

January 20, 2016

Steven V. King
Executive Director and Secretary
Washington Utilities and Transportation Commission
P.O. Box 47250
Olympia, Washington 98504-7250

Subject: Comments of NW Energy Coalition regarding Puget Sound Energy's
2015 Integrated Resource Plan, Docket No. UE-141170 and UG-
141169.

NW Energy Coalition ("Coalition" or "NWECC") appreciates the opportunity to comment on Puget Sound Energy's ("PSE" or "Company") 2015 Integrated Resource Plan ("IRP") in response to the Commission's notice dated December 9, 2015 and the Commission's notice of comment extension dated January 6, 2016.

With this and the next IRP, PSE still enjoys the time to make strategic long-term decisions about resource strategy without the pressure of near term capacity or energy shortfalls. We recommend the Commission encourage PSE to take advantage of this time to study possible portfolio decisions that will emphasize clean, efficient resources.

Our comments will focus on just a few major issues – new methodologies introduced late in the planning cycle, the lack of data for the Colstrip generator and the proposed actions and supporting analyses.

New Resource needs and Reliability Assessments

One of the problematic aspects this IRP posed was not just the fact that it was delayed twice, but that very late in the process, PSE changed the methodologies they were using to project demand and to determine if there would be enough capacity available in the wholesale market to purchase. This did not allow enough time for the stakeholders to understand or offer useful critiques of the new approaches. Changing the methodologies also made it more difficult to try to understand this IRP in the context of regional planning.

The development of PSE's 2015 IRP coincided with the development of the NW Power and Conservation Council's ("NPCC") Seventh Power Plan (Seventh Plan). The draft power plan for the Northwest states calls for meeting growth in electric needs (which is almost flat at .5 to 1.0 percent average annual increase) by using the power we already have more efficiently and sees no immediate regional need for any new gas-fired plants. The Seventh Plan finds that in more than 90 percent of modeled future conditions, cost-effective energy efficiency meets *all* electricity load growth in the region through 2035. Regional investments in 3,800-4,500 aMW of energy efficiency are cost-effective over the next 20 years and will help the region

meet new load growth; demand response will help meet winter peaking capacity requirements, while some new power generation may be needed to replace retiring coal plants around 2026. ¹

The PSE 2015 IRP diverges from the regional plan in several areas. The IRP projects that several new gas plants will need to be constructed by 2035, with the first constructed in 2021; the Seventh Plan projects that by 2035 just one or two additional plants might be built out in the entire region. The IRP's assumptions about the reliability of the wholesale market also differ from the Plan, with the IRP modeling that peak needs cannot be met on the open market by 2025, and so calls for new resources, while the Plan asserts new winter peaking capacity needs can be met with energy efficiency and demand response resources and some increased market imports.

Those differences apparently stem from PSE's decision to use a new methodology for resource needs analysis and not the one used by the Northwest Planning and Conservation Council (and by PSE since 2009). Using the Expected Unserved Energy (EUE) metric (which purports to measure the value of reliability to customers) instead of the Loss of Load Probability (LOLP) metric (which predicts the chance the power system has of experiencing a short fall), and incorporating new market reliability estimates ² changed PSE's electric resource forecast from capacity surplus of 150MW to capacity deficit of 234 MW. The 2015 IRP estimates the need for an additional 275MW of peak hour capacity³ in the next seven years to be met with a new gas resource in 2021.⁴ Even though projected average growth in both load and peak demand has declined from the 2013 IRP,⁵ the need for new resources has moved forward a few years in the 2015 IRP to 2021 from 2023, again due to the use of EUE methodology and the new market reliability review.

With the very late substitution of the EUE metric, more questions have been raised than answered. Is the value of lost load avoidance the same to all customers? Does the new metric lead to over building? Does the change benefit all customers - a large industrial customer would benefit more from reduced risk in terms of cost than perhaps a small family. How and will the cost of the reduced risk be translated

¹ NWPCC, Seventh Northwest Conservation and Electric Power Plan, Executive Summary, page 1-2

² 2015 IRP Chapter 2:Resource Plan decisions, pages 2-5, 2-6. The regional resource configuration Included 440MW from a yet to be built Carty 2 and eliminated 650MW from Grays Harbor for lack of "firm gas supplies".

³ 2015 PSE Integrated Resource Plan, Chapter 1: Executive Summary, pages 1-2, 1-17.

⁴ Ibid. page 1-14

⁵ PSE's Peak Demand projected average annual growth rate declined from the 2013 IRP to 1.6 percent from 1.9 percent (without demand side resources) which is two to three times the annual average growth rate of .4 to .8 percent for projected regional peak load forecasts. Likewise, the electric load average annual growth rate in the 2015 IRP is 1.7 percent compared to the estimated regional load growth rate of .5 to 1.0 percent. However, if the 2013 demand-side resources are applied to the 2015 load and peak, the average growth drops to a range very similar to the regional ranges (chapter 5, Demand Forecasts page 5-26, 5-27).

to rates? Are the assumptions underlying the market reliability assessment accurate? Were all other potential sources fully vetted?

Market reliability raises a point made in the Seventh Plan about in-region surplus generation. As the Draft Seventh plan notes: *“Several of the scenario analyses conducted for the Seventh Plan highlight the benefit of using surplus generation for in-region energy and capacity needs; it avoids the need to build new resources and lowers total system cost. Under a wide range of future conditions, the least-cost resource strategy depends on the BPA selling surplus generation in-region. While by law regional utilities have first claim to Bonneville’s surplus generation, the region’s investor owned utilities IOUs ultimately compete with out-of-region buyers for that generation...IOU access to Bonneville’s surplus peaking capacity is limited to seven-year contracts. If the IOUs and Bonneville do not enter into contracts for energy or capacity, it’s likely that new generation will need to be build, despite the availability of energy and capacity resources from Bonneville to serve in-region demand.”*⁶ It seems timely to consider this idea, given the concerns about market reliability and carbon reduction.

There is also a tendency in this IRP to choose natural gas options over any other choice (pages 6-91 through 99). For example, rather than meeting needs with non-carbon options, such as existing resources, more efficiency or demand response (or any bundled combination of cleaner resources), a CCCT was selected to meet the projected need of 275MW, with the gas plant’s higher costs justified by off-setting income from selling energy throughout the WECC region when not meeting seasonal demands.

Given the differences in approach, we would urge the Commission to convene a series of workshops with *all* IOUs, stakeholders and others to deal with planning standards metrics, market reliability metrics and the challenges of aligning local and regional planning.

Colstrip

In acknowledging the 2013 IRP, the Commission suggested PSE consider a Colstrip Proceeding to determine the prudence of any new investment in Colstrip or in a closure or partial closure plan outside of the 2015 IRP. PSE has yet to take up that suggestion. Unfortunately, this IRP lacks information of Colstrip as well.

There is very little discussion of the consequences and details of removing some of the Colstrip power from the resource portfolio mix. Appendix K: Colstrip simply describes the physical facility, site history, governance and operations and relevant rules and regulations under which it operates. Chapter 6: Electric Analysis uses the Colstrip units in a sensitivity that was tested across the low, base and high scenarios.

⁶ NWPC Seventh Power Plan, Chapter 1: Executive Summary, page 1-13.

Units 1 and 2 were retired in 2026 in one case, while all four units were retired in 2026 in another (pages 6-52 through 54); in every case.

In contrast, the Seventh Plan recommends replacing Centralia, Boardman and North Valmy coal plants primarily by developing 4,500 average megawatts of energy efficiency by 2035 and increasing the development of demand response resources.⁷ PSE's IRP does not include adequate analysis of other alternatives or combinations of alternatives were not evaluated as replacements. The replacement of part of Colstrip by eastern Montana wind was priced at a very high rate, nor was any option such as wind and storage.

Stakeholders pressed for information on closure, decommissioning and replacement costs and possible transition plans in the IRP process, but that was not provided. The suggestion by PSE in early summer that Colstrip be dropped from the IRP entirely was met negatively by stakeholders, so remained in the IRP, but in a minimal way.

At the time of this response, the issue of closure and power replacement is the subject of legislation. The ultimate outcome of the legislation does not change the fact that Colstrip has an enormous impact on PSE's portfolio and operations and should be fully analyzed in the IRP. In the absence of legislation, the Clean Power Plan, regional haze regulations, and pollution laws and regulations will add costs to the operation of Colstrip. In the past, we have suggested the Commission request the ratepayer impact analysis for units 1 and 2 separate from 3 and 4 urgently reiterate that request.

Specific recommendations

The findings from the analyses in the IRP result in several specific activities presented as elements of the Action Plan. Several of them will have near term impacts or shape the 2017 Plan.

Energy Efficiency

The 2015 IRP again reaffirms that energy efficiency is crucial resource for meeting future capacity needs. By 2035 the achievable technical potential of electrical conservation measures amounts to 1,394 winter peak MW or 22% of retail energy sales and 20% of peak demand. The achievable natural gas potential accounts for 17% of forecasted 2035 retail sales.

The IRP sets a goal of achieving a cumulative 411 MW of electric efficiency by 2021. PSE has again chosen to accelerate acquisition of electric and gas efficiency, which

⁷ NWPPCC Seventh Power Plan, Chapter 1: Executive Summary, page 1-3

will require a close look technically feasible versus achievable conservation potential to ensure the maximum amount of conservation is achieved. We again suggest PSE assess generation efficiency potential at partially owned facilities and any facilities outside of Washington.

Requests for Proposals

One of the Action Plan elements in the 2015 IRP calls for preparation of an all-source Request for Proposal (RFP). An RFP is the best way to determine the actual cost of various resources. The RFP relied on dated information for the several technologies (e.g., the costs of utility scale solar). The responses to an RFP will provide current information on costs. An all-source RFP should not exclude any resource out of hand at the beginning of the process, but encourage the submission of proposals that combine or aggregate resources (wind with storage, for example) and that recognize more than one value of a resource (storage offers multiple values, from minimizing peaks to voltage regulation; isolating and analyzing one value is not the best approach). Stacked or bundled resources may perform as well as, and at less cost than, a single resource to meet peak demands. An open and wide ranging RFP will be able to resolve many questions.

Another of the Action Plan elements commits to an RFP to acquire demand response resources. That is a very positive step. The RFP should not cap the amount of Demand Response sought. Demand response measures that emerge from the RFP process should be developed and implemented as soon as possible, and not delayed until 2021.

In the 2015 IRP, demand response is forecast to increase quickly up to 2021, then slow to a snail's pace each year after that. The Commission should direct PSE to fully explain just how much demand response will be acquired each year and how those amounts relate to the amounts shown as "cumulative nameplate capacity" in Table 1-7 in the IRP Executive Summary.

Investigate emerging resources

We would like to see a robust investigation of emerging and, we would add, evolving technologies as proposed in the 2015 IRP. Any investigations should not be used to delay the all-source RFP, but broaden understanding about various technologies. It is particularly critical to acquire expanded and updated information on all types of storage, distributed solar, utility scale solar, micro grids and changing weather and temperature trends.

In the letters acknowledging the 2013 IRPs, the UTC gave the IOUs specific guidance on how to address storage and batteries in the 2015 IRP, since storage analysis in the 2013 IRPs was inadequate. The storage analysis in the 2015 IRP is slightly better, but still too limited. PSE should undertake a holistic analysis that quantifies all the benefits associated with energy storage. As the UTC pointed out in their

white paper on storage, without quantified benefits to offset costs, the current modeling practices will preclude the selection of energy storage as cost prohibitive.⁸ We would urge the UTC to continue to work with all the IOUs to develop consistent methodologies and proxy cost frameworks for the various grid services storage can provide to enable storage to develop in Washington.

Likewise, the forecast for installed distributed solar seems overly conservative and should be reviewed. Cadmus' forecast estimates no more than 309MW can be installed by 2035. Since 2009, PSE has seen nearly a 50 percent increase in installed residential MW capacity year over year. A back of the envelope calculation starting with the same data Cadmus used for their projection, shows that if growth continues at it's current pace, PSE will reach 300MW by the end of 2021 for residential installations alone, which is far higher than the maximum of 309MW of both residential and commercial installations predicted by Cadmus (actual installed MW increased from 10.8 to 26.3 from the end of 2013 to the end of 2015).

We suggest that instead of Cadmus' approach of estimating the available square feet of roof and a decadal reduction in installation costs of 2.9 percent, the estimates for installed distributed solar be recalculated using experience curve analysis.

Experience curve analysis is robust and has been thoroughly tested across many industries and product categories, and has well characterized solar PV from 1970 to the present. A learning rate of 80 percent for solar PV modules and 85 percent for balance of system costs is broadly accepted, meaning for every aggregated doubling in installed capacity, module costs on average decline by 20 percent and soft costs by 15 percent. In an experience curve analysis, the decline in costs per market doubling is fixed, but the duration for each doubling can change. So for analysis purposes, doubling over 20 years can be set at 5 doublings (which means MW double every 4 years), or 6 doublings (doubling every 3.3 years), which would be slower than the average rate over the last 6 years.

Utility scale solar received minimal consideration in the 2015 IRP – a 20MW system was considered in just one scenario.⁹ The concern here is that the costs PSE assigned to utility scale solar are far higher than market. National average costs for utility scale projects are at a maximum of \$1750/KW (more than 30 percent lower than IRP assumptions) with a levelized cost of energy of \$70/MWH. The assumption has been that solar cannot provide capacity after dark, which is true, if the technology is using photovoltaic panels (although those systems do provide system adequacy capacity). However, there are other technologies, such as molten salt thermal energy storage, that store solar thermal energy in a media like silica salt, then release the salt stored heat after dark to drive turbines to generate electricity. If coal power can be transmitted from Montana, it does not seem that great a stretch to transmit solar power from the east side of the Cascades.

⁸ Modeling Energy Storage: Challenges and Opportunities for Washington Utilities 2015, page 2.

⁹ 2015 PSE IRP Chapter 2: Resource Plan Decisions, Page 2-13.

The costs assigned to wind projects were equally puzzling; current national averages for wind range from \$1250-1700\$/kW, yet the cost for Washington based wind was assumed to be \$1968/kW and for Montana \$2061 -\$4913/kW (due to “transmission and shaping costs”). We would want to see an analysis with up to date costs with locations presumed to be in western Montana.

Improving analytical capabilities

The IRP contains another action plan element aimed at improving analytical capabilities. Along with improving analyses around intra-hour flexibility, we would like to see a full analysis comparing shorter and longer temperature and weather cycles to determine if the differences, if any, impact modeling and planning assumptions. There was quite a bit of disagreement on this issue during the development of the 2015 IRP with several participants expressing concern that eighty or one hundred years of data did not and could not account for more recent trend changes brought about by increasing temperatures. Using 20 years of records would better reflect current realities and the ongoing changes expected by continuing warming.

With regulations reducing greenhouse gas emissions increasing, increasing costs and risks associated with fossil fuel generation should become a major concern of any IRP. Accounting for the full price of carbon for those generating facilities that create carbon, instead of externalizing those costs. The social cost of carbon is calculated to capture all such costs. In previous IRPs the full social cost of carbon was used, but in this IRP was excluded in favor of a carbon price. If we are to move any closer to reducing carbon, the social cost of carbon should be applied in any analysis to not only new generators, but to existing generators and dispatch rules.

NWEC appreciates the opportunity to participate in PSE’s IRP stakeholder process as well as the opportunity to present our recommendations to the Commission. Thank you for your attention to our comments.

