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Attn: Amanda Maxwell, Executive Director and Secretary
Washington Utilities and Transportation Commission
621 Woodland Square Loop SE
P.O. Box 47250
Lacey, WA 98503

Re: Puget Sound Energy's 2023 Electric Integrated Resource Plan Progress Report (**Docket UE-200304**) and 2023 Gas Integrated Resource Plan (**Docket UG-220242**)

Dear Director Maxwell:

The NW Energy Coalition ("NWEC" or "Coalition") appreciates the opportunity to comment on Puget Sound Energy's 2023 Electric Integrated Resource Plan Progress Report and 2023 Gas Integrated Resource Plan ("IRP"), as provided by the Notice of Opportunity to File Written Comments issued April 21, 2023.

The Coalition is an alliance of over 100 environmental, civic, and human service organizations, progressive utilities, and businesses. Our mission is to advance clean, equitable, and affordable energy policies in Oregon, Washington, Idaho, Montana and British Columbia. We envision the Northwest comprised of communities that benefit from a carbon-free energy system that equitably meets the needs of people and preserves the region's natural resources. Coalition staff participates in Puget Sound Energy's Conservation Resource Advisory Group, Low-income Advisory Group, and Integrated Resource Plan Stakeholder Group. We appreciate PSE's engagement of stakeholders throughout this IRP process, and look forward to continuing to work with the Company, Commission staff, and other stakeholders to continue to make progress on the issues raised in stakeholder comments.

2023 Electric IRP Progress Report

There is a lot to like about the Electric IRP Progress Report. We appreciate improvements to the organization and accessibility of the Report over the 2021 Electric IRP. We also appreciate the focus on resource diversity. We applaud PSE's acknowledgement that the 2030 Clean Energy Transformation Act ("CETA") standard can now be met almost entirely with renewable and non-emitting resources, with only a small amount of RECs for compliance in one year. Fig. 3.5 demonstrates that the preferred portfolio is well above the 80 percent requirement for clean energy resources used to serve customers, with only $3.18 million of unbundled RECs to make up 3.4 percent of delivered energy. For all future years of the Clean Energy Action Plan, the preferred portfolio meets the 100 percent clean standard without the need for alternative compliance options. This is a significant milestone, and demonstrates the significant effect of the Inflation Reduction Act on resource costs, as well as modeling improvements made after the completion of the 2021 IRP for battery storage.

However, several issues from the 2021 Electric IRP remain unaddressed in this Progress Report, and several concerns we have raised previously have become more urgent.

1. **More work is needed to ensure that PSE is procuring sufficient customer-side resources to meet system needs in light of aggressive decarbonization goals and equity considerations.**

Energy Efficiency: We are concerned about the long-term downward trend in PSE's conservation potential, which has deteriorated even since the 2021 IRP. Overall, the 2023 Progress Report CPA potential is down from the 2021 IRP by approximately 13 percent by 2045. We reiterate the concerns raised in our comments on the 2021 IRP:

> *Broadly, NWEC has serious concerns that the tried-and-true power planning models in use in the region are not well-suited for a high-penetration renewables scenario, and are undervaluing demand-side resources ("DSRs"). If the shortcomings of our current planning models are not addressed, this trend could have long-term implications for EE and DR programs in the region, reducing their operational capacity and ultimately, their effectiveness. DSRs have many benefits, some of which are not accounted for in current cost-effectiveness criteria:*
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> - *Unlike many clean energy resources, energy efficiency is available at all hours and provides many ancillary system benefits and non-energy benefits.*
> - *Energy efficiency and demand response bring locational value and time of use value to the grid, which is currently not adequately accounted for in cost-effectiveness calculations.*
> - *The societal benefits of reducing energy burden to overburdened communities and vulnerable populations, and promoting job growth in the region after a period of economic hardship, are not accounted for in cost-effectiveness calculations.*
> - *DSRs are also an essential part of reducing the risk of the overall CETA-compliant portfolio, in the event that supply-side resources are unavailable, construction is delayed, or transmission pathways are constrained.* [1]

[1] See May 6, 2021 Comments of NW Energy Coalition on PSE's 2021 Electric Integrated Resource Plan

We further note that PSE is not alone in this challenge. As a region, Northwest utilities' current energy efficiency targets are not ambitious enough to meet our climate goals. Many factors contribute to the reduction in savings, not the least of which is low market prices for renewable energy – a condition also discussed in PSE's 2021 Electric IRP and the 2021 NW Power Plan. However, the NW Power and Conservation Council has acknowledged that its cost-effectiveness model does not easily capture all of the benefits of energy efficiency, and in particular, some risks that utilities in the region currently face are not easily captured:

1. **Some power system attributes, including adequacy, flexibility, and resilience.** These are supported under the Northwest Power and Conservation Act, but are not readily valued in the Council's portfolio model.
2. **Hedging against the risk that comparable resources, like utility scale wind, solar, or storage, may not be available and reliable within the time needed to meet power system needs.**
3. **Uncertainty about future sustained low market prices.** During weeks when Mid-C prices were over $400/MWh, we were sharply reminded that falling behind on our EE acquisition exposes customers to fuel price volatility.
4. **Growing decarbonization goals for specific jurisdictions.** Particularly, with state legislators considering legislation focused on reducing reliance on the gas system for residential heating, the role of EE in reducing electric system costs becomes even more important.
5. **Equity.** EE directly reduces energy burden, while supply-side resources do not. Equity is not addressed in the Council's methodology.
6. **Value of maintaining a robust EE infrastructure.** Maintaining the ability for programs in the region to deliver energy efficiency is critical, even if savings temporarily become more expensive.

We urge the Commission to direct regulated utilities to step up their Energy Efficiency savings targets substantially in the very near term, while we also get to work on updating the cost-effectiveness methodology to capture these risks and benefits.

Recommendation: PSE and the Commission should evaluate what changes to existing planning models and cost-effectiveness criteria are needed in order to properly value DSRs in a 100% clean grid. This will be an important consideration in ensuring that utilities implement CETA in a lowest reasonable cost manner, supported by analysis in their IRPs. For the 2025 Electric IRP, the Commission should direct PSE to update its cost-effectiveness analysis for energy efficiency to incorporate consideration of the six factors above.

Demand Response: We remain disappointed that PSE has no strategy for taking advantage of the CTA-2045 requirement for "signal capable" water heaters. Overall, there continues to be an urgent need for a real demand response strategy and roadmap, as we advocated in the 2021 Electric IRP and PSE's 2022 Clean Energy Implementation Plan docket (UE-210795).

PSE projects a need for 337 MW of demand response by 2030, much of which is front loaded for 2024-26. While there has been improvement in "signal capable" DR (water heaters, HVAC, EV charging), we think the magnitude of this potential is still understated (Table 2.4). The NW Power and Conservation Council estimates that at least 2,500 MW of additional winter load reduction potential and 3,500 MW of summer load reduction potential in the region. A large majority of this potential can be achieved in this decade. With current regional system peaks in the 30,000 MW range, that means we can reduce peak demand by as much as 10%. But, we aren't seeing the uptake in the region that we will need in order to achieve this. In particular, despite many years of exploring the issue, PSE has yet to develop a full DR program.

Recommendation: In general, all new load, including replacements for existing water heating and HVAC, should be demand-response enabled in order to manage loads. PSE should develop a comprehensive demand response strategy and roadmap to transition to fully managed replacement appliance load.

2. **Methane leakage assumptions and global warming potentials should reflect the most current science.**

PSE continues to rely on outdated upstream emission rates for methane, both in terms of the leakage rates and the global warming potential for methane. The company cites U.S. Environmental Protection Agency and the Washington Department of Ecology's requirements for direct reporting entities to use the AR4 100-year global warming potentials (GWPs) in their annual emissions inventory compliance reports.[2] However, EPA acknowledges that these GWPs are outdated:

> *The EPA considers the GWP estimates presented in the most recent IPCC scientific assessment to reflect the state of the science. In science communications, the EPA will refer to the most recent GWPs from the IPCC's Sixth Assessment Report, published in 2021. The EPA's* Inventory of U.S. Greenhouse Gas Emissions and Sinks *(Inventory) complies with international GHG reporting standards under the United Nations Framework Convention on Climate Change (UNFCCC). UNFCCC guidelines now require the use of the GWP values from the IPCC's Fifth Assessment Report (AR5), published in 2013.*[3]

For planning purposes, we recommend using the most recent GWPs that reflect current science, and to use shorter (20-year) GWPs that align with the IRP planning horizon.

[2] Table A-1 at 40 CFR 98 and WAC 173-441-040.

[3] https://www.epa.gov/ghgemissions/understanding-global-warming-potentials

In addition, the Canadian values for upstream emissions used by PSCAA for the 2019 Environmental Impact Statement for the Tacoma LNG project are also out of date.[4] Quite a lot of new research on upstream emissions rates in Canada has been conducted. Here is a summary of several relevant publications from our 2020 review of the literature:

- Atherton et al. (2017)[5] conducted an extensive field survey of gas and oil production areas in northeastern British Columbia, covering more than 1600 well pads and processing facilities. They conclude: "Our calculated emission frequency values, combined with estimated and pre-established emission factors for wells and facilities, provided a CH4 emission volume estimate of more than 111 800 ± 15 700 t per year for the BC portion of the Montney. This value exceeds the province-wide estimate provided by the government of BC even though the Montney only represents about 55 % of BC's total natural gas production."
- Wisen et al. (2020)[6] conducted a review of natural gas well leakage data from the British Columbia Oil and Gas Commission. They found that about 11% of over 21,000 wells have reported leakage during their lifetime, twice the rate indicated from earlier research in Alberta, and highlighted that both BC and Alberta have almost no leakage reporting from abandoned or retired wells.
- Ravikumar et al. (2020)[7], as part of a field study of leak detection and response (LDAR) efforts, reviewed emissions studies in both Alberta and British Columbia and likewise concluded: "Both ground-based and aerial-measurements in Alberta showed higher vented and total methane emissions compared to provincial regulatory estimates. Similarly, mobile measurements using truck-mounted sensor systems in British Columbia and Alberta have consistently shown that a majority of the emissions are dominated by a small number of high-emitting sites, often identified as 'super-emitters.'"
- O'Connell et al. (2019)[8] surveyed 1,299 oil and gas well pads and 2,670 unique wells and facilities in Alberta, and found: "As a result of measured emissions being larger than those reported in government inventories, this study suggests government estimates of infrastructure affected by incoming regulations may be conservative. Comparing emission intensities with available Canadian-based

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[4] See page 5.7 2023 Electric IRP Progress Report

[5] Atherton et al., 2017, "Mobile measurement of methane emissions from natural gas developments in northeastern British Columbia, Canada," *Atmospheric Chemistry and Physics*, 17, 12405–12420, 2017, DOI: 10.5194/acp-17-12405-2017.

[6] Wisen et al., 2020, "A portrait of wellbore leakage in northeastern British Columbia, Canada," *Proceedings of the National Academy of Sciences*, 117 (2) 913-922; DOI: 10.1073/pnas.1817929116

[7] Ravikumar et al., 2020, "Repeated leak detection and repair surveys reduce methane emissions over scale of years," *Environmental Research Letters* 15 (2020) 034029, DOI: 10.1088/1748-9326/ab6ae1

[8] O'Connell et al., 2019, "Methane emissions from contrasting production regions within Alberta, Canada: Implications under incoming federal methane regulations. *Elementa* 7: 3. DOI: 10.1525/elementa.341

> research suggests good general agreement between studies, regardless of the measurement methodology used for detection and quantification."

Recommendation: We urge the Commission to direct the Company to update its assumptions for methane leakage and global warming potential, and to use 20-year GWPs for methane in its 2025 Electric IRP and 2025 Natural Gas IRP Progress Report.

3. **Better integration of electric and natural gas planning, consolidation of some planning processes, and regular feedback from the Commission is likely to lead to better results.**

Several other important unresolved issues from PSE's 2021 Electric IRP carry over into the 2023 Electric IRP update. For example, we remain skeptical of PSE's capacity strategy, which relies on 237 MW of new peaking resources in 2024, 2026, and 2028. This is a very aggressive strategy that relies on dubious cost and availability assumptions for clean fuels. We urge the Commission to examine these assumptions closely, in particular the assumptions for hydrogen fuel, which would likely require significant infrastructure upgrades in order to incorporate at high blend rates, and which affects both the Electric IRP and the Natural Gas IRP.

Further, the winter capacity need continues to be the most difficult challenge for PSE. We continue to support the recommendation in our 2021 Electric IRP comments proposing that PSE follow a staged approach to meeting its capacity need, maximizing the availability of so-called "energy limited" clean flexible resources to meet needs during typical peak periods BEFORE considering supplemental resources to meet rare long-duration peaks. Alternatives for supplemental long-duration peak capacity could include increased demand response, storage and hybrid systems, and surplus capacity imports from California. We urge the Commission to direct PSE to conduct a more thorough analysis of potential capacity solutions, including renewable hybrid systems, demand-side resources, and California winter capacity imports.

We also continue to disagree with PSE's method for applying the SCGHG as a planning adder. We point the Commission to the testimony of Elaine Hart in Docket UE-210795 for a full explanation of why applying the SCGHG as a dispatch cost leads to more optimal outcomes.

Recommendation: In general, we recommend that the Commission address contested issues in IRP acknowledgement letters so that they can be resolved through an iterative planning process. In the absence of Commission action on IRPs, contested issues are likely to remain unresolved in the Progress Report. To get ahead of this for the 2025 Electric IRP, we offer the following recommendations:

(a) Integrate Distribution System Planning into the IRP process in a more transparent and equitable way. See the Oregon PUC Distribution System Planning docket for an example.

(b) Conduct one or more technical workshops in 2023 to further review transmission constraints, alternatives and costs. Assigning fixed transmission interconnection adders is unsatisfactory for planning that relies a great deal on out of state resources (e.g. Montana wind, see Table 5.5, p. 5.17)
(c) Conduct a technical workshop to address technology assessment and fuel risk -- comparison of development pathways for hydrogen, nuclear, offshore wind, new battery chemistries, etc. and for their respective supply chains and fuel supplies.

2023 Natural Gas Integrated Resource Plan

The 2023 Natural Gas IRP is PSE's first IRP conducted since the passage of the 2021 Climate Commitment Act ("CCA"). CCA created a cap-and-invest program, administered by the department of Ecology through an economy-wide emissions trading system. This program imposes a new compliance obligation on natural gas utilities, which they must consider in all aspects of their business, including integrated resource planning.

NWEC's comments on PSE's 2023 Natural Gas IRP are informed by NWEC's Resolution on Gas Utility Decarbonization, which was adopted by a consensus vote of our membership on May 18th.[9]

Concerning gas utility resource planning, we recommend that gas utilities should incorporate decarbonization pathways into all planning, with the goal of identifying the lowest reasonable cost pathways to decarbonize the overall energy system including the gas system, in accordance with the timelines required by science, and consistent with Washington's statutory greenhouse gas limits. Gas utilities should also continually examine their business model, and proactively propose and adopt business model reforms to adapt to the changing regulatory environment. Given Washington's climate policies, it is not reasonable for gas utilities to assume that historic customer growth rates will continue, nor is it reasonable *not* to plan for customer attrition in the future. PSE is wisely planning for no new customer growth, but the Company has not included any electrification in its preferred portfolio. It is not possible for the Company - or the Commission, policymakers, and stakeholders – to consider necessary regulatory reforms or the prudence of associated costs if the Company does not plan for these impacts.

To do this, gas utilities should consider a wide variety of decarbonization programs and measures that are available to customers and that maintain affordable energy services, and compare them on a level playing field, supporting fair competition and without bias, to develop a lowest reasonable cost and risk approach to decarbonization. We don't believe PSE has achieved this goal in its 2023 Natural Gas IRP.

[9] https://nwenergy.org/wp-content/uploads/2023/05/NW-Energy-Coalition-Resolution-Regarding-Gas-Utility-Decarbonization-May-18-2023.pdf

1. **PSE should pursue more energy efficiency, demand response, and electrification beyond what is deemed cost-effective in order to mitigate for fuel price and allowance price risk.**

Going forward, the Commission should not accept any gas utility plan that simply passes allowance costs on to customers without reducing emissions. Such a strategy would be inconsistent with the principles of lowest reasonable cost planning and prudent utility practice, as it exposes customers to increasing compliance cost risk, and is likely costlier in the long-term than strategies that actually reduce gas system emissions. Based on our review of PSE's 2023 Natural Gas IRP, we believe that the Full Electrification Scenario should be PSE's preferred portfolio, as it is the most cost-effective solution for reducing greenhouse gas emissions at the pace necessary to meet the state's greenhouse gas limits, which are based on the most recent climate science.

Under this logic, it would be prudent for the utility to pursue customer-side resources beyond the levels dictated by the Commission's current cost-effectiveness methodology in order to ensure that PSE will meet its proportional share of statewide greenhouse gas reductions, and to prudently manage risks to customers.

Recommendation: The Commission should decline to acknowledge PSE's 2023 Natural Gas IRP for its inconsistency with lowest reasonable cost planning principles and prudent utility practice.

2. **PSE's faulty electrification assumptions lead to suboptimal results for customers.**

We are concerned that PSE's building electrification assumptions inflate the costs of electrification in the Full Electrification Scenario. By not properly accounting for all incentives provided by the Inflation Reduction Act ("IRA") for electric appliances such as heat pumps, PSE underestimates the potential deployment of these appliances. PSE also overstates the costs of installing electric appliances and underestimates heat pump performance in ways that unduly understate their cost-effectiveness. We suspect that PSE is attributing the total costs for electric equipment and installation to the measure costs, which is inconsistent with the way costs are considered for other customer-side resources, like energy efficiency and demand response.

Specifically, PSE uses outdated assumptions for cold climate heat pump technology. NW Energy Coalition, Front and Centered, and Sierra Club provided detailed expert testimony on cold climate heat pumps in Puget Sound Energy's 2022 General Rate Case, highlighting the technology advancements and cost reductions.[10] The 2022 General Rate Case Settlement requires PSE to update its cold climate heat pump assumptions in a

[10] Burgess Test., Dockets UE-220066/UG-220067 at 24-25, 31

comprehensive decarbonization study. We recommend that those assumptions also be corrected in the 2024 Natural Gas IRP update.

Further, PSE assumes zero new gas customer growth under the preferred portfolio, but it does not apply this assumption to the electrification scenario. This inflates the number of gas customers that will need to be electrified under the scenario, with the associated measure costs and electric system costs attributed to electrification. In the preferred portfolio, these prospective new gas customers still electrify, but the costs of that electrification are not accounted for in the analysis. This artificially inflates the electrification scenario costs relative to the preferred portfolio.

In addition to electrification, demand response, and energy efficiency, emissions reduction strategies could include targeted deployment of customer-side clean heat technologies like solar thermal, geothermal, or district energy systems. PSE did not adequately consider these alternatives.

Recommendation: The Commission should require PSE to update its assumptions for electric heat pump technologies, costs, and performance; and to consider a all commercially available customer-side clean heat technologies in the 2025 Natural Gas IRP update.

3. **PSE's assumptions regarding the emission reductions, safety, reliability, and future availability of green hydrogen for blending on its natural gas distribution system are unfounded.**

NWEC supports the evaluation of alternative zero-carbon and renewable fuels for use in hard-to-electrify applications, such as manufacturing, maritime, aviation, and heavy industrial processes. However, such applications should be pursued only after a thorough review of the availability, cost, safety, and reliability of green hydrogen for these end-uses. The 2023 Natural Gas IRP's analysis of these factors is insufficient to support PSE's aggressive plans to incorporate hydrogen into its fuel mix starting in 2028.

Recommendation: The Commission should require PSE to conduct a more comprehensive analysis of its alternative fuels assumptions, and advise against their use for residential and small commercial heating loads, where electrification measures are already commercially available.

4. **Better integration of electric and natural gas planning, consolidation of some planning processes, and regular feedback from the Commission is likely to lead to better results.**

It is necessary for a dual-fuel utility like PSE to integrate electric and gas planning to fully capture decarbonization options and optimize resources to achieve the lowest reasonable cost and risk. An integrated system plan should consider loads and resources across both systems down to the distribution and customer level. The planning model should solve for the optimal decarbonization pathway across both systems that also addresses needs for reliability, equity, and statutory requirements. To accomplish this, it may be necessary to completely rethink the way PSE conducts integrated resource planning. We urge a coordinated process to reimagine PSE's planning paradigm for the 2025 planning cycle to better address the evolving policy and market landscape for decarbonization in Washington.

Respectfully submitted,

/s/ Lauren McCloy

Lauren McCloy
Policy Director
NW Energy Coalition
811 1st Ave. Suite 305
Seattle, WA 98104
(509) 201-3581
lauren@nwenergy.org

/s/ Fred Heutte

Fred Heutte
Senior Policy Associate
NW Energy Coalition
811 1st Ave. Suite 305
Seattle, WA 98104
(503) 757-6222
fred@nwenergy.org