Pool, http://www.wspp.org/), HET

Research and Presentations

1. 2017 NIPPC annual conference. DER opportunity and risks on the distribution system. (Northwest and Intermountain Power Producers Coalition).
2. 2017 PNWER Carbon Pricing in the Pacific Northwest moderator
3. 2016 Washington State legislative work session, DER value: jobs and rate reduction
4. 2015 Distribution System Collaborative, State of Washington, Dec. 1, 2015.
5. 2015 PNWER Summit, Big Sky MT, Distributed Energy Resources in the Pacific Northwest.
6. 2015 Western Interstate Energy Board, paper on Distribution Issues of expanding Distributed Energy Resources. *http://westernenergyboard.org/2015/05/final-report-released-by-eql/*
7. Western Energy Institute March 2015: Panel on Energy Storage
8. Transactive Energy in US Power Markets, PLMA Conference October 2013.
9. AutoDR irrigation controls. Southern California Edison Water Conference, October 2012.
10. AutoDR refrigeration controls vendor analysis, 2012. Confidential.
11. Peak Load Management Association, May 2012, New York, NY, "End Use Energy Storage and Renewable Integration."
12. *BPA, TI-220 Smart End-Use Energy Storage and Integration of Renewable Energy, Sep 2012.* http://www.bpa.gov/EE/Technology/demand-response/Documents/TI_220_Project_Ecofys_Evaluation_Report.pdf
13. Bonneville Environmental Foundation, "End-Use Energy Storage and Demand Response at BPA: What are the gaps to Demand Response in BPA's service territory?," October 2011. Confidential.
14. *Smart Grid Oregon policy paper, Rethinking Regulation; Mismatches between Smart Grid and traditional regulation. 2010* http://www.smartgridoregon.org/Resources/Documents/Rethinking%20Regulation%20V6A%20011611.pdf
15. "Review of PGE's Feeders Advanced Storage Transaction system", A utility scale battery and high reliability zone smart grid pilot project. 2010
16. "Tools of the Trade" article on price/volume risk management for Energy Power and Risk Management Journal, June 2002.
17. Energy Exchanges Online conference. September 10-11 New Orleans LA, Seminar on clearing and credit risk mitigation.
18. FIA (Futures Industry Association) conference Boca Raton March 2001. Panel on New Clearing Models. (other panel members include CME, BOTCC, CapClear, OnExchange, and eMetra)
19. Energy Exchanges Online conference. December 6-7 2000 Scottsdale AZ, Panel on Credit issues in energy trading marketplace

20. “ISO development: The Cost of Cost and Complexity” EUS conference, March 1999, ISO Development and Transmission Pricing.
21. “Trading in California’s ISO and PX markets,” November 1998. Presented at Electric Utility Consultant conference “ISOs and related transmission pricing.” Also used in FERC intervention ER-98-211.
22. “Using Option Theory in Pricing Spark Spreads,” EUS Conference on Converging Deregulation in Natural Gas and Power Markets. (1996)

1.

23. "Valuing Flexible Resources in an Uncertain Future," Option Pricing in Planning and Contracting. 1994 American Council for an Energy Efficient Economy (ACEEE), and 1994 17th Annual International Association for Energy Economics.
24. "Moving from DSM to Value-Added Customer Services: A Guidebook for the Journey," ADSMP Topic paper, 1994.
25. “Incorporating Risk into IRP,” Electricity Journal, June 1993.
26. “Reducing the Capital Costs of Utility Scale Wind Energy,” NREL, 1992.
27. Market Penetration study for Solar Photovoltaics, NREL white paper, 1992.
28. "Profit on Conservation: A Critical Look at PG&E's Shared Savings," PG&E white paper, 1991.

Other notes:

In 2015 EQL Energy was hired by CENSE to evaluate the need and alternatives of Puget Sound

Energy's (PSE) Energize Eastside project. We found many flaws in PSE's load forecasts, modeling assumptions, modeling, and Non-Wire Alternatives (NWA) screening study. We were surprised that PSE 1) would not provide CENSE or other stakeholders with historical load and load type information on the Eastside substations and circuits, and 2) did not perform an open RFP for NWA solutions. Because of the opaque process, we could not perform a complete needs and alternative analysis, but based on available information, it appears clear that PSE has sufficient non-wire alternatives at their disposal to completely avoid building the Energize Eastside transmission line. Moreover, in October 2015 EQL also submitted a formal economic study request to PSE Transmission's group pursuant to Attachment K of PSE's FERC OATT (Open Access Transmission Tariff) requesting that PSE evaluate a portfolio of non-wire solutions.[1] This study was never conducted.

PSE has historically only analyzed and screened for EE/DR cost effectiveness on a system basis and does not consider <u>specific locational values</u> of these programs.

1. PSE compares EE/DR to supply side costs, e.g., natural gas plants, market purchases, etc. They do not consider use of EE/DR to address any specific T&D cost avoidance.
2. This separate planning method is changing across the US, especially in places with open markets, e.g., CA, TX, NY, and New England. References to be provided. PSE will likely join the rest of the country as the WUTC rulemaking process UE-161024 provides clear rules and processes for improved planning and procurement processes. EQL will reference our testimony and others in U-161024.
3. This is changing for most utilities in US, examples include all open market areas, and CA, NY, New England, etc. Specific examples of projects targeting T&D include:
   - CA: PG&E, SCE, and SDG&E
   - PNW: PGE doing DER testbeds for 3 substations,
   - NY: ConEd, Rochester

[1] http://www.oatioasis.com/PSEI/PSEIdocs/Oct_31_PSET_Economic_Study_Request_from_EQL.PDF

ACKNOWLEDGEMENT

I am now and at all times herein mentioned a citizen of the United States, over the age of 18 and competent to testify as a witness herein. I am the author of the preceding report,

EQL Report for City of Bellevue Land Use Hearing on:

Puget Sound Energy's application for a Conditional Use Permit ("CUP") to construct and operate the Richards Creek substation and 3.3 miles of 230 kV transmission line located in the City of Bellevue ("City"), Washington. ("Project" or "THLTL")

I declare under the penalty of perjury under the laws of the State of Washington that the preceding report is true and correct to the best of my knowledge and belief.

DATED this 28th day of March, 2019.

Signature: _____

Printed Name: Ken Nichols

CENSE REPORT / Jan Medley

Supreme Court rules "Demand Response" receive same rates for *conserving* electricity as companies earn for *generating* electricity

Abstract

A 2016 Supreme court decision written by Justice Elena Kagan[1] elegantly explains the economic value of "demand response," a strategy where large users of electricity are compensated for reducing power consumption during periods of peak electrical demand. The Court's arguments support the position that the authority of the Federal Energy Regulatory Commission (FERC) should be upheld to pay large users of electricity the same rate to reduce power consumption during periods of peak electrical demand as it would cost companies to generate enough electricity to meet demand.

The regulatory approach, known as "demand response," lowers costs for consumers and lessens the risk of system failures that can cause blackouts. As Justice Elena Kagan wrote for the majority in the 6-to-2 decision:

> *"That practice (demand response) arose because wholesale market operators can sometimes — say, on a muggy August day — offer electricity both more cheaply and more reliably by paying users to dial down their consumption than by paying power plants to ramp up their production."* [2]

The Court's decision rejected a claim by the Electric Power Supply Association (EPSA) that FERC's regulation of demand response interfered with retail rates and thus extended beyond FERC's authority to regulate only wholesale rates.

The Court also rejected EPSA's second argument that even if the commission had the authority to issue the regulation, it had acted arbitrarily in adopting it.

Clean energy advocates celebrate the decision, stating that it places demand response on a level playing field with power plants and will spur investment and innovation leading to a cleaner power grid.

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[1] Fed. Energy Regulatory Comm'n v. Elec. Power Supply Ass'n, 136 S.Ct. 760, 193 L.Ed.2d 661 (2016)

[2] https://www.supremecourt.gov/opinions/15pdf/14-840-%20new_o75q.pdf. p 2

1. What is Demand Response

Demand response pays large energy consumers (universities, manufacturers, large office buildings, etc.) to reduce energy during times of peak demand. For electric grid operators and utilities, who must provide its customers with cost-effective, consistent and reliable electricity, demand response is a much cheaper alternative than paying power providers premium prices to provide the system with more electricity. Because demand response is such a cost-efficient way to meet peak demand, the savings can be passed along to all energy consumers.[3]

Since 1935, as part the Federal Power Act, the Federal Energy Regulatory Commission has had the authority to regulate the demand response market.[4] FERC manages the compensation related to demand response for the wholesale electricity markets, in which electricity is competitively bought and sold.

In March 2011, FERC amended the Federal Power Act ruling that companies delivering demand response services should receive the same rates for *conserving* electricity as companies earn for *generating* electricity. [5]

2. State vs. Federal authority

In response, the Electric Power Supply Association (EPSA), representing electric power producers, took FERC to court and challenged the order, arguing that FERC is authorized to regulate wholesale, but not retail electricity transactions.[6]

In 2014, a D.C. Circuit court sided with the EPSA and found that states, not the federal government, have exclusive jurisdiction over the demand response market.[7]

In 2016, Justice Kagan rejected that argument, stating that the regulation affected retail sales only incidentally. She wrote:

> *"It is a fact of economic life that the wholesale and retail markets in electricity, as in every other known product, are not hermetically sealed from each other. To the contrary, transactions that occur on the wholesale market have natural consequences at the retail level. And so too, of necessity, will FERC's regulation of those wholesale matters."* [8]

Justice Kagan rejected a second argument from the challengers: that even if the commission had the authority to issue the regulation, it had acted arbitrarily in adopting it.

> *"The commission, not this or any other court, regulates electricity rates" The disputed question here involves both technical understanding and policy judgment. The commission addressed that issue seriously and carefully, providing reasons in support of its position and responding to the principal alternative advanced. . .*

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[3] https://www.energysmart.enernoc.com/why-does-supreme-court-care-about-demand-response
[4] http://fortune.com/2016/01/25/supreme-court-demand-response-ruling/
[5] https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf
[6] http://fortune.com/2016/01/25/supreme-court-demand-response-ruling/
[7] Ibid
[8] https://www.supremecourt.gov/opinions/15pdf/14-840-%20new_o75q.pdf p.18

"It is not our job to render that judgment, on which reasonable minds can differ. Our important but limited role is to ensure that the Commission engaged in reasoned decision making — that it weighed competing views, selected a compensation formula with adequate support in the record, and intelligibly explained the reasons for making that choice." [9]

3. Conclusion

To clean energy advocates, this case epitomizes the confrontation between those who cling to the "fossil fuel-centric 20th century centralized grid" and those who seek a more decentralized, resilient, nimble, and diverse 21st century grid that includes a wide range of demand-side resources, including rooftop solar, wind power, batteries, demand response, and energy efficiency.[10]

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[9] https://www.supremecourt.gov/opinions/15pdf/14-840-%20new_o75q.pdf p.33

[10] https://www.energysmart.enernoc.com/why-does-supreme-court-care-about-demand-response

CENSE REPORT / Karen Esayian

Bonneville Power Administration Decision to Cancel I-5 Corridor Project

Overview

The final environmental impact statement on BPA I-5 Corridor project was released in February of 2016. At that time BPA's Elliot Mainzer promised that BPA would conduct additional analyses of financial forecasts, planning assumptions and commercial practices.

On May 18, 2017 the BPA announced that it would not build the proposed 80-mile, 500kV transmission line that would have stretched from Castle Rock, WA. to Troutdale, OR. The decision reflects BPA's commitment to "*taking a more flexible, scalable and economically and operationally efficient approach to managing its transmission system.*"

BPA's decision embraces grid solutions that rely more on distributed resources and modern tools of technology rather than infrastructure builds.

Attachment:

Elliot Mainzer letter of May 17, 2017

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

EXECUTIVE OFFICE

May 17, 2017

In reply refer to: A-7

To parties interested in the I-5 Corridor Reinforcement Project:

The Bonneville Power Administration has completed an extensive analysis of the need for the I-5 Corridor Reinforcement Project and decided not to build the proposed transmission line. This decision caps an intensive review that included one of the most comprehensive public engagement processes BPA has ever undertaken. Much has changed since BPA proposed the transmission line, and I have concluded that constructing the line would not fulfill our commitment to making the right investment at the right time.

BPA proposed the I-5 Corridor Reinforcement project in 2009 as a solution to preserve reliability, meet existing contract requirements, reduce curtailments, and serve demand on the transmission system – which at the time was growing. More recently, BPA considered the size, local impacts and increasing costs of the proposed project, which prompted us to take a hard look at all of our transmission practices and analytics, including a fresh look at load (electrical demand) forecasts, generation changes and market dynamics.

As a result of this comprehensive review and the inherent difficulties associated with building this line, we are taking a new approach to managing congestion on our transmission grid. My decision today reflects a shift for BPA – from the traditional approach of primarily relying on new construction to meet changing transmission needs, to embracing a more flexible, scalable, and economically and operationally efficient approach to managing our transmission system. We will also increase our reliance on advanced technology, robust regional planning, industry standard commercial practices and coordinated system operations.

Going forward, we will leverage the tools of the modern energy economy to maximize the value of federal assets for our customers and the broader region. Through the transformational efforts described below, we will maximize grid availability, use and reliability to support economic growth along this and other important transmission corridors.

To those who have been with us every step of the way, I would like to acknowledge and thank you for the time you invested in reading our material, attending meetings and providing comments as we took nearly nine years at significant cost to complete a comprehensive review of the project and its potential impacts. This was a difficult decision, compounded by many technically complex and moving parts, and I understand the uncertainty this created for the landowners and homeowners along the route alternatives. Though the process was lengthy, I simply could not risk making a decision of this magnitude without first acquiring the best possible information, and I can say with confidence today that Bonneville is making the best decision for the region.

A summary of our in-depth review
In September 2016 we convened an independent review panel of industry experts to review study assumptions, methodologies, results and assessments supporting the need for the I-5 Corridor Reinforcement Project. The panel concluded that "the proposed 500-kV line could meet the reliability needs…, but that line will add far more capacity than is required for reliability alone." We agreed.

We also observed changes to our regional power system and transmission reliability planning standards. For example, the proposed transmission line would have helped manage the summer congestion impacts of power that flows north to south across the South of Allston flowgate – the portion of the transmission grid this project would have augmented. Contributing to this congestion is power from the coal-fired generators in Centralia, Washington, that are required by state law to close in 2020 and 2025. This should help relieve summer congestion, depending on where replacement generation is sited. Additionally, new national reliability regulations took effect in January 2016. These reliability standards changed the way line limits are calculated. This new standard will increase the potential for other regional utilities to consider infrastructure upgrades or additions that would provide additional transmission capacity and relieve congestion in this corridor.

Further, recent trends indicate that load growth has generally slowed relative to what was assumed in prior studies. However, we are also seeing the potential rapid development of large loads associated with the technology sector that could add hundreds of megawatts of baseload demand in a concentrated geographic area. Meeting the needs of such sudden and unexpected loads is a demanding task, whether through builds, technology or business changes. In this case, where we have decided against building the proposed project, Bonneville and its regional utility partners will need to maximize the use of modern approaches to grid design to meet load growth and economic development objectives.

Moving forward
We will be transforming our approach to adding transmission capacity by making more scalable and flexible investments in the federal transmission system. Focused effort will be given to integrated coordination of operations, transmission planning and commercial processes to support our product portfolio. Bonneville will need to establish a new level of risk tolerance to maximize the use of its transmission assets while meeting customer needs.

We have already put in place or are considering the following transformational approaches:

- Available transmission capacity calculations will be modified to take a more risk-informed profile, potentially enabling greater sales on the existing transmission system.

- In alignment with FERC *pro forma* tariff and industry standards, BPA will review and may modify its commercial transmission products and services.

- New state awareness tools and use of generation redispatch together with increased operational connectivity with the California Independent System Operator will ensure more effective real-time monitoring. The incorporation of real-time data and analysis into the calculation of system limitations may release excess capacity while maintaining reliability. Enhanced visibility and control of loads, resources and flows (including market flows) will

allow more accurate, effective and reliable management of the transmission system.

- Non-wires measures to manage generation and loads to reduce peak congestion will launch this summer. We also will look to use cutting-edge grid technologies such as battery storage and flow control devices to proactively manage congestion and further extend operational capacity of the existing system.

- We will work closely with the region's other utilities, regional planning organizations and economic development organizations to convey the economic and operational implications of siting loads and generation resources in different areas. We will incentivize new load centers and resources to locate in areas that will make the best use of existing transmission capacity and minimize costs to them and to the region's electricity consumers.

The decision to not build the I-5 Corridor Reinforcement Project does not mean we and others will not need to build new lines in the future to provide additional transmission capacity in the Northwest. The region inevitably will need to build new lines, as well as rebuild existing, aging lines. But through this decision today, Bonneville is committing to taking a forward-looking approach with its investment decisions, and the region can be certain that BPA will seek first to use efficiencies and build at the smallest scale possible to meet our customers' needs, ensuring Bonneville remains a reliable engine of economic prosperity and environmental sustainability in the Northwest.

Understanding the certainty of business dealings our customers require, I want to reinforce Bonneville's commitment to offering terms and conditions of transmission service that align with FERC's *pro forma* tariff as much as possible; and indeed, we will be moving closer to that paradigm.

Work is already underway to craft solutions and design our way forward. Within a month, we expect to begin discussing these new approaches with our transmission customers and other stakeholders. During these discussions, Transmission Services will explain how we will advance our strategy and provide options for those seeking service across the South of Allston flowgate.

Thank you again for working with us as we take steps toward a more innovative transmission grid, updated business practices and improved regional coordination. This work is indicative of our commitment to working collaboratively with all of our stakeholders to deliver the best value for the region.

Sincerely,

/s/ Elliot E. Mainzer, May 17, 2017

Elliot E. Mainzer
Administrator and Chief Executive Officer

CENSE REPORT / Karen Esayian

ColumbiaGrid Connection & Seattle City Light

Abstract

The formation of the ColumbiaGrid in 2006 was intended to facilitate multi-system transmission planning between its members. The *Memorandum of Agreement* signed on January 31, 2012 between the Department of Energy/Bonneville Power Administration, the City of Seattle/City Light Department and Puget Sound Energy states "*transmission congestion affecting the Puget Sound Area interconnection is a shared problem."*

A single transmission planning process was implemented beginning in 2015. In July of 2015 a report was published laying out a 10 year plan. Included in this plan was the precursor of what is known today as Energize Eastside. Somewhere along the line, this shared multi-system planning with ColumbiaGrid members was forgotten.

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1. ColumbiaGrid Members and Working Agreements

"ColumbiaGrid was formed with seven founding members in 2006 to improve the operational efficiency, reliability, and planned expansion of the Northwest transmission grid. Eleven parties signed ColumbiaGrid's Planning and Expansion Functional Agreement (PEFA) to support and facilitate multi-system transmission planning through an open and transparent process. In addition, starting in 2015, ColumbiaGrid has implemented a single transmission planning process that satisfies the requirements under both PEFA and

Order 1000. This leads to a more comprehensive process which includes a wide range of studies with different purposes."[1] Currently listed as ColumbiaGrid members and participants are:

- Avista Corporation
- Bonneville Power Administration
- Chelan County PUD
- Grant County PUD
- Puget Sound Energy
- Seattle City Light
- Snohomish County PUD
- Tacoma Power
- Other Contributors are: Cowlitz County PUD, Douglas County PUD

2015 was the first year that ColumbiaGrid implemented its planning process under the PEFA/Order 1000 Functional Agreements. In the July 2015 System Assessment Report, it is explained that the process involves a Ten-Year Plan and comprises a list of projects that planning participants are committed to build in the coming years to address known transmission deficiencies.

In the 2015 list of proposed projects this "*Eastside 230/115 kV Transformer and conversion of Sammamish-Lakeside-Talbot Line to 230 kV which provides additional transformer capacity for the Bellevue area and additional transmission capability through the Puget Sound area.*[2] was listed. This was an immediate precursor to Energize Eastside as currently proposed by PSE. This point is made clear in an April 30, 2015 letter from the Department of Energy, Bonneville Power Administration to Larry Johnson.[3]

PSE is only one of several members of the ColumbiaGrid who are committed to a multi-system transmission plan in the Pacific Northwest. With regard to the Puget Sound area interconnection, the *Memorandum of Agreement* signed on January 31, 2012 (attached to a FOIA letter from Dept. of Energy to Mr. Larry Johnson dated April 30, 2015) between the Department of Energy/Bonneville Power Administration, the City of Seattle/City Light Department and Puget Sound Energy, details the cooperation expected of these parties in preserving the reliable operation of the Puget Sound Area interconnection.[4] The document further states that "transmission congestion affecting the Puget Sound Area *interconnection is a shared problem*,"[5]

1 https://www.columbiagrid.org/client/pdfs/2015SAfinal.pdf
2 https://www.columbiagrid.org/client/pdfs/2015SAfinal.pdf page 59
3 attachment: letter dated April 30, 2015 from Department of Energy to Larry Johnson
4 https://www.columbiagrid.org/client/PEFA-conformed-copy.pdf. page 3
5 https://www.columbiagrid.org/client/PEFA-conformed-copy.pdf. page 2

Another key member of the ColumbiaGrid is Seattle City Light. This is a municipal electric utility, owned by the residents of Seattle and run by the City's elected officials. The Utility serves a population of almost 700,000 people living in a 130 square-mile area, including the City of Seattle and several adjoining jurisdictions. To serve these customers, City Light owns, maintains, and operates a multi-billion-dollar physical plant. The physical plant includes:

- A distribution system with 14 major substations and more than 2,500 miles of overhead and underground cable;
- A generation system comprising seven hydroelectric plants on the Skagit, Cedar, Tolt, and Pend Oreille Rivers with a combined capacity of almost 2,000 megawatts;
- 650 miles of high-voltage transmission lines linking these plants to Seattle [6]

6 http://www.seattle.gov/financedepartment/1116adoptedcip/documents/SEATTLE_CITY_LIGHT.pdf

2. Questions on the Use of the Seattle City Light Power Poles for Energize Eastside

As the map below illustrates, several miles of the SCL transmission line are actually located on the Eastside, running from the northern border of the proposed Energize Eastside project in Redmond through Bellevue and Newcastle and into Renton, the southern border of the proposed PSE 230kV transmission line.

Location of Seattle City Light Transmission Line on Eastside

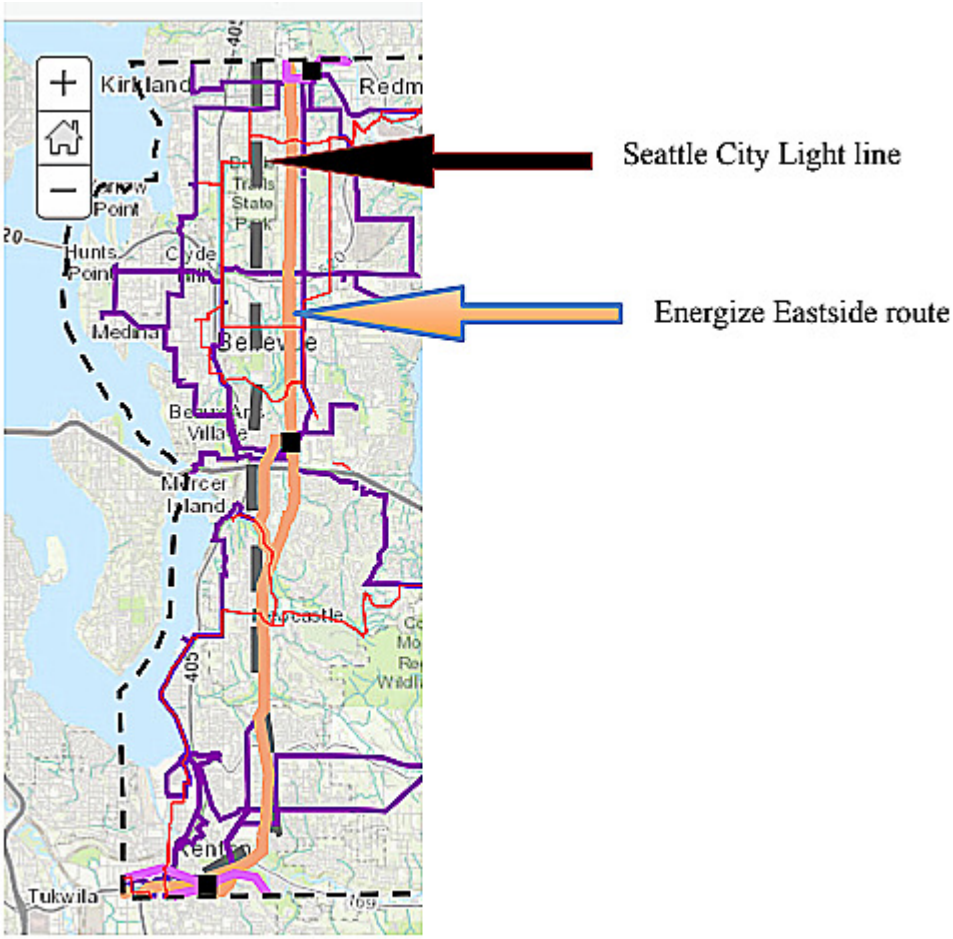

Figure 1 *SCL represented by dashed black line parallels the route of Energize Eastside through much of Bellevue.*

One of the alternatives not fully addressed by PSE for the proposed Energize Eastside project is the use of Seattle City Light power poles for the 230kV transmission lines.

Uzma Siddiqi of Seattle City Light, in a letter to Nichols Matz of the City of Bellevue dated June 2, 2014,[7] stated that SCL preferred not to use SCL's transmission lines for PSE's *native load service needs*.

In 2017 the question was again asked about using the existing SCL transmission towers to support the purportedly needed 230kV PSE transmission lines. The letter to Mr. Larry Weis, Seattle City Light, from Larry Johnson dated March 20, 2017 asked that question.[8] The response was written by Sephir Hamilton, Seattle City Light, on April 25, 2017. Mr. Hamilton replied that "PSE has never formally requested transmission service on Seattle City Light's Eastside transmission lines." "Obviously, if PSE would make a formal request for transmission service on Seattle City Light's Eastside lines, Seattle City Light would respond appropriately."[9]

The letter also contends "Energize Eastside project is not subject to the Order No. 1000 because it is located completely within Puget Sound's service territory." Further, "neither Puget Sound nor any eligible party requested to have the project selected in the regional transmission plan for purposes of cost allocation."[10]

It is apparent from these attached letters that the use of the Seattle City Light transmission line towers was an *alternative **not** fully researched nor pursued* by PSE in their planning.

3. Regional Reliability Need or Local Reliability Need?

In original proposals for Energize Eastside by PSE, studies were included that described 1,500 MW flow to Canada as a necessary component to this proposal.

This would indicate that Energize Eastside was developed as a *regional plan*.

In the *Memorandum of Agreement* signed on January 31, 2012, by representative parties from Seattle City Light, Bonneville Power Administration and Puget Sound Energy, it specifies the memorandum as relating to the Preferred Puget Sound Area Plan of Service Projects and Cost Allocation. There is emphasis on sharing the problems in the Puget Sound Area, with *projects and* cost *sharing arrangements* provided as appropriate. [11] Under the title*: Preliminary Capital Cost Allocation*, it is stated that "Parties agree to share in the capital costs of Preferred Plan Projects." For Puget (Sound Energy) plan projects, it is stated that "BPA

7 attachment: letter dated June 2, 2014 from Uzma Siddiqi, Seattle City Light, to Mr. Nicholas Matz
8 attachment: letter dated May 20, 2017 from Larry Johnson to Larry Weis, General Mgr. Seattle City Light
9 attachment: letter dated April 25, 2017 from Sephir Hamilton to Mr. Larry Johnson
10 attachment: letter dated April 25, 2017 from Sephir Hamilton, Seattle City Light, to Mr. Larry Johnson
11 attachment: Memo of Agreement obtained through FOIA from Dept of Energy, Bonneville Power Admin. page 2

and Seattle City Light shall each pay to Puget an amount equal to one-third of the adjusted projected capital cost of the Maple Valley to SnoKing Reconductor Project."[12]

All this leads to the conclusion that Energize Eastside, labeled as the Maple Valley to SnoKing Reconductor Project, is a regional project.

There are questions that need to be answered: is Energize Eastside a regional project or is it for local service needs? If it is for local service needs, why is the 1,500 MW flow to Canada part of the original proposal? Given the *Memorandum of Agreement* stipulations, why is PSE not requesting the cost of the project to be shared by BPA and SCL? The arrangement pursued by PSE only places the cost of the project on the PSE rate base - the residents of the Eastside.

In the 2008 Acknowledgement Letter to PSE on the 2017 Integrated Resource Plan, the WUTC addresses Energize Eastside with the comment that "it is still not clear if a joint utility analysis of all available transmission and potential interconnections in the Puget Sound region might solve the Energize Eastside reliability issues." A further criticism: "PSE's choice not to provide modeling data to stakeholders with Critical Energy Infrastructure Information clearance from FERC[13]

4. Conclusion

A cooperative road plan was in place among ColumbiaGrid members for solving any transmission deficiencies on the Eastside. It is clear that PSE did not fully research or pursue use of the Seattle City Light transmission line towers for any purported reliability needs.

12 attachment: Memo of Agreement obtained through FOIA from Dept of Energy, Bonneville Power Admin. page 6

13 https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=5&ved=2ahUKEwiTirrhocPdAhUjGzQIHdN2BmMQFjAEegQIBhAC&url=https%3A%2F%2Fwww.utc.wa.gov%2F_layouts%2F15%2FCasesPublicWebsite%2FGetDocument.ashx%3FdocID%3D1743%26year%3D2016%26docketNumber%3D160918&usg=AOvVaw3yNtZgvlPKizND-bXT6fcQ page 10

5. Appendix A

City of Seattle

Seattle City Light

June 2, 2014

Mr. Nicholas Matz
Planning & Community Development Department
450 110th Avenue NE
P.O. Box 90012
Bellevue, WA 98009

Dear Mr. Matz:

Seattle City Light (SCL) has transmission facilities that run through the City of Bellevue and other jurisdictions on the east side of Lake Washington. The SCL transmission lines in Bellevue were installed in the early 1940's to transfer power from hydro-generation in the North Cascades to the west side of Lake Washington. Puget Sound Energy (PSE) has lines in the same general vicinity which primarily serve the PSE customer load east of Lake Washington.

SCL's double circuit 230kV transmission lines are used to meet current and future operating needs. Specifically, SCL needs the connectivity and capacity of these transmission lines to:

- Maintain a contiguous Point of Delivery for transmission service from BPA;
- Serve existing load growth and maintain reliability;
- Provide for future SCL growth;
- Support regional transmission flows; and
- Meet NERC reliability requirements.

SCL foresees current and future uses of these existing east side facilities and prefers not to utilize SCL's transmission lines for PSE's native load service needs.

Please contact me via email at uzma.siddiqi@seattle.gov if you have any questions.

Sincerely,

Uzma Siddiqi

Uzma Siddiqi, PE
System Planning Engineer

cc: Phil West
Tuan Tran

Seattle City Light

700 5th Ave. | P.O. Box 34023 | Seattle WA 98124-4023
TEL (206) 684-3000 TTY/TDD (206) 684-3225 FAX (206) 625-3709
seattle.gov/light
twitter.com/SEACityLight facebook.com/SeattleCityLight

April 25, 2017

Mr. Larry Johnson
Attorney at Law
Citizens for Sane Eastside Energy (CSEE)
8505 129th AVE SE
NEWCASTLE, WA 98056

Re: PSE's Energize Eastside Project

Dear Mr. Johnson,

This letter responds to your letter dated March 20, 2017 to our General Manager, Larry Weis. We appreciate your interest in the regional energy issues and are aware of your concerns regarding Puget Sound Energy's ("PSE") Energize Eastside Project. As your letter mentions, although PSE and Seattle City Light have had limited discussions about PSE's Energize Eastside Project, PSE has never formally requested transmission service on Seattle City Light's Eastside transmission lines.
Obviously, if PSE would make a formal request for transmission service on Seattle City Light's Eastside lines, Seattle City Light would respond appropriately. Likewise, Seattle City Light remains willing to discuss options with PSE regarding the potential use of Seattle's Eastside lines. However, as PSE's project located entirely within its own service territory, PSE's project remains within PSE's discretion.

In addition, the Energize Eastside Project is not subject to the Order No. 1000 regional approval process because it is located completely within Puget Sound's service territory, it was included in Puget Sound's local transmission plan to meet Puget Sound's reliability needs, and neither Puget Sound, nor any other eligible party, requested to have the project selected in the regional transmission plan for purposes of cost allocation.

We trust that this resolves the concerns expressed in your March 20th letter with respect to Seattle City Light.

Sincerely,

Sephir Hamilton
Engineering and Technology Innovation Officer
Seattle City Light

COLUMBIAGRID

PLANNING AND EXPANSION FUNCTIONAL AGREEMENT

January 17, 2007

Full 98-page Report @ https://www.columbiagrid.org/client/PEFA-conformed-copy.pdf