Integrated Resource Planning

STAKEHOLDER FEEDBACK: February 2023

Received	***Stakeholder***	***Question/Comment/Response***
1/26/2023	OPUC Staff	1. Slide 28: Please elaborate on the "uncertainty" that caused a change in assumption for Colstrip exit from 2025 to 2029.
2/15/2023	PGE Response	We provided this answer to this specific question during the January roundtable: PGE is in active discussion with other Colstrip owners regarding it's 20% share of Units 1 & 2. We previously assumed these discussions would lead to a full exit of Colstrip at the end of 2025. However, due to the ongoing nature of the discussions, and without certainty on the 2025 exit, we find it appropriate to extend the offtake of power through 2029 for IRP planning purposes. We are hoping to have additional clarity on the issue in the not-so-distant future.
	OPUC Staff	2. Slide 29: Please provide for comparison purposes the graph for the Colstrip retirement date of 2025 as was assumed earlier, superimposed on the current graph for both winter and summer.
	PGE Response	The graph below shows capacity need with Colstrip offline at the end of 2029 (February 2023 assumptions – solid lines) and end of 2025 (December 2022 assumptions - dashed). The primary difference in the graphs occurs in years 2026 – 2029.
	OPUC Staff	3. Slide 34: Which optimization assumptions are expected to change before portfolio modeling is finalized?
	PGE Response	We're not sure which changes we'll make between now and finalization. One change we have made is the inclusion of two generic resources; this will be discussed at the February roundtable.
	OPUC Staff	4. Slide 41: Are there both EE and DR resources in the EE/DR category for each portfolio? Do each of these portfolios include only cost-effective EE/DR?

PGE Response	All portfolios on slide 41 include both cost-effective EE and DR. The values shown in purple are non-cost-effective EE and DR – the cost-effective values were not shown.
OPUC Staff	5. Slides 42 and 43: a. Please explain how the semi-deviation of NPVRR metric was calculated. How should it be interpretated in the current context?
PGE Response	Semi-deviation captures the potential variation in cost outcomes across futures, considering only futures in which customer cost impacts exceed the Reference Case (costs below the reference case are not included). It was used as the 'risk' scoring metric in the 2019 IRP and 2019 IRP Update. The formula below shows the calculation. [see saved Word doc for image of formula]. This should be interpreted as the potential negative risk (or higher cost) associated with each portfolio. PGE used the semi-deviation rather than a standard deviation in response to Staff's concerns in the 2019 IRP that the latter would also identify positive risk (lower cost) outcomes. For example, consider two portfolios equivalent in all ways but the second had much lower cost in a low need future. If the portfolio's standard deviation was used as the risk metric, that portfolio would appear to carry more risk and could potentially be less favored relative to the first.
OPUC Staff	b. Could you provide a rate impact estimate for the GHG 1 and GHG 2 portfolios?
PGE Response	To clarify, PGE will not be estimating rate impacts. Extensive discussion took place in UM2225 regarding what data was appropriate to share coming from IRP analysis. As a result, specific requirements were established mandating the inclusion of annual revenue requirements associated with generation assets. We are still developing these estimates, and we are hoping to show them in the February IRP roundtable.
OPUC Staff	6. Slide 53: Why are there no DR resources in the CBRE portfolios?
PGE Response	Cost effective amounts of DR are in the portfolio but not shown in the graph. They are embedded into the need assumptions (taken off the load forecast).
OPUC Staff	7. Slides 56 and 57: a. How did you determine the quantity of additional energy efficiency to be 10MWa? How does 10 MWa compare to the quantity of efficiency that Energy Trust has determined to be technically feasible?

PGE Response	The quantities of additional NCE EE available in portfolio analysis represent only values that the ETO believes to be technically achievable. As mentioned in the roundtable, an error in the calculation of NCE EE quantities was discovered before the roundtable, and that the EE analysis presented was probably correct directionally but would change in the future.
OPUC Staff	b. What resource alternative is used to determine that current costs of additional DR are prohibitively high? What are the current costs of DR that the slide is referring to, and how did PGE estimate these costs? Has PGE ever done a Demand Response RFP to find out what market prices for DR would be?
PGE Response	Following direction from both Staff and the Commission, we included the costs and benefits of NCE EE and DR in our capacity expansion model (ROSE-E) to have these resources compete with other supply-side options. All other resources in portfolio analysis are included in the determination that the NCE quantities of DR are prohibitively expensive. The current DR costs come from the DSP pt. II and were estimated using AdopDER. This model was developed by consultants to PGE, Cadeo and Brattle Group, to develop the cost estimates for DR included in this forecast vintage. The model combines cost data from market research with actual costs from PGE's currently approved DR pilot programs, where appropriate. The costs reflected in our AdopDER forecast include the full range of technology and enablement costs, customer participation incentives, and program administration costs. PGE has fielded RFPs periodically for various components of implementing our DR pilots, ranging from implementation contracts to DERMS and other solution providers. In addition, we negotiate contracts under our MSA with each vendor on an annual basis, and are continually seeking opportunities to reduce costs of securing these resources. Going forward, the DR forecast will be updated with new market data as it becomes available, and if potential DR resources come down in cost, PGE will propose to pursue them through our Multiyear Plan budgeting process.
OPUC Staff	c. Please provide details on the procurement risk and cost pressures that are preventing PGE from selecting the portfolio with additional EE which is better than the No NCE portfolio. Please explain how these factors create enough risk to cancel out the significant NPVRR benefit of the additional EE portfolio.
PGE Response	Information pertinent to this question will be shared at subsequent roundtables and in the 2023 IRP.
OPUC Staff	8. Slide 72:

	a. What metric is used to determine that the new non-emitting resources needed to comply with HB 2021 will fulfill the RPS obligations.
PGE Response	As discussed in the previous roundtables, ROSE-E uses forecasts of load and PGE's REC bank, and future REC generation to ensure that RPS obligations are met. Calculation of the physical RPS obligation requirements does not consider banked RECs. See PGE'S April 14, 2022 roundtable starting on slide 41 (link). Additional information presented about RPS compliance treatment in the IRP was discussed: December 2022 (slide 60); November 2022 (slide 72); June 2021 (slide 16).
OPUC Staff	b. Please provide a timeline to show when these resources will exceed the escalating RPS obligations, which requires 50% of electricity sold to be from renewable energy by 2040.
PGE Response	This question is unclear. If the question is 'when will the Preferred Portfolio have sufficient RPS-eligible resource generating to meet 2040's RPS obligation', then the answer in the Reference Case is 2031.
OPUC Staff	9. Slide 80: Will PGE seek external funding opportunities in order to continue additional transmission studies?
PGE Response	The IRP/CEP team cannot answer that question and/or commit the company either way, though it seems reasonable that the company would want to leverage all resources available to make the best decisions possible.
OPUC Staff	10. Can PGE provide information on resource additions by type, by year for the entire length of the planning period?
PGE Response	We can – this is the Preferred Portfolio's Reference Case: [see saved Word doc to see tables] Note though that the information is an already outdated version of portfolio analysis: We will provide updated information in subsequent roundtable meetings – please let us know if you would prefer to have the January results.
OPUC Staff	11. Sensitivity runs request: a. Colstrip exit in 2025 b. Endogenous selection of EE and DR resources.
PGE Response	Thank you, we will consider running these sensitivities as part of the 2023 IRP.

	OPUC Staff	12. With the purpose of understanding the need for the 300 MW Colstrip power plant from 2026 -2029, please provide: • Forecast daily generation at Colstrip in MWh data from 2026-2029.
	PGE Response	Colstrip runs on economic dispatch and its daily peak is determined by market conditions. In the adequacy model, PGE's share of Colstrip can provide up to 296 MW of power provided it is not on forced outage. In the reference case price future, PGE's 296 MW share of Colstrip generates around 1.94 million MWh per year from 2026-2029, equivalent to around 5,300 MWh per day, or an average annual capacity factor of 75%. These values are subject to change as the IRP is finalized.
	OPUC Staff	• A narrative description of Colstrip's contribution to capacity needs from 2026-2029.
	PGE Response	Colstrip provides up to 296 MW of power in the Sequoia model, which is used for resource adequacy. It reduces resource adequacy needs by roughly this amount.
	OPUC Staff	• Daily peak usage of Colstrip in MW for the last ten years, and
	PGE Response	Historical daily peak values are not currently shareable.
	OPUC Staff	• Daily generation of Colstrip in MWh for the last ten years
	PGE Response	Historical daily generation values are not currently shareable.
1/26/2023	Fred Huette	Is the Centralia unit 2 offline date is included in transmission portfolio analysis?
3/7/2023	PGE Response	We are following up on a question you asked about Centralia unit 2 and whether the offline date is included in transmission data which we use for portfolio analysis. We use BPA posted available transfer capability (ATC) values and the underlying assumptions are not published publicly. We aren't sure if data regarding that unit's closure is included in the assumptions. Thank you for participating in our roundtable process. Let me know if there is anything I can help you with.
		We will share your questions and our answers in the next online stakeholder feedback pdf, posted in March – IRP Team