Oregon Public Utility Commission

March 10, 2025

Docket No. UM 2141: PGE Flexible Load Plan

Staff Response to PGE's Cost-Effectiveness Proposals

Background

Since the 2020 Flexible Load Plan, PGE has highlighted the importance of cost-effectiveness for the flexible load portfolio. Staff appreciates PGE's consistent focus on this topic. In response to PGE's 2024 Multiyear Plan (MYP) Supplemental filing, Staff noted the need for PGE to review its cost-effectiveness methodology and update avoided costs which were based on the 2019 Integrated Resource Plan (IRP).[1] PGE's 2023 IRP clearly identified that demand side resources within PGE's balancing authority deserve a significantly higher avoided cost, which impacts the flexible load portfolio.

In the 2025-2026 MYP, PGE proposed new methodologies for Staff and stakeholder consideration.[2] PGE proposes three substantive changes to cost-effectiveness:

1. Apply available market incentives as a benefit to customers in the total resource cost test,
2. Use energy efficiency avoided cost values from Docket No. UM 1893, and
3. Use a forward-looking assessment for primary cost-benefit analysis.

In this update, Staff discusses PGE's proposals and additional proposed changes for future consideration. Staff then provides observations of its review of PGE's cost-effectiveness workpapers, followed by Staff analysis using different planning assumptions. Finally, Staff concludes with discussion of alternative perspectives that can inform future cost-effectiveness.

These Staff comments are posted to Docket No. UM 2141. Staff decided not to include this discussion in its Staff Report for the February 18, 2025 Public Meeting to maintain the focus on Staff's recommendations regarding MYP approval.

Proposed Changes and Staff Response

<u>Apply Available Market Incentives</u>

PGE proposes recalculating total resource cost (TRC) benefit-cost ratios by reducing customer incremental costs by available incentives in the market, including Energy Trust incentives. The company previously applied this direction to the participant cost test, but not the TRC.

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[1] See Order No. 24-049, *Flexible Load Portfolio Multiyear Plan and Budget for 2025-2026,* Docket No. UM 2141, (Feb. 22, 2024), p. 11, https://apps.puc.state.or.us/orders/2024ords/24-049.pdf.

[2] See Docket No. UM 2141, *PGE's 2025-2026 Flexible Load Multiyear Plan*, (Oct. 18, 2024), https://edocs.puc.state.or.us/efdocs/HAQ/um2141haq332220025.pdf.

Staff supports PGE's inclusion of Energy Trust incentives to TRC calculations, so long as there is clear evidence that PGE is ensuring funding independence and that benefits are not double counted. Staff rationale relies on cost-causation: that Energy Trust incentives may be included when the argument can be made that those would exist independent of PGE's program.

To further align with Energy Trust planning, PGE requested access to the Energy Trust avoided cost tool in UM 1893. Staff supports PGE's access to this tool and provided it to PGE via email in November 2024. As Energy Trust and PGE conduct more sophisticated co-deployment of energy efficiency and flexible load resources, Staff sees value in use of the same tool to ensure benefits are not double counted.

<u>Use Energy Efficiency Avoided Cost Values from UM 1893</u>
Staff supports the use of Commission-approved values from UM 1893 in PGE's flexible load pilots and programs. In fact, Staff made the same recommendation in 2020, when PGE issued the initial Flexible Load Plan, and again in review of the 2024 MYP Supplemental.[3] Staff discusses some of the individual data decisions below.

1. *Conservation/Community Benefit Indicator Credit*

Staff supports PGE's use of a 10 percent credit for flexible load resources, but not based on the 1980 Northwest Power Act, which intentionally preferences conservation resources over non-conservation resources with the 10 percent credit. The Northwest Power and Conservation Council applies this credit to the benefits of energy efficiency measures, but not to demand response valuation, on the basis that demand response does not meet the definition of conservation.

In arguing for the application of this credit, PGE applies a broader perspective of the value of demand side management. Staff agrees that the benefits of demand-side activities can be hard to quantify and appreciates PGE's alignment with planning in other dockets including the 2023 IRP's use of a 10 percent credit to reflect Community Benefits Indicators (CBIs). For now, Staff supports the use of a 10 percent adder for flexible loads, but expects future, more granular CBI valuation. Staff's expectation is that CBI valuation may exceed the 10 percent credit.

2. *Avoided Capacity Cost*

Staff finds that a more reasonable avoided capacity cost is justified versus PGE's current UM 1893 value and thus the value used for flexible load planning. PGE's 2025-2026 MYP analysis used an avoided capacity cost of $175/kW-yr, which is a value that PGE submitted in UM 1893 in April 2024. PGE also submitted a value of $228/kW-yr in

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[3] See Docket No. UM 2141, *PGE Flexible Load Plan*, (December 24, 2020), p. 103, https://edocs.puc.state.or.us/efdocs/HAS/um2141has132229.pdf.

March 2024, and the Commission adopted the higher value on the basis that it represented a four-hour battery's declining effective load carrying capacity (ELCC) over the IRP planning horizon.[4]

In November 2024, PGE proposed a new, lower avoided capacity cost of $146/kW-yr in Phase 2 of UM 1893. Staff raises two primary concerns about PGE's avoided capacity cost. First, the use of a four-hour battery as the marginal capacity resource in each year of the planning horizon omits years in which the IRP selects more expensive capacity. Second, Staff finds that the fixed cost assumptions are materially different than more recent cost data.

PGE's preferred portfolio, documented in a September 2023 response to Staff comments, selects a generic capacity resource starting in 2035.[5] PGE provided Staff with fixed cost assumptions for that generic capacity resource by year, which are 121 percent more expensive than PGE's submitted four-hour battery values for 2035-2043. Staff finds that the avoided capacity cost should reflect the preferred portfolio's selection of more expensive capacity resources.

Staff's second concern is related to fixed cost assumptions. PGE's 2023 IRP relies on the 2020 National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB). PGE reports this fixed cost value as $129/kW-yr in the 2023 IRP, which is then decremented by a $34/kW-yr tax credit.[6] Via a response to an information request, Staff has access to more recent four-hour storage pricing.[7]

Staff has reason to believe that with inflation and higher interest rates, fixed prices have increased. Staff believes that the most recent and accurate source of fixed cost assumptions to be bid data from Docket No. UM 2274, PGE's 2023 all-source request for proposals (RFP). Due to the highly confidential nature of those data, Staff was unable to use them for analysis in this docket, UM 2141.

Without access to the most current RFP bid data, Staff turned to reputable public data from Lazard regarding the levelized cost of a utility four-hour battery. Staff then calculated a 20-year levelized net cost of capacity based on a Lazard fixed cost assumption of $214/kW-yr for 2026-2034, and the PGE supplied values for generic

[4] See Order No. 24-119, Docket No. UM 1893, (May 2, 2024), https://apps.puc.state.or.us/orders/2024ords/24-119.pdf.
[5] See Docket No. LC 80, *Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan Reply to Round 1 Comments*, (September 6, 2023), p. 75, https://edocs.puc.state.or.us/efdocs/HAC/lc80hac131341.pdf.
[6] See Docket No. LC 80, *PGE's 2023 Integrated Resource Plan and Clean Energy Plan*, (March 31, 2023), https://edocs.puc.state.or.us/efdocs/HAA/lc80haa8431.pdf.
[7] PGE Response to PUC Data Request 010.

capacity costs covering 2035-2043.[8] All values are in 2024 dollars and includes PGE's net cost adjustments for energy, flexibility, and ELCC from the 2023 IRP.

The result of Staff's analysis is a 20-year levelized net avoided cost of capacity of $353/kW-yr, with Table 1 demonstrating the detail of annual avoided capacity costs. Staff uses this value in cost-effectiveness sensitivity analysis to understand the flexible load portfolio's value. Staff views the Company's avoided capacity cost as the most important value for determining whether PGE is making prudent investments in the flexible load portfolio.

Table 1: Staff's proposed avoided net cost of capacity (2024$)

Year	Resource	Fixed Cost	ELCC	Net Cost
2026	4-Hour Battery	$214	43%	$452
2027	4-Hour Battery	$214	46%	$426
2028	4-Hour Battery	$214	48%	$402
2029	4-Hour Battery	$214	51%	$381
2030	4-Hour Battery	$214	54%	$362
2031	4-Hour Battery	$214	56%	$345
2032	4-Hour Battery	$214	58%	$337
2033	4-Hour Battery	$214	59%	$329
2034	4-Hour Battery	$214	60%	$322
2035	Generic Capacity Resource	$366	100%	$383
2036	Generic Capacity Resource	$365	100%	$382
2037	Generic Capacity Resource	$364	100%	$381
2038	Generic Capacity Resource	$363	100%	$380
2039	Generic Capacity Resource	$362	100%	$379
2040	Generic Capacity Resource	$361	100%	$378
2041	Generic Capacity Resource	$361	100%	$378
2042	Generic Capacity Resource	$360	100%	$377
2043	Generic Capacity Resource	$359	100%	$376

3. Transmission and Distribution Deferral Credits and Risk Reduction Value

Staff supports PGE's application of the transmission and distribution deferral credits and the risk reduction value from UM 1893. Inclusion of transmission and distribution deferral credits are in line with demand response practice in other venues such as the Northwest Power and Conservation Council and the National Standard Practice Manual for Distributed Energy Resources. Staff notes, however, that PGE reduced these

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[8] Lazard, *Levelized Cost of Storage Comparison—Version 9.0,* (June 2024), https://www.lazard.com/media/xemfey0k/lazards-lcoeplus-june-2024-_vf.pdf.

deferral credits by 62 percent with its recent November 2024 UM 1893 filing. As PGE noted, Staff is interested in PGE's exposure to market prices, such as the extreme values experienced during the August 2023 heat wave. A risk reduction value can help price this risk into avoided costs.

4. *Transmission Expansion Credit*

On January 21, 2025, the Commission approved new avoided costs in UM 1893.[9] PGE's avoided energy costs increased substantially, in large part, due to the influence of a new transmission expansion credit. Flexible load resource value is typically driven by capacity, but there is energy value where flexible load events result in a decrease in energy consumption. With new avoided energy costs, flexible load assets should have marginally more value, particularly those with energy efficiency and load shifting qualities to move use out of expensive hours.

The larger impact, which was not fully addressed in this recent cycle of UM 1893, is that transmission expansion delivers two primary benefits: access to energy and to capacity. PGE's November 2024 UM 1893 submission did not place any value on the capacity component of transmission expansion, though it is likely warranted. Staff is open to future analysis which includes both energy and capacity components.

Use a Forward-looking Assessment for Primary Benefit-cost Analysis

Staff supports the use of a forward-looking assessment for the primary display of flexible load benefit-cost ratios. Currently, PGE provides lifetime benefit-cost ratios, such that startup costs are indefinitely included. Staff continues to find value in this perspective and requests PGE report it in future MYP cycles. However, for the purpose of future decision-making, Staff sees the most value in forward-looking benefit-cost ratios, as startup costs are sunk and forward-looking cost-effectiveness reveals whether the flexible load asset is least cost. PGE expects the average program participation to be ten years, and Staff found several instances in workpapers where the duration of benefits and costs did not match. Staff recommends the Company review those calculations in future analysis.

Other Cost-effectiveness Changes

Staff offers the following responses to other changes proposed by PGE:

1. **Move administrative costs to portfolio level**: Staff can support this, but requests additional conversation around the needs and benefits. Including costs at the measure level increases the transparency that might spur cost savings.

[9] See Order No. 25-017, *Request for approval of energy efficiency avoided cost data to be used by Energy Trust,* Docket No. UM 1893, (Jan. 21, 2025), https://apps.puc.state.or.us/orders/2025ords/25-017.pdf.

Only administrative costs that cannot be allocated by measure should be assessed at the portfolio level.

2. **Add a marginal one-year, forward-looking perspective**: Staff supports exploring this additional perspective, but not replacing the other perspectives.
3. **Quantify load's mitigation of market insufficiency**: Staff interprets this to be an effort to validate the assumptions of avoided capacity costs. Staff supports comparing how demand response is modeled to how it is dispatched.
4. **Determine locational value**: Staff supports exploring nodal avoided cost of the distribution system as separate avoided costs from the generation system.
5. **Determine Western Resource Adequacy program obligations**: Staff supports exploring the monetary value of this credit.

Staff Review of PGE's Cost-effectiveness Workpapers

In this section, Staff details observations from review of PGE's cost-effectiveness workpapers, and suggests remedies:

1. **Treatment of costs in base rates and deferrals:** PGE began including flexible load portfolio labor costs in base rates starting with Docket No. UE 394. However, PGE's workpapers exclude flexible load plan related base rate costs and the rate of return from deferring operations and maintenance costs from MYP cost-effectiveness tests. Further, PGE's workpapers exclude the carrying cost of flexible load pilot and program deferral funding from cost-effectiveness tests. PGE's flexible load activities are funded via three separate deferrals, UM 2234, UM 1827, and UM 1514. Utilities earn interest on deferral spending, which increases the ratepayer cost of program operations. Staff recommends inclusion of these costs in flexible load portfolio cost-effectiveness testing.
2. **Value of lost service**: Since the 2020 Flexible Load Plan, Staff has recommended against PGE's use of an assumed value of lost service until PGE has the data to establish such a penalty.[10] This was not a categorical rejection of this component but rather a call for a more empirical basis. PGE's program evaluations should study this impact, because its absence may not be supported.
3. **Environmental benefit**: As discussed in the 2020 flexible load plan, PGE includes an environmental benefit in the TRC for flexible load resources. This inclusion can be traced to the California PUC's 2016 Demand Response Cost Effectiveness Protocols.[11] In the CPUC's guidance, societal benefits can be included as a benefit in the TRC. Inclusion of societal benefits turns the TRC

[10] PGE's 2020 Flexible Load Plan, p. 103.

[11] California Public Utilities Commission, *2016 Demand Response Cost-Effectiveness Protocols*, (July 2016), https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-cost-effectiveness.

into a societal cost test. Staff is not opposed to the inclusion of negative externalities such as carbon emissions in cost-effectiveness testing, but this perspective should be uniform across demand side resources, and thus be applied to energy efficiency and perhaps other non-utility resources. Staff notes that stakeholders advocated for the use of the societal cost test in the recent Phase 2 of UM 1893. PGE's flexible load resources have minimal energy savings and thus the environmental benefit is small. Staff supports the use of an environmental benefit, should it also apply to other non-utility, non-emitting resources.

4. **Flexible load pilot and program ELCC values:** Staff finds that PGE's flexible load ELCC values appear high. ELCC of these measures was not derived from Sequoia modeling used in PGE's 2023 IRP. Instead ELCC values date back to the 2019 RECAP model used in for Docket No. LC 73. Staff questions how a flexible load resource ELCC that is used less than five times a year has a higher ELCC than batteries that are dispatched daily.

Staff Cost-effectiveness Results

Staff conducted additional cost-effectiveness sensitivity analysis. Table 2 compares PGE's Utility Cost Test (UCT) ratios with three Staff sensitivities. Staff elected to do UCT analysis instead of TRC, because for flexible load pilots and programs the UCT tends to be lower than the TRC. Table 4 contains the following adjustments:

- **Capacity:** Staff used an avoided capacity cost of $353/kW-yr instead of PGE's $175/kW-yr. This reflects application of more recent fixed costs for a four-hour battery and PGE's preferred portfolio selection of generic capacity starting in 2035.
- **Cost:** Staff added in pilot and program costs that PGE omitted from its cost-effectiveness analysis. These include staffing, operations and maintenance, and deferral carrying costs which are not currently included.
- **ELCC:** Staff used PGE's four-hour battery ELCC assumptions from the 2023 IRP as the 2023 IRP analysis did not use Sequoia modeling to derive flexible load resource ELCCs.

The results in Table 2 should be read as cumulative from left to right. In other words, the Cost column reflects PGE's values adjusted for a higher avoided capacity cost *and* adjusted with the inclusion of previously omitted costs. The ELCC column reflects all three adjustments and represents the final proposed values which Staff bases its recommendations.

Table 2: Staff Cost-effectiveness Results

Pilot or Program	PGE	Capacity	Cost	ELCC
Residential Smart Thermostat	2.61	3.70	3.48	2.89
Peak Time Rebates	0.98	1.20	1.10	1.10
Time of Day	5.24	6.51	4.97	4.97
Energy Partner on Demand	2.04	3.09	2.88	2.26
Multifamily Water Heater	0.61	0.88	0.84	0.59
Energy Partner Smart Thermostat	0.51	0.73	0.72	0.59

Of Staff's three recommended changes, the increase to capacity cost drives UCT ratios higher, while including excluded costs and making ELCC adjustments drives UCTs down. In aggregate the portfolio-level score remains positive. Staff shares this analysis to validate its 2025-2026 MYP recommendations.

Alternative Perspectives on Flexible Load Cost-Effectiveness
Traditional cost-effectiveness testing is one lens to understand flexible load resource value. These tests have historical precedent, but new techniques should supplement as PGE transitions to use of its flexible load assets within a virtual power plant (VPP).

First, IRP modeling should provide insight into flexible load cost-effectiveness. Endogenous selection of flexible load resources using capacity expansion software that identifies a preferred portfolio would send a clear signal that those resources compete on cost, availability, and performance against other resource options. Staff has concerns that current IRP analysis does not provide a signal for flexible load resources.

In current practice, deployment of cost-effective flexible load is determined using the Distribution System Plan's (DSP) AdopDER model. While AdopDER has sophistication around market adoption expectations, it relies on cost-effectiveness tests such as the TRC and UCT. PGE's flexible load pilots and programs do not compete against supply side options in IRP modeling. PGE's 2023 IRP included the DSP commitment of 211 MW of summer flexible load by 2028 as a reduction in capacity need.[12] By contrast, PGE did compete higher cost flexible load as a supply side option, but the model did not select any due to the high costs of the available options.[13]

Second, review of economic dispatch can validate avoided cost assumptions. This perspective of actual resource use can help confirm IRP analysis and traditional cost-effectiveness testing. Staff is concerned that the current integration of PGE's flexible load portfolio with its Power Operations group only resulted in two events in 2024. Other

[12] See Docket No. LC 80, *PGE's 2023 Clean Energy Plan and Integrated Resource Plan*, (March 31, 2023), p. 275, https://edocs.puc.state.or.us/efdocs/HAA/lc80haa8431.pdf.
[13] See PGE's 2023 IRP, p. 394.

events were called over the course of the year, but the origin was not a request from Power Operations. Staff will increasingly focus on PGE's integration of flexible loads with Power Operations to confirm the assets' use meets planning assumptions.

Review of flexible load operations is a key component of understanding value of the VPP. There are discrete values for resources used infrequently for emergency load shed versus those used more regularly for load shifting, frequency response, or contingency reserves. In the DSP, PGE endeavored to value the benefit of avoiding a loss of load event, which can be an additional perspective for valuing flexible load resources. This requires consideration of power costs and what resources PGE currently relies on to meet frequency deviations and to meet contingency reserve obligations.

Conclusion
Staff appreciates PGE's proposals to revise flexible load cost-effectiveness and to align with Energy Trust and UM 1893 energy efficiency avoided costs. Staff recommends adoption of the proposed changes as outlined in the above comments and agrees with PGE that such practices should better inform other avoided cost venues. These include non-wire solutions, community based renewable energy, and small-scale renewables. Staff looks forward to continuing the cost-effectiveness dialogue with PGE as the flexible load portfolio grows in sophistication to offer locational value and be increasingly used in market participation.

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