Puget Sound Energy Resource Planning Advisory Group (RPAG) meeting

Meeting Summary

Tuesday, March 12, 2024 | 12 – 3 p.m.

Meeting purpose and topics

Below are the meeting topics of this Resource Planning Advisory Group (RPAG) meeting:

- Present public feedback summaries from Jan. 17, 2024 RPAG meeting
- Share and discuss resource adequacy results
- Share and discuss social cost of greenhouse gas (SCGHG) modeling

Time	Agenda Item	Presenter
12:00 p.m. – 12:05 p.m. 5 min	Introduction and agenda review • Safety moment • Introductions • Agenda review and meeting purpose	**Sophie Glass,** Facilitator, Triangle Associates
12:05 p.m. – 12:15 p.m. 10 min	Feedback summary • Public and RPAG feedback from Jan. 17, 2024 RPAG meeting	**Phillip Popoff,** Director, Resource Planning Analytics, PSE
12:15 p.m. – 1:30 p.m. 75 min	Resource adequacy results • Background on resource adequacy • Changes in the 2025 IRP • Results • Q&A	**Joe Hooker,** Director, Energy + Environmental Economics (E3) **Arne Olson**, Senior Partner, E3
1:30 p.m. -1:40 p.m. 10 min	Break	**All**
1:40 p.m. – 2:50 p.m. 70 min	Social Cost of greenhouse gas modeling • Methodology • Costs • Results • Discussion	**Elizabeth Hossner,** Manager, Resource Planning and Analysis, PSE
2:50 p.m. - 3:00 p.m. 10 min	Next steps and public comment opportunity	**Sophie Glass,** Facilitator, Triangle Associates

Time	Agenda Item	Presenter
3:00 p.m.	Adjourn	**Sophie Glass,** Facilitator, Triangle Associates

The full meeting materials, including agenda, and presentation are available online under the March 12, 2024 meeting heading on the IRP website.

Action items

Below is a summary of actions from the March 12, 2024 RPAG meeting.

What	Who	When
Share available ELCC saturation curves for additional resources with RPAG	PSE	Sent to RPAG on 4/9
Research PacificCorp's SCGHG methodology for similarities and differences	PSE	In progress
Share levelized capacity cost formula from 2023 EPR with RPAG members	PSE	PSE is providing an example workbook on the IRP website (23EPR_Levelized_Capacity_Cost_4hr_BESS.xlsx) with calculations for the levelized capacity cost of a 4-hour lithium-ion battery, specifically the highlighted lines 444-451.

Introduction and agenda review

Sophie Glass, facilitator, provided an overview of the agenda for the meeting and welcomed RPAG members (see "RPAG members in attendance" on the last page for a list of RPAG members who joined this meeting). Sophie shared several facilitator requests for the meeting. She highlighted the importance of defining acronyms and being mindful of the amount of space RPAG members take up in discussion, encouraging members who are quiet to speak up and for those who participate more to step back.

Feedback summary

Philip Popoff, PSE, summarized the feedback received since the January 17, 2024 RPAG meeting. PSE heard public feedback on a range of topics, including a request to spell out acronyms, public participation in RPAG meetings, and PSE electric reliability concerns. RPAG feedback included questions from UTC staff about the EV forecast and resource adequacy modeling.

Resource adequacy results

Sophie Glass, facilitator, shared that this section of the meeting will be at the inform and consult levels on the International Association of Public Participation (IAP2) spectrum.

Joe Hooker, E3, and Arne Olson, E3, provided background on resource adequacy (RA) and E3's role. E3 has developed a proprietary loss of load probability model, RECAP, to perform resource adequacy studies. E3 has worked with PSE in the past and performed a resource adequacy study for PSE's 2023 Electric Progress Report (EPR). E3's analysis quantifies key inputs for characterizing RA needs for the system by calculating a Planning Reserve Margin (PRM) and Effective Load Carrying Capability (ELCC). A PRM indicates the total amount of capacity needed to satisfy the reliability target. E3 uses a 5% loss of load probability (LOLP) and 0.1 loss of load energy (LOLE) as their reliability targets for modeling purposes. This is measured as a percentage above PSE's expected peak load and indicates how many megawatts are needed in total. An ELCC is the equivalent perfect capacity that a resource provides in meeting PSE's reliability target. This is measured as a percent of a nameplate capacity and indicates how many megawatts are provided by each resource. E3 looks at hundreds of simulation years across three climate models to condense resource adequacy characteristics down to three metrics. These analyses help PSE know which types of resources to add in the future.

E3 used a table to illustrate the key changes in the 2025 IRP as compared to the 2023 EPR. E3 highlighted the inclusion of electric vehicles (EVs) in the 2025 IRP, which causes a meaningful increase in resource needs. Additionally, the 2025 IRP excludes balancing reserves to align with the Western Resource Adequacy Program (WRAP), which causes a slight drop in the operation reserve. Thirdly, the Pacific Gas & Electric Company (PG&E) exchange contract has been canceled. Previously, this required PSE to export to PG&E in the summer to receive imports in the winter. Regarding market availability, E3 changed the regional market characterization resulting in all purchase curtailments in the summer, which changes the timing of loss of load events. There is a reduced resource need for mid-C hydro units due to an increased capacity and increased flexibility in the model. Lastly, demand response in the 2025 IRP now includes both winter (119 megawatts) and summer (149 megawatts).

E3 used two graphs illustrating a typical peak load day across thirty simulated years for the winter and summer to share the impact of electric vehicles on peak energy demand. The graphs demonstrate that in the winter, the addition of EV demand increases energy demand in the evening more than in the morning. However, in the summer, the addition of EV demand increases peak demand and shifts the overall peak back by one hour.

E3 shared the change in the timing of the loss of load events. In the 2025 IRP, winter loss of load events are less concentrated in morning periods for two reasons. First, the addition of EVs causes a higher demand in the evening. Second, the reduction in market purchase curtailments means that there are no longer deep market purchase curtailments in the morning. Together these two changes result in a shorter length of loss of load events. In the summer for the 2025 IRP, the loss of events shifts slightly later in the day due to the addition of electric vehicles. The length of the loss of load events is similar to the 2023 EPR.

E3 shared the 2025 IRP results regarding the LOLE runs. In a comparison of the PRM between the 2025 IRP and the 2023 EPR, E3 showed the median peak load has increased. This increase in both winter and summer is driven primarily by EV load, especially in the summer. Additionally, the overall capacity shortage increases to approximately 3,000 megawatts in both seasons. Lastly, the PRM is approximately 4 percent lower in the 2025 IRP due to reduced load variability across weather years and a slightly lower operating reserve requirement. E3 also noted that the winter shortfall increases and summer decreases for the capacity short versus target. This is due in part to the removal of the PG&E exchange. E3 used graphs to illustrate the resource need and available resources in winter and summer for the 2023 EPR and 2025 IRP. These graphs help illustrate the 3,000 megawatts of total resources PSE is short that need to be filled in. E3 also modeled via graph the 2031 and 2036 IRP which demonstrates the projected growth in need, partly due to EVs. The capacity shortfall grows from 2031 to 2036 from 3,000 to 4,500 megawatts.

E3 shared the ELCC for renewable resources including wind and solar resources. The ELCC quantifies how much potential candidate resources can contribute to filling the resource need. Results are similar across the 2023 EPR and 2025 IRP. One notable difference is that solar ELCC decreases when moving geographically from west to east.

E3 shared the ELCCs for energy storage and demand response, highlighting changes across the 2023 ERP and 2025 IRP. For storage, the ELCC results for the 2025 IRP are very similar to those from the 2023 EPR. One notable difference is that PSE is currently considering a long-duration (100-hour) iron-air battery resource. There are many differences in the demand response ELCCs. One key difference is in the 2025 IRP the ELCC is higher in the winter and lower in the summer. This is caused by shorter winter loss of load events, making it easier for demand response resources to meet winter needs. For summer, there is the opposite change. The addition of demand response in the base portfolio reduces the ELCC for subsequent additions of demand response for the summer.

E3 shared ELCC saturation curves for Washington (WA) wind in the winter and solar in the summer to illustrate differences between the 2025 IRP and 2023 EPR. Overall ELCC results are similar. E3 highlighted that PSE already has approximately 1,200 megawatts of existing WA wind, which E3 estimates has an average ELCC of 24%. The ELCC of incremental additions shown in E3’s graphs is lower due to the ELCC saturation effect. For solar, there is a slight decline for the 2025 IRP because the timing of the loss of load events shifts back one hour due to the increase of EVs.

E3 shared ELCC saturation curves for four-hour Li-ion batteries for the 2025 IRP and 2023 EPR in the summer and winter. Overall, the ELCCs across both analyses are similar. E3 highlighted that the ELCC for storage in the winter is slightly higher due to the shorter duration of loss of load events.

Results from the 2025 IRP for the LOLE (0.1) and LOLP (0.5) for the PRM are very similar. These are close enough that they will not make a difference in the portfolio analysis. PSE selected the LOLE to be closer aligned to the WRAP methodology.

There are only minor differences when comparing the Washington wind and solar LOLE and LOLP across the 2025 IRP and 2023 EPR. Energy storage modeling based on the four-hour Li-Ion battery similarly has only minor differences across the IRP and EPR.

E3 finished their presentation by summarizing six key takeaways.

1. The planning reserve margin is quantified at 21-24% for the IRP depending on the model year and season.
2. In analyzing PSE's energy shortfall E3 found that PSE needs 3,000 megawatts of additional perfect capacity in both seasons for 2031. The addition of electric vehicles in the load forecast and the removal of the PG&E exchange are the two biggest factors in PSE's energy shortfall.
3. Compared with the 2023 EPR, loss of load events are more concentrated in the evening in the winter, and in the summer loss of load events shift back by one hour.
4. The ELCC of renewable resources is like those quantified for the 2023 EPR.
5. The ELCC of storage and demand response resources increased in winter when compared to the 2023 EPR.
6. Neither the 0.1 LOLE nor the 5% LOLP reliability targets result in large differences in PRM or ELCC values for PSE's system.

E3 and PSE responded to RPAG member questions on resource adequacy.

- RPAG member: Could you clarify the difference in approach between the portfolio model and resource adequacy analysis regarding the inclusion of EV loads?
  - PSE response: We included EVs in the portfolio model but not the resource adequacy analysis. We applied the PRM to the higher load.
- RPAG member: Regarding demand response for the 2025 IRP, where did the megawatt nameplate calculation come from? How did you select 149 megawatts for the summer nameplate and 119 megawatts for the winter nameplate?
  - PSE response: These are from new demand response contracts. PSE will follow up in the feedback report (see response #2).

- RPAG member: How was the load shape for the EV forecast created? What is the basis of the EV forecast?
  - PSE response: The EV forecast comes from external consultants, Guidehouse, who provide weekend and weekday load shapes per month and year from industry data and assumptions of vehicle adoptions in PSE's service area.
- RPAG member: Can we have access to the Guidehouse study?
  - PSE response: Guidehouse will be presenting to RPAG members at the April 17, 2024 meeting.
- RPAG member: Are the charts for the change in timing of loss-of-load events to scale?
  - E3 response: E3 believes they are designed to scale but will follow up to confirm. One reason there can be a decrease in unserved energy is the number of total years for loss of load events (see response #3in the Feedback Report).
- RPAG member: I noticed the shortness in the duration of morning events for this planning cycle. Are there also changes to multi-day loss of load events in this cycle?
  - E3 response: Now that the region is meeting the overall reliability target, E3 no longer sees multiday regional shortages. The system is tuned to meet the reliability target by adding perfect capacity to PSE's system. During the tuning, the duration of events is short. Short-duration resources start with a high ELCC, but the overall portfolio still requires long-duration resources to fill in.
  - PSE response: PSE is concerned with the implications of using shorter-term duration storage during extreme weather events. PSE will be mindful of doing a back-end analysis of the IRP portfolio to ensure PSE has enough off-peak firm energy to charge batteries.
- RPAG member: Why did PSE remove the PG&E exchange?
  - PSE response: PSE gave PG&E notice that they are canceling the contract because PSE no longer has surplus capacity in the summer to export.
- RPAG member: In the charts comparing the PRM between the EPR and IRP, is the 3,000-megawatt capacity shortfall for the model year 2031?
  - E3 response: Yes, that is correct.
- RPAG member: Regarding storage and demand response resource ELCCs, has PSE considered hybrid systems with solar and storage?
  - E3 response: Yes, it is not included in our presentation, but we are modeling wind plus storage, solar plus storage, and wind plus solar plus storage. The ELCC for a combined resource is similar to the ELCC for standalone resources that are the sum of its parts.
- RPAG member: Could you expand on the divergence between a 4-hour demand response resource and a 4-hour Li-ion battery?

  - E3 response: Two factors impact this. First, the demand response does not provide the same resource capacity as battery storage. Additionally, E3 assumed battery storage can provide operating reserves to the system in their analysis.
- RPAG member: Why is the PRM so high for the 2025 LOLE vs LOLP results?
  - E3 response: E3 is modeling thirty years of future climate data. This year-to-year variability in load increases the PRM. Additionally, PSE has approximately a 7% reserve operating requirement. Lastly, PSE has a convention to count the PRM of existing mid-C and thermal resources based on nameplate capacity. This slightly increases the PRM to account for differences between the nameplate and PRM.
- RPAG member: Are the saturation curves for additional resources available?
  - E3 response: We have ELCC saturation curves for all the resources.
  - PSE response: PSE will follow up after the meeting to send the saturation curves.

Social cost of greenhouse gas modeling

Sophie Glass, facilitator, shared that this section of the meeting will be at the consult and involve levels on the International Association of Public Participation (IAP2) spectrum.

Elizabeth Hossner, PSE provided an overview of the social cost of greenhouse gases (SCGHG) methodology as required by the Clean Energy Transformation Act (CETA). Under this requirement, PSE has modeled greenhouse gas as a cost adder when making resource decisions for the IRP. However, there is the possibility to also model greenhouse gases as a dispatch cost. PSE recommends maintaining greenhouse gases as an externality to not inappropriately influence dispatch. In running scenarios with SCGHG in dispatch, PSE has found that the results are broadly similar to the selection of capacity resources changing.

PSE detailed how SCGHG is modeled as a cost adder. When applying the SCGHG as a cost adder in thermal plants, the SCGHG cost is included in the value reporting for the resources Long Term Capacity Expansion model run, but the emission costs are not included in the dispatch. When applying the SCGHG to unspecified market purchases, PSE uses 0.473 metric tons of CO^2 per megawatt-hour as the emission rate per CETA requirements. The SCGHG is accounted for post-economic dispatch to evaluate competing resource portfolios as they would function in the real world. Allowing dynamic changes to the model based on dispatch was an update in the 2023 Progress Report that did not exist for the 2021 IRP.

To calculate total costs for making intermediate and long-term resource decisions, direct costs and externality costs are added together. Direct costs are comprised of what drives operation such as plant costs, operations and maintenance, fuel, and variable costs. These costs are paid for by PSE and are reflected in customers' bills. Externality costs are the values that do not affect operations and are costs to society. This is a calculation of the tons of pollution including upstream emissions times the SCGHG based on a dollar-per-ton rate from the UTC. The

SCGHG is not included in the dispatch costs because SCGHG is not a binding policy, or a cost charged to customers like carbon taxes. For example, modeling SCGHG as a cost adder provides an economic disincentive for building thermal plants without artificially increasing the price of electricity for ratepayers. Including the SCGHG in dispatch would risk making decisions that do not reflect real-life operations.

PSE received feedback that the SCGHG should be included in dispatch costs for the long-term capacity expansion when making resource decisions. In this alternative methodology, SCGHG is calculated as a carbon cost to the plant. This means the SCGHG is included in the direct costs under dispatch costs, which change the operations of the resource.

There are two iterations in the modeling to apply the SCGHG in the portfolio. First, is the Long-Term Capacity Expansion where SCGHG is included alongside generic renewables and generic non-renewables. Then PSE runs the Hourly Dispatch Run where the SCGHG is removed to calculate the final portfolio dispatch cost of the plants.

PSE shared data from the 2021 IRP and 2023 EPR to illustrate how changing the methodology for modeling the SCGHG impacts the levelized cost of capacity measured in dollars per kilowatt per year. In both reports, PSE needs to create portfolios that meet CETA requirements of providing 100% renewable or non-emitting electricity by 2045. In the 2021 IRP, PSE found that the levelized cost of capacity decreases when SCGHG is modeled as a dispatch cost, resulting in a model that will favor peakers over demand response (DR) and battery energy storage systems (BESS).

Additionally, the levelized cost of energy decreases for peakers, but these resources are added for their capacity value, not their energy production. Overall, modeling SCGHG as a dispatch cost changes the resources dispatch and does not reflect the reality of operation. This can make the plant look more expensive to dispatch than it is and can result in suboptimal decision-making. In the 2023 EPR, where the SCGHG was modeled as dynamically changing in the reference case, PSE found that the methodology choice impacted the distribution of the capacity of resources. Overall PSE found that the dispatch methodology resulted in more natural gas – hydrogen (NG/H2) blend peakers than batteries and demand response. Meanwhile, in the reference case where the SCGHG was modeled as an externality cost, PSE saw fewer peakers with the majority being biodiesel, and an increase in batteries and demand response. Ultimately, PSE found that both portfolios meet CETA requirements, and while modeling SCGHG as a dispatch cost resulted in a higher portfolio cost, there was a similar total cost when using the externality methodology.

PSE responded to questions from RPAG members on the SCGHG. Members varied on their opinions about the best approach but generally agreed modeling both approaches was appropriate.

- RPAG member: Is PSE proposing to use the same methodology as the EPR or to change it?
  - PSE response: We are proposing to use the same methodology, but our discussion will be to hear feedback on whether RPAG members think we should change it.
- RPAG member: Do you discuss Climate Commitment Act (CCA) costs?
  - PSE response: CCA costs are included as direct carbon costs in the dispatch costs.
- RPAG member: We previously provided expert testimony on how the fixed cost methodology undervalues clean energy. How has that feedback been addressed?
  - PSE response: The SCGHG is no longer a fixed cost. It is now dynamically changing for the social cost of carbon as plants dispatch. The methodology includes a final model run without the SCGHG to isolate it.
- RPAG member: It would be helpful for RPAG members involved with multiple utilities to understand how PSE's methodology might differ from others. How does PSE's methodology compare to PacifiCorp's methodology?
  - PSE response: We are not familiar with PacifiCorp's methodology. PSE is looking into PacifiCorp's methodology and will follow up at a later date.
- RPAG member: Is the cost of capacity the net cost? Why is the cost of capacity lower if it is running less?
  - PSE response: Capital costs, variable costs, and emissions are all included in the cost of capacity. The change in dispatch reduces the cost of fuel, emissions, and the social cost of carbon.
- RPAG member: Can you provide the calculation for the levelized cost of capacity?
  - PSE response: We will follow up with the formula used for the 2023 Progress Report.
- RPAG member: Order 08 in UE-210795 says "In the 2023 Biennial CEIP Update and future CEIPs, PSE should be required to model the SCGHG in dispatch, and the Company should provide an alternative scenario where SCGHG is modeled as a fixed cost adder. The Commission also found that modeling SCGHG in dispatch resulted in lower portfolio costs in the No-CETA case."
- RPAG member: If PSE is participating in the regional market, I believe that including the social cost of carbon in dispatch costs would violate market rules.
  - PSE response: Thank you for sharing this, we need to double-check regional market regulations.
- RPAG member: How are we defining dispatch? Are we referring to operation dispatch or dispatch being used for long-term planning?
  - PSE response: We are discussing dispatch for long-term planning to forecast what dispatch will look like for twenty years. We use current operations to help us model the forecast.
- RPAG member: How is PSE aligning with the Commission's order from the 2021 Biennial CEIP to model the SCGHG as a dispatch?

    - PSE response: The Commission's order is to look at it both ways to see how the methodology would change the results. In the 2021 CEIP based on the 2021 IRP, the SCGHG was inputted as a fixed cost. Taking feedback into account, PSE now models the SCGHG as dynamically changing. Given the Commission's order, PSE is asking for feedback if they should keep modeling the SCGHG both ways or streamline the process.

Sophie facilitated a discussion on how they should model the SCGHG moving forward. PSE asked RPAG members which methodology they preferred for the 2025 IRP. RPAG members had the option to choose from modeling the SCGHG as an externality cost adder or as a dispatch cost for the long-term capacity expansion.

- RPAG member: My preference is for PSE to continue to model the SCGHG both ways.
- RPAG member: Given that the results point to different peaker options, I would like to continue to see both methodologies.
- RPAG member: We have concerns about adding the SCGHG in dispatch and its impact on actual operations for fossil fuels. Given the order from the Commission, it makes sense to continue modeling with both methodologies.
- RPAG member: We support including the SCGHG as an externality cost adder because adding it as a dispatch cost creates the risk of a portfolio that favors additional peakers and emission-intensive plants.
- RPAG member: How heavy of a lift is it for PSE to continue modeling it with both methodologies?
    - PSE response: Running the additional sensitivity is easy. However, the incremental cost calculations take extra time. Calculating incremental costs for the CEIP would be more time-intensive.
- RPAG member: Modeling operations differently than they happen in real life creates a suboptimal set of resources and is not beneficial. I recommend using SCGHG as an externality rather than a dispatch cost.
- RPAG member: My understanding is that for the long-term capacity expansion, PSE models policies and laws that exist across the West resulting in a dispatch that indicates who can purchase PSE's power. Are there additional limitations to the model other than the SCGHG to reflect the limits of the value of the resources?
    - PSE response: We will follow up with an overview of the modeling process in a future meeting. In the portfolio model, we are not modeling what happens outside the market zone.
- RPAG member: What drives the dispatch of peakers? A deeper explanation of the dispatch model would be helpful.
    - PSE response: We will cover this at a future meeting.

- RPAG member: I could also benefit from a review of how these approaches vary (2021 approach vs 2023 approach vs 2025 proposed approach). Testimony and Order 08 in Docket UE-210795 may be a helpful place to start.

Next steps

- March 19, 2024: feedback report form closes for March. 12, 2024 meeting
- March 25, 2024: RPAG meeting on gas and electric resource alternatives (supply-side) and scenarios and sensitivities

Public comment

The public comments shared during this meeting can be viewed online in the feedback report posted under the March 12, 2024 heading on the PSE website.

RPAG members in attendance[1]

1. Aliza Seelig
2. Ezra Hausman
3. Froylan Sifuentes
4. Joel Nightingale
5. Kate Brouns
6. Katie Chamberlain
7. Lauren McCloy
8. Megan Larkin
9. Rose Monahan

Attendees

10. Bill Westre
11. Brandon Green
12. Chris Goelz
13. Claire Richards
14. Diana Aguilar
15. Don Marsh
16. James Adcock
17. John Robbins
18. Mark Klein
19. Meghan Anderson
20. Pete Stoppani
21. Quinn Weber
22. Rosemary Moore
23. Scott Neumeister

Presenters

1. Joe Hooker, E3
2. Arne Olsson, E3
3. Elizabeth Hossner, PSE
4. Phillip Popoff, PSE

[1] Alphabetical by first name

Other PSE staff

1. Brett Rendina
2. Wendy Gerlitz
3. Kara Durbin
4. Meredith Mathis
5. Jennifer Coulson
6. Stephanie Price
7. Niecie Weatherby

Facilitation staff

1. Emilie Pilchowski
2. Pauline Mogilevsky
3. Sophie Glass
4. Jack Donahue