Resource Planning Advisory Group feedback report

Meeting details

- Tuesday, July 28, 2026, 1:00 p.m. - 3:00 p.m.
- Virtual webinar hosted by PSE and facilitated by Maul Foster & Alongi
- Links to:
    - Presentation
    - Agenda
    - Meeting recording

Feedback

The following records participant questions and PSE responses from the public comment opportunity and comments submitted via online feedback form or email to isp@pse.com. Meeting materials are available on the clean energy planning website.

PSE endeavors to provide clarity in responses but subsequent follow-up may be required at times. Please direct any follow-up clarifications to isp@pse.com. *PSE responses are in teal italics.*

2. RPAG member feedback

Dennis Suarez, July 28, 2026 via isp@pse.com

1. With regard to the analysis done by E3, it would be helpful for our understanding for E3 to explain a base case in detail from start to finish.

2. Methodology and assumptions must be clearly stated.

3. Variables and influences should be listed with their potential effects.

4. Conclusions must be stated clearly, unambiguously and rated by PSE's value measurement framework (cost reduction, ghg, electrification metrics …)

Pages 21-39 had a lot of important things to say. I had to go over it several times after the meeting today. The brief would benefit from a clear path and ranking to inform a prioritized and confident action plan and assessment model.

Thank you for this feedback. E3 will be preparing a complete report that will be submitted with the ISP and your feedback on the current analysis will inform the information included in that analysis.

PSE is also looking into option for scheduling an optional meeting with E3 in the near future. Feedback that cannot be addressed in this ISP cycle will inform revisions for future iterations of this analysis.

Quinn Weber on behalf of the Washington Utilities and Transportation Commission staff, August 4, 2026 via isp@pse.com

General:

Staff appreciates the changes PSE made to the RPAG structure to engage the RPAG with specific asks, identifying the IAP2 spectrum of a topic, and being transparent about how it will incorporate RPAG member feedback.

Thank you for your comments.

Reference Case Load forecasts:

1. Has PSE's electric system average line loss factor reduction, and subsequent reduction in total electric system load and peaks, been factored into other modeling efforts, such as resource adequacy?

The line loss reduction has been factored into the portfolio model and all results reflect the update. The resource adequacy analysis was completed last year before we knew of this update. However, this update will not have an impact on the planning reserve margin.

Electrification Potential and Nonpipelines Alternatives Assessments:

1. Please clarify if the analysis presented by E3 in this RPAG meeting will be the sole electrification potential assessment for electrification of customer end uses in the 2027 ISP.

This geographically targeted electrification potential assessment is designed to address WAC 480-96-040(1)(b). PSE is also looking at electrification through scenario analysis, which considers a wide range of potential electrification.

   a. How will this electrification potential assessment, which seems to be largely geared towards nonpipeline alternatives, inform PSE's decision to pursue electrification measures in the Cost Test?

PSE will consider electrification measures "at the portfolio level" as required by the cost test rules in WAC 480-96-030(8). If non-pipeline alternatives have material portfolio implications, then they would be captured in the portfolio analysis via the cost test (e.g., non-pipe alternative reduce gas demand measurably).

   b. Will PSE's electrification potential assessment analyze geographically targeted electrification broken down by customer type? If not, why not?

The targeted electrification potential assessment identified customers in "overburdened communities" as compared to the entire customer base, consistent with WAC 480-96-040(1)(b), as we work to ensure an equitable distribution of benefits and reduction of burdens. The rule indicates "geographically targeted electrification ***may*** *be delineated by customer class" (emphasis added) At this time PSE has not identified a need for further, optional delineation.*

2. Staff notes that WAC 480.96.040 (1)(b) specifies that "The integrated system plan must include an assessment of cost-effective electrification that encompasses the potential for geographically targeted electrification including, but not limited to, in overburdened communities..." Staff also notes that slide 27 references 1.7 miles of pipeline in highly impacted communities.

    a. In addition to this use case, how will PSE's electrification potential assessment incorporate analysis of geographically targeted electrification in overburdened communities?

Based on the definition of geographic electrification, PSE will continue to identify areas where there are operating challenges or where there is an identified system need, including impacts to named communities (highly impacted communities and vulnerable populations)

3. Staff notes that WAC 480.96.040 (3)(b) specifies that "The integrated system plan must assess nonpipeline alternatives, including geographically targeted electrification and gas demand response, as an alternative to replacing aging gas infrastructure or expanded gas capacity." How does PSE's NPA analysis for the ISP incorporate assessment of gas demand response?

The electrification potential assessment presented was a subset of the broader non-pipeline alternative (NPA) analysis and was not intended to address all ISP requirements. PSE recognizes that assessment of demand response is required and that demand response could potentially play a role in reducing system peaks, both through electric demand response associated with electrification and through natural gas demand reduction strategies. However, the application of demand response as a targeted, location-specific alternative to gas infrastructure investments is still an emerging area. PSE's evaluation of demand response will be addressed in the ISP filing.

4. On Slide 22, E3 introduced the cost effectiveness tests used by the firm in the nonpipeline alternative and electrification potential assessments. E3 also explained that they used the Joint Utility Cost Effectiveness test (also referred to by E3 as Utility Cost Test or UCT) in the analysis of both the DuPont and 7 large reliability projects. Staff has several questions about the UCT:

    a. What are the specific cost and benefit assumptions included in E3's version of the UCT? Please specify dollar amounts for each cost and benefit assumption and any relevant calculations associated with their development. What information or data sources were these assumptions based on? For example, what assumptions are made regarding costs beyond the specific electrification measure, including costs associated with electric panel upgrades, weatherization, and any other implementation activities such as "rightsizing" the specific heat pump. What assumptions are made about avoided gas pipeline costs?

The benefits in the Utility Cost Test included the avoided cost of the identified gas infrastructure project, including the planning-level project estimate and 20 years of avoided operating and maintenance costs. The costs included utility incentives, electric supply, generation, transmission and distribution (T&D) costs, and program administration costs. Electrification costs were based on industry-average installation cost assumptions of approximately $28,000 for residential customers and $163,000 for commercial customers. The specific cost and benefit assumptions, calculations, and supporting data sources used in the analysis will be provided as part of the workpapers when the ISP is filed.

It is worth noting that E3 performed additional costs tests, including the Total Resource Cost Test (TRC).

Additionally, these results should be considered directional and are intended to illustrate where non-pipeline alternatives may warrant further consideration. They are not intended to serve as a final determination of whether a particular opportunity should or should not move forward. Each project will be evaluated on its own merits as planning advances, taking into account customer-specific conditions, costs, implementation considerations, and the underlying system need being addressed.

b. Staff notes that under WAC 480-96-030(3), PSE must consider the SCGHG when developing the ISP and incorporate it as a cost adder. How does PSE plan to incorporate this for the electrification potential assessment and nonpipeline alternatives assessment?

As stated in the presentation, E3 included the SCGHG in the modified Total Resource Cost test analysis provided.

c. Staff points out under WAC 480-96-020 (9)(b), cost-effectiveness should be assessed against a project or resource that includes the cost of compliance with chapter 70A.65 RCW. How does PSE plan to comply with this, given that the UCT does not include avoided CCA costs associated with electrification?

As stated in the presentation, E3 included the SCGHG costs and avoided CCA costs in the modified Total Resource Cost test analysis.

d. During the presentation, PSE noted that the UCT would be the "primary" test used by PSE. Will PSE incorporate results from the other two cost tests specified by E3, Total Resource Costs and Ratepayer Cost-Effectiveness into its assessment of potential DuPont segment targeted electrification candidates? If so, how? If not, why is only the UCT being used?

Yes. When individual projects are evaluated, PSE will use the Utility Cost Test (UCT), Total Resource Cost (TRC) test, and Ratepayer Impact Measure (RIM) test to assess cost-effectiveness.

While the UCT was presented as the primary screening metric for this electrification potential assessment, the TRC and RIM tests will also be used to inform project selection and evaluate impacts from the utility, ratepayer, and total resource perspectives. As PSE continues to mature its NPA capabilities, the results of these tests will be incorporated into project evaluations and provided, as appropriate.

e. Why are electric supply and gas supply costs not included in the UCT?

Electric supply costs are included in the UCT as incremental electric system costs associated with electrification. Gas supply costs are not included as a direct UCT benefit because the test focuses on whether an NPA can avoid or defer utility infrastructure costs. Avoided gas commodity and emissions-related costs are reflected in the broader cost-effectiveness analysis, including the TRC where applicable.

f. Did PSE and/or E3 consider including other impacts typically included in TRC tests, such as health, safety, environmental, or other NEIs? Why were these impacts not included, and how would their exclusion comply with WAC 480-96-030(8)(a)(ii)?

Consistent with the "to the extent practicable" language in WAC 480-96-030(8)(a)(ii), PSE considered nonenergy impacts with available time and information for this ISP cycle. PSE will continue refining this methodology and potentially incorporate additional nonenergy impacts as the analysis and supporting data improves in future ISP cycles.

Will PSE incorporate analysis and consideration of participant bill impacts in its ISP electrification potential assessment and nonpipeline alternatives assessment? Staff strongly encourages PSE to quantify participant bill impacts in these assessments and consult the RPAG for feedback.

PSE will calculate the RIM to understand impacts from a ratepayers' perspective for this ISP cycle. PSE appreciates Staff's recommendation and will consider opportunities to further engage the RPAG as the methodology is refined for future ISP cycles.

5. In their presentation, E3 specified that the decision to consider DuPont electrification for segments with greater than 5 customers would be a programmatic decision that PSE has to make. Does PSE intend to pursue electrification of DuPont segments with >5 customers? If not, why not? Staff encourages PSE to consider electrification for segments with >5 customers and set a reasonable limit for segment size.

PSE intends to pursue targeted electrification opportunities where they are both cost-effective and feasible. While the electrification potential assessment identified opportunities on segments serving more than five customers, experience across the industry has shown that converting larger groups of customers as part of a replacement project can be challenging due to the need for a high level of customer participation and increased costs. Because PSE has an obligation to serve and cannot require customers to electrify or disconnect from the gas system, the feasibility of targeted electrification decreases as the number of affected customers increases.

For this reason, PSE currently views targeted electrification opportunities involving more than five customers as less likely to be practicable on a broad programmatic basis. However, PSE will continue to evaluate all cost-effective opportunities and may consider pilot projects involving larger customer groups to gain additional experience and better understand customer participation, implementation challenges, and program design considerations. Findings from these efforts will help inform future decisions regarding the appropriate size and applicability of targeted electrification projects.

6. On slide 35, in the assessment of the seven large reliability projects, what is the "Societal Net Cost" and "Utility Net Cost" specified by E3? Is this equivalent to the "Total Resource Costs" and "Joint Utility Cost Effectiveness" tests, respectively, specified on slide 22? If not, please explain the methods use in both the "Societal Net Cost" and "Utility Net Cost."

The "Societal Net Cost" and "Utility Net Cost" labels correspond to the broader cost-effectiveness perspectives discussed on slide 22. Societal Net Cost is generally aligned with the Total Resource Cost perspective, while Utility Net Cost is generally aligned with the Utility Cost Test/Joint Utility Cost Effectiveness perspective. These labels were intended to summarize the net cost results from those perspectives for the seven projects. PSE will clarify this terminology in the final materials and provide supporting assumptions and calculations in the ISP workpapers.

7. Please explain how the seven major reliability projects were selected, including how the appropriate size for individual projects was determined for the NPA.

The projects shown in the presentation were incorrectly labeled as reliability projects. They are specific projects identified in Docket U-190531 Policy Statement on Property that has become Used and Useful after Rate Effective Date, pg 5.

PSE identified eight known system needs between 2028 and 2048 that would require more than $10 million in capital investment under a traditional infrastructure replacement approach. One of these needs was not included in the analysis because it can be addressed without a capital replacement project and does not create a capacity shortfall. The remaining seven projects were selected for analysis because they represent the largest potential non-pipeline alternative (NPA) opportunities and account for approximately $292 million in forecasted capital investment.

PSE also identified eight additional supply-side system needs with a combined estimated cost of approximately $6.5 million. One of these projects has already been deferred through an NPA. The remaining seven projects were not included in the initial analysis because they were either identified after the analysis began or had relatively small costs (less than $600,000 each) and limited impact on overall capital spending.

These additional projects have been added to the project inventory for NPA evaluation and may be incorporated into the final Electrification Potential Assessment, as appropriate.

8. On slide 25, PSE notes that gas hydraulic model analysis is needed to determine the share of projects that could be avoided in the “Potential System Impact” category. Given that this category comprises the majority of the pipeline PSE is assessing for potential decommissioning, is PSE actively conducting this analysis? If so, when does PSE expect to know how many additional projects in that category could be feasible? If not, why not?

Yes. The hydraulic model analysis referenced on slide 25 is part of the follow-on work identified by PSE. As part of developing the comprehensive inventory of known projects, PSE will:

- *Validate whether remediation is required for each project*
- *Perform the necessary hydraulic analyses to assess system impacts and alternatives*
- *Update the associated cost-effectiveness evaluations based on the results*

The outcomes of this work will be incorporated into the NPA deliverable and documented for all known system needs.

This process is detailed and requires project-specific evaluation; PSE does not currently have a definitive estimate of how many additional projects within the “Potential System Impact” category may ultimately be avoided. PSE expects this analysis to be substantially complete by early 2027, prior to filing the ISP, at which point a more informed assessment of feasible projects within this category may be available.

9. Will the different sensitivities PSE plans to run influence the extent to which NPAs are feasible/cost effective and potentially change the analysis that was presented during this RPAG? Or will the NPA analysis remain the same across the different sensitivity runs?

This electrification potential assessment will remain the same. E3 analyzed the different scenarios and due to the timing of the needs and electrification changes, the results did not change significantly at the portfolio level.

10. On slide 42, PSE notes that other key questions include “customer prioritization”, including “equity “and “other priorities required”. How is PSE and its consultant, E3, currently thinking about these topics? How is PSE currently thinking about incorporating these into its electrification potential assessment and/or development of its preferred portfolio through the cost test and decision framework?

E3 does not take a specific position on how customers should be prioritized for targeted electrification. The slide referenced was meant to indicate that customer prioritization is an open question that PSE and interested parties will need to consider. However, over the course of the work on targeted electrification and non-pipeline alternatives, E3 has observed multiple competing criteria that could be used to prioritize targeted electrification, including cost effectiveness and equity, among others. For more from E3’s past projects please see:

- *An Analytical Framework for Targeted Electrification and Strategic Gas Decommissioning: Identifying Potential Pilot Sites in Northern California’s East Bay Region Final Project Report*

- *Selecting Gas Decommissioning Pilot Locations - Gridworks*

11. On slide 43, PSE notes that "PSE can use and refine this workflow to identify potential targeted electrification opportunities as future system needs are identified, and system and customer data are refined." How often does PSE plan to revisit this and reassess what's feasible, especially in the context of future ISPs and ISP approval timelines? How will PSE ensure that it doesn't let opportunities elapse before the project need by date?

PSE is required to evaluate planned projects for non-pipeline alternatives and pursue the most cost-effective and feasible solution from Final Order 09 in Dockets UE-240004 and UG-240005, paragraph 329 from the 2024 GRC. As system needs are identified, PSE will apply and refine the targeted electrification screening workflow using the best available system and customer data.

PSE recognizes that opportunities must be evaluated early enough to allow for customer outreach and implementation before a project's need date. At the same time, system conditions, customer participation, costs, and project timing can change over time. As a result, while the analysis presented through the ISP process provides a snapshot based on available information, PSE expects opportunities to be reassessed and refined as projects move toward implementation. This will be an important consideration as PSE works through the relationship between ISP approvals and the practical management of a dynamic utility system.

Katie Ware and Megan Larkin on behalf of Renewable Northwest and Climate Solutions, August 5, 2026 via isp@pse.com

I. INTRODUCTION

Renewable Northwest ("RNW") and Climate Solutions appreciate Puget Sound Energy's ("PSE" or "the Company") continued engagement with stakeholders during development of its 2027 Integrated System Plan ("ISP"). These comments seek clarification regarding the apparently inconsistent outcomes of RNW's July 23 discussion with PSE and the subsequent July 28 public Resource Planning Advisory Group ("RPAG") meeting. RNW requested the July 23 discussion to ensure that PSE fully understood the purpose and design of the recommended middle-ground reference case and left that meeting with the understanding that PSE had agreed to run the additional case. At the July 28 RPAG meeting, however, PSE stated that the recommendation would be evaluated only through sensitivity analysis. Because RNW devoted focused one-on-one time to clarifying the recommendation and believed that a shared understanding had been reached, we request that PSE clarify its intentions and explain the apparent change in approach.

In addition to following up on the middle-ground reference case, these comments provide additional feedback on the July RPAG materials, particularly the sequencing and scope of PSE's non-pipeline alternatives analysis.

II. FEEBACK

Follow-up on Reference Case C

During the July 23 meeting with PSE, we discussed our May and June RPAG feedback recommending that PSE develop an additional middle-ground reference case reflecting the statutory definition of “commercially available” in WAC 480-96-020(5). The intent was to create a more realistic baseline that would allow the model to select from the full suite of commercially available and reasonably anticipated resources—including multiple battery storage durations (at least 4-, 6-, and 8-hour storage), hybrid resource configurations, and supported volumes of biodiesel—while avoiding the abrupt 2045 gas retirement that creates a large capacity gap requiring extensive reliance on emerging technologies.

Our concern remains that neither existing reference case serves this purpose. Reference Case A was presented as the commercially available case, yet it excluded technologies that appear to meet the WAC definition of commercially available or reasonably anticipated within the ISP study period. Reference Case B broadens the resource set but does so by relying on technologies whose commercial deployment at scale remains highly uncertain. As a result, stakeholders are left comparing two bookends rather than evaluating what may be the most plausible pathway to a CETA-compliant portfolio.

During our July 23 discussion, PSE indicated that this middle-ground case could be modeled. We appreciated that response because we believe—and we noted during the call—it would provide a stronger analytical foundation for the subsequent scenario and sensitivity analysis, regardless of whether the resulting portfolio ultimately proved feasible.

During the July 28 RPAG meeting, however, PSE clarified that this analysis would instead be conducted only as a sensitivity. We appreciate PSE’s willingness to test these assumptions, but we continue to believe that the middle-ground case is most valuable as a reference case rather than a sensitivity. The purpose of the recommendation has always been to establish a more representative baseline against which subsequent scenarios and sensitivities can be evaluated, rather than testing those assumptions only after Reference Case B has already been established as the starting point for preferred portfolio development.

We are seeking clarification on PSE’s intentions for the reference case given the mixed messaging between our sideline July 23 discussion and the public-facing July 28 RPAG meeting. We maintain that proposing two significantly different reference cases as the only options to form the basis for a later preferred portfolio exposes the company to significant regulatory risk. RNW’s belief is shared by other members of the RPAG. Presenting only one viable proposed reference case greatly diminishes RPAG members’ ability to assess its veracity and will not be viewed favorably by the Commission.

Thank you for the ongoing dialogue with us about your concerns with the reference case and what you would like to see modeled.

As you acknowledged in your comments, PSE and RNW met on July 28 to discuss RNW’s feedback on the ISP analysis at RNW’s request. During that meeting, PSE committed to testing the *assumptions RNW requested above. PSE remains committed to evaluating those assumptions through sensitivity analysis and sharing the results with the RPAG.*

In our view, the reference case, as it has been established, appears to reflect most of what RNW is looking for, as it allowed the model to "select from the full suite of commercially available and reasonable anticipated resources" consistent with the WAC definition of "commercially available." RNW and PSE may have different perspectives on which resources are "reasonably anticipated" and which ones are more uncertain, and the anticipated timing of each. Still, PSE consulted with the RPAG in developing its emerging technology assumptions based on PSE's best estimates, and RPAG members were given an opportunity to comment. PSE is reluctant to change these assumptions embedded in the reference case at this time, but we are performing sensitivities based on RNW's request.

Feedback from the July RPAG Meeting

We appreciate PSE's effort to begin identifying opportunities for targeted electrification and other non-pipeline alternatives ("NPAs"). We also appreciate PSE's acknowledgment during the RPAG discussion that additional analysis may be warranted.

However, we are concerned that the current approach narrows the project universe before fully understanding the technical potential for NPAs across the gas system. The analysis first selected a small number of candidate projects and then performed detailed technical evaluation on those projects. This sequencing makes it difficult to understand whether the selected projects are actually representative of the broader opportunity.

We recommend reversing that process. PSE should first conduct a broader technical potential assessment to identify where NPAs are technically feasible across the gas system—including opportunities to avoid, defer, or reduce traditional gas investments. Once that technical potential is understood, PSE can then narrow the analysis to specific candidate projects using customer adoption, implementation complexity, cost-effectiveness, and other practical considerations. We view the DuPont analysis as a useful example of the type of project-specific analysis that should follow, rather than precede, the broader technical screening.

We are also concerned that several of the projects analyzed required conversion of very large numbers of customers before a pipeline investment could be avoided. While this may be informative as a boundary case, projects requiring thousands of customer conversions are unlikely to represent the most practical near-term opportunities. We encourage PSE to identify and evaluate projects with more modest customer counts where targeted electrification or other NPAs may have a more realistic chance of success and where lessons learned can be applied more broadly over time.

PSE appreciates the feedback and the recommendation to consider broader electrification across the gas system. PSE understands a broader technical potential assessment to mean evaluating where electrification or other NPAs may be technically feasible. However, technical feasibility alone does not demonstrate that an NPA can avoid, defer, or reduce a planned gas infrastructure *investment. PSE does not interpret the Electrification Potential Assessment requirement as requiring a systemwide technical feasibility assessment of all gas system assets. Rather, meaningful NPA opportunities are identified through specific system needs and planned investments.*

For this reason, PSE focused on known system needs rather than asset characteristics alone. Evaluating assets based solely on factors such as pipe age, material type, or system configuration would not necessarily identify actionable NPA opportunities, as many assets do not have an associated investment need within the planning horizon. In addition, many investments are driven by safety, integrity, reliability, or regulatory requirements that would not be avoided through electrification or other NPAs.

The assessment therefore focused on projects with the largest identified capital investments, including seven major system projects representing approximately $292 million in forecasted capital spending and the DuPont replacement program, currently estimated at approximately $72 million annually over five years. These projects provided the greatest opportunity to evaluate whether NPAs could produce meaningful cost avoidance or deferral benefits.

While several projects would require substantial customer participation to fully avoid the underlying investment, they were selected because of the magnitude of the system need and capital investment. PSE agrees that projects involving fewer customers may present practical near-term opportunities and will continue to evaluate projects of varying size and complexity for cost effective NPA opportunities as additional system needs are identified.

The assessment was not limited to major reinforcement and replacement projects. PSE also evaluated other categories of known system needs, including farm taps, inside regulator replacements, and low-pressure system upgrades.

PSE continues to identify and evaluate additional system needs for inclusion in the final Electrification Potential Assessment and NPA project inventory. As new system needs are identified and existing needs are refined, they will be evaluated for NPA opportunities and considered for inclusion in future assessments, as appropriate. Additional information will be included in the Integrated System Plan filing.

III. CONCLUSION

RNW and Climate Solutions thank PSE for its consideration of this feedback. We look forward to continued engagement in the RPAG process toward development of PSE's 2027 ISP.

2. Public feedback

Don Marsh on behalf of the Washington Clean Energy Coalition, June 19, 2026 via isp@pse.com

I have attached **Washington Clean Energy Coalition's feedback regarding PSE's May 28 and June 23 RPAG presentations.** Our detailed document attempts to provide reasonable numbers for a diversified clean portfolio that substantially eliminates GHG emissions by 2050, reduces risks posed by PSE's preferred portfolio, and moderates customer costs. It aligns with the goals of Washington laws such as the Climate Commitment Act, Clean Energy Transformation Act, and HB 1589 (whether or not I-2066 is upheld). Please include our document in the June 23 RPAG Feedback Report, since we are otherwise excluded from the RPAG planning process.

We feel that it does not benefit customers or your company to prevent us from participating in RPAG meetings or engaging with any PSE employee to answer our questions. However, if you find any significant errors or omissions in our document, we will consider corrections before we submit it to the UTC's ISP docket. If you do not respond by June 30, we will submit the document in its current form (or possibly with corrections from RPAG members).

We feel very passionate about a better solution for customers, the climate, and the rule of law. If we cannot engage with PSE, we are still able to take our case to the UTC, the legislature, our partner organizations, and national media. This could serve as an interesting case study in how citizens can productively participate in their energy future, even if their utility prefers to ignore them.

PSE note: Mr. Marsh provided this linked document as part of his feedback. PSE has reminded Mr. Marsh that we cannot comment on his "proposal" because our analysis is far from complete. As such, PSE cannot validate nor endorse the content in the submitted document but have provided a link in the interest of transparency. Below we respond to questions he asked on pages 16 and 17 of the linked document along with PSE's response.

1. Model a diversified clean portfolio as a true third reference case. Replace the disqualified single-resource Reference A with the diversified clean portfolio described here, or any reasonable variation of a portfolio without new gas or commercially unproven SMRs. Run it through the same chronological reliability and production-cost models as Reference B, considering impacts on both the gas and electric systems before any preferred portfolio is selected.

PSE is evaluating a range of resource assumptions through scenarios and sensitivities developed for the 2027 ISP, including sensitivities that test alternative technology availability, cost and build-limit assumptions. PSE does not plan to add a third reference case for this ISP cycle; the reference case provides a consistent analytical starting point, while sensitivities are the appropriate tool for testing how different clean-resource assumptions affect portfolio results. Results will be shared with the RPAG and documented in the ISP filing.

2. Model a high-electrification future as a matter of prudent planning. Test the electric capacity need under significant levels of electrification, not only the flat-gas forecast. Include commercial gas load, a reasonable low/mid/high adoption range like ours, and heat pumps that revert to electric resistance heating in cold weather. Customer-driven attrition is plausible under any legal regime, and modeling it violates nothing in I-2066.

PSE is modeling progressively higher electrification scenarios as part of the 2027 ISP, including multiple high-electrification futures that evaluate impacts to electric capacity needs and the gas system. Results will be shared with the RPAG later this summer and documented in the ISP filing.

3. Publish symmetric, comparable assumptions. Give every clean resource the same paper trail the gas peakers get. For each non-gas resource, publish the values that determine how much winter capacity it is credited with (accreditation, ELCC, deliverability, duration, and enrollment). Publish the biofuel-conversion assumption behind the 5,042 MW of peakers, which is hard to square with PSE's own finding that renewable-fuel supply is limited to 4–5% of conventional fuel (slide 44). Also publish the demand-side growth embedded in the reference cases, along with PSE's ELCC scaling curves that show how a resource's capacity credit falls as more of it is added.

PSE's assumptions for resources have been presented and discussed with the RPAG on multiple occasions. For example, winter incremental capacity was detailed on slide 43 of the Sept. 30, 2025 RPAG meeting. Much of the requested information above will be presented at future RPAG meetings and/or included in the detailed analysis and work papers submitted as part of the ISP – consistent with WUTC rules.

4. Compare the combined economics transparently. Produce a combined-utility revenue-requirement comparison that contrasts the CCA allowances the gas plan would pay with the customer bill savings electrification delivers. Allowances should be priced at the ceiling for all peaker dispatch, matching how PSE's reference case already prices CCA across both its gas and electric systems (slide 87). Include a stranded-cost scenario assuming the 2045 biofuel conversion fails, and disclose the assumed siting and permitting timelines for the roughly twenty peaker units Reference B requires. In its June 23 RPAG update (slides 24-25), PSE says ~$1.5B will be needed to integrate 3,000 MW of clean resources. PSE should compare that with the local-network-upgrade cost to interconnect peaker units and provide fuel-assurance investments to keep them firm when the gas system itself is stressed (on-site backup fuel storage, dual-fuel capability, or firm pipeline contracts). As the January 2024 Jackson Prairie outage showed, a gas peaker is only as firm as the delivery system behind it.

PSE appreciates the request for transparent comparison of portfolio costs and customer impacts. The 2027 ISP will evaluate resource portfolios using consistent assumptions for fuel costs, emissions compliance costs, capital costs, transmission and distribution impacts, reliability, and customer demand. CCA compliance costs, electrification impacts, and avoided gas-system costs will be reflected in the appropriate scenario, sensitivity and cost analyses, with supporting assumptions documented in the ISP workpapers. PSE is also evaluating resource adequacy, siting, permitting, fuel availability, and transmission constraints as part of portfolio development; however, the ISP is a planning analysis and does not make project-specific siting, permitting or procurement commitments. These topics will be addressed in future RPAG discussions and documented in the ISP filing.

5. Account for the net distribution cost of electrification. Model the transformer, feeder, and service upgrades a high-electrification scenario requires. Account for the gas distribution investment avoided as customers leave gas and the non-wires value of distributed storage and managed load. PSE's June 23 distribution reference case already tests substation battery co-location as a non-wires alternative, but it pre-screens just 10 candidate substations and assumes only 3 of them succeed (a 30% rate). PSE should disclose the criteria that excluded the other substations and justify the 30% success rate, which looks conservative as distributed-storage technology matures (June 23 RPAG, slides 14–18).

PSE will evaluate incremental electric distribution impacts associated with higher electrification scenarios as part of the 2027 ISP, including potential transformer, feeder and service-level needs where sufficient planning information is available. The ISP will also consider avoided gas distribution investment, managed load and distributed storage as part of the broader assessment of electrification and non-wires alternatives. The June 23 distribution analysis was intended as an initial screening of candidate substations, not a final determination of non-wires alternative potential. The 30% success rate was an assumption based on past experience and external sources, as discussed in the June 23, 2026 feedback report. PSE will continue refining the screening criteria, success assumptions and cost inputs as distribution planning data improves and will document the methodology and key assumptions in the ISP filing or supporting workpapers.

6. Plan an equitable gas transition. Prepare a geographically targeted electrification and cost-allocation plan that protects renters and low-income customers from a death-spiral cost shift and specifies how stranded gas-distribution costs are recovered.

PSE presented the initial results of its first geographically targeted electrification potential assessment during the July 28, 2026 RPAG meeting. PSE will further describe the scenario analysis which models increasing electrification during the August 25, 2026 RPAG meeting. This work is ongoing.

7. Treat transmission limits as variables, not constants. Assess dynamic line ratings, advanced reconductoring, and power-flow control on the WA East and Montana paths, as FERC Order 1920 contemplates, and disclose how much of PSE's 746 MW of Colstrip transmission rights and its prospective ~750 MW (up to 25%) North Plains Connector share is committed to Reference B's own builds versus available for winter weighted Montana and North Dakota wind.

The reference and scenario cases include all of PSE's existing transmission capacity, including existing rights on the Colstrip Transmission System. PSE will evaluate variations in regional transmission capacity, including investment in the North Plains Connector project, through analysis of several transmission sensitivities. This work is ongoing.

In several sensitivities, transmission capacity would be made available through known projects being developed by third parties (i.e. GERP 1.0 and 2.0 or North Plains Connector), the scope of which is outside of PSE's control. For sensitivities which contemplate projects that are more conceptual in nature, the analysis models capacity without specifying the technology enabling that *capacity. It is important to note that GETs such as dynamic line ratings and advanced conductors are well suited for thermal constraints on the system but are not typically viable for other types of constraints, such as voltage or stability constraints, which more commonly occur when transferring large amounts of power over long distances. Their application on the regional transmission system is limited in scope.*

8. Justify the SMR against geothermal under the lowest reasonable cost and risk standard. Publish the ELCC, capacity-factor, lifetime, fuel, and O&M assumptions behind the nuclear and geothermal screens on slides 81, 88, and 89, and model a geothermal-first portfolio that replaces the 300 MW SMR before any nuclear commitment is made.

PSE is modeling multiple emerging technology sensitivities, including lower-cost advanced geothermal and cases that vary reliance on emerging technologies. These sensitivities will help assess the relative cost, risk and portfolio value of resources such as advanced geothermal and small modular reactors before any preferred portfolio is identified. Results will be shared during the Aug. 25, 2026 RPAG meeting, and detailed assumptions will be included with the ISP filing.

9. Model customer attrition from gas with both exits open. Replace the constant customer-count assumption with rate-driven attrition scenarios that include defection to unregulated fuels such as propane. Report the resulting rate, revenue, and emissions leakage effects on the gas system.

PSE is modeling rate-driven attrition through the iterative analysis presented during the Feb. 26, 2026 RPAG meeting.

Don Marsh on behalf of the Washington Clean Energy Coalition, July 24, 2026 via isp@pse.com

Since we are not allowed to speak at RPAG meetings, I'm forwarding questions that we wish to have answered **during the July 27 RPAG meeting.** We are hoping to hear discussion among RPAG members regarding these questions during the meeting, but since some require detailed responses, please include these questions in the Feedback Report along with your responses.

Washington Clean Energy Coalition submits the following questions for discussion at PSE's July 27 RPAG meeting. We are submitting these questions in advance of the meeting so they can be discussed during the meeting (since we are excluded from asking questions while the meeting is in progress).

Slide 51: The 34% drop in transmission line losses (7.58% to 5%) is a big deal! We were very happy to see this adjustment. If system peaks are reduced by 2.7%, this is likely to reduce costs for customers, reduce impact on the environment, and make transmission of clean energy from outside our region more efficient.

To make sure we understood the justification for reduced line losses, we looked at PSE's EIA 861 and FERC Form 1 reports. Loss rate below is losses ÷ (retail sales + company use + losses) — i.e., losses as a share of energy input to serve PSE's own load.

Year	Reported losses (MWh)	Retail sales (MWh)	Loss rate	Source
2020	1,588,951	20,088,222	7.32%	EIA-861
2021	1,459,849	21,036,614	6.48%	EIA-861
2022	1,343,941	21,613,415	5.95%	EIA-861
2023	1,090,701	21,165,762	4.90%	EIA-861
2024	998,350	21,161,605	4.49%	EIA-861=FERC Form 1 p.401a

The trend of declining losses is clear. Is it due to more accurate tracking of electricity through AMI investments?

Note: PSE has not validated the above information provided by the commenter. PSE is continuing to look into the cause of the line loss reduction.

Is 5% a reasonable loss rate during a system peak? Probably not. Resistive losses rise with the square of loading (I^2R), so the loss percentage during a winter peak hour is always higher than the annual average. The standard regulatory reference is Lazar & Baldwin (RAP, 2011)[1], which reports peak-hour average losses of 10–15% and marginal losses of 20%+ on systems averaging 6–10%. Scaled to PSE's ~5% average and ~55% load factor, peak-hour total losses pencil out to roughly 6–7%, so applying a flat 5% average factor to the winter peak may understate the generation-level peak requirement by ~1–1.5% — on the order of 50–80 MW today and 120–170 MW under S2–S4 peaks.

Thank you for the feedback. PSE plans to use 5% for line loss for this ISP but will look into this further for future ISP cycles.

Slide 10: The Reference B portfolio now includes "long-duration storage" according to this slide. We are happy to see this! As our feedback for the June 23 RPAG meeting (which PSE has not included in the Feedback Report or shared with RPAG members) stated, 100-hour iron-air batteries appear to be a good match for the 100-hour *dunkelflaute* (German for "dark lull" or "dark doldrums") event that stresses both Reference A and B portfolios. Is PSE now including some amount of 100-hour storage in Reference B? Would this not help the Reference A portfolio as well?

PSE has not changed the Reference B portfolio as previously presented. Slide 10 indicates that long-duration energy storage was included as an available resource option for the model to select, along with other candidate resources, but the model did not select long-duration storage in the Reference B portfolio under the assumptions used for that case. PSE is testing additional sensitivities related to emerging technologies, storage availability, timing and cost assumptions to better understand how different treatment of long-duration storage could affect portfolio results.

[1] Lazar, J. & Baldwin, X., "Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements," Regulatory Assistance Project, Aug. 2011 (peak-hour vs. average vs. marginal losses); figures also reproduced in EPA/NACAA "Menu of Options," Ch. 10 — https://www.raponline.org/knowledge-center/valuing-the-contribution-of-energy-efficiency-to-avoided-marginal-line-losses-and-reserve-requirements/

Results from those sensitivities will be shared during upcoming RPAG discussions and documented in the ISP filing.

To help us understand why Reference B is the "realistic" portfolio, please tell us:

• What capital cost ($/kW), fixed O&M, earliest in-service year, and cumulative MW limit **was AURORA given**, and what did the model select each year?

PSE has already shared relevant emerging technology assumptions. For example, first year available and capital costs were included on slide 81 of the presentation. Resources were not limited. Technology assumptions are discussed again during the Aug. 25, 2026 RPAG meeting.

• We especially need to know what battery costs and in-service years PSE is assuming now. What mix of short- and long-duration storage is optimal?

Please see slide 81 of the presentation referenced above.

• Given the federal withdrawal of the OCS from wind leasing and the absence of any Washington lease area, what probability and in-service date does PSE assign to offshore wind, and what replaces it if it does not materialize?

Please see slide 81 of the May 28, 2026 RPAG presentation for the offshore wind assumptions used in the modeling. Offshore wind was available as a generic resource option in the model but was not selected in the Reference B portfolio. Because the ISP evaluates generic resource options for long-term planning purposes, the model does not assign a project-specific probability or identify a replacement resource for an option that is not selected. Actual resource acquisition decisions, including assessment of availability, timing, costs, permitting and siting risks, occur through separate acquisition and procurement processes.

• Will PSE commit to publishing a Reference B stress sensitivity (delayed availability + first-of-a-kind costs) so stakeholders can see how much of the plan's feasibility rests on these bets?

The Reference Case is intended to serve as an analytical starting point for comparing scenarios and sensitivities, not as a preferred portfolio or resource acquisition plan. PSE is not committing to any procurement strategy through the ISP analysis. PSE is testing multiple sensitivities related to emerging technologies, resource availability and cost assumptions to better understand how changes in these assumptions affect portfolio results. As stated previously, PSE uses n^{th}-of-a-kind assumptions for modeled emerging resources, meaning those resources are assumed to have reached a higher degree of commercial availability for planning purposes. Results from these sensitivities will be shared during upcoming RPAG discussions and documented in the ISP filing.

Slide 10 says "Transmission limits maxed out wind and solar." This appears to be the primary constraint that cause Reference A to lean so heavily on 4-hour batteries that it broke. Yet new transmission — BPA network upgrades, third-party lines, upgraded interties — is a well-known solution, with known engineering, known (if slow) permitting pathways, and regional precedent. It is arguably a safer bet than first-of-a-kind nuclear. Treating import capability as immutable while opening the resource set to emerging technologies is an asymmetric assumption that will incur risks for customers, schedules, and resource adequacy.

Also, because line losses appear to be less than we previously thought, transmission competes more directly with other resources.

• Please disclose the capital cost, fixed O&M, and earliest in-service year of various kinds of transmission investments.

For the original Reference A to solve, PSE relaxed the transmission constraints and the build limits for 4-hour batteries, wind and solar. The model relies heavily on 4-hour batteries as the primary peak capacity resource, since wind and solar contribute only marginally to peak capacity needs.

The total regional transmission capacity additions were presented to the RPAG at the May 28, 2026 meeting. These additions account for capacity from the Plans of Service identified in the last several BPA cluster studies, including their GERP 1.0 and 2.0 projects, which provide capacity for the delivery of Transmission Service Requests into the Puget Sound Area. It was assumed that capacity for two upgrades included in BPA's GERP 1.0 projects would be available in 2028 and 2030. BPA's GERP 2.0 projects were assumed to be in service by 2035. PSE applied the BPA Network Rate with an assumed growth rate of 5.57% per year to this capacity. Additional assumptions include the reallocation of PSE's existing Mid-C capacity, utilization of unused capacity from PSE's Lower Snake River project, and Montana capacity for wind facilities under contract, also made available under BPA's Network Rate. The final capital cost for on-system transmission investment is currently being evaluated for each scenario. Evaluation of additional regional transmission investments that are currently conceptual in nature will occur in the transmission sensitivity analysis.

Slides 56-61: We don't know how these S1-S4 scenarios will be used to shape PSE's final ISP proposal, but there is a very large gap between S1 (735,000 gas customers in 2045; 6,030 MW electric peak) and S2 (437 customers; 10,617 MW). Just as we need a middle reference case on the source side between Reference A and B, it would be more realistic to have an intermediate reference case on the demand side – perhaps something like a 30-50% rate of departure from gas.

Although we could wish for more, this is a practical response to the reality that the 2025 federal law upended adoption assumptions: the Section 25C credit (up to $2,000 for heat pumps) no longer applies for units placed in service after December 31, 2025, and the Section 30D clean-vehicle credit was discontinued after September 30, 2025[2]. Any adoption or incentive-cost calibration done before mid-2025 (including the Guidehouse EV forecast presented June 2025 and the EPA's incentive sizing) is now outdated and probably too optimistic.

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[2] [11] IRS, "FAQs for modification of sections 25C, 25D, 25E, 30C, 30D… under Public Law 119-21 (OBBB)" (§30D ends after Sept. 30, 2025; §25C after Dec. 31, 2025) — https://www.irs.gov/newsroom/faqs-for-modification-of-sections-25c-25d-25e-30c-30d-45l-45w-and-179d-under-public-law-119-21-139-stat-72-july-4-2025-commonly-known-as-the-one-big-beautiful-bill-obbb

PSE will present the scenario results during the August and September RPAG meetings, including analysis of higher electrification futures and associated electric and gas system impacts. The current demand scenarios were developed to test a range of potential pathways for the 2027 ISP, and PSE is continuing to evaluate recent policy and market changes as part of its broader planning assumptions. While there is not sufficient time to revise the demand scenarios for this ISP cycle, PSE is tracking this feedback and will consider whether additional intermediate demand scenarios should be evaluated in future ISP cycles.

Don Marsh on behalf of the Washington Clean Energy Coalition, July 28, 2026 via public comment opportunity

I'm Don Marsh speaking on behalf of the Washington Clean Energy Coalition, an all-volunteer nonprofit comprised of many individuals and organizations who participated in previous advisory groups for more than 10 years before PSE refused to allow us to participate in these meetings. We partner with organizations such as Sierra Club, Third Act 350.org chapters in multiple cities, climate action, Bainbridge, Vashon climate action team and others. We are collectively dismayed and opposed to the ISP process PSE is conducting. The problem began in May when PSSE compared two reference base cases. Reference A with a ridiculous amount of 4-hour batteries being stretch stretched way beyond their capacities and reference B which includes more gas peaker plant capacity than all other new resources combined wind, solar, nuclear and geothermal. When reference A failed to meet demand, PSE put all its bag eggs in the gas basket. PSE says “don't worry, we will study all kinds of sensitivities to develop our final preferred portfolio”. The problem is that you can't get to a holistic clean portfolio by starting with a gas-heavy plan and studying one incremental change at a time. In isolation, each sensitivity might fail just like the battery solution in reference A. Although we may end up with a better portfolio than reference B, the final portfolio is likely to exceed emission targets in the Climate Commitment Act to the detriment of the environment and customers’ wallets. We didn't want to lodge a theoretical complaint. So, we developed a detailed alternative portfolio that uses a diverse collection of 100-hour batteries, vehicle-to- grid, virtual power plants, and geothermal energy to produce a portfolio that doesn't need peaker plants or a risky nuclear plant. According to our calculations, this would meet Washington's clean energy goals, both CETA and CCA, without costing customers any more than the reference B plan. In fact, our offering is exactly reference B, but substituting clean resources for PSE's gas plants and nuclear plant. We submitted this feedback to PSSE before the June RPAG meeting and expressly asked that it be shared with RPAG members. PSE thanked us for our submission and said it would be valuable to the process, but the company did not share it with our PAG members or include any mention in the feedback report. This has severely harmed our trust in the process. RPAG members can read our report at our website wacleanergy.org. That's wacleanenergy.org. We insist that PSSE study a real clean energy reference case rather than a straw man designed to fail. We are committed to making this a national issue if that is necessary to protect PSE's customers and the well-being of future generations. Thank you.

Thank you for your comments. PSE has since included the shared report in this document and has responded above to the specific questions provided in the written feedback. PSE appreciates the *continued engagement and will consider this feedback, along with other interested party input, as it continues developing scenarios, sensitivities and portfolio analysis for the 2027 ISP.*

Becky Crompton, August 9, 2026 via isp@pse.com

Puget Sound Energy’s (PSE) proposed plans to construct new methane gas-fired power plants are unacceptable. Washington residents have consistently demanded affordable, zero-carbon energy—a need made painfully urgent by the climate-driven wildfires that have devastated communities like Spokane and destroyed hundreds of homes across our state. PSE’s strategy relies on expensive fossil fuel infrastructure rather than committing to the work of scaling renewable energy. We need accelerated investment in solar (residential, commercial, and utility-scale), wind, geothermal, transmission, and diverse energy storage solutions like thermal, pumped hydro, and battery systems. Furthermore, rapidly maturing technologies—such as long-duration storage, SMRs, fusion, and next-generation solar—risk turning new peaker plants into stranded assets, leaving ratepayers to foot the bill. On the demand side, PSE must follow the lead of proactive utilities by implementing aggressive demand-management programs. This includes: - Partnering with high-load users to co-locate thermal and electric batteries - Scaling Virtual Power Plants (VPPs) using residential and small-business batteries - Promoting heat-pump water heaters, HVAC retrofits, LEDs, and weatherization - Expanding Time-of-Use (TOU) rates to flatten peak demand These programs cannot remain hidden on PSE's website; they must be actively promoted on billing statements, social media, and local broadcast channels to drive rapid adoption. Additionally, high-demand facilities like data centers should be required to provide their own 24/7 zero-emission power or wait in line until PSE can supply clean energy. PSE’s mandate as a public utility is to serve the state’s residents, not maximize corporate returns at the expense of our climate and wallets.

Thank you for your feedback. PSE is evaluating a wide range of resources, scenarios and sensitivities as part of the 2027 Integrated System Plan, including renewable generation, storage, transmission, emerging technologies, demand-side programs and increasing electrification. PSE will continue to assess resource options against reliability, affordability, customer impact, emissions reduction and regulatory requirements, and we appreciate your input as this analysis continues.