# Feedback report

RPAG Meeting

## Meeting details

- Monday, March 25, 2024, 12:00 p.m. - 4:00 p.m.
- Virtual webinar hosted by PSE and facilitated by Triangle Associates
- Links to:
  - Presentation
  - Meeting recording

## Feedback report

The following table records participant questions and PSE responses from the public comment opportunity and comments submitted via online feedback form or irp@pse.com. Meeting materials are available on the IRP website.

Note: PSE aims to provide clarity in responses but subsequent follow-up may be required at times. Please direct any follow-up clarifications to irp@pse.com.

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| 1 | 3/25/2024 | Meghan Anderson | irp@pse.com | I appreciate the implementation of Puget Sound Energy's (PSE) "Free In-Home Electrification Consultation" pilot program for study of the transition of 10,000 natural gas customers with this program.<br><br>A gas customer is able to set up a free in-home electrification assessment that Franklin Energy offers in partnership with PSE. The program is limited now to those invited by email, as I understand it. | 1. PSE's IRP process is designed and intended to model a system that complies with all relevant laws and regulations that pertain to PSE.<br><br>2. PSE has evaluated the impacts of electrification a few times. The most recent analysis does include the financial analysis you are asking for which was completed by |

<table>
<tr><th>No.</th><th>Date</th><th>Interested party</th><th>Submitted via</th><th>Question or comment</th><th>PSE response</th></tr>
<tr><td></td><td></td><td></td><td></td><td>
The in-home consult takes less than an hour and the customer is then emailed a report summarizing what they’d been told about their home energy systems. The report to the customer also includes detailed information on local and federal financial incentives and links to the IRA-funded site where the customer can calculate individualized incentive amounts based on income.<br><br>
Also provided is a chart, see below, that shows the typical operating costs for various heating systems based on the size of the home. The representative identifies the cost efficiencies of ductless heat pumps, and encourages transition evaluations by the customer to factor in the financial incentives when thinking about payback periods.<br><br>
I would draw your attention to the fuel cost comparison chart below provided by PSE. As you can see there are big savings annually from switching from high efficiency gas furnaces to ductless heat pumps.<br><br>
Estimated annual heating for PSE gas and electric (dual fuel) customers
<table>
<tr><th>Square Footage</th><th>0-1,000</th><th>1,000 - 1,500</th><th>1,500-2,000</th><th>2,000-2,500</th><th>2,500-3,000</th><th>3,000-3,500</th><th>3,500-4,000</th><th>4,000 +</th></tr>
<tr><td>Gas Furnace (80% AFUE)</td><td>$601</td><td>$793</td><td>$965</td><td>$1,101</td><td>$1,376</td><td>$1,552</td><td>$1,884</td><td>$2,100</td></tr>
<tr><td>Gas Furnace (95% AFUE)</td><td>$506</td><td>$668</td><td>$812</td><td>$927</td><td>$1,158</td><td>$1,307</td><td>$1,587</td><td>$1,768</td></tr>
<tr><td>Electric Furnace</td><td>$1,178</td><td>$1,554</td><td>$1,891</td><td>$2,158</td><td>$2,697</td><td>$3,043</td><td>$3,694</td><td>$4,116</td></tr>
<tr><td>Baseboard/ Cadet Heaters</td><td>$883</td><td>$1,165</td><td>$1,418</td><td>$1,618</td><td>$2,022</td><td>$2,282</td><td>$2,770</td><td>$3,087</td></tr>
<tr><td>Ducted Heat Pump</td><td>$496</td><td>$655</td><td>$797</td><td>$909</td><td>$1,136</td><td>$1,282</td><td>$1,556</td><td>$1,734</td></tr>
<tr><td>Ductless Heat Pump</td><td>$317</td><td>$419</td><td>$509</td><td>$581</td><td>$726</td><td>$820</td><td>$995</td><td>$1,109</td></tr>
</table>
Estimated annual energy costs do not include added or reduced air-conditioning costs. Gas furnace or heat pump actual efficiency may be less than listed due to ductwork condition, installation practices or equipment wear and tear. Usage based on regional building stock estimates. Actual results may vary depending on home characteristics, occupancy, and customer behavior. Supplemental heat is often necessary for DHP/HP applications; load applies to all existing system calculations. Calculated using PSE gas and electricity rates effective November 2023.<br><br>
Also even larger savings are evident when switching from electric baseboard or electric furnace to ducted and ductless heat pump systems.
</td><td>
PSE for the 2022 GRC Settlement, Stipulation O and filed with the commission in December 2023 under Docket UE-220066. The decarbonization study can be found in the Docket and on our IRP website under the March 25, 2024 meeting section. If you reference page 9 & 10 this illustrates the financial impacts by 2030 and 2045 of the study. The various bar graphs show the impacts to the average residential customer if they were to transition to become an all-electric customer or if they stayed as a gas customer within each scenario. You’ll also find a view which shows the impact on a low-income customer on pages 97 & 98 for the same time periods.<br><br>
3. At present, state Climate Commitment Act (CCA) auction proceeds are not available for programs that transition customers from gas to electric. PSE receives allowances from the Department of Ecology at no cost. Per the CCA statute (law), the proceeds associated with these auction sales are to be used to mitigate the cost-burden of the CCA program for PSE gas customers. Currently, PSE spends those proceeds on:<br><br>
a. Eliminating costs associated with CCA for income qualified customers<br><br>
b. Bill credits for all customers to help mitigate CCA compliance costs<br><br>
c. Electrification programs for customers.<br><br>
4,5. PSE evaluated electrification of customer end uses in the 2023 Gas Utility
</td></tr>
</table>

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
| --- | --- | --- | --- | --- | --- |
| | | | | The big thing lacking from these assessments are the copious funding available from Climate Commitment Act (CCA) auction proceeds. Why would PSE ignore these monies in funding through PSE? Imagine instead a world where PSE has the funding to pay for 80% of the cost of these transitions? Or 50%, or 60%?<br><br>While I am glad PSE has finally admitted (via the chart of fuel comparison above) that it costs far less to heat with ductless heat pumps, I am not convinced the pilot program is anything but a show for critics. Truly and effective transitions aren't going to happen without CCA auction proceeds funding. Why ignore free money? It makes no sense unless there is *no will to transition.*<br><br>The evidence of 'no will' continues in the Integrated Resource Plan (IRP), where it is very clear there is no planning for any transition. It instead weaves a path to 2050 with a fantasy of 'clean fuels' and 'renewable natural gas', ultimately reducing emissions by paltry sums, far short of the 95% reductions required by law. Buying your way through the CCA leaves a fiscal and climate cliff for your customers and shareholders in 2050. But just as, or more impactful, is the *harm it causes directly to your customers* by not facilitating transitions from gas to electric as quickly as possible. Essentially, the PSE plan to not transition will result in higher costs for heating every year for each customer. What are the additional costs annually those customers must endure over the next 25 years?<br><br>It is puzzling to me that you are willing to admit that heat pumps cost far less to operate, and at the same time produce an IRP that ignores this fact, as well as ignoring CCA funding. | IRP. This can be found on our past IRP website.<br><br>The analysis looks at customer end use and the transition over time based on appliance burn out from gas furnaces to electric heat pumps.<br><br>6. The social cost of carbon is posted on the Washington Utilities and Transportation Commission's website: Social Cost of Carbon (wa.gov). We will use this for the 2025 IRP.<br><br>7. The Climate Commitment Act (CCA) is not designed as a command-and-control regulation that requires gas utilities to stop selling natural gas to end-use customers to hit a specified target. Instead, the CCA allows covered entities to trade allowances to comply with CCA allowance (i.e., authorized emissions) obligations. We recognize that allowable emissions across the entire market will decline over time, but as Washington moves towards joining the California and Quebec cap and trade markets, it will significantly increase the size of the allowance market. Therefore, it is appropriate to model the price related impacts of CCA allowance obligations of PSE's gas utility service to customers in the IRP, not a hard emissions cap. |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | I'm a grateful net metering customer of PSE. You have mastered this policy and it offers the opportunity for further development of distributed energy resources.<br><br>I'd like to see responses to these questions if possible:<br>1. Why doesn't PSE model robust transition planning from gas to electric heat pumps?<br><br>2. Why doesn't PSE model robust transition planning from electric resistance to heat pumps?<br>1. Vigorous transition planning from electric resistance heating to heat pumps will reduce electric load consumption by at least 50%. There's a huge inventory of this kind of heat in our state.<br><br>3. Why doesn't PSE include CCA auction proceed funding in transitioning gas customers to electric?<br><br>4. Why doesn't PSE model the extra costs to customers if no transitions occur by 2050?<br>1. I'd like to see a comparison model of a customer that stays with a natural gas furnace and a customer that transitions to a ductless heat pump over 25 years—disregarding equipment costs. Equipment costs should be mostly covered by CCA auction proceeds. Doesn't the UTC want to see these numbers also? The lack of transitioning harms customers.<br><br>5. Why doesn't PSE estimate the impact of the modeled cliff at 2050? This seems to indicate to me a | |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | gross event after 2050, impacting customers, climate and costs.<br><br>6. What are the social costs of carbon with the current IRP by 2050?<br><br>7. Your Integrated Resource Plan seems to indicate greenhouse gas emissions laws in our state are optional. What is your position on the law and your requirements? | |
| 2 | 3/25/2024 | RPAG member | In meeting | In metal-air batteries, where would there be molten metal? | Response from Black & Veatch:<br><br>There was a typo in the safety concerns slide. The statement “molten metal can be a potential risk” should have been omitted.<br><br>There is no molten metal in metal-air batteries. There are two types of commercially available metal-air batteries that exist today- iron-air and zinc-air batteries. Both of them work at near room-temperature. The battery cells are made of nanoparticles of iron, zinc, carbon, platinum, palladium etc.<br><br>Molten metal batteries on the other hand, are different. For example, in sodium-sulfur battery, which is commercially available today, the battery cells are made of molten sodium and sulfur, and they operate efficiently above 300 C. |
| 3 | 3/25/2024 | RPAG member | In meeting | How fast do iron-air batteries discharge, and how fast do they charge? | Response from Black & Veatch:<br><br>The iron-air batteries provided by Form Energy are designed for 100-hour discharge at the rated power. From the specification |

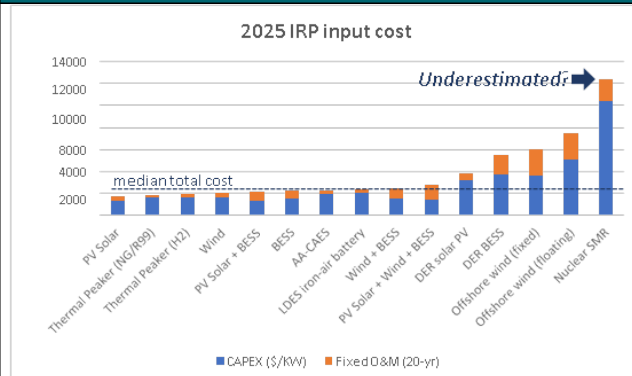
| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | | sheet provided by Form Energy, the AC roundtrip efficiency (RTE) of the system (battery + power conversion unit) is between 40-45%. To charge it fully at the rated power, approximately 220-250 hours will be needed. This range can be obtained by dividing the design discharge time (100 hrs) by the provided RTE range. |
| 4 | 3/25/2024 | RPAG member | In meeting | What is the total installed cost for iron-air batteries? Where do they fall on the total installed cost chart (slide 42)? | Response from Black & Veatch:<br><br>According to the data provided by From Energy, the total installed cost of an iron-air battery storage plant will lie between $15-20/kWh in 2030 onwards when their production capacity ramps above 1 GW/year.<br><br>In comparison, other technologies such as lithium-ion and flow batteries of 100-hr duration have total installed cost in the range of $300-450/kWh. This is shown in slide 42. Please note that the scale considered in the slide is one order of magnitude lower (10 MW) than the scale considered by Form Energy for their cost estimate (for 100 MW). Typically, the unit cost ($/kWh) is lower for a project of bigger scale. |
| 5 | 3/25/2024 | RPAG member | In meeting | What are the decommissioning costs for nuclear small modular reactors? | Response from Black & Veatch:<br><br>This information is not readily available for SMRs since it is a new/emerging technology and there are no full-scale units in operation. Depending on size and technology, these costs are going to vary greatly, especially with all the different fuel types. Vendors are designing plants with the goal of reducing these costs, but again, there is nothing |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | | published because the technology is still in development. |
| 6 | 3/28/2024 | Ezra Hausman (RPAG alternate) on behalf of WATG Public Counsel Unit | Feedback form | Public Counsel notes that in several cases, PSE's cost and emissions analysis did not include full fuel cycle impacts. Specifically:<br>• For Small Modular Nuclear Reactors, the cost and environmental impact of managing and ultimately disposing of nuclear waste was neglected. Fuel reprocessing was mentioned, but not its very significant cost and environmental impacts.<br>• For CCS, the feasibility, cost, and environmental impacts of storage, transportation, and disposal of captured $CO_2$, and whether the carbon would be used for enhanced hydrocarbon recovery, which would greatly increase lifecycle emissions.<br>• For "renewable diesel", or "R99", the availability, cost, and indirect environmental impacts of this fuel vs. gas; how or where such fuel would be fabricated; and its cost and environmental profile.<br>Overall, Public Counsel urges PSE to ensure that its analysis includes consideration of the full cost and environmental impacts, including carbon emissions, of all resource alternatives in its IRP process. | Thank you for your comments. You identify an important element when analyzing generic resources. Work is ongoing to ensure we have the most accurate information available for all resources we model, but this is particularly challenging when analyzing emerging technologies whose costs are not fully known. We will consider this feedback going forward. |
| 7 | 4/1/2024 | Don Marsh on behalf of Washington Clean Energy Coalition | irp@pse.com | The Washington Clean Energy Coalition observed the March 25 meeting of PSE's Resource Planning Advisory Group. PSE continues to exclude direct participation by the public and our organization. Although we were allowed to make brief comments during the final minutes of the four-hour meeting, this is not sufficient to ask our questions or interact with PSE staff or other RPAG members. Excluding members of the public who have demonstrated a strong interest in resource planning efforts over many years does not improve the IRP. We ask PSE to facilitate public participation by opening the meetings to more members of the public and providing more time for comments and questions. | Thank you for your feedback. As stated previously, PSE is discussing resources we plan to model for the 2025 IRP and why. The IRP model will inform our preferred portfolio that will be developed through engagement with the RPAG and the public. Even then, the IRP preferred portfolio is not a list of resources we will immediately acquire. Instead, it gives us a clearer picture of the scale of resource acquisition and/or conservation needed as we transition to a clean energy future. PSE will provide the B&V report on emerging resources at a later date, after the consultant's work is complete. |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
| --- | --- | --- | --- | --- | --- |
| | | | | This comment focuses on two key areas of the RPAG meeting:<br>• Solutions to address transmission deficiencies<br>• Risk factors for Small Modular Nuclear Reactors<br><br>**Transmission deficiencies**<br>PSE's presentation began with 87 slides surveying different emerging energy technologies, followed by 27 slides describing a very significant shortfall in regional transmission capacity of approximately 3,000 MW by 2035. PSE says transmission constraints may determine the type and location of generation resources until at least 2038.<br><br>We feel the RPAG presentation put the cart before the horse. If transmission challenges had been described first, RPAG members might have asked questions or provided advice about how each emerging technology could be beneficial or detrimental in transmission-constrained scenarios.<br><br>An even bigger opportunity was missed on slide 124, in which PSE provided four ideas of how transmission problems might be addressed (such as co-location of resources, BPA solutions in 2040, PSE-built transmission, and combined BPA and PSE solutions). Listing these rather vague solutions on the final slide of a long meeting le□ us feeling nervous about what might happen to our clean energy goals in the 2030s.<br><br>We propose that PSE schedule another RPAG meeting to consider the transmission solutions in some detail.<br><br>Such solutions include (but are not limited to):<br>1. Reconductor existing transmission lines<br>2. Use Dynamic Line Rating | As discussed with the RPAG, transmission constraints are a challenge to access clean energy resources. PSE is proactively including multiple transmission capacity improvement options in this IRP for study. This is important to understand how improved access to clean energy resources through additional transmission capacity can help achieve our clean energy objectives. These specific transmission solutions were identified based on their ability to meaningfully address the substantial shortfall. Thank you for your recommendations; we will consider them going forward. |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | 3. Switch to DC transmission to increase capacity and reduce line losses<br>4. Use flow control gates to protect lower capacity lines<br>5. Join Seattle City Light in a single imbalance market<br>6. Accelerate acquisition of demand side resources<br>7. Make use of artificial intelligence, virtual power plants, and vehicle-to-grid technologies<br><br>Regarding the imbalance market, we are unclear about why PSE is currently pursuing membership in the Southwest Power Pool, potentially bifurcating the imbalance market in the Northwest. RPAG members should understand why PSE thinks this would be advantageous compared to joining Seattle City Light as a member of CAISO's Extended Day Ahead Market, which does not bifurcate the market. The wrong choice could affect the availability and price of electricity for consumers when they need it most.<br><br>If demand is still at risk of outstripping regional transmission capacity plus local generation, we would expect PSE to accelerate acquisition of demand side resources during periods of peak transmission congestion. In addition to traditional demand response (there is much potential in smart water heaters, smart thermostats, high efficiency heat pumps, building weatherization, and motivating time of use rates), there are new opportunities with Artificial Intelligence, Virtual Power Plants, and Vehicle-To-Grid technologies. If these technologies were fully embraced, a future transmission crunch might be avoided.<br><br>**SMR risks**<br>We appreciate the analysis and cost estimates provided in Black and Veatch's study of emerging energy technologies. Slides 95 and 96 of the presentation provide a useful summary of the capital | |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | and O&M costs of various technologies, including an array of storage technologies, onshore and offshore wind, thermal peaker plants, and hybrid generation plants. However, we are disturbed that no details of the consultant's analysis were provided to the RPAG beyond the summary slides.<br><br>On slide 23, the consultants say they were engaged to "characterize technologies for potential implementation in the near-term (3 to 7 years)." Given this criterion, we question why nuclear SMR plants were included in the analysis. No one we know believes that an SMR design will clear NRC review, obtain permits to build on an appropriate site, and start operation in less than 10 years. In that timeframe, transmission issues may begin to subside, and other technologies (such as geothermal energy) may provide energy at less expense and less risk than an SMR.<br><br>Regarding costs, the following chart presents information from slides 95 and 96. To capture both the CAPEX and Fixed O&M costs, we added the two, assuming 20 years of operation. We realize this ignores different lifespans and the cost of capital over time, but it provides a useful qualitative comparison of costs to ratepayers. | |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | <br>Our chart (previous page) shows the estimated cost of CAPEX and O&M for an SMR ($12,368/KW) is more than *quintuple* the median cost of these 15 technologies ($2,373/KW).<br><br>Are the cost estimates for SMRs realistic? Black and Veatch provided scant detail on how their estimates were developed, and PSE provided no link to the consultant's report. No RPAG member asked any probing questions about the SMR cost estimates. However, in March 2023, X-energy updated its cost estimates as part of the Department of Energy's Advanced Reactor Demonstration program. The company said the CAPEX cost of a four-unit project with a capacity of 320 MWe would be $4.75-$5.75 billion, or $14,844/KW to $17,969/KW. This is significantly higher than Black and Veatch's estimate of $10,368/KW (CAPEX only).<br><br>If ratepayers will be required to pay for SMR plants, we ask for greater clarity on the cost and schedule risks. Aside from exorbitant CAPEX costs, the high (and uncertain) O&M cost for a baseload resource is an additional concern. On slides 50 and 51, PSE assumes SMRs would provide baseload electricity with a 93% capacity factor. Such operation would overlap hours of the day and seasons where much | |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
| --- | --- | --- | --- | --- | --- |
| | | | | less expensive generation resources are available, resulting in higher electric bills for customers.<br><br>According to Black and Veatch, SMRs have a lower Technology Readiness Level than most of the other technologies included in the assessment. The consultant did not contemplate a “Social Readiness Level,” which could be equally important in determining how difficult it will be to deploy nuclear technologies.<br>The public is wary of the health and safety risks of nuclear energy. Although relatively few nuclear accidents have occurred, extreme accidents have rendered parts of our planet uninhabitable for many decades. Often, nuclear waste is stored on premises while regulators try to find a long-term storage solution. A fire, earthquake, or concerted attack might cause a dangerous radioactive discharge.<br><br>Allaying the public’s fear, if possible, will only be achieved by an expensive education and PR campaign. Even if the company or its partner ultimately succeeds, the financial cost of that effort will be a burden to shareholders and consumers alike.<br><br>PSE has recent experience selling an unpopular project to its customers. In 2013, PSE announced “Energize Eastside,” a transmission upgrade through four Eastside cities. PSE stated the project would take only four years to complete and cost less than $100 million. The first half of the project started operation in 2023, six years later than expected at a cost almost quadruple PSE’s original estimate. Construction still hasn’t started on the second half of the project.<br><br>In comparison to a nuclear plant, Energize Eastside is a somewhat routine upgrade of a technology that is well-established and understood by citizens. People are not likely to feel comfortable living next to a “First- | |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | of-a-kind" nuclear plant that has no significant safety record anywhere in the world.<br><br>To achieve its target capacity of 600 MWe, PSE would need at least seven Xe-100 SMR units, possibly at multiple sites. Most communities will not welcome these facilities, and siting is likely to gravitate to areas of lower resistance, such as rural or disadvantaged communities. This would risk conflict with equity provisions of the Clean Energy Transformation Act.<br>If SMRs lead to higher prices for electricity, customers will find many new technologies capable of reducing their monthly bills, such as solar panels and batteries with growing capacities and declining costs, smart technologies that time shift or reduce consumption, and vehicle-to-home solutions to offset peak charges. As more customers find economical and reliable alternatives, the burden of maintaining a central grid will fall on customers who do not invest in these solutions. High priced nuclear electricity might spark a spiral of defection that threatens PSE's future business model.<br><br>**Recommendations**<br>PSE held a 90-minute webinar to "inform" the public about the company's possible foray into SMR technology. The meeting spurred a higher level of feedback than RPAG meetings that are typically twice as long. In the Feedback Report, PSE complains, "we received more than 60 questions or comments during the 90-minute meeting, with more than 1/3 coming from a small group of highly engaged participants who are also RPAG members." Despite PSE's apparent discomfort with this level of engagement, the webinar provided no details regarding costs, and no alternatives were considered. | |

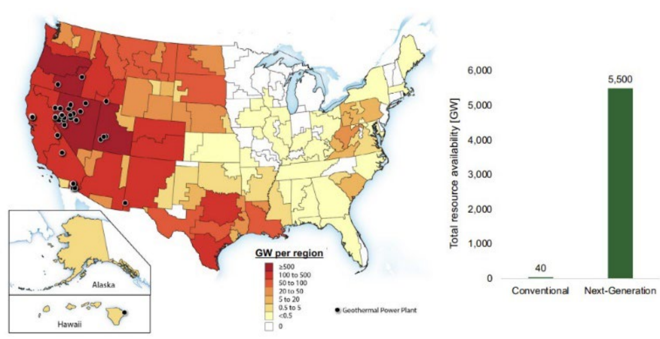
| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | In the March 25 RPAG meeting, cost estimates for SMRs were provided. However, discussion was limited. Before PSE models SMR resources, we ask that an RPAG meeting be held so that members can understand the basis of the cost estimates. The RPAG should be given an opportunity to provide advice on the decisions PSE appears to be making about nuclear technology.<br><br>We are also curious about how Black and Veatch justifies an O&M cost for offshore wind of $120/KW-yr. Recent reports from the National Renewable Energy Laboratory and Wood Mackenzie project a cost of $40-$60. We ask PSE to help the RPAG understand why operating a wind farm in Grays Harbor might cost 2-3 times more than wind farms in other parts of the world.<br>The combined effects of cost-competitive emergent technologies and looming transmission constraints lead to some obvious conclusions. Containing the growth of peak demand would relieve transmission congestion and increase the value of remote clean energy generation (like Montana wind and California sun). As mentioned previously, there are many emerging demand side resources (DSRs) that could help. PSE should schedule an RPAG meeting to explore DSRs as thoroughly as Black and Veatch covered generation and storage technologies (hopefully including a report with references and assumptions).<br><br>If DSRs are not enough to get us through the transmission crunch of the 2030s, it would be wise to invest in transmission technologies (and an imbalance market) like we mentioned earlier. We need an RPAG meeting to discuss the pros and cons of these technologies/markets. | |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | Given the magnitude of the challenges ahead, we are disappointed with PSE's tepid consideration of Vehicle-To-Grid solutions. As EVs become more prevalent, charging them will add stress to the grid unless they become part of the solution. Parked EVs already contain the biggest battery resource in the Pacific Northwest, and we expect rapid growth. Tapping into that resource isn't easy, but it could be cost effective and financially rewarding for participants. PSE should be leading the charge.<br><br>An energy grid comprised of many different resources will be a challenge to coordinate. **Artificial Intelligence** is likely to play an important role in this complex control problem. We would like to hear how PSE might leverage local expertise (Microsoft, Amazon, and many startups) to lead the industry in modernizing the communication and control systems that will operate the next-gen clean energy grid. | |
| 8 | 4/1/2024 | Kate Brouns (RPAG alternate) on behalf of Renewable Northwest | irp@pse.com | **I. INTRODUCTION**<br>Renewable Northwest (RNW) thanks Puget Sound Energy (PSE or "the Company") for the opportunity to comment on the March 25th RPAG meeting. We appreciated Black & Veatch's in-depth review of the emerging technology assessment they conducted on behalf of PSE. To reiterate some of our prior comments, we support PSE's exploration of emerging clean energy technologies and believe this work is critically important to meeting Washington's decarbonization mandate. RNW was encouraged to hear that offshore wind, compressed air energy storage, and iron-air batteries were selected for inclusion in 2025 IRP modeling. However, we remain concerned about PSE's treatment of 'clean firm' technologies like advanced nuclear and enhanced geothermal. It seems that the selection of advanced nuclear power is a foregone conclusion given the Company's agreement with Energy Northwest. It is likely that many of the technologies Black & Veatch | Thank you for your feedback. When PSE and Black & Veatch began this study geothermal was categorized at a lower TRL. However, as you note, substantial new information has become available recently. We will consider this feedback as we continue work on the IRP. Please note that neither the resources we model nor the<br><br>IRP preferred portfolio resources are a list of resources we will immediately acquire. Instead, it gives us a clearer picture of the scale of resource acquisition and/or conservation needed as we transition to a clean energy future. |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | assessed will be part of a decarbonized grid, and RNW encourages PSE to model all viable emerging resource alternatives, as we discuss below.<br><br>**II. FEEDBACK**<br>RNW was disappointed to hear that PSE will not be modeling enhanced geothermal in the 2025 IRP despite the favorable projected resource costs and characteristics we outlined in previous comments. Black & Veatch detailed the cost and performance characteristics of most of the resources it studied, but enhanced geothermal was a notable exception. RNW would like to better understand the criteria the Company used to evaluate which technologies would be included in the 2025 IRP modeling based on Black & Veatch's assessment. For example, PSE has decided to continue modeling (what appear to be) Gen IV nuclear reactors, despite Black & Veatch assessing this technology as the *least* mature energy technology in their readiness assessment. However, when PSE explained its decision to not model enhanced geothermal, the Company responded they did not know how much was available and did not know where it could be sited. When looking at Vehicle to Grid technology, PSE similarly noted that given the newness of Vehicle to Grid, the Company decided not to model it. These delineations of which technologies are too new—and which are therefore appropriate to model—appear arbitrary in light of Black & Veatch's assessment, and we encourage the Company to explain this distinction further. In the following section, RNW highlights the work of the U.S. Department of Energy and the Washington State Legislature in advancing next-generation geothermal technology.<br><br>**U.S. Department of Energy: "Pathways to Commercial Liftoff: Next Generation Geothermal Power"** | |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | A U.S. Department of Energy report published in March of 2024 details the current state of next-generation geothermal technology, its value proposition, pathways to commercialization, and remaining challenges.[1] Below we include several key findings from the report:<br>● *Commercialization timeline*<br>○ "Although a nascent industry, next-generation geothermal enjoys several starting advantages, including transferable technology, supply chains, and workforces from the oil and gas sector, that will help it achieve rapid scale."<br>○ "If the industry can achieve a set of market conditions around cost, demonstrations, value, and community engagement, commercial liftoff is attainable as early as 2030."<br>● *Declining costs*<br>○ "The Enhanced Geothermal Shot (EGS) targets an aggressive yet plausible path to a 90 percent reduction in the cost of EGS by 2035, to an effective [Levelized Cost of Energy] of $45/MWh. Current cost reductions outpace that estimate."<br>○ "With the 47% decrease in cost estimates as a starting point, EGS can reach an [Overnight Construction Cost] of $4,700–5,000 per kW by 2030 with further 33% reductions costs, driven by exploration, well and reservoir construction, and power plant costs."<br>○ "One study finds that aggressive implementation of flexible geothermal operations can also reduce the cost of fully decarbonizing the Western Interconnection in 2045 by up to 25 percent."<br>● *Value to the grid*<br>○ "Next-generation geothermal could capture a significant share of the power market | |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | because of multiple value propositions. It is clean firm, flexible; requires a small land footprint and no additional energy input; and is exposed to minimal supply chain risk. **It is among the few options that can provide the clean firm power necessary to enable widespread deployment of variable renewables, such as solar and wind energy.** It is also positioned to deliver that power flexibly, effectively offering needed long duration energy storage grid benefits by storing energy in the subsurface when demand is low and releasing it when demand is high. These capabilities make it both a useful grid asset and a potential generation source for other power users like behind-the-meter industrial centers with high electricity demand, data centers, or direct air capture facilities. Geothermal technologies require some of the smallest land area per kilowatt of any energy technology, firm or renewable. Next-generation geothermal can also scale supported by the availability of workers with translatable skillsets, many from the oil and gas sector."<br>● *Resource availability*<br>○ "Next-generation geothermal technologies expand geothermal resource potential to 5,500 GW distributed across much of the country and remove the need to search for unique geologic environments."<br>○ Figure 2 shows the wide geographic extent of next-generation geothermal energy, with particularly high resource estimates in the West. | |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | **Next-generation and conventional geothermal resource estimates**<br><br><br>*Figure 2: [Left panel] Total next-generation potential across the United States (red shading), overlain by locations of current conventional geothermal plants producing 3.7 GW of power (black dots). [Right panel] comparison between total available resource for conventional geothermal (left) and next-generation geothermal (right).*<br>○ Figure 8 shows the potential extent of next-generation geothermal deployment in 2030, 2040, and 2050. **Washington state is one of seven states identified with the potential to deploy next-generation geothermal in 2030.** | |

Potential geographic extent of next-generation geothermal deployment over time

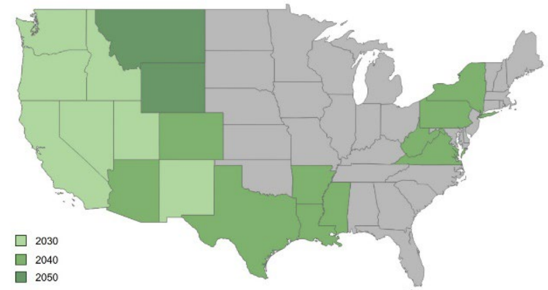



*Figure 8: Geothermal deployment over time across the U.S. in 2030 (light green), 2040 (middle green), and 2050 (dark green) based on the "Energy Earthshot Original" modeling scenario. See Appendix A for details.*

**Washington SB 6039, Promoting the Development of Geothermal Resources**

During the 2024 legislative session, PSE supported SB 6039 promoting the development of geothermal resources. With the bill's successful passage, Washington state can now rapidly build its capacity to deploy enhanced geothermal technology. The law requires several complementary efforts, which include:

- The Washington Geological Survey to compile a geological study and maintain a publicly available database of subsurface geologic information;
- The Department of Natural Resources to update lease rates for state lands to attract geothermal exploration and development projects;
- The Department of Commerce to develop a geothermal exploration cost-share grant program to incent and offset the cost of exploratory drilling; and
- The Department of Ecology, in collaboration

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | with other agencies, to identify the opportunities and risks of geothermal development in the three highest priority areas, starting in November 2024.[2]<br><br>The prospect of enhanced geothermal is real enough in the Pacific Northwest that geothermal developer Fervo Energy has intervened in PacifiCorp's 2023 IRP at the Oregon Public Utility Commission. RNW asks that PSE seriously consider enhanced geothermal for inclusion in 2025 IRP modeling, in line with PSE's "all of the above" approach to emerging technologies. Our recommendation is supported by the results of Black & Veatch's technological assessment for the Company and builds off of the gaining momentum of enhanced geothermal energy in Washington. The model should be allowed to select the most optimal combination of resources—with realistic assumptions of each resource's costs, characteristics, and commercial availability—instead of starting with a predetermined outcome.<br><br>Importantly, a utility's preferred portfolio sends signals to energy developers, which can be especially critical for long-lead time resources, such as enhanced geothermal and offshore wind.<br><br>[1] U.S. DOE, "Pathways to Commercial Liftoff: Next-Generation Geothermal Power." March 2024. https://liftoff.energy.gov/wp-content/uploads/2024/03/LIFTOFF_DOE_NextGen_Geothermal_v14.pdf | |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | [2] Final Bill Report ESSB 6039. February 2024. https://lawfilesext.leg.wa.gov/biennium/2023-24/Pdf/Bill%20Reports/Senate/6039-S.E%20SBR%20FBR%2024.pdf?q=20240328090551 | |
| 9 | 4/1/2024 | Joel Nightingale (RPAG member) on behalf of Washington Utilities and Transportation Commission staff | irp@pse.com | General:<br>• Staff appreciates PSE staff, as well as Black & Veatch being available for an extended period of time to present on the various options available to PSE for their IRP.<br>• Staff encourages PSE to avoid overpacking IRP meeting agendas. Having too much to cover in a single meeting can discourage questions/discussion, makes it difficult for participants to remain engaged, and makes scheduling conflicts more likely.<br>• On slide 19, PSE mentioned that they are working to compile the generic resource data for all resources the Company plans to include in the 2025 IRP modeling. Staff would appreciate this spreadsheet being circulated when it is available.<br><br>Energy Storage<br>1. For Vanadium Flow Batteries, has PSE discussed with Snohomish PUD their experience with this type of project? Staff understands that they recently decommissioned their Vanadium Flow Batteries due to issues with corrosion from the Vanadium.<br>2. Staff would like clarification on whether the Metal-air battery PSE is considering for this 2025 IRP is a 10 MW battery or 100 MW battery, it was unclear during the presentation and in Black & Veatch's slides. Staff would also like clarification on the duration of this battery (10-hour vs. 100-hour). | Energy Storage<br>1. We modeled 4- and 6-hour flow batteries as part of our generic resources through the 2021 IRP cycle. However, because Li-ion batteries were more cost effective and filled the same storage duration niche, the models did not select the flow batteries and it was removed for the 2023 Electric Progress Report. We have discussed the complications experienced with vanadium flow battery pilot project with other utilities.<br><br>2. We are considering a 100 MW 100-hour Fe-air battery as our long-duration energy storage generic resource in the 2025 IRP. Separate from the IRP process, we are pursuing a 10 MW 100-hour pilot project with Form Energy.<br><br>3. We are using a 10-hour advanced adiabatic CAES (AA-CAES) as our medium duration generic storage option in the 2025 IRP. We have modeled pumped hydro storage as a resource option for several IRP cycles, but given the higher costs, it does not come in as a low-cost option in comparison to lithium-ion batteries that were also modeled. We already have all the information needed to model PHES which is why we did not ask Black and Veatch to include in the assessment. We decided to take the |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | 3. On slide 18, PSE mentioned that one of the reasons compressed air energy storage (CAES) was chosen over pumped hydro as the representative medium-duration energy storage resource was because pumped hydro is not geographically agnostic. Is CAES geographically agnostic? Black and Veatch's presentation seemed to suggest that there are geographical constraints on at least some applications of CAES (slide 26). Which of the CAES options described on slide 27 (diabatic, adiabatic, isothermal) does PSE plan to include as a generic resource in its 2025 IRP?<br><br>SMRs<br>4. Given PSE's support for the Xe-100 Energy Northwest project at the Columbia Generating Station, how confident are PSE and Energy Northwest about the fuel – both availability and cost – that it will require (HALEU, per slide 49)?<br><br>Hydrogen<br>5. What are the main drivers of the significant increase in green hydrogen costs?<br><br>Offshore Wind<br>6. Does PSE see offshore wind as a resource that a single utility can procure on its own, or something that would require collaboration between multiple entities? If the latter, has PSE engaged in this type of collaboration, and if so, what has come of that engagement?<br>7. How sensitive are PSE/Black and Veatch's offshore wind cost assumptions to overall project size (nameplate MW) for PSE's proposed generic resources? For example, would a 1.4 GW project like the Hornsea II project (slide 55) be | opportunity to explore other energy storage options for the mid-duration (8 – 12 hours). But you are correct, AA-CAES also has geographic considerations.<br><br>4. HALEU, or high-assay low enriched uranium is fuel that is enriched up to 20%, or 19.75%. That fuel and its supply chain is one of the bigger challenges for the deployment of the next generation of reactors. The Department of Energy and the reactor developers recognized this challenge, and the first two demonstrations are working very closely with the Department of Energy to establish that initial supply for the first two cores. In addition to that, the developers and the Department of Energy recognize that we need to eventually establish our own supply chain for that particular fuel. There are active projects and program and requests for proposal that recently came out specifically asking conglomerates of companies in the United States to apply for funding to establish HALEU supply in the U.S. It's one of those things that we recognize is a risk to the U.S. industry, but it's a risk that is being actively tackled and managed by the Department of Energy and the U.S. industry.<br><br>5. The biggest drivers are the increasing cost of electricity, the availability of adequate renewable energy supply in the region including transmission, and the cost of capital. The wholesale costs of electricity have doubled in recent years |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | significantly cheaper (on a $/kW basis) than a 120 MW project (slide 58)?<br>8. As NWEC mentioned during the meeting, expected lifetime has a significant impact on the levelized cost of energy of a resource. Staff encourages PSE to ensure its estimated operating life of offshore wind (and all generic resources) is realistic.<br><br>Transmission<br>9. How does PSE plan to assess the risk of a constrained transmission system in the 2025 IRP? If BPA and others continue to struggle to meet the growing demand for transmission, how will PSE ensure that this IRP sets the company up to make least-regret resource decisions (including generation and delivery system investments)?<br>10. How will the 2025 IRP weigh non-wires alternatives (NWAs) against the need for more transmission? Are the LTCE and delivery system planning models sufficiently coordinated to produce and "optimized" solution?<br>11. How much of the 2030 new 3,217 MW transmission capacity will be repurposed/upgraded transmission versus new transmission, and does that distinction impact the likelihood of these builds coming to fruition?<br>12. Staff would appreciate more details on the sensitivities PSE described briefly on slide 113. Would the transmission builds in these sensitivities be prescriptive or would they respond to the resources that the LTCE model selects? | in the northwest power markets as demand for clean power has spiked and fossil generation is retired. Power costs make up the bulk of the cost of green hydrogen, and the strength of IRA tax credits is being dwarfed by the power costs. Higher borrowing and financing costs drive up the cost of the equipment, resulting in a significant upward pressure on delivered prices. In addition, if the 45V tax credits are enacted as written in draft form, costs are estimated to increase another 50% to 300%.<br><br>6. PSE has been engaged in conversations with offshore wind developers for several years as it considers this technology. PSE views offshore wind as a resource in Washington as something that will require floating offshore platforms, significant dedicated transmission infrastructure (both on and offshore) and further infrastructure to build and support such resources that does not exist today. Whether procured on its own, or through collaboration with multiple entities, it would require significant investments, new siting and permitting considerations, and likely new policy or legislative action to support offshore wind development in the state. Due to the size of offshore wind projects in our area, it is likely PSE would be one of multiple energy offtakers of a project. PSE has not engaged in collaborative efforts exploring offshore |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | | wind at this time. However, we continue to monitor the progress of local projects.<br><br>7. Due to the lack of executed projects on a global scale, the projected costs for floating offshore wind technology are based on a combination of fixed-bottom offshore wind and the few pilot and demonstration floating platform offshore wind projects that have been constructed to date. These cost assumptions are largely based on project sizes of 1,000 MW. Therefore, Black & Veatch has extrapolated costs to scale to 100 MW to meet our generic resource technology sizing. Costs are not highly sensitive to project sizing, therefore. However, because the technology is still nascent, costs predictions vary widely across sources.<br><br>8. Briefly, the cost of offshore wind is not sensitive to the overall size of the project. In more detail, Black & Veatch extrapolated cost predictions available for offshore wind projects of approximately 1,000 MW to meet our desire for a 100 MW offshore wind generic resource. However, since floating offshore is still a nascent technology, cost predictions are higher than fixed bottom offshore wind technology, and subject to |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | | 9. We have worked with Black and Veatch to get best estimates on operating life of resources and including an ongoing maintenance and costs to keep the resource operating at capacity.<br><br>10. For the 2025 IRP, we will be taking the regional transmission constraints into account by limiting the amount (MW build limit) of resources available in regions along with allowing co-location of resources to optimize available transmission and interconnection which would allow us to build more resources than firm transmission available, but include a generation limit out of that region. For example, if there is limited transmission, there could be a wind, solar, and or energy storage resource sized to fit well together and limit curtailments.<br><br>11. We are working with system planning to account for any transmission and distribution benefits that we will get by adding distributed resources.<br><br>12. The additional 3,217 MW by 2030 includes additional transmission capacity BPA has identified in their evolving grid projects. BPA has committed to building those projects and the likelihood of those transmission upgrades coming to fruition is high. The upgrades include reconductor projects as well as new substation upgrades to the transmission system. The transmission reconductor projects are still substantial rebuilds with |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | | the risk they get delayed in implementation.<br><br>13. Regarding the sensitivities described on slide 113, PSE will be looking at a combination of two possible transmission capacity upgrades to address the Cross-Cascades capacity need. Slides 122 and 124 discuss these further. One option will include a self-build transmission line to increase the cost and capacity on the West of Cascades North flowgate across the Cascade Mountains by 2035. A second option will include the cost and capacity of BPA's Coulee-Schultz-Olympia project identified in their latest 2023 cluster study results. The intent is to explore and evaluate the benefit transmission capacity additions have to meeting a lower cost portfolio to achieve PSE's clean energy objectives. |
| 10 | 4/9/2024 | James Adcock | lrp@pse.com | Please note that "Small Modular Nuclear Reactors" is NOT an existing available technology -- none have been built in the free Democratic world -- where realistic price and timing information would be available for PSE to actually evaluate.<br><br>In addition to expressing extreme concerns that SMRs will be destructive to at least the pocketbooks of PSE ratepayers, I also express great concerns that "Hydrogen" technologies will not actually be used in ways that are sensible and cost effective for human society, but rather will be persued for reasons of "Regulatory Game-Playing" including double-counting schemes -- where the supposed "environmental benefits" of Hydrogen are counted more that once, for | Thank you for your feedback. Once we finalize the resources and receive the draft costs, we will add the PTC or ITC benefits. |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
| --- | --- | --- | --- | --- | --- |
| | | | | example if both the supposed "environmental benefits" of the "green electricity" going into the Hydrogen project, and also the supposed "environmental benefits" of the burning of that "green hydrogen" for example by injecting it into Puget's gas system, or into Puget's gas electrical generating units. But: There is actually only ONE environmental benefit happening there: namely the amount of natural gas usage actually dispatched by the hydrogen being injected into one or the other gas usage points. Any other "environmental benefit" from the creation of "green electricity" is destroyed when that electricity is used to make hydrogen, and not some other societal use.<br><br>I believe, that since they are major influences, at least draft benefits of ITC and PTC *should* be included in the draft costs. It is wrong to pretend that these benefits do not exist, and they have a major influence on which resources should be selected.<br><br>To quote NIH re LAES, "LAES is premature to be fully studied because lack of actual operating conditions and results from large plants, which affect the techno-economic predictions, in turn, affecting technology commercialization. Furthermore, the off-design conditions are not fully covered although it is a crucial step in system performance evaluation. "<br><br>https://pubs.rsc.org/en/content/articlelanding/2023/ra/d3ra04506d<br><br>In terms of the Form Energy iron-air battery, the round trip efficiency is less than 50%. That means that more | |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | than 2 Megawatt-hours of clean energy have to go into the battery to get 1 Megawatt-hour of clean energy back out.  At that rate it would be better for Puget simply to run an NG Peaker, and then use the 2 Megawatt-hours of "green electricity" better for something else!<br><br>In terms of Mr. Popoffs comments that Wind, Solar, and Hydro do not have the reliability "to keep the lights on" -- these renewable do not have to "keep the lights on."  There is nothing "special" which Wind, Solar, and Hydro which would require Puget to lose power -- something Puget manages to do quite regularly in my perfectly "normal" suburban neighborhood I might point out. What Wind, Solar, and Hydro do is reduce Puget's reliance on Natural Gas generation in the time frame prior to 2045, reducing the amount of Puget emissions, so that Puget for example, can actually meet CETA requirements to actually be "80% clean" by 2030.<br><br>Re: BPA Transmission and/or Flowgate "Saturation." -- Looking at BPA data, most of these things are not actually saturated on a 24 hour basis -- some are, but many are not.  Which implies that many of these "transmission constraints" can actually be solved by storage or co-located storage, to smooth out the "spikes" of generation coming from Renewables generation.<br><br>Wheeling Costs: to put these in perspective, these costs are about 1/2 of one penny per delivered kilowatt-hour.  Not "trivial" but not "prohibitive" either. | |

| No. | Date | Interested party | Submitted via | Question or comment | PSE response |
|---|---|---|---|---|---|
| | | | | This compares to about 30 pennies per kilowatt-hour that Puget is charging me retail for peak hour rates.<br><br>James Adcock, Electrical Engineer | |